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The Future of the European Electricity System and the Impact of Fluctuating Renewable Energy – a Scenario Analysis

by

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Abstract

The ongoing transformation of the European energy system comes along with new challenges, notably increasing amounts of power generation from intermittent sources like wind and solar. How current objectives for emission reduction can be reached in the future and what the future power system will look like is, however, not fully clear. In particular, power plant investments in the long run and power plant dispatch in the short run are subject to considerable uncertainty. Therefore an approach is presented which allows electricity market development to be assessed in the presence of stochastic power feed-in and endogenous investments in power plants and renewable energies. To illustrate the range of possible future developments, five scenarios for the European electricity system up to 2050 are investigated. Both generation investments and dispatch as well as utilization of transmission lines are optimized for these scenarios and additional sensitivity analyses are carried out.

Keywords: integration of renewable energies,stochastic optimization,scenario analysis

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1. INTRODUCTION

In 1992, the United Nations Framework Convention on Climate Change defined the objective of stabilizing greenhouse emissions on an adequate level. Based on this, the European Union derived a temperature target to limit global temperature increase to 2°C or below (1939th EU Council meeting, 1996). Later, this target was adopted on a global level (UN, 2010). According to the IPCC (2007), this means a reduction of CO_2-equivalent emissions of between 50% and 80%. Especially the electricity sector has large potential for emission reduction, with scenarios of up to 100% electricity production from renewable energies (see ECF, 2011). Many of these concepts give the impression that target scenarios are developed neglecting any potential risk and imponderables along the envisaged way (see Laughton, 2007). But often the triangle of energy policy targets, consisting of security of supply, sustainability and economic efficiency, is not balanced. For example, de Jager et al. (2011) and Ragwitz et al. (2011) estimate that current investments have to double just to reach the 20% renewable energy production target of the European Union until 2020 (Directive 2009/28/EC). In the context of the global economic crisis and high national debts, these targets are ambitious and might be revised in the future in favor of economic growth.

In general, governments and societies may choose among four groups of approaches to reduce CO_2 emissions (Knopf et al., 2010) and fulfill the aforementioned targets. A first option is to focus on putting a price on greenhouse gas emissions. This can be done by taxes or via an emission trading system as applied in the European Union since 2005 (covering approximately 40% of Europeans emissions). Such an approach internalizes externalities for emissions, as Pigou (1920) has already shown, in principle. Difficulties occur when trying to determine a suitable price (or quantity) level.

A second approach is to foster technological progress to reduce emissions. This can be done via subsidies or tax reductions. In nearly all the countries of Europe, governments heavily support renewable energy sources (RES). Already at the end of 2011, there was wind power capacity of about 94 GW and solar capacity of about 50 GW (EWEA, 2011). In 2011 alone, European solar capacity increased by 20 GW. Italy (9 GW) and Germany (7.5 GW) were the main drivers of this growth due to high incentives. In the past also Spain saw high investments, but with a cut in subsidies market growth was reduced (EPIA, 2011). It is expected that PV will soon reach grid parity compared with household prices in many European countries due to learning curve effects if this has not yet happened, as in Italy and in Germany. Actually, governments prefer direct interventions instead of setting the required framework. This is especially true for the feed-in of fluctuating energy sources like wind and solar energy. Different support instruments can be found all over Europe (Klessmann et al., 2011; Kitzing et al., 2012).

A third approach is "command and control". This means that policy makers or regulators define a technology's specific upper limit for emissions. Of course, this only works when an appropriate compliance system is implemented. Upper limits for CO_2 emission of new vehicles are one example.

Life style changes are a fourth approach to reach the target. This means on the one hand the reduction of energy demand and on the other hand an increase of public acceptance of changes that come along with new technologies.

Especially the latter aspect indicates that the different approaches should not be handled separately. Rather, governments will probably apply a bundle of measures from all four groups to reach the objectives – yet the question is to what extent they will follow the three paths of the triangle of policy targets.

Setting different foci in the triangle of policy targets is analyzed in this paper and impacts on the development of the European power system are shown. Besides the description of target visions, also different paths to reach the final target are compared. Therefore the instruments described above are used to different extents.

Nevertheless, grid operators have to integrate the huge capacity of RES into the system. Notably technologies with intermittent production make system planning more difficult, because their capacity credit is limited compared with conventional generation and their stochastic behavior has an impact on both the dispatch of plants and also the long term investment planning in power systems (i.a. Möst and Fichtner, 2010; Swider and Weber, 2007; Tuohy et al., 2009). But this is not only a European problem. MacGill (2010) presents approaches to how to integrate fluctuating wind energy in the Australian power system where a renewable energy target has existed since 2001. Liu et al. (2010) have shown the limitations of the Chinese power system to integrate more than about 25% of wind energy and how this will affect grid stability. Baldick (2012) analyzes the integration of wind energy in Texas. He balances the effect of wind energy against carbon dioxide emissions and the related costs of wind extensions.

Especially the infeeds of PV and wind decrease the current price level and conventional power plants may be put out of business. On the other side, controllable power plant capacity is needed to provide system services and to cover demand when fluctuating renewable energies are not available. Hence, a suitable model framework is necessary which can handle all these influencing factors.

In order to consider the impact of renewable energy fluctuation, it is not sufficient to use deterministic planning tools as they were established previously, because these do not properly consider volatile generation (i.a. Tuohy et al., 2009). Several models have been developed to determine unit commitment and dispatch, taking into account the stochastic behavior of wind generators (i.a. Pappala et al., 2009; Ruiz et al., 2009; Garcia-Gonzalez et al., 2008), but these models are not designed for assessing long-term developments with endogenous investments, nor do they include the fluctuating behavior of other intermittent technologies like photovoltaic in particular. Thus, Nagl et al. (2012) present a stochastic linear system modeling approach for Europe in which they consider the uncertainty of having a year with high or low infeeds from wind and solar. But they neglect the uncertainty of the respective hourly dispatch decision by having a perfect forecast within one scenario branch (year). Notably Swider and Weber (2007) present such an approach including short-term uncertainties in the long-term investment decisions. There they use recombining trees to cover short-term uncertainties in wind infeeds and hydro inflows.

In the paper at hand, we combine the modeling of uncertainties in power plant dispatch and the inclusion of endogenous investments in renewable energies. Hence, we present a stochastic power system market model that takes the intermittent characteristics of wind and solar into account and is capable of modeling the whole European power market in order to evaluate future power system developments. We use the model to assess the influence of intermittent production of renewable energies on future power markets based on several scenarios. The scenarios reflect different overall objectives and a subsequent choice of instruments among those defined above in order to reach the general objectives.

The remainder of this article is organized as follows: first the applied model and enhanced methodology to consider stochastic inputs are described in section 2. The investigated electricity system and scenarios are reviewed in section 3. In section 4 we present model results and discuss their implications. The article ends with brief conclusions on the achieved results.

2. FORMULATION OF THE MODEL

We use a stochastic model of the European electricity market in order to assess the impact of additional fluctuating RES. The first part of this section includes the general principles of the model, followed by the modeling of the renewable stochastics. Subsequently, the introduction of cost resource curves for additional renewables is described and finally the treatment of reserves and capacity requirements. Especially the last two aspects, as well as the stochasticity of solar power, extend the basic model of Swider and Weber (2007).

2.1 European Electricity Market Model E2M2s

The applied stochastic European electricity market model (E2M2s) starts from the well-established result that a functioning competitive market will lead to the same results as system optimization by an omniscient central planner. The market is assumed to manage and coordinate supply and demand optimally like an invisible hand. Then markets are expected to maximize social welfare at least in the short run. As a result, cost-efficient power plants cover electricity and heat demand. With inelastic demand in the short run it is possible to use a cost minimizing optimization approach. Costs include capital cost payments and other fixed annual costs, variable costs which are differentiated in fuel costs, costs for emission allowances and other variable costs, as well as start-up costs. In the end, prices and payments for produced energy and system services can be derived from the shadow prices of the different side constraints. The model is implemented in the General Algebraic Modeling System (GAMS), where we use CPLEX as solver. The model equations of the basic model are described in detail in Swider and Weber (2007).

