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Abstract

In recent years, many countries have implemented policies to incentivize renewable power generation. In this paper, we analyze the variance in profits of renewable-based electricity producers due to weather uncertainty under a 'feed-in tariff' policy, a 'fixed bonus' incentive and a 'renewable quota' obligation. In a first step, we discuss the price effects of fluctuations in the feed-in from renewables and their impact on the risk for green electricity producers. In a second step, we numerically solve the problem by applying a spatial stochastic equilibrium model to the European electricity market. The simulation results allow us to discuss the variance in profits under the different renewable support mechanisms and how different technologies are affected by weather uncertainty. The analysis suggests that wind producers benefit from market integration, whereas producers from biomass and solar plants face a larger variance in profits. Furthermore, the simulation indicates that highly volatile green certificate prices occur when introducing a renewable quota obligation without the option of banking and borrowing. Thus, all renewable producers face a higher variance in profits, as the price effect of weather uncertainty on green certificates overcompensates the negatively correlated fluctuations in production and prices.

Keywords: RES-E policy, financial risk, mixed complementarity problem

JEL classification: C61, L50, Q40

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1. Introduction

Partly due to concerns about global warming, many countries are attempting to reduce CO_2 emissions from power generation by increasing the proportion of electricity generated from renewable energy sources. As power generation from renewable energy sources is usually more costly than conventional power generation, at least when ignoring external effects, many European countries have implemented various support schemes to promote renewable energies in recent years.

One established policy instrument is a *'feed-in tariff'* (FIT) for renewable power generation. Renewable producers are offered a long-term contract with guaranteed tariffs for each unit of electricity fed into the grid. To promote a broad mix of renewable energies, tariffs are usually differentiated by technologies representing the differences in generation costs. Feed-in tariff policies have led to a sharp increase in the share of renewable power generation in Spain (+12 %) and Germany (+11 %) from 2001 to 2010 (Eurostat, 2012). An alternative policy instrument is a *'fixed bonus'* (FB), which electricity producers receive in addition to the hourly market price for each unit of renewable energy (e.g., in Denmark and the Netherlands). Producers of renewable-based electricity are then exposed to the hourly market price, which is usually referred to as 'market integration'. Another common policy instrument is a *'renewable quota'* (often also referred to as *'renewable portfolio standard'*), demanding utility companies (or electricity consumers) to procure a certain share of their electricity from renewable sources within a defined period. This gives rise to a market for green certificates (TGC) issued by renewable-based electricity producers, which allows revenues in addition to the revenues from the wholesale market for electricity. A green certificate market is currently the main promotion scheme for renewable energies in Sweden and Poland.

It is an ongoing debate as to if and how renewable energies should be promoted in Europe once the envisaged national renewable targets of the National Renewable Energy Action Plans in 2020 have been achieved (EC, 2013). If the European Union or individual Member States make the decision to continue incentivizing renewable power generation, the promotion system should be cost-efficient in achieving this target. From a purely economic perspective, the support scheme should be technology-neutral, be implemented across Europe and include the hourly wholesale price for electricity. A technology-neutral policy, rather than technology-specific incentives, are cost-efficient as renewable energies with different generation costs and generation pattern are competing against each other. A harmonized RES-E policy would allow competition between European sites, which is particularly important for wind and solar technologies. Moreover, integrating renewables in the power market drives cost-efficient investments, as green electricity producers consider the hourly value of electricity in their investment and production decisions. Thus, the introduction of a European bonus system or renewable quota, with the above mentioned characteristics, is currently being discussed for the time frame after 2020.

However, one could question such policies, as the investment risk for electricity producers may be significantly higher than under a feed-in tariff support. A higher risk for producers may increase the costs of renewable-based electricity in particular due to the higher capital-to-operating cost ratio (compared to conventional power plants). Under a feed-in tariff system, electricity producers are remunerated by the fixed tariff and thus the produced quantity represents the only source of uncertainty. When exposing renewables to the power market, as under a bonus system, revenue streams are affected by uncertainty about the production as well as the future market price of electricity. Under a quota obligation, the produced amount of electricity, the market price and the price of green certificates are uncertain.

In this case, the effect of weather uncertainty is of particular interest mainly because of the increasing impact of intermittent generation on wholesale prices of electricity. The envisaged transition to a low-carbon and mostly renewable-based electricity supply implies a substantial increase in generation from wind and solar technologies due to the limited economic potential of dispatchable renewables (i.e., biomass or hydro power) in Europe. As variable generation costs of intermittent renewables are negligible, the feed-in of these technologies has a decreasing effect on wholesale prices. Thus, renewable-based electricity producers may face negatively correlated fluctuations in production and wholesale prices. Therefore, integrating renewables in the power market may actually reduce the variance in revenues.

This paper outlines the effect of weather uncertainty on the variance in profits of green electricity producers under the three most common renewable policies. We concentrate on the risk for green electricity producers (partial analysis) and refrain from an analysis on the risk sharing between renewable and conventional-based electricity producers. Moreover, an analysis on the risk for regulators when setting prices under feed-in tariff support or quantities under a renewable quota is beyond the scope of this paper.[1] In a first step, we discuss the price effects of fluctuations in the feed-in from intermittent renewables and their impact on the risk for renewable-based electricity producers. As potential balancing effects (negatively correlated fluctuations in production and wholesale prices) depend on the slope of the supply curve of dispatchable plants, we analyze the variance in revenues under the three renewable policies depending on the slope of the supply curve in a simple analytical framework. In a second step, we numerically solve the prob-

[1]In general, there is no difference between a bonus incentive (price-based control) and a quota obligation (quantity-based control) because for each instrument there is a corresponding way to implement it as the other in order to achieve the same results. However, price-based or quantity-based control mechanisms are not equivalent in markets with uncertainties (Weitzman, 1974). It is an interesting question whether price or quantity controls are preferable to promote renewables in power markets, but it is beyond the scope of this paper.

lem by applying a spatial stochastic equilibrium model to the European electricity market. The simulation results allow us to discuss the variance in profits under the different renewable support mechanisms, the size of the described balancing effects and how different technologies are affected by weather uncertainty.