The model is formulated as a linear, stochastic program that encompasses different time steps (typical days and typical hours), different regions and all relevant actors. A single optimization comprises a whole year in order to capture seasonal effects on production like temperature-dependent heat and electricity demand, as well as the management of large-scale hydro reservoirs. The year is divided into four seasons representing winter, spring, summer and autumn. A typical working day and a typical non-working day represent each season to reduce computational time. These weekdays are again divided into seven time segments in order to represent temporary fluctuations in demand and in production of RES. The first time-step has six hours and the second one has five hours. The third time-segment comprises the peak hour at noon. After the peak hour the remaining twelve hours are divided into four segments of equal length. Higher volatility of demand as well as solar infeeds are the reason for shorter time periods during the day, while lower fluctuation allows longer time periods during the night and the morning hours. Altogether there are eight typical days with seven typical hours each. A stochastic approach allows nearly the whole range of possible infeeds from renewable energies to be covered despite using typical time segments (see Spiecker et al., 2013 and further description below). This approach allows scheduling decisions for thermal power plants to be modeled, including start-ups and operations at part load.

Currently, there are about 100 power plant classes implemented in the model. They differ in the primary energy used, vintage class and technology type. Efficiencies depend on these factors and for various technology types like steam turbine, gas turbine, combined-cycle plant and different kinds of CHP plants further technical restrictions are included. Availability is also related to the technology type and depends additionally on the time of the year. In addition, we model the operation of CHP plants in detail. This means that we consider electricity load profiles for regions and heat load profiles for subordinated sub-regions. One region may have several sub-regions. Power plants in the respective region optimize their operation against these curves. Power plants can only deliver heat in their respective sub-region, while they can all cover electricity demand in the higher level electricity region.

The model determines endogenously the optimal power plant operation and transmission line loading restricted by net transmission capacity (NTC), but also investments in new generation capacity. Investment in new power plants and CHP units are decided endogenously in the model, taking into account restrictions like nuclear phase-out or limited lignite potential. But within these limits investments in new capacity to replace older plant depend only on costs. Notably, new CHP plants are therefore built as long as heat can be sold and the costs of those CHP plants are less than the opportunity costs of electricity and heat. This leads to investment decisions in line with the Peak Load Pricing approach, as developed, for example, by Boiteux (1960), with the yearly full load hours being a key driver for technology selection. Thereby myopic expectations are assumed for the decision makers and the decision problems for different years are solved in a dynamic recursive sequence.

Prices are derived from shadow prices of the demand restriction in the optimization model and therefore relevant costs are the main driver. In analyzing shadow prices, it is necessary to consider that if a technology is not working to full capacity, the additional costs for one further demand unit are the variable costs. When they reach the capacity limit, the additional costs include a shadow price for capacity. Summing up over the year, these shadow prices ensure that the existing facilities used earn not only their variable costs but also their fixed operational costs.

2.2 RES stochastics

The representation of stochastics in long-term system modeling is of importance when increasing amounts of renewable energy are to be integrated. With the inclusion of uncontrollable infeeds, system operators have to cope with the risk of rapid drops or increases of renewable energy generation. Stochastic infeeds require sufficient system flexibility, but deterministic planning tools do not fully reflect the benefits of such generation flexibility. Available generation capacities may then provide too little flexibility for dealing with intermittent generation and cannot guarantee system security. Therefore, a stochastic model chooses not only the most cost-efficient dispatch, but also a dispatch that is capable of handling potential large changes of renewable energy feed-in at least cost.

In the model used, a recombining tree approach accounts for the intermittency of wind and solar infeeds and also helps to overcome the limitations of typical time segments. We consider not only one operation mode of the system for each of the 56 time segments, but different alternative modes depending on the stochastic states of actual RES generation. Therefore typical time segments are aggregated to four stages *s* per typical day with a length of six hours. Each stage is connected to typical time segments. The first time segment is linked to the first stage, the second and third time segments are linked to the second stage and so on. For each stage, three branches (nodes) are possible – namely high, mid and low infeeds of RES.

Recombining the nodes at each stage (see Figure 1) avoids exponential growth in the number of nodes. This requires approximations in the state variables. But Küchler and Vigerske (2007) have shown that a largely similar approach provides a consistent approximation to the full stochastic model. In addition, Spiecker et al. (2013) have shown that realized and approximated infeeds are consistent.

Cluster analysis is used to derive the probabilities of the nodes and the corresponding transition probabilities between the nodes from historical wind and solar production. First, the single time segments of the historical time series for the different regions are connected to the aforementioned stages. For each stage, three stochastic states or nodes *n* are then determined by means of cluster analysis (see MacQueen, 1967).

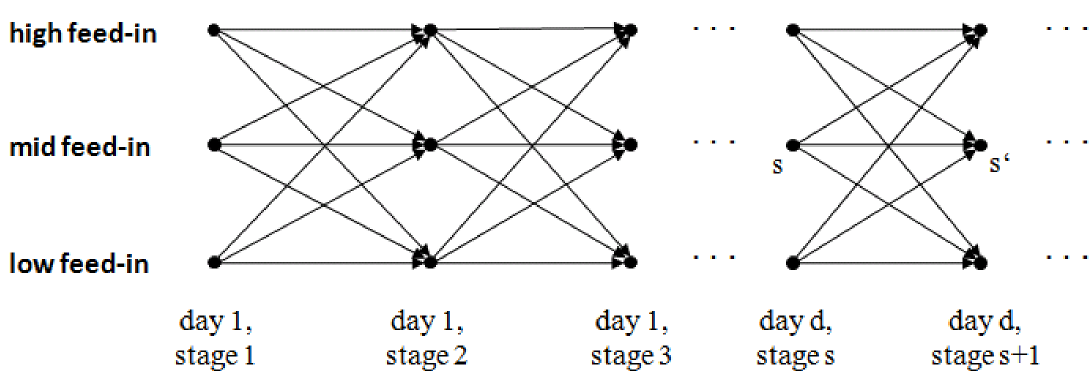

Figure 1: Application of recombining decision tree

The time segments associated with each node (cluster) are counted and this number is compared with the total number of time segments at this stage. This gives the probability $\psi_{s,n}$ of the different nodes at one stage. The transition probabilities $\tau_{s\rightarrow s+1,n\rightarrow n'}$ describe the likeliness of transition paths. Considering typical days, the transition probabilities at the end of each day take into account the possibility of switching to a day of the same type, as well as the possibility of a shift from weekday to weekend or vice versa. Again, this probability is derived from counting the number of historical observations and setting it in relation to the total relevant time segments.

Finally, we get the wind and solar availability in each node *n* of each time segment from the mean of the availabilities during the historical time segments associated with the node.

2.3 Cost resource curves

The stochastic behavior is of primal importance when it comes to investment decisions in RES. Besides regional analyses (e.g. investment in wind power plant in the United Kingdom; see Neuhoff, 2008), also European-wide analyses for the extension of renewable energies exist. Heide et al. (2010) focus on the optimal portfolio of wind, solar and storage facilities with only minor proportions of conventional power plants. But they neglect system constraints by using an econometric approach. These are considered in ECF (2010) as well as EWI and Energynautics (2011), but they too fail to consider the uncertainty of dispatch decisions.

It is necessary to consider available resources and related costs to develop these resources in order to model investment in renewable energies endogenously. Hoogwijk et al. (2004) describe the methodology for their assessment; the potential for Europe can be found, for example, in the Green-X project (2002-2004). Based on Green-X, several projects (e.g. Biomass Futures 2012) and policy studies have focused on different national support schemes (e.g. Huber, Faber, Resch, 2006). But again system constraints are only roughly approximated and the fluctuations of renewables are barely considered.

Therefore we extend the model described in the previous sections by implementing cost-resource curves. Opportunities and potential for further market-driven investments still remain, depending on the extent of policy-driven investment in renewable energies. In this paper we focus on resources for wind (onshore and offshore), solar and biomass. For these energy sources, a bottom-up approach is chosen.

Biomass, as the most flexible renewable power source, has no specific operating restrictions and may even supply operating reserve. On the other hand, natural conditions restrict PV and wind and they are subject to fluctuations. This characteristic has also an impact on the resource usage. Biomass fuel is storable and mainly limited by the amount of plants and waste. Therefore we define the available resource $R_{r,g}^{bio}$ in each region *r* and fuel group *g* for the total input volume, taking into account the conversion efficiency.

$$R_{r,g}^{bio} \geq \sum_{u \in g,t,n} \psi_{n,s(t)} d_t f_t \left(\frac{1}{\eta_u^m} \left(P_{r,u,t,n} - l_u L_{r,u,t,n}^{onl} \right) + \frac{1}{\eta_u^0} l_u L_{r,u,t,n}^{onl} \right) \tag{1}$$

In this formulation using a weighted average of (the inverses of) minimum efficiency η_u^0 and marginal efficiency η_u^m of unit *u* considers the operation of plants at part load. The weighting factors are the minimum stable load, obtained as a product of capacity online $L_{r,u,t,n}^{onl}$ and minimum capacity factor l_u, and the excess production $P_{r,u,t,n} - l_u L_{r,u,t,n}^{onl}$ that goes beyond the minimum production of a power plant. Finally, the input in each node n and time step t is weighted with its duration d_t and frequency f_t as well as the probability of occurrence $\psi_{n,s(t)}$.

Further restrictions apply if biomass-fired power plants are operated in heat grids. Depending on technical restrictions, their ability to produce electricity is related to their heat production in a heat-driven application.

In contrast, the constructible surface rather than maximum yearly production mainly restricts the resources of wind and solar. Thus, total wind capacity $L_{r,u,t}$ should not exceed the potential $R_{r,g}^{wind}$, which can be derived from the frequently provided data on yearly potential by considering the (location-dependent) capacity factor.

$$R_{r,g}^{wind} \geq \sum_{u \in g} L_{r,u,t} \tag{2}$$

2.4 Reserve markets and capacities

Reserve capacities assure system stability. They are used to handle unforeseen events, i.e. deviations between expectations and realizations. In general, there are three main reasons for these deviations – power plant outages, load forecast deviations and renewable forecast deviations. Especially with an increase of renewable energies, reserve requirements are increasing, although the opposite has been observed in Germany in recent years. Forecast improvements and efficiency gains in the reserve handling caused this development, yet in the future no continued decrease may be expected (Weber, 2010).

In Europe, different designs of reserve markets are established in different control zones. In the model we only distinguish spinning and non-spinning reserve (see Swider, Weber, 2007). In addition, a long-run capacity restriction has now been implemented to ensure that the cumulated secured capacity $L_{r,u}$ is higher than maximum demand $D_r^{\max}$ in each control zone. Thereby hourly data instead of averaged data in typical time segments is used to determine sufficient reserves. Only power plants which are not weather-dependent can offer secured capacities. These power plants are especially conventional power plants and biomass power plants. The consideration of hydro power plants depends on the current storage level. In addition, we consider the availability of power plants as well as a security adjustment.

$$\sum_{u \in g} L_{r,u} \geq D_r^{\max} \tag{3}$$

In the current energy-only market design in Europe, power plants earn money on the electricity and heat market as well as on reserve markets. With decreasing prices on the spot market, power plants might be out of the money and pushed out of the market. On the other side, prices for reserve capacity might increase but, with only short-term tenders compared with the lifetime of a power plant, such an investment bears high risks. Thus sufficient incentives for adequate long-term capacity provision are needed to guarantee system stability. In the present model this is implemented through the above-mentioned, capacity-market like condition. The shadow price of this side constraint reflects the price on the capacity market. If this price is zero, the introduction of capacity markets is not needed.

3. ANALYZED SCENARIOS

We use the model to analyze different energy scenarios in Europe in general and in Germany in particular. These scenarios set the focus on different aspects and possible developments which have been discussed in the first chapter. Since renewable energy integration and the electricity market itself is a European-wide phenomenon, a European perspective in the analysis is essential. Therefore the following case study encompasses almost the whole of Europe, although the focus is on Germany. The other countries are considered as one single region (or electrical node) in the model. Only Germany is split into seven regions to consider bottlenecks and analyze local congestions within the country. Denmark consists of two regions since there are two different synchronous areas. The German splitting is in line with the different control zones within the country. A further splitting considers possible bottlenecks within a control zone caused by a weak grid system.

3.1 Scenario description

Besides short-term uncertainty due to stochastic renewable energy infeeds, long-term uncertainty has to be taken into account. This is done here via scenario analysis, with the scenarios describing different policy priorities inside Europe based on the discussions from the first chapter. Thereby the earlier introduced “magical triangle” of energy policy targets, encompassing sustainability, economic efficiency and security of supply, is taken as the starting point.

Table 1: Scenario overview

	Conflict	Climate - Policy	Climate - Market	Efficiency	Secure Growth
Demand	mid	low	low	mid	high
Politically driven RES development	mid	high	high	mid	low
Fuel prices	mid	high	high	high	low
CO_2-reduction compared with 1990	60%	95%	95%	80%	30%
Acceptance of nuclear power	low	low	low	high	high
RES policy change [year]	2030	(-)	2020	2030	2040

3.1.1 Scenario Conflict

The scenario *Conflict* is based on the assumption of continued conflicts of interests and objectives in Europe and is assumed as the most likely case in our analysis (base case). This includes conflicts between ecological and economic priorities, as well as the debate about the development of electricity markets and energy policy. Accordingly, no consistent climate policy emerges and different kinds of support of renewable energy persist. Also, EU member states maintain their divergent policies as far as the usage of nuclear energy is concerned. Issues of security of supply are similarly addressed only occasionally. In the more distant future in this scenario the pure market-driven expansion of renewables is put into place from 2030 onwards and demand follows a medium growth path.

3.1.2 Scenario Climate-Policy

The focal points of the scenario *Climate-Policy* are the renewable energies and increasing energy efficiency. The major policy objective here is a reduction of greenhouse gas emissions by as much as 95% in 2050 as compared with 1990 levels. Thereby specific support policies for the development of renewable energies apply until 2050. Substantial efficiency improvements are achieved with reduced transformation losses in the end use and energy sectors. In most EU member states, moreover, policy choices will lead to a phase-out of nuclear energy. Furthermore, carbon capture and sequestration technologies are not put into practice due to low public acceptance. This is in line with the current public debate in Germany and the rather restrictive legislation there. This means that transition technologies are abandoned and that in the end the future generation system will radically differ from the generation system of today.

3.1.3 Scenario Climate-Market

In a modification of this scenario, society wants to achieve the same ambitious environmental objectives relying more on market mechanisms (scenario *Climate-Market*). Here no specific policy stimulus for renewables is kept in place after 2020, so growth paths of renewable energies are not set exogenously. Instead, abatement costs for CO_2 emissions mainly drive investment in renewable energies. Renewable energies compete with efficient conventional power plants, whereupon conventional power plants have an additional benefit due to their contribution to system security.

3.1.4 Scenario Efficiency

The scenario *Efficiency* puts even more emphasis on market forces and the focus is set on economic efficiency all over Europe. The underlying idea is that competition fosters innovation and that governments should focus on setting a regulatory framework. Ideally, this is designed uniformly all over Europe to eliminate distortions of competition and to offer a market that is as big as possible to match supply and demand. At the same time, ambitious environmental targets come into force, especially for CO_2 emissions to be reduced by about 80% compared with the base year 1990. This reduction target corresponds to the minimum target which the European Union proclaimed officially. At the same time, demand is developing on an average level with the emphasis being more on economic efficiency than on energy savings at any cost. In Germany, for example, the electricity consumption then remains widely unchanged by 2050. Specific policies support the expansion of renewable energies in this scenario until 2020. After that, they are in plain competition with other technologies. This is notably nuclear energy, starting from the assumption that security risks are mostly eliminated through advanced designs. Also, politics have solved the issue of the permanent disposal of nuclear waste. Hence this scenario builds on a change in public opinion in Europe so that nuclear power is assessed only based on its costs and its potential contribution to the reduction of CO_2 emissions. In addition, the carbon capture and sequestration (CCS) technology is also envisaged to achieve a low CO_2 power generation.

3.1.5 Scenario Growth

In the scenario *Secure Growth*, by contrast, the focus is on security of supply issues as a basis for continued economic growth. Therefore domestic energy sources and those with diversified sourcing are prioritized. Security of supply for Europe is the first priority and the issue of climate change mitigation is envisaged as just some minor goal. Renewable energies are still expanded in order to reduce import dependencies until 2040, but only at a low level. Subsequently, market forces will again decide on the further expansion of renewables. In line with economic growth, demand is also increasing. Moreover, shale gas resources are explored in many countries and the dependency on a single supplier can thus be reduced. Coal reserves are not a limiting factor and therefore prices stay low. In addition, societal concerns about nuclear energy are reduced.