The main findings of this analysis include that the effect of weather uncertainty on the risk for green electricity producers, under the three described renewable policies, highly depends on the slope of the supply curve (dispatchable power plants). For example, in the case of a supply curve with a relatively low slope, intermittent renewables profit from market integration due to negatively correlated fluctuations in production of intermittent renewables and the wholesale price. However, the price effect overcompensates the fluctuations in production if the supply curve is rather steep. Moreover, given any slope, only some technologies benefit from the described balancing effect. For example, biomass plants are likely to achieve high (low) full load hours in years with low (high) intermittent generation and thus high (low) prices. Thus, biomass plants face a higher risk when integrated into the power market due to the positive correlation of production and prices. The results of the numerical analysis for the European power market suggest that wind producers benefit from market integration, but producers from biomass and solar plants face a larger variance in profits. Furthermore, the simulation indicates highly volatile green certificate prices when introducing a renewable quota obligation without the option of banking and borrowing. Thus, all renewable producers face a higher variance in profits, as the price effect of weather uncertainty on green certificates overcompensates the negatively correlated fluctuations in production and prices. However, one should keep in mind that a well-functioning banking and borrowing scheme may reduce the variance in certificate prices considerably and thus the variance in profits of green electricity producers.

The main contribution of this paper to existing literature is the illustration of the impact of weather uncertainty on the risk for green electricity producers under the three most common renewable policies. The literature concerning risks for green electricity producers has so far mainly concentrated on green certificate markets (e.g., Berry (2002), Lemming (2003), Dinica (2006) and Kildegaard (2008)). Berry (2002) discusses the price mechanism and the management of risks associated with using the tradable credits market. Amundsen et al. (2006) discuss the price volatility of green certificates due to strong fluctuations in wind power production by using a simulation model to show that the introduction of a banking scheme may considerably reduce price volatility. Moreover, banking and borrowing leads to increased social welfare but not necessarily to higher profits of green producers. As most renewable energies are dominated by fixed costs, Kildegaard (2008) points out that there exists a risk of over-investments and resulting periods of low certificate prices. Thus, banking and borrowing plays an important role in green certificate markets.

Lemming (2003) argues that negatively correlated fluctuations in the production of intermittent renewables and the pricing of green certificate may actually reduce the financial risk for renewable-based electricity producers. This analysis adds to the discussion on the impact of weather uncertainty on the risk for green electricity producers in Lemming (2003) by comparing the most common renewable policies. Moreover, the impact on different technologies is discussed along with a numerical analysis for the European power market.

The remainder of this paper is structured as follows: In Section 2, the influence of weather uncertainty on the risk of green electricity producers is discussed. Section 3 describes the numerical analysis, including a detailed description of the model, input parameters and results. Conclusions are drawn in Section 4, along with an outlook of possible further research.

2. Analytical analysis

Many different policies exist to incentivize power generation from renewable energies. Most commonly applied are *'feed-in tariffs'*, *'fixed bonus'* incentives and *'renewable quota'* obligations, or slight variations of these policies.[2] Thus, we analyze these three renewable policies. Concerning the renewable quota obligation, we consider the case of a certificate market without the option of banking and borrowing (referred to as *'renewable quota (no BaB)'*). As discussed in Amundsen et al. (2006), the introduction of a banking scheme may considerably reduce the price volatility of green certificates. Moreover, in case of a perfectly well-functioning banking and borrowing mechanism such that weather uncertainty is resolved, the risk for green electricity producers equals the risk in the case of a fixed bonus incentive (referred to as *'renewable quota (perf. BaB)'*).

We assume an electricity market where intermittent generation (i.e., wind or solar power) makes up a significant share of the renewable supply. Due to the stochastic nature of wind and solar power, electricity generation of intermittent renewables (Q_w) varies among years with equal probability $Q_1 < Q_2 < Q_3$. We are looking at a single renewable-based electricity producer with power generation $q_1 < q_2 < q_3$ that is perfectly correlated with all other intermittent renewable generation in the market. The renewable policies are designed such that the expected profit equals the capital costs and thus $E(R_{fit}) = E(R_{bonus}) = E(R_{quota}) = K$. Figure 1 schematically depicts the revenues of the renewable-based electricity producer under the three policies.

[2] As we concentrate on the effect of weather uncertainty on the risk of green electricity producers under these three policies, we refrain from a discussion on the benefits of a price (i.e., feed-in tariffs or bonus payments) or quantity control instrument (i.e., quota obligation) from a social welfare perspective (including the risk of regulators and conventional power generators).

Under a *'feed-in tariff'* policy, the renewable-based electricity producer is offered a long-term contract with guaranteed tariffs (fit) for each unit of electricity fed into the grid. Consequently, electricity producers invest in renewables as long as capital costs can be recovered under the offered feed-in tariff. As such, renewable-based electricity producers do not consider the market price for electricity in their investment decision. Since prices are fixed under a feed-in tariff system, revenues vary according to the volatility in generation. As depicted, the renewable-based electricity producer can expect high revenues ($R_{fit,3} = [0, FIT, o', q_3]$) in years with large generation but substantially lower revenues ($R_{fit,1} = [0, FIT, o, q_1]$) in years with low generation. Hence, the related risk for the renewable-based electricity producer is purely based on the volatility in generation.

Under a *'fixed bonus'* incentive, renewable-based electricity producers receive the wholesale price of electricity and, in addition, a fixed bonus payment ($p_e + b$). As variable generation costs of intermittent renewables are negligible, the feed-in of intermittent renewables reduces the residual load ($d - Q_w$) that has to be met by dispatchable plants. Thus, the feed-in of intermittent renewables has a price lowering effect on the wholesale market ($p_{e,1} \geq p_{e,2} \geq p_{e,3}$). Furthermore, renewable-based electricity producers may face negatively correlated fluctuations in production and wholesale prices, which may actually reduce the financial risk under a fixed bonus policy compared to feed-in tariffs. However, the balancing effect highly depends on the marginal supply curve of the dispatchable plants. In the case of a very steep merit order, the feed-in from intermittent renewables may have such a large effect on prices that it overcompensates for the fluctuation in production.

Under a *'renewable quota (no BaB)'* obligation, utility companies (or electricity consumers) are required to procure a certain share of their electricity from renewable energy sources within a defined period. This gives rise to a market for green certificates issued by renewable-based electricity producers. In the equilibrium, the certificate price corresponds to the difference in marginal costs between renewable and conventional power generation. The renewable-based electricity producer faces fluctuations in production, wholesale/green certificate prices. In addition to the potential balancing effect between fluctuations in production and wholesale prices, certificate prices ($p_{c,1} \geq p_{c,2} \geq p_{c,3}$) are also negatively correlated with the production of intermittent electricity generation (Lemming, 2003). Thus, renewable-based electricity producers may face a higher or lower risk compared to a feed-in tariff or fixed bonus policy.

In summary, weather uncertainty affects the risk for renewable-based electricity producers under the three policies differently. Due to the negatively correlated fluctuations in production and wholesale/certificate prices, renewable-based electricity producers may face a lower risk when integrating renewables into the power market or creating a green certificate market. Next, we introduce a simple analytical example to depict the impact of the supply function on the risk for green electricity producers in light of weather uncertainty.

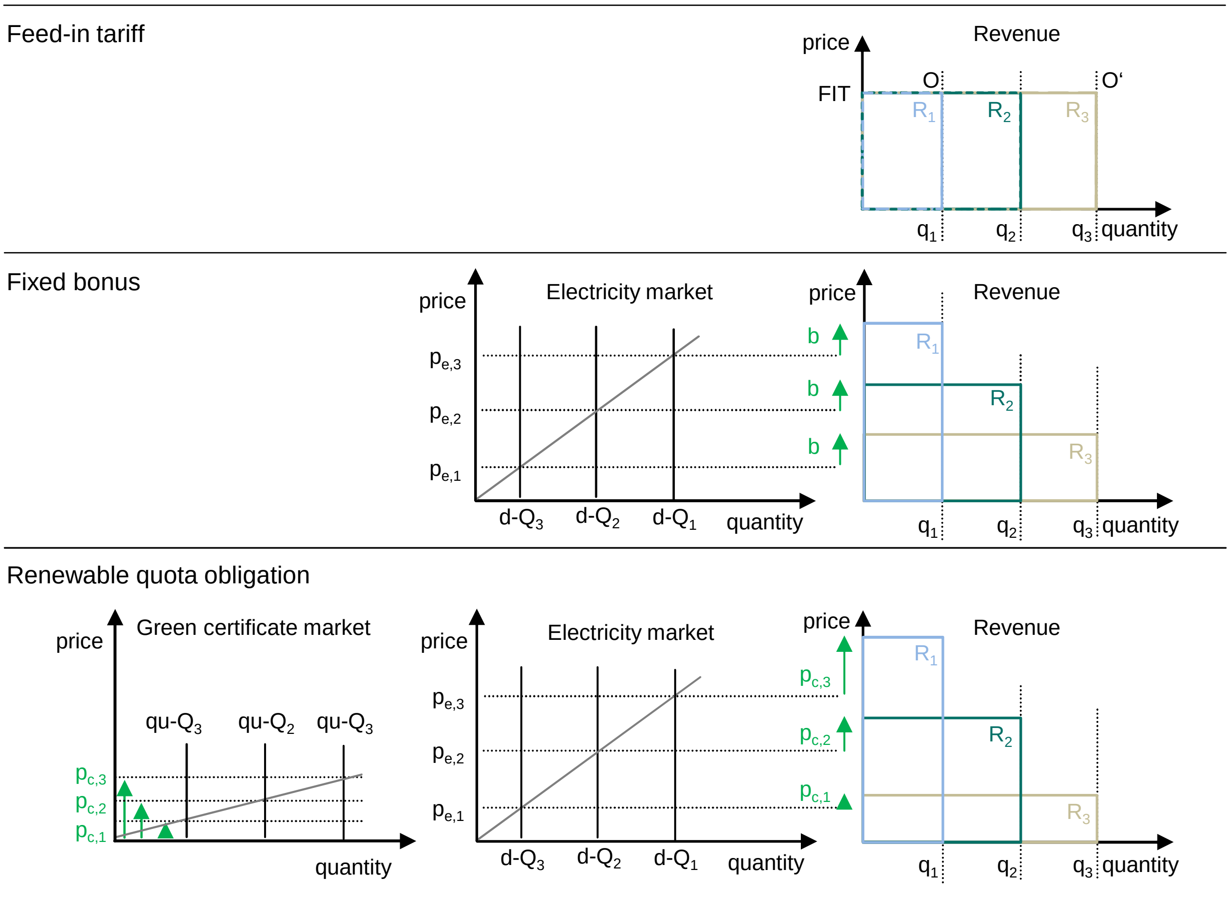

Figure 1: Effect of weather uncertainty on the variance in revenues of green electricity producers

Let us assume a technology with total capital costs $K = 2500$ and intermittent renewable-based electricity generation $q_w = \{14; 15; 16\}$ with equal probability $p = 1/3$. Total electricity demand (inelastic) is $d = 20$ and the marginal cost curve of dispatchable plants (conventional and renewable) is given by $C'_d = \alpha_d \cdot q_d^2 + \gamma_d$ with $\gamma_d = 10$.[3] The rather flat part of the supply function represents the marginal costs of already existing plants (i.e., based on short-term marginal costs). The strong increase in generation costs, due to the quadratic form, depicts the high costs when additional investments are needed (i.e., long-run marginal costs). The variable α_d represents the steepness of the supply function. Given the first-order conditions

[3]Other functions may actually be a better approximation of a typical merit order of dispatchable plants. We pick a quadratic supply curve mainly to keep the example as simple as possible.

for electricity producers, the electricity price is equal to the marginal costs in the equilibrium ($p_e = C'_d = \alpha_d \cdot (d - q_w)_d^2 + 10$). Thus, electricity prices vary due to the fluctuating generation of intermittent renewables with $p_1 = 36 \cdot \alpha_d + 10$; $p_2 = 25 \cdot \alpha_d + 10$ and $p_3 = 16 \cdot \alpha_d + 10$. Under all renewable policies, the expected revenue should equal to total capital costs $E(R_w) = K$ (zero profit condition).