3.2 Scenario parameters

For the scenario evaluation, we translate the scenario storylines sketched above into sets of parameters for demand, fuel prices, CO_2 reduction targets and acceptance of nuclear power. These are summarized in Table 1. For RES, development paths are exogenously set until the year of policy change. After that, investment in renewable energy technologies is endogenous and driven by market conditions.

Table 2: Conventional power plants

	Inv. cost [€/KW]	Fixed cost [€/KW]	Other var. cost [€/MW]	Start-up var. cost [€/MW]	Start-up fuel cons. [MWh/MW]	Efficiency [%]
Coal	1590 - 1950	42.6 – 64.4	2 – 2.7	10.7 - 43.7	5	0.3 – 0.5
Gas CC	800 - 1250	13.4 – 19	1 – 1.3	7.2 - 39.6	5 - 8	0.3 – 0.6
Gas turbine	420 - 1000	19 – 40	1.1 – 1.5	1.6 - 5.8	7.8 - 8	0.3 – 0.5
Lignite	1710 - 2320	52.4 – 78	1.5 – 2	1.7 – 6.2	5	0.2 – 0.4
Nuclear	3240	37.1 – 38.1	0.5 – 1.2	4.6 – 16.7	2 – 32.6	0.3 – 0.4

Table 3: Fuel prices [€/MWh]

	Coal			Natural gas		
	Low	Mid	High	Low	Mid	High
2010	10.0	10.0	10.0	19.4	19.4	19.4
2020	12.1	13.3	13.5	27.8	28.9	30.0
2030	9.7	13.7	14.4	27.5	32.5	34.3
2040	8.9	13.9	14.9	26.7	34.7	36.5
2050	8.9	14.0	15.6	26.7	37.0	38.7

Power plant data were collected in the SUPWIND project (2009) and were further improved in various projects with industry and government agencies. Technical assumptions are presented in Table 2. The fuel price is modeled as a sum of a general fuel price and an additional country-specific transport cost component (see Table 3). Fuel prices for coal, oil and natural gas are based on current forward prices. Beyond the time horizon of future contracts, growth in fuel prices is aligned on the scenarios in the World Energy Outlook (IEA, 2010). For coal, the transportation costs depend on the access to sea. Countries with direct access thus have lower transport costs than countries without direct access, while countries with access to the North Sea have the lowest transport costs. Similar considerations have been used for oil. The transport cost component for natural gas depends on the distance of the supplier region from the demand region and current price premiums.

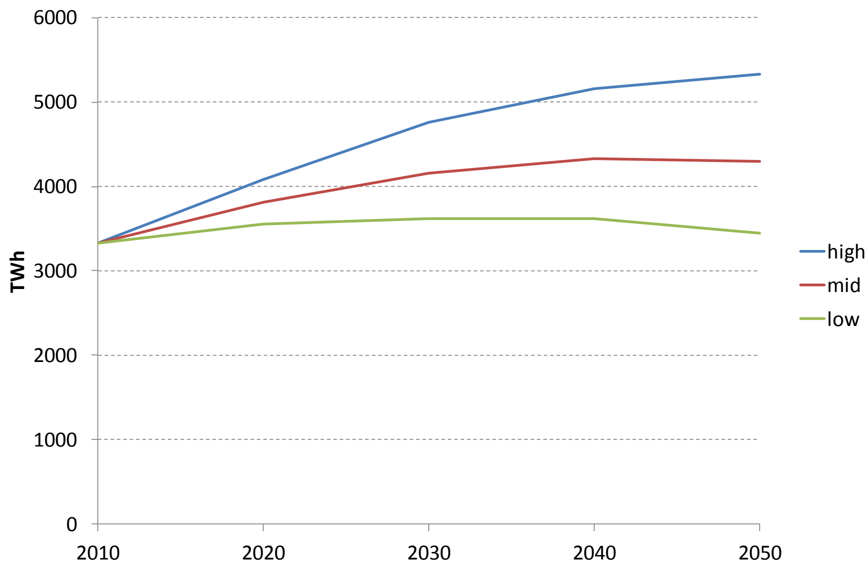

Figure 2: Demand development for Europe in different scenario specifications

Demand is defined along with the definition of ENTSO-E as gross demand including transmission losses and internal consumption of power plants. Still today electricity is a modernization energy and causes demand growth. Depending on factors like the degree of industrial electricity demand, different growth rates for future demand development in different countries are assumed based on EU (2009) and own estimations. For Europe as a whole, demand returns to 2010 levels until 2050 in the low growth scenario, increases by 30% in the mid case and by as much as 60% in the high case (Figure 2).

Besides electric load, also heat demand is given for selected countries. We consider Germany, Denmark, Sweden, Norway, Finland, the Netherlands, Poland, Austria and Italy. Further on, Germany is divided into 34 heat regions, so that only units located within one of these heat regions can cover the particular heat demand. The heat load is taken from EUROSTAT (2010) and is assumed to decrease over time at a rate between 0.5%/year and 1.5%/year, depending on the specification. Underlying is the assumption that efficiency gains in heating of current customers exceed additional heat demand of new customers.

In addition, scenario-specific CO_2 targets are implemented. Different reduction paths with a reduction by 30 to 95% until 2050 (compared with 1990 levels) for the electricity sector are defined as input to the model. Here, we focus on CO_2, as it is the most important emission type in the electricity sector. The shadow price of the related constraint in the optimization model then corresponds to the expected CO_2 market price.

For renewable expansion plans, estimations were made based on several studies (e.g. Tradewind, 2009; BMU, 2009; Green-X, 2004), updated information and national renewable energy action plans. Wind power capacity is differentiated between onshore and offshore capacity; moreover, the development of solar and biomass capacity is specified as long as they are not driven by market outcomes.

Cross border capacity is approximated with NTC values as they are published by system operators (ENTSO-E, 2012). Investments and extensions are assumed in line with the "Ten Year Network Development Plan" for the future (ENTSO-E, 2012).

Acceptance of nuclear power mainly has an influence on countries with versatile nuclear policies in the past or with current public discussions. Other countries like Austria are assumed to refuse nuclear power, while France will use nuclear power independently from the scenario. Germany will enforce the nuclear phase-out in all cases. Also investment in lignite power plants is limited according to available deposits and current mining capacities.

3.3 Resources and costs for RES

In literature, different types of potential are distinguished (Fischer and Schrattenholzer, 2001).The theoretical potential covers total global energy resources. The technical potential is the part of the theoretical potential that can be used with a given technology. The part of the technical potential that can be used cost-effectively is called economic potential. For the chosen approach, we focus on the technical and economic potential. A detailed description can be found in Spiecker and Weber (2011).