Under a *'feed-in tariff'* policy, the renewable-based electricity producer is offered a long-term contract with guaranteed tariffs (fit) for each unit of electricity fed into the grid. In our example, the feed-in tariff needs to be $fit = \frac{500}{3}$ to allow the renewable-based electricity producer to recover (on average) the capital costs. The variance in revenues simply depends on the volatility in generation and is thus fixed in this framework. Numerically, this is stated as:

Zero profit condition: $\frac{1}{3} \cdot (14 + 15 + 16) \cdot fit = 2500$

$$\Rightarrow fit = \frac{500}{3}$$

thus $R_{fit,1} = \frac{7000}{3}$, $R_{fit,2} = \frac{7500}{3}$ and $R_{fit,3} = \frac{8000}{3}$

and $Var_{fit} = \frac{(R_{fit,1}-K)^2+(R_{fit,2}-K)^2+(R_{fit,3}-K)^2}{3} = 18518\ \frac{14}{27}$

Under a *'fixed bonus'* incentive, renewable-based electricity producers receive the wholesale price and, in addition, a fixed bonus payment ($p_e + b$). The necessary bonus can be determined through the zero profit condition and amounts to $b = \frac{470}{3} - \frac{227}{9} \cdot \alpha_d$.[4] The variance in revenues depends on the slope of the supply function: A relatively low slope of the supply curve leads to a lower variance in revenues, whereas a steep supply curve leads to a greater variance in revenues compared to the case of a feed-in tariff. Numerically, this is stated as:

Zero profit condition: $\frac{1}{3} \cdot [14 \cdot (36 \cdot \alpha_d + 10 + b) + 15 \cdot (25 \cdot \alpha_d + 10 + b)$

$$+16 \cdot (16 \cdot \alpha_d + 10 + b)] = 2500$$

$$\Rightarrow b = \frac{470}{3} - \frac{227}{9} \cdot \alpha_d$$

thus $R_{b,1} = \frac{7000}{3} + \frac{1358}{9} \cdot \alpha_d$, $R_{b,2} = \frac{7500}{3} - \frac{10}{3} \cdot \alpha_d$ and $R_{b,3} = \frac{8000}{3} - \frac{1328}{9} \cdot \alpha_d$

and $Var_b = 14850\ \frac{98}{243} \cdot \alpha_d^2 - 33160\ \frac{40}{81} \cdot \alpha_d + 18518\ \frac{14}{27}$

Under a *'renewable quota (no BaB)'* obligation, producers receive a green certificate for each unit of renewable-based electricity fed into the grid. Thus, renewable-based electricity producers generate revenues

[4] As the bonus is expected to be positive ($b \geq 0$), the slope of the supply curve of dispatchable plants has an upper bound with $\alpha_d \leq \frac{1410}{227}$ in this example.

on the wholesale market and the green certificate market ($p_d + p_c$). The residual supply curve of green certificates represents the marginal cost difference between dispatchable renewables q_r (i.e., biomass) and dispatchable conventional power generation ($p_c = C'_r(q_r) - C'_d(q_d)$). For our example, we assume a green certificate supply curve (residual) with $p_c = \alpha_c \cdot q_r^2 + \gamma_c$ ($\gamma_c > \gamma_d$). The renewable target ($qu = 18$) is expected to be achieved independently of the weather realization. Thus, green certificate prices are given by $p_c = \alpha_c \cdot (qu - q_w)^2 + \gamma_c$: $p_{c,1} = 16 \cdot \alpha_c + \gamma_c$; $p_{c,2} = 9 \cdot \alpha_c + \gamma_c$ and $p_{c,3} = 4 \cdot \alpha_c + \gamma_c$. The resulting function for the variance $Var_{qu}(\alpha_d, \alpha_c)$ indicates that low slopes of the supply curves (α_d and α_c) reduce the variance but high slopes increase it due to the quadratic form. Numerically, this is stated as:

$$\begin{aligned}
\text{Zero profit condition:} \quad & \tfrac{1}{3} \cdot (14 \cdot (36 \cdot \alpha_d + 10 + 16 \cdot \alpha_c + \gamma_c) + 15 \cdot (25 \cdot \alpha_d + 10 \\
& + 9 \cdot \alpha_c + \gamma_c) + 16 \cdot (16 \cdot \alpha_d + 10 + 4 \cdot \alpha_c + \gamma_c)) = 2500 \\
& \Rightarrow \gamma_c = \tfrac{470}{3} - \tfrac{227}{9} \cdot \alpha_d - \tfrac{47}{5} \cdot \alpha_c
\end{aligned}$$

thus $R_{q,1} = \frac{1358}{9} \cdot \alpha_d + \frac{462}{5} \cdot \alpha_c + \frac{7000}{3}$, $R_{q,2} = -\frac{10}{3} \cdot \alpha_d - 6 \cdot \alpha_c + \frac{7500}{3}$ and

$R_{q,3} = -\frac{1328}{9} \cdot \alpha_d - \frac{432}{5} \cdot \alpha_c + \frac{8000}{3}$

$$\begin{aligned}
Var_q = {} & 14850\ \tfrac{98}{243} \cdot \alpha_d^2 + 5346\ \tfrac{6}{25} \cdot \alpha_c^2 + 17807\ \tfrac{13}{45} \cdot \alpha_d \cdot \alpha_c \\
& -33160\ \tfrac{40}{81} \cdot \alpha_d - 19866\ \tfrac{2}{3} \cdot \alpha_c + 18518\ \tfrac{14}{27}
\end{aligned}$$

The variance in revenues under the three renewable policies are affected differently by variations in the slope of the supply function of the power market and the green certificate market (Var_{fit}, $Var_b(\alpha_d)$ and $Var_q(\alpha_d, \alpha_r)$). Figure 2 shows the variance in revenues under the three policies depending on the slope of the power market's supply function. For the variance under a renewable quota obligation, two different cases for the slope of the supply function of green certificates are depicted ($\alpha_c = 1$ and $\alpha_c = 3$).