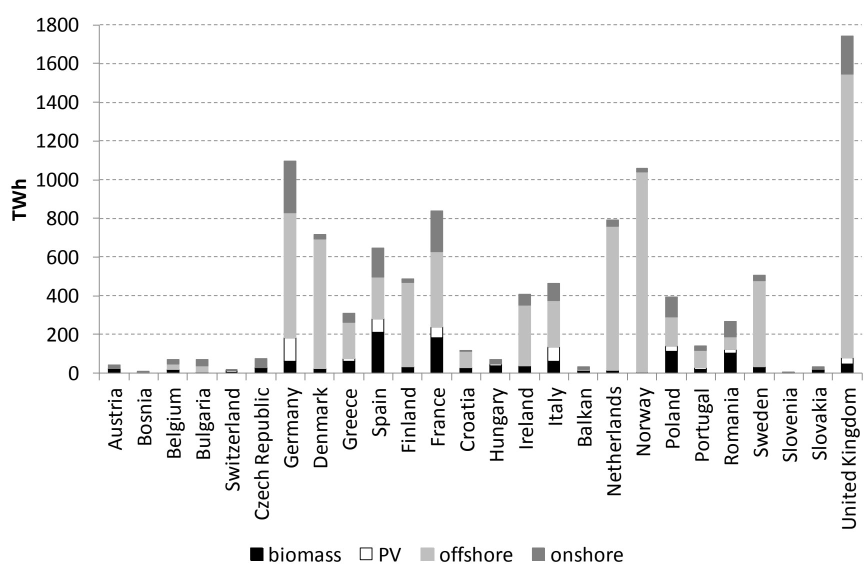

Figure 3: RES potential in different European regions

Figure 3 provides an overview of the identified resources. Efficiencies of typical plants are considered to determine the biomass potential in terms of electricity. Furthermore, production of heat in CHP units or boilers is possible. But this reduces the potential for electricity production from biomass-fired power plant. In the following scenario analysis, this decision is made endogenously based on cost effectiveness considerations. Therefore we separate costs into investment costs, variable costs and other fixed costs (see Table 4). Variable costs of biomass are distinguished according to groups of fuels and technologies. Differences in investment cost occur depending on the usage for pure electricity production or in a CHP power plant. We assume that mainly small-scale biomass CHP power plants are built, which explains the relatively high investments cost. On the other hand, biomass power plants can generate a dual income stream from both the electricity and the heat market. Exceptions to this assumption can, be found, for example, in the United Kingdom and in the Netherlands, where biomass (co-)firing in large-scale power plants is supported.

Table 4: RES parameters

	Max. eff. [%]	Invest. cost [€/kW]	Variable cost [€/MWh]	Other fixed cost [€/kW]	Full-load hours [h]	Avg. yearly cost reduction [%][1]
PV	-	2800	0	18	690 - 1350	3.4
Biomass	32 - 42	4000 - 6370	0-50	145-180	-	0.4
Onshore	-	1500	0	45	1280 - 3320	1
Offshore	-	3800 - 4700	0	50-70	1350 - 3750	3.6

The resources of wind and solar power plants are described in terms of possible capacity and corresponding full load hours on a region by region basis. For offshore wind, investment costs differ depending on the distance to the coast as well as full load hours. Also, for onshore regions different full load hours exist even within the same region to reflect differences in site quality. The same applies for solar power plants.

Cost reduction factors depending on technology and year are considered for renewables to reflect technological development (see Table 4). For conventional technologies, improvements in efficiency are included, yet these are expected to come at

[1] Cost reductions differ widely between technology and cost component

zero additional cost.

4. Results and Discussion

The following section presents the outcome of the scenario analysis. The various scenarios and the resulting penetration of fluctuating renewable energy have multiple impacts on the European electricity market. Subsequently, the effects on costs and prices – electricity as well as CO_2 - are analyzed first. Then the implications for power plant capacity and production are examined. In a third step, the resulting cross-border power flows are described. In some cases there is a spotlight on single countries to highlight particular effects.

4.1 Impact on electricity prices, CO_2 prices and system cost

Fehler! Verweisquelle konnte nicht gefunden werden. shows the development of the electricity base price for selected countries and years. It is calculated as the average of hourly wholesale prices. Starting in 2010, electricity prices are increasing until 2020 and then decrease in most countries until 2050. This latter result is at first sight rather surprising. Yet, three effects may generally be distinguished during the analyzed time period. On the one hand, increasing fuel prices and binding CO_2 limits increase the price level. On the other hand, an expansion of renewables has a price-dampening effect – especially if the expansion is financed by side-payments outside the market. For market-based RES investment, this is not relevant, which particularly explains the stronger increase in electricity prices in the scenario *Climate-Market* compared with the scenario *Climate-Policy*, with, e.g., an average price difference of 5 €/MWh in Italy. However, one has to consider that this price difference is the result of government interventions which lead to additional costs outside the market. Ultimately, these also have to be paid by society. This is obvious from a comparison of total system costs for electricity production, which are 10 €/MWh higher in the scenario *Climate-Policy* than in the scenario *Climate-Market* (see Figure 5).

The price increase in the first years is also influenced by increasingly tight CO_2 limits and the resulting higher CO_2 prices (Table 5). Differences in CO_2 prices are the main driver for electricity price differences between the scenarios in the year 2020. Other scenario parameters, like investment possibilities, demand growth and renewable expansion have an indirect effect on the CO_2 price by tightening or relaxing the emission constraint. In this context, nuclear power plants have the biggest impact. Nevertheless, prices in France are still high in 2020 compared with Germany and Spain. This is mainly due to the higher share of renewables in these two countries, which decreases the price level on the wholesale market. Further on, given a demand profile with large amplitude, France is exporting in times of low demand, which increases the price level. In times of high demand (e.g. electricity heat demand in winter), electricity has to be imported at even higher prices.

But also the combined effect of lower demand growth and higher subsidized renewable penetration is clearly observable for the year 2020 when comparing the *Climate* scenarios with the *Secure Growth* and the *Efficiency* scenarios. Expansion of renewables and lower demand growth offset tighter emission restrictions in the first scenarios, leading to a CO_2 price more than 10 €/t lower than in the latter scenarios.

In the later years, the average CO_2 intensity of electricity production is low especially in high CO_2 price scenarios. Therefore, the correlation between CO_2 prices and base load prices is reduced. This is mainly caused by renewables driving the wholesale price to zero in many hours of the year. Wind and solar capacity has no or only a small variable cost. Together with must-run capacity from hydro and CHP, the capacity of these renewables puts other capacity with higher variable costs out of the market. In situations where this supply at zero short-term cost exceeds demand, electricity is no longer a scarce good and thus prices are zero or even become negative. With a further extension of RES, the likelihood of such events increases.

An increased use of solar power obviously reduces the relative gap between off-peak and peak prices on days with higher solar infeeds during peak hours. Even today a reversal of traditional price patterns may be observed for selected summer days in Germany and neighboring countries.

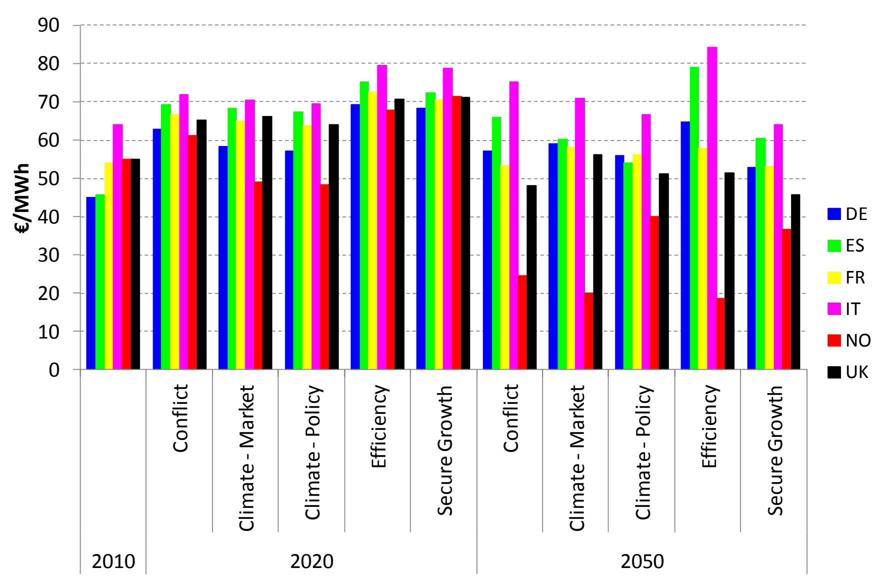

Figure 4: Base prices in different scenarios (real terms)