For the special case of a flat supply curve of dispatchable plants (conventional and renewable with $\alpha_d = 0$), fluctuations in intermittent renewable generation have no effect on the wholesale price. Thus, renewable-based electricity producers face the same variance in revenues under all renewable policies, which represents the fluctuations in power generation.

In power markets with a rather low slope of the supply curve ($0 < \alpha_d < 1.1$), meaning that the power plant mix has similar generation costs, fluctuations in intermittent generation lead to slightly higher (lower) prices in years with low (high) feed-in from intermittent renewables. Thus, the variance in revenues is reduced under bonus support due to slightly higher (lower) revenues in years with low (high) intermittent generation compared to the feed-in tariff support. An increase in the steepness of the supply curve results in more balanced revenues due to the negatively correlated fluctuations in production and wholesale prices. In fact, at a specific steepness ($\alpha_d = 1.1$) the variance in revenues actually becomes zero.

However, in power markets with a rather steep supply curve of dispatchable plants ($\alpha_d > 1.1$), wholesale prices vary substantially due to fluctuations in intermittent power generation. This could be the case in power markets with large base-load capacities that are supplemented by only peak capacities rather than a mix of mid and peak capacities. Due to the large price effect, renewable-based electricity producers achieve large revenues in years with low generation and low revenues in years with high generation. In other words, the price effect overcompensates for the fluctuation in generation and, as a result, the variance becomes relatively large.

A similar effect can be observed under a renewable quota obligation. A relatively low slope of the power market and the green certificate market helps to balance the revenues. However, large price effects on both markets can overcompensate for the fluctuations in production such that the variance in revenues becomes relatively large.

Considering today's power markets in Europe, the most relevant case seems to be a relatively low slope of the supply curve of the power market but a rather steep supply curve of the green certificate market. A large mix of conventional technologies with slightly different efficiency factors (due to the different installation years) and fuel costs usually results in a merit order with a relatively low slope. The supply curve becomes relatively steep once new capacity is needed to cover demand (representing long-term marginal costs). The situation is different for the supply curve of renewable energies. At first, marginal generation costs are zero, as variable generation costs of (existing) wind, solar and hydro plants are negligible. The second part is relatively flat as the costs represent short-term marginal generation costs of (existing) dispatchable plants (mainly biomass plants). Thereafter, the merit order becomes relatively steep, representing the long-term marginal costs of new capacities.

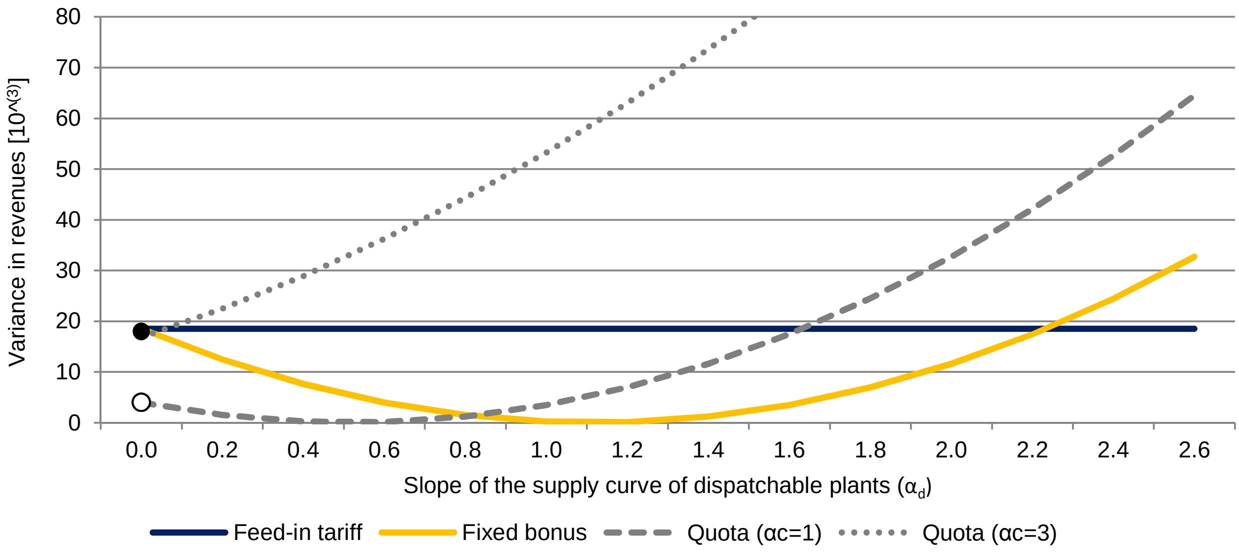

Figure 2: Variance in revenues depending on the slope of the supply curves [10^3]

The effect of weather uncertainty on the risk for renewable-based electricity producers under the most common renewable policies is not obvious. The simple analytical example has shown that the effect depends on the function of the conventional and the renewable supply curves. Furthermore, there remain a few important aspects that have not yet been considered in this simple framework.

First, the simple framework assumes one period of power supply, thus ignoring dynamic effects. Second, we look at the case of one intermittent renewable-based electricity producer (marginal technology) with power generation that is perfectly correlated to all other intermittent renewable generation. It is shown that negatively correlated generation and wholesale/certificate prices may reduce the financial risk. However, taking the example of dispatchable renewables (e.g., biomass), generation can be positively correlated with wholesale/certificate prices. Another example could be negatively correlated generation of wind and solar technologies. Thus, some renewable energies face a higher risk when integrated into the power market due to the positive correlation of production and prices.

As the analytical framework allows us only limited arguments for a policy discussion about a suitable renewable promotion scheme for Europe after 2020, we solve this problem numerically by applying a stochastic simulation model to the European electricity market. The stochasticity as well as the negative correlation of wind and solar power are modeled by three different wind and solar years. The model is not exactly comparable to the analytical example, as several renewable energies and periods are modeled. However, the simulation results allow us to discuss the variance in profits under the different renewable support mechanisms (via a ranking of support mechanisms), the size of the described balancing effects and how different technologies are affected by weather uncertainty.

3. Numerical analysis for the European power market

In this section, the numerical analysis of the financial risk for green electricity producers under weather uncertainty is presented. The analysis is based on a stochastic spatial inter-temporal equilibrium model for the European electricity market. The model considers the uncertainty of annual full load hours of wind and solar technologies. In Subsection 3.1, the electricity market model developed for this analysis is described and the model assumptions are presented in Subsection 3.2. The performance of renewable policies is analyzed based on the model results in Subsection 3.3.

3.1. Model description

The model developed for this analysis is a stochastic spatial inter-temporal equilibrium model for liberalized electricity markets. Economic analyses on spatial markets date back to Samuelson (1952), who developed a framework to describe the equilibrium by modeling marginal inequalities as first-order conditions. Takayama and Judge (1964) reformulated the Samuelson model as a quadratic programming problem and presented a computational algorithm to find the optimal solution for such problems. Spatial equilibrium models have been used to analyze investments under uncertainty or firms with non-competitive market behavior for various energy markets in recent years: coal markets (e.g., Haftendorn and Holz (2010); Paulus and Trüby (2011)); natural gas markets (e.g., Haurie et al. (1988); Zhuang and Gabriel (2008); Hecking and Panke (2012)) and electricity markets (e.g., Hobbs (2001); Metzler et al. (2003); Neuhoff et al. (2005); Lise and Kruseman (2008); Vespucci et al. (2009) as well as Ehrenmann and Smeers (2011)).

The electricity market model developed for this analysis is similar to the perfect competition case of the electricity market model described in Traber and Kemfert (2013). It is formulated as three separate optimization problems. First, a representative European electricity producer (acting as a price taker[5]) maximizes its profit by selling electricity to the domestic market. Second, an international electricity trader acts as an arbitrageur, representing the linkage between model regions (grid investments are exogenous). Third, a transmission system operator regulates the curtailment of wind and solar generation. The model is formulated as a mixed complementary problem by deriving the Karush-Kuhn-Tucker (first-order) conditions for the European electricity producer's, the arbitrageur's and the transmission system operator's maximization

[5]Given the oligopolistic structure of most electricity markets, the competitiveness of power markets, including the European power market, may be questioned (Borenstein et al., 1999; Newberry, 2002). An analysis of how various renewable support schemes are affected by market power is an interesting question but is beyond the scope of this paper.

problem. The model is programmed in GAMS and run with the PATH solver (Dirkse and Ferris, 1995; Ferris and Munson, 1998).

The time horizon of the model is T = 2010, 2013, 2020, 2030,...t,... 2050 on a ten-year basis up to 2050.[6] The model consists of several electricity market regions r $\in$ R where electricity demand and supply must be balanced. All common power generation technologies a $\in$ A (conventional, renewable and storages) are implemented in the model. The set A can be divided into two subsets $A \equiv N \cup Q$, where n $\in$ N is a conventional or storage technology (not subsidized) and q $\in$ Q is a renewable-based technology (potentially subsidized). To distinguish between storage and non-storage technologies, an additional subset b $\in$ B $\in$ A is added. Different electricity demand levels during a single year are represented by several load levels l $\in$ L. An overview of all sets, decision variables and parameters can be found in Table 1.

Representative European electricity producer's maximization problem: power supply

The supply side is modeled by an aggregation of all producers to a single price taking European electricity producer. The European electricity producer maximizes its discounted pay-off function, defined as the revenues from sales and capacity payments minus costs for electricity production, recharging storages, fixed operation and maintenance costs as well as investment costs. In reality, power plant investors face many uncertainties that influence the profitability of their investments. Among others, the electricity demand development, future capital costs, fuel prices, political developments and future competition are uncertain. Another source of uncertainty is the stochastic annual generation of wind and solar technologies. Empirical data shows that full load hours vary by a magnitude of more than 20 % from the long-term average. The volatility of annual wind and solar generation has a large impact in electricity systems with a high share of wind and solar technologies (Nagl et al., 2013). In the presented model, the stochasticity as well as the negative correlation of wind and solar power are represented by a low wind/high solar year (w_1), an average wind/average solar year (w_2) and a high wind/low solar year (w_3). The European electricity producer is assumed to be risk-neutral[7] and thus maximizes expected profit.

The model allows different renewable support schemes: *'feed-in tariff'* (bf=1), *'fixed bonus'* (bp=1) and *'renewable quota obligation'* (bg=1). It is important to note that all support schemes are technology-neutral, independent of the installation year and implemented across Europe (harmonized European policy). In all

[6]To account for different technical lifetimes of technologies, the years 2060 and 2070 are additionally modeled but not interpreted.

[7]In many economic situations, firms seem to act rather risk-averse (Mas-Colell et al., 1995). Nevertheless, the analysis assumes a risk-neutral electricity producer to simply quantify investment risks under various support schemes rather than analyze how producers react to uncertainty, given their risk preference.

support mechanisms, payments are guaranteed even if generation cannot be integrated into the grid (energy is curtailed by the transmission system operator). Renewable generator have to make an annual decision whether to receive the renewable subsidy or the market price. Furthermore, it is assumed that the European renewable policy is already implemented in 2013. As only one renewable support scheme can be in place at a time, bf + bp + bg = [0;1].