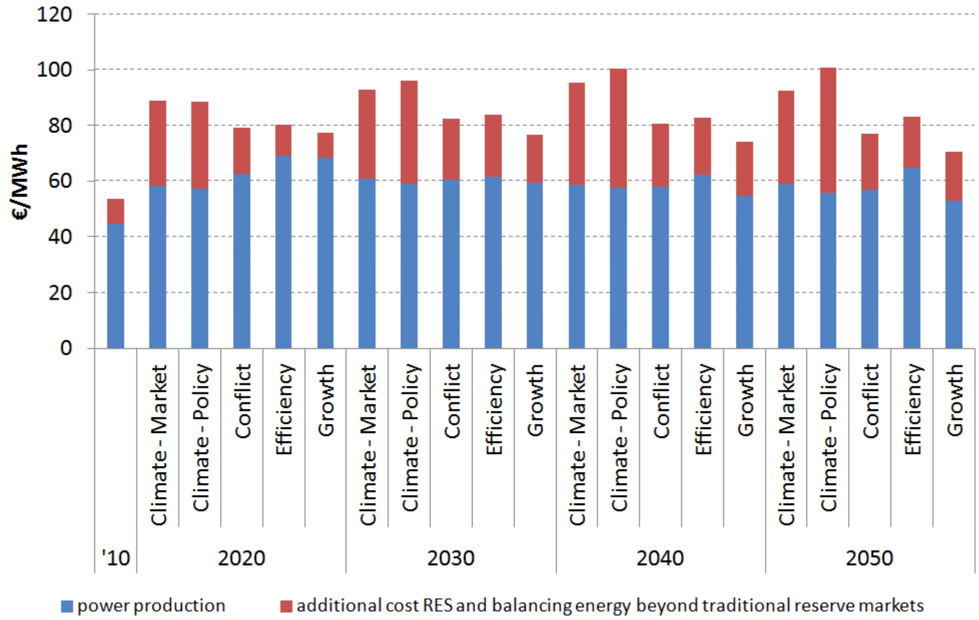

Figure 5: Average wholesale prices and system costs for power production (real terms)

But wholesale market prices do not reflect the full truth when it comes to electricity system cost in the presence of renewables. This becomes obvious in Figure 5, where the average system cost per unit supplied is depicted for the five analyzed scenarios. The focus is on the costs for electricity supply. Therefore we reduce total system costs by costs for heat supply[2]. Earnings from the wholesale market are shown as a fraction of system costs. In contrast to the base price calculated before, this price is weighted by demand.

The difference between average system costs and wholesale power prices represents costs for renewable subsidies, costs of ancillary services and costs of capacity requirements. Given the modeling assumption of workable competition, any new generation technology will recover its annualized full cost in the year of construction – otherwise it would not be built. If the wholesale price is low, a major part of cost recovery comes from the ancillary service and capacity markets (see section 2.4). This is especially true in the scenario *Climate – Policy* with heavily subsidized renewable expansion, where the conventional capacity is still necessary as "backup" to guarantee system security. Also, the costs of renewable subsidies are included in the latter cost component.

It can be observed that total costs for electricity supply increase in the first decade and traditional wholesale prices are more or less equal in 2020 for the different scenarios. After 2030 costs decrease slightly. The main differences occur in the composition of the

[2] These are all costs of heat boilers and the costs of CHP units attributable to heat production. The latter are determined using the marginal value of heat delivered to customers.

price and the shares of the different components. While costs are strongly increasing in both climate scenarios, they are slightly decreasing in the other three scenarios.

Table 5: CO_2 price development in real terms for different scenarios [€/t]

	Conflict	Climate - Market	Climate - Policy	Efficiency	Secure Growth
2020	28.6	26.1	24.7	38.2	41.3
2030	30.4	33.2	31.2	30.4	36.7
2040	34.2	44.3	42.9	45.5	40.0
2050	45.2	133.5	110.9	70.2	41.3

4.2 Impact on capacity and production

Power plant capacity is evolving along with the electricity demand in the different scenarios. However, intermittent renewables are contributing almost nothing to firm capacity and therefore total capacity increases disproportionately (see Figure 6). When analyzing the mix of generation technologies, one has to be aware that investments in renewable energies are partly defined by the scenario. But an investment beyond subsidized investment programs is always possible. Additionally, projects under construction or with firm announcements are prevalent until 2020.

In line with the demand development, the highest capacity occurs in the scenario *Secure Growth* with a final renewable energy capacity share of about 50%. So, even without strong subsidization or ambitious climate targets, renewables take an important share in power generation. Yet the highest share of renewable energy capacity is found in the scenario *Climate-Policy* (72%). Comparing this result with the more market-oriented *Climate-Market* scenario, it is striking that in an efficient framework a share of 64% is sufficient to fulfill the emission target. Especially solar and wind onshore capacity is reduced, and wind offshore capacity is therefore added.

Natural gas fired facilities dominate investments in conventional power plants. The advantages of gas fired power plants are their flexibility, their low CO_2 emissions and their low fixed costs, which make them a suitable complement to fluctuating energies. Nuclear power plants are advantageous in scenarios with a high base load. But also in scenarios with high infeeds of renewable energy, nuclear power plants are still in use even if capacity is reduced. In this case, a meshed transmission grid is important to handle fluctuations of power production and allow access to high demand areas for less flexible power plants with low variable costs.

For biomass and wind onshore, grid parity on the wholesale market is already reached in 2020, offshore wind power plants reach it in 2030 and in most scenarios PV reaches grid parity on the wholesale market in 2040. Due to differences in full load hours between the analyzed regions and different production costs among the modeled scenarios, there are, however, regional and also temporal deviations.

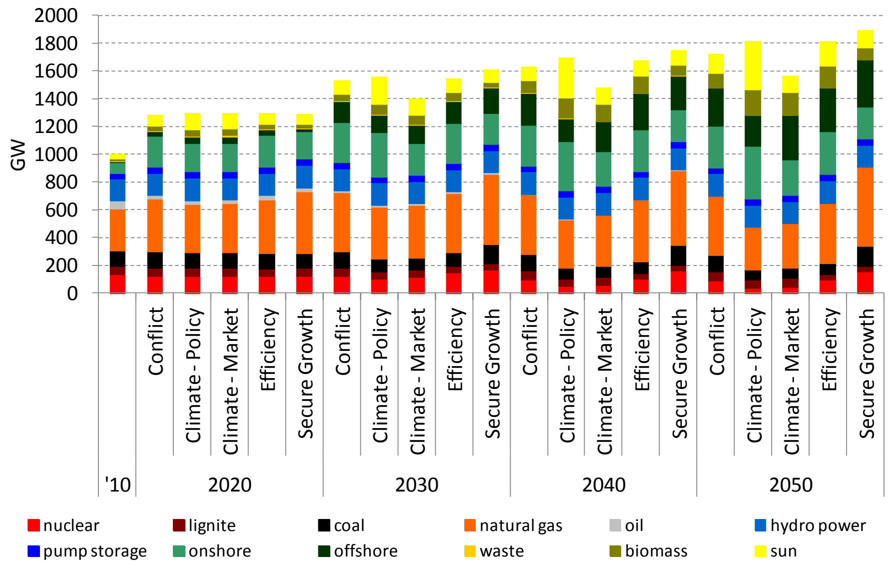

Figure 6: Capacity development in different scenarios

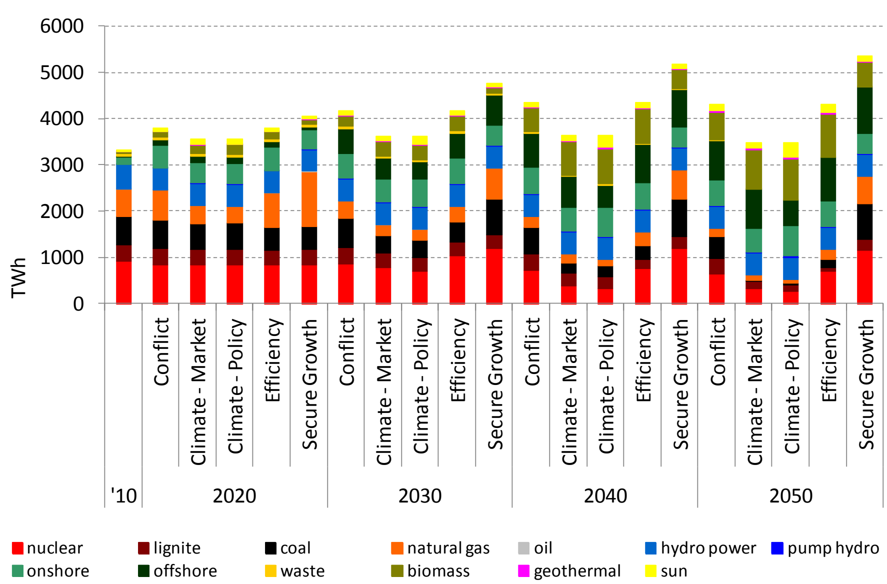

Figure 7: Production development in different scenarios

Even in the case of high CO_2 prices, CCS technology (carbon capture and storage) does not play an important role, even in countries without access to nuclear or hydro power plants. Despite being controllable, higher costs prevent CCS from being widely used. Among CCS plants, lignite units are the most advantageous. Only in countries without lignite resources are CCS plants using hard coal built. High fixed costs are a major economic problem with this technology that makes it economically disadvantageous to use it for only a few hours. But especially in the case of systems with large renewable extension, full load hours of conventional power plants decrease along with the advantage of CCS power plants in markets with high CO_2 prices.