The pay-off function Π_f can be written as shown in (1a) to (1k). Line (1a) defines the annual revenues gained from electricity sales generated in conventional and storage plants (non-subsidized). Sales ($S_{t,r,l,f,a,w}$) are rewarded by the domestic electricity price ($\phi_{t,r,l,w}$) at the specific load level multiplied by the number of hours (h_l). Line (1b) defines the revenues from renewable-based sales (subsidized generation) depending on the specific support mechanism.[8] Line (1c) defines the revenues from the reserve market that firms can achieve by offering securely available capacity to the market (technology-specific capacity factor ca_a). Due to the simplification to a few dispatch situations per model year, potential peak demand is not considered as a dispatch situation. The modeled capacity market simply ensures that sufficient investments in back-up capacities are made to meet potential peak demand. However, such investments could also be triggered in an energy-only market in the event of price peaks.[9] Line (1d) defines the variable production costs, including fuel and CO_2 emission costs, for the generated electricity for each technology. Storage technologies can be recharged ($P_{t,r,l,f,a,w}$), but electricity has to be bought on the market as stated in line (1e). Line (1f) defines the fixed operation and maintenance costs. Line (1g) defines investment costs, which are annualized with an interest rate (ir) and occur until the end of the plant's technical lifetime. An earlier decommissioning of power plants is not considered in the model.

Profit maximization of the European electricity producer is constrained by a set of restrictions for production capacities and storage limits, as defined in line (1h) - (1k). The variables in parentheses on the right hand side of each constraint are the Lagrange multipliers used when developing the first-order conditions. Line (1h) states that available capacity (considering outages and revisions) has to be greater or equal to generation at all times. Line (1i) ensures that electricity charging is at least as high as generation from storage capacities on an annual basis. Line (1j) restricts the capacity potential for all technologies. Line (1k) states the typical non-negativity constraints.

[8] In the first model year (2010), no renewable support is modeled and therefore all technologies receive the market price.

[9] Based on the International Energy Agency, 'markets in which marginal pricing of electricity is the only remuneration are often called energy-only markets' (IEA, 2007). It is an ongoing debate whether sufficient incentives to invest in generation capacity exist in energy-only markets (Joskow (2008), Cramton and Stoft (2005) and Cramton and Stoft (2008)). Implementing a capacity market in this model is purely a result of the chosen model approach.

Table 1: Model sets, variables and parameters

Sets		
a ∈ A	technologies for power generation	
b ∈ B ∈ A	storage technologies	
q ∈ Q ∈ A	renewable technologies	
n ∈ N ∈ A	not subsidized technologies	
f ∈ F	electricity producer	
l, l' ∈ L	load levels	
r, r' ∈ R	regions	
t, t' ∈ T	time periods	
w ∈ W	weather years	
Boolean policy		
bf	boolean indicating feed-in tariffs as support	[0;1]
bp	boolean indicating bonus payments as support	[0;1]
bg	boolean indicating green certificate market as support	[0;1]
Primal variables		
$\Pi_{f/ARB/TSO}$	profit of producer, arbitrageur or transmission operator	EUR_{2010}
$I_{t,r,f,a}$	capacity investments	MW
$E_{t,r,l,r',w}$	electricity exchange	MW
$S_{t,r,l,f,a,w}$	domestic sales / generation	MW
$P_{t,r,l,f,a,w}$	charging storage	MW
$M_{t,r,l,w}$	renewable curtailment	MW
Dual variables		
$\alpha_{t,r,l,f,a,w}$	shadow price of capacity constraint	EUR_{2010}/MW
$\beta_{t,r,f,a,w}$	shadow price of annual storage constraint	EUR_{2010}/MW
$\gamma_{t,r,f,a}$	shadow price of capacity potential	EUR_{2010}/MW
$\phi_{t,r,l,w}$	shadow price of power equation (electricity price)	EUR_{2010}/MWh
$\chi_{t,r,l,r',w}$	shadow price of transfer constraint (congestion price)	EUR_{2010}/MWh
$\psi_{t,w}$	shadow price of renewable constraint (certificate price)	EUR_{2010}/MWh
$\omega_{t,r}$	shadow price of peak capacity constraint (reserve price)	EUR_{2010}/MW
Parameters		
$ai_{t,r,f,a,t'}$	boolean indicating technical lifetime (t'=periods after t)	[0;1]
$av_{r,l,a,w}$	capacity availability	MW/$MW_{inst.}$
bb_a	boolean indicating storage technologies	[0;1]
$bc_{t,a}$	fuel costs	EUR_{2010}/MWh_{th}
$bi_{t,r,f,a,t'}$	boolean investments in previous periods (t'=periods before t)	EUR_{2010}/MWh
bo_t	fixed bonus payment	[0;1]
ca_a	percentage of securely available capacity	MW/$MW_{inst.}$
$cp_{t,r,f,a}$	capacity potential	MW
$d_{t,r,l}$	electricity load	MW
$dp_{t,r}$	peak electricity demand	MW
dr_t	discount factor	%
$ec_{t,r,f,a}$	existing capacity	MW
ef_a	emission factor	t CO_2 /MWh_{th}
et_t	tax on CO_2 emissions	EUR_{2010}/t CO_2
η_a	net efficiency of power plants	MWh_{el}/MWh_{th}
$fc_{t,a}$	yearly fixed operation and maintenance costs	EUR_{2010}/MWa
fit_t	feed-in tariff	EUR_{2010}/MWh
$fp_{t,r,r'}$	net transfer capacity	MW
h_l	number of hours	h
$ic_{t,a}$	investment costs	EUR_{2010}/MW
ir	interest rate	%
lh_b	losses in storage charging	%
$lo_{r,r'}$	transfer losses	%
$pl_{a,w}$	boolean for technologies receiving market price	[0;1]
pr_w	probability of weather realizations	%
qu_t	demanded RES-E share	%
qq_a	boolean indicating renewable technologies	[0;1]
tl_a	technical lifetime of technologies	a
tr_t	number of years	-
$vc_{t,a}$	variable costs	EUR_{2010}/MW
$y_{t,r,f,a}$	natural inflow storage technologies	MWh
$\bar{\phi}$	minimal price for curtailment (helping parameter)	EUR_{2010}/MWh