In general, European production develops in accordance (see Figure 7) with demand paths (adjusted by a few imports from outside Europe). But comparing capacity with production, it is obvious that the proportions of the various technologies differ. Base load technologies have a higher share in production, while the share of renewable energies is lower due to their inferior availability. Natural gas fired power plants are mainly used as back-up capacity and therefore have a quite low share in production.

In scenarios with high renewable penetration, renewable energies dominate production. The only exception is the scenario *Secure Growth*, where in some countries conventional energy still has a share of more than 75% in 2050. Efforts for renewable expansion are low in this scenario and coal and CO_2 prices play in favor of conventional power plants. Nevertheless, renewable energies reach a share of 55% of total European production in 2050 and the absolute level of renewable production is almost as high as in the *Climate* scenarios. Yet the share of renewable energies is much higher in the scenarios *Climate-Policy* and *–Market*, reaching 88.5% and 85% respectively. Also, in the *Efficiency* (75%) scenario and in the *Conflict* scenario (71%) more than two thirds of production comes from renewables in 2050.

The integration of such high shares of renewable energies requires large cross-country exchanges of power (see section 4.3) as well as flexible power plants. Moreover, full load hours of conventional power plants are dramatically reduced and especially gas fired power plants are mostly used as back-up technologies that are kept available to ensure security of supply. In Europe, average full load hours for coal fired power plants in 2050 vary between 5250 hours (scenario *Secure Growth*) and 1000 hours for different countries in the scenario *Climate-Policy*. In the scenario *Climate-Market*, 1500 full load hours are achieved, indicating that technologies are used more efficiently. In the scenarios *Conflict* and *Efficiency* full load hours are around 3500 hours. A worse situation occurs for natural gas fired power plants. Even in the *Secure Growth* scenario full load hours vary between 3600 hours in Switzerland and only single-digit hours in other countries because of high back-up capacity needs. With a high share of renewable energies as in the climate scenarios, full load hours of more than 400 hours are an exception. This emphasizes the need for capacity market mechanisms to ensure capital cost recovery.

But also for renewable energies a decrease in full load hours occurs, since low demand and high availability of renewable energies partly coincide. Especially full load hours of solar installations are reduced, with high penetration rates and more than 70% capacity utilization in the maximum. On average, the reduction reaches 15% in the *Climate* scenarios, and in some countries even more. Similar patterns can be observed for onshore wind. Reductions are lower compared with solar power because of more even infeeds. Correspondingly, full load hours are reduced even less for offshore wind power plants. Exceptions to this rule are found when the necessary RES capacity is overestimated, which occurs especially in the scenario *Climate-Policy*. Besides reductions due to overproduction, decreases are also the consequence of the development of additional resources with lower full load hours.

4.3 Impact on cross-border power exchange

As mentioned before, the successful integration of renewable energies also depends on sufficient transmission capacity. Over time, not only is the transmission volume increasing but also directions may change. In Table 6 this is shown for the German balance of cross-border trades. In all scenarios the net balance is decreasing. The extent depends on the degree of policy harmonization within Europe. The policy orientation (environment vs. economy), by contrast, has no significant impact. A more harmonized framework such as in the scenario *Climate-Market* entails a lower deficit than in the scenario *Efficiency*. Here, German investments in RES are lower than in the *Climate* scenarios but compared with neighboring countries they are still high.

Table 6: German trade balance in different scenarios [TWh]

		Conflict	*Climate - Policy*	*Climate - Market*	*Efficiency*	*Secure Growth*
2020	Export	59.59	55.96	56.61	59.29	72.42
	Import	36.43	43.11	40.91	30.71	24.17
	Balance	23.16	12.85	15.70	28.58	48.25
2050	Export	49.45	60.52	55.07	52.96	38.50
	Import	87.76	74.53	79.39	92.12	75.59
	Balance	-38.31	-14.02	-24.32	-39.16	-37.09

A more detailed analysis can be found in Figure 8 for the *Climate-Market* scenario in the year 2050. The figure shows different power exchange situations in Europe. Here, the upper pictures depict a situation at a weekend in summer in hour twelve. On the right side RES infeeds are low, while they are high on the left side. Still in 2050 Germany is a major producer of fluctuating renewable energy. But other countries like France and Spain also increase their capacity. Yet they are less affected by fluctuations and uncertainty due to better weather conditions, especially for solar but also for wind. In the case of high infeeds, the Scandinavian hydro-dominated system is used to adjust the fluctuating production on the European mainland. When renewable infeeds are low, electricity from Scandinavian hydro power plants is exported to continental Europe as well as to the United Kingdom and vice versa. Also, alpine countries are used to buffer fluctuating renewable energies. But, in contrast to Scandinavia, they absorb more energy in high infeed situations than they export in low infeed situations. The United Kingdom is heavily dependent on transmission possibilities. In high infeed situations, they export 6.7 GW while they import 8 GW in low infeed situations. That means a spread of 14.7 GW between different load flow situations.

The lower pictures present a similar situation on an evening in winter with high load and low renewable infeeds. In comparison with the situation in summer, changes in RES infeeds have a lower impact on power system flows. The main changes occur for the United Kingdom, which relies on electricity imports independent from the RES situation. Also, the pattern between the Iberian Peninsula and core Europe is inverted. Instead of importing from France, they are exporting energy. Such a reversal can also be found at the Czech-German border. In the high demand situation, energy is exported to Germany and vice versa. Especially in the high wind case, situations like today with flows from North Germany to South Germany via Poland and the Czech Republic still occur due to internal bottlenecks within Germany. Norway's flexibility is still used for production in core Europe. Norway imports electricity with high wind and solar production and vice versa. The Austrian and Swiss behavior changes, too. In cases of high demand, the balance of cross-border power trade is always negative. In contrast to today's situation, differences occur for Italy. Imports and dependencies from other countries are reduced because of increasing production, especially from renewable energies.

5. Sensitivity Analysis

A sensitivity analysis has been conducted to assess the role of differing demand developments on CO_2 price and power production. Therefore the scenarios *Climate-Market*, *Climate-Policy* and *Secure Growth* are recalculated with mid demand development assumptions.

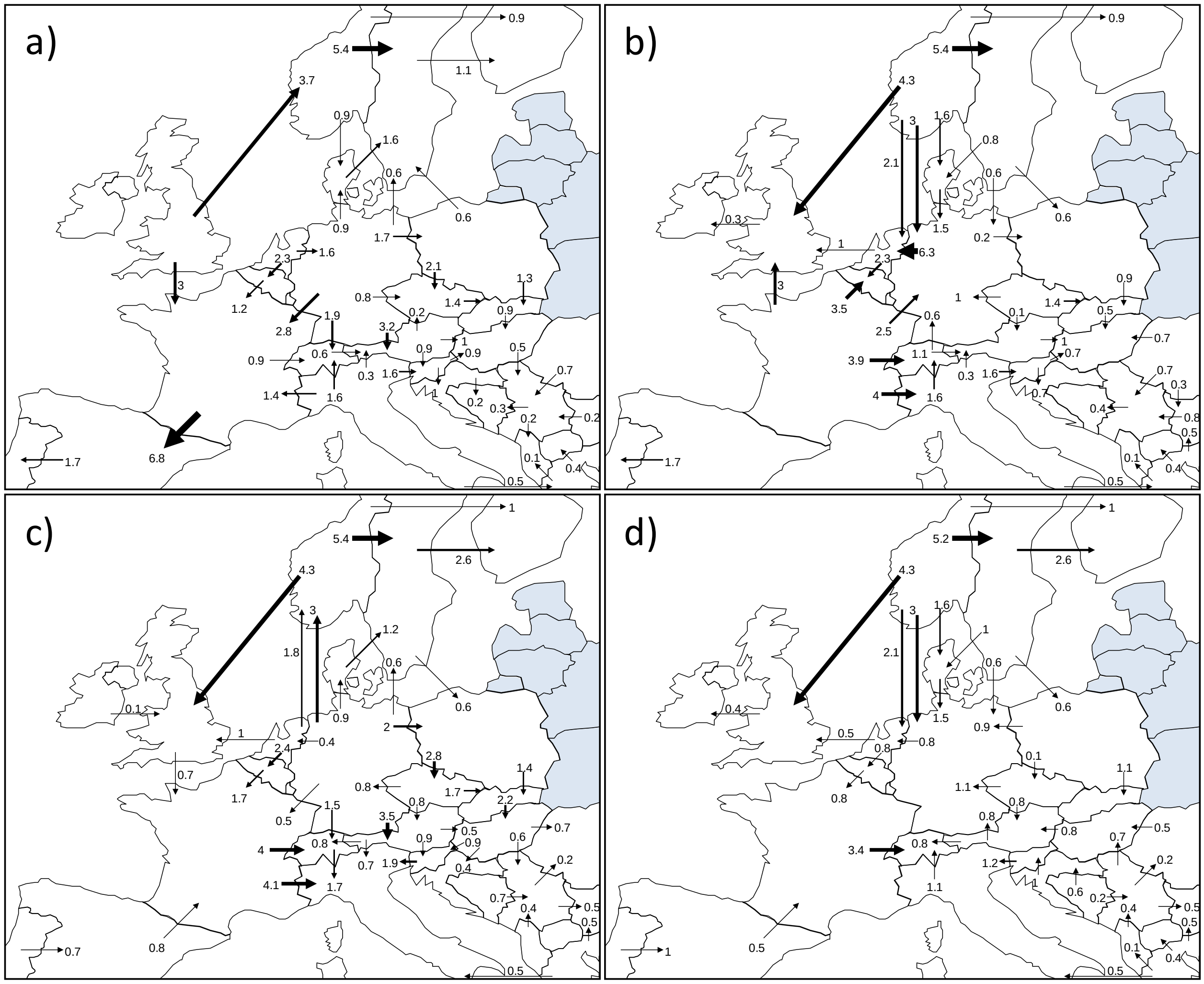

Figure 8: Cross-border flows in GW on a typical summer weekend day with a) high and b) low RES infeeds and low load at noon, as well as a typical winter working day with c) high and d) low RES infeeds and high load in the evening (7 p.m.)

Table 7: CO_2 price development in real terms for selected scenarios and sensitivities [€/t]

	Climate-Market		*Climate-Policy*		*Secure Growth*	
	org.	sen.	org.	sen.	org.	sen.
2020	26.1	36.4	24.7	33.1	41.3	31.4
2030	33.2	39.1	31.2	37.6	36.7	27.2
2040	44.3	52.3	42.9	50.1	40.0	33.3
2050	133.5	188.6	110.9	168.8	41.3	30.9

In Table 7, CO_2 prices for the different sensitivities are compared. Especially in the *Climate* scenarios, price differences of up to 50 €/t occur. With 10 €/t, the differences in the scenario *Secure Growth* are considerably smaller. This shows that energy efficiency on the demand side is a key aspect to avoid soaring abatement costs while having ambitious CO_2 emission targets. In the other case, the influence on CO_2 prices is limited.

Higher demand causes more production of nuclear power plants in all three scenarios (see Figure 9). Similar observations are made for offshore wind farms. Here, higher demand causes higher emissions, which lead to higher CO_2 prices. These make investment in renewable energies more advantageous. The same applies to biomass. These results underline the importance of demand reductions for the energy transition in the case of ambitious CO_2 targets.

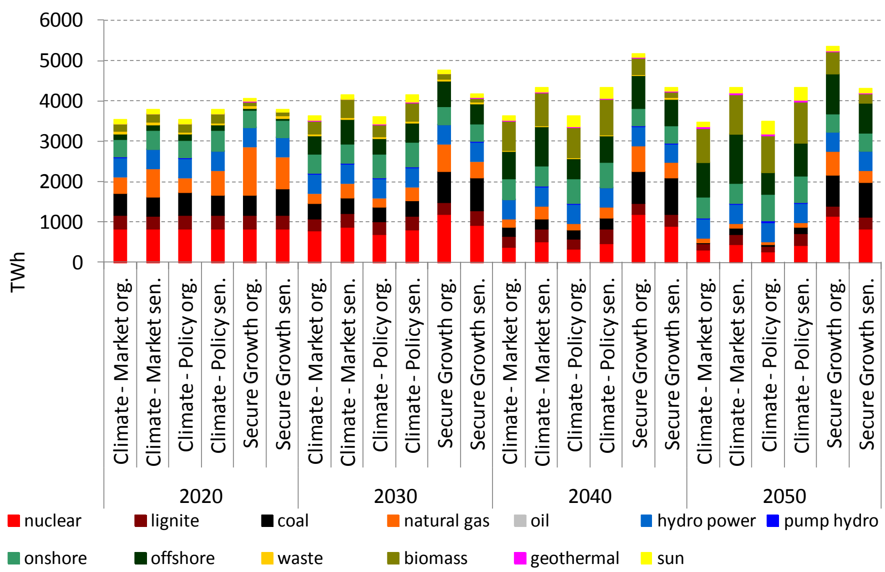

Figure 9: Production development in different scenarios and sensitivities

6. Conclusion

In this article, different possible paths of the transition of the European energy system are analyzed. Despite a vision of a "green" European power system in the year 2050, the path to this state itself and the continuity of this objective remain uncertain. Hence, the chosen scenarios reflect different political priorities and allow a differentiated assessment of various impacts on political framework conditions. In some of these scenarios a renunciation of current objectives is considered. In other scenarios different ways to reach the final objective are analyzed. A major challenge in all these scenarios is the impact of fluctuating renewable energies on the future European power market. We use a stochastic energy system model with endogenous cost-resource curves in order to cope with this challenge from a methodology point of view.

A major driver in the different scenarios is the development of demand. This can already be observed in today's CO_2 prices, which are caused by the low demand due to the economic crisis. This relationship remains for the future. CO_2 emissions can be reduced significantly with a reduction of demand. In line with that, abatement costs decrease, which lowers macroeconomic costs. Also, the extent of investments in conventional power plant capacity is dependent on total demand level. Fluctuating renewable energies have a low capacity credit and hence conventional back-up capacity is still necessary. Their absolute level is therefore still defined by total demand.

It can be observed that renewables drive wholesale prices to zero. But the heavily subsidized renewables lead to an increase in total system costs. The wholesale market does not reflect these additional costs because they are financed through levies or taxes paid by final customers. Instead the subsidized renewables have a dampening effect on the wholesale price. The scenarios particularly indicate that incentive measures for renewables tend to lower the price of conventional power, especially lignite power plants, by reducing the shortage of CO_2 certificates. At the same time, RES push conventional power prices out of the market and destroy their income stream from the wholesale market if they are over-subsidized. Without coordination, the renewables promotion in some European countries will therefore lead to benefits, especially in neighboring countries, through lower carbon and electricity prices, while system costs are increasing. But, even in a coordinated approach, power transmission will become more important in the future to allow the integration of fluctuating renewable energies.

In order to integrate stochastic infeeds from renewable energies, investment in flexible power plants is important beside grid extensions to secure the stable operation of the system. The financing of these investments will rely more and more on capacity payments, while wholesale prices tend to decline especially in the scenarios with strong political interference.

Summing up, one has to be aware that the achievement of ambitious environmental targets comes along with high costs. Nevertheless, depending on the efficiency of the political framework, costs might be further increased. Hence, it is important to have a market design where an efficient allocation of resources is still possible. A further threat is low fuel prices, which make a turning away from agreed objectives more and more attractive from an economic point of view.

For the future, a more detailed modeling of the impact of different market designs and support mechanisms on the investment risk for both renewables and conventional power plants is desirable. In particular, the impact on risk from an investor perspective and the resulting willingness to invest should be described better. Market and system models as described in this paper might be a useful tool to understand and evaluate the different ideas that are currently being discussed. In the long run also, a higher temporal and regional resolution, as well as additional stochastic stages, should be implemented when computational power increases further in the future.

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