Optimization problem of European electricity producer: electricity supply

$$\max_{I_{t,r,f,a};S_{t,r,l,f,a,w};P_{t,r,l,f,a,w}} \Pi_f = \sum_{t\in T} dr_t \cdot tr_t \cdot [\sum_{r\in R}\sum_{l\in L}\sum_{a\in N}\sum_{w\in W}(pr_w \cdot h_l \cdot \phi_{t,r,l,w} \cdot S_{t,r,l,f,a,w}) \tag{1a}$$

$$+\sum_{r\in R}\sum_{l\in L}\sum_{a\in Q}\sum_{w\in W}(pr_w \cdot h_l \cdot S_{t,r,l,f,a,w} \cdot (bf \cdot fit_t + bp \cdot (\phi_{t,r,l,w} + bo_t) + bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}))) \tag{1b}$$

$$+\sum_{r\in R}\sum_{a\in A}(\omega_{t,r} \cdot ca_a \cdot (ec_{t,r,f,a} + \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))) \tag{1c}$$

$$-\sum_{r\in R}\sum_{l\in L}\sum_{a\in A}\sum_{w\in W}(pr_w \cdot h_l \cdot \frac{bc_{t,a} + ef_a \cdot et_t}{\eta_a} \cdot S_{t,r,l,f,a,w}) \tag{1d}$$

$$-\sum_{r\in R}\sum_{l\in L}\sum_{a\in B}\sum_{w\in W}(pr_w \cdot h_l \cdot \phi_{t,r,l,w} \cdot P_{t,r,l,f,a,w}) \tag{1e}$$

$$-\sum_{a\in A}(fc_{t,a} \cdot (ec_{t,r,f,a} + \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))) \tag{1f}$$

$$-\sum_{a\in A}(ic_{t,a} \cdot \frac{(1+ir)^{tl_a} \cdot ir}{(1+ir)^{tl_a} - 1} \cdot \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))] \tag{1g}$$

s.t.

$$S_{t,r,l,f,a,w} + P_{t,r,l,f,a,w} - av_{r,l,a,w} \cdot \left(ec_{t,r,f,a} + \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a})\right) \leq 0 \qquad (\alpha_{t,r,l,f,a,w}) \qquad \forall t,r,l,f,a,w. \tag{1h}$$

$$\sum_{l\in L}(h_l \cdot S_{t,r,l,f,a,w}) - y_{t,r,f,a} - \sum_{l\in L}(h_l \cdot P_{t,r,l,f,a,w} \cdot (1 - lh_b)) \leq 0 \qquad (\beta_{t,r,f,a,w}) \qquad \forall t,r,f,a,w. \tag{1i}$$

$$\left(ec_{t,r,f,a} + \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a})\right) - cp_{t,r,f,a} \leq 0 \qquad (\gamma_{t,r,f,a}) \qquad \forall t,r,f,a. \tag{1j}$$

$$I_{t,r,f,a};\ S_{t,r,l,f,a,w};\ P_{t,r,l,f,a,w} \geq 0 \tag{1k}$$

The next step in developing the model is to derive the Karush-Kuhn-Tucker conditions from the Lagrangian $\mathcal{L}_f$ of the original optimization problem. Equation 2 defines the equilibrium condition for electricity sales. Electricity is generated as long as the expected revenues are greater than production ($\mathrm{vc}_{t,a}$) and capacity costs ($\alpha_{t,r,l,f,a,w}$).[10] Electricity generation from renewable sources receive additional payments depending on the support scheme. Electricity generation from storage technologies also consider the shadow price of the annual storage equilibrium condition ($h_t \cdot \beta_{t,r,f,a,w}$).[11]

$$\begin{aligned}\frac{\partial \mathcal{L}_f}{\partial S_{t,r,l,f,a,w}}:\ & dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (-pl_{a,w} \cdot \phi_{t,r,l,w} - bf \cdot fit_t \\ & -bp \cdot (\phi_{t,r,l,w} + bo_t) - bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}) + vc_{t,a}) \\ & +\alpha_{t,r,l,f,a,w} + bb_a \cdot h_l \cdot \beta_{t,r,f,a,w} \geq 0 \quad \perp S_{t,r,l,f,a,w} \qquad \forall t,r,l,f,a,w.\end{aligned} \tag{2}$$

Equation 3 defines the equilibrium condition for charging storage technologies. Storage operators charge their storages as long as the market price is lower than the marginal price of the annual storage equilibrium condition ($\beta_{t,r,f,a,w}$), while considering losses during charging operations (1-lh_b) and the capacity limit ($\alpha_{t,r,l,f,a,w}$).

$$\begin{aligned}\frac{\partial \mathcal{L}_f}{\partial P_{t,r,l,f,a,w}}:\ & dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot \phi_{t,r,l,w} + \alpha_{t,r,l,f,a,w} \\ & -h_l \cdot (1 - lh_b) \cdot \beta_{t,r,f,a,w} \geq 0 \quad \perp P_{t,r,l,f,a,w} \geq 0 \qquad \forall t,r,l,f,w,a \in B.\end{aligned} \tag{3}$$

Equation 4 defines the equilibrium condition for investments in new power plants and storage facilities. Investments are made as long as the sum of marginal benefits of additional capacity is greater than fixed operation and maintenance costs, investment costs and the marginal price of the capacity potential constraint ($\gamma_{t,r,f,a}$) over the total lifetime.

$$\begin{aligned}\frac{\partial \mathcal{L}_f}{\partial I_{t,r,f,a}}:\ & -\sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot \omega_{t,r}) + \sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot fc_{t,a}) \\ & + \sum_{t' \in T} \left(ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot ic_{t,a} \cdot \frac{(1+ir)^{tl_a} \cdot ir}{(1+ir)^{tl_a} - 1} \right) + \sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot \gamma_{t,r,f,a}) \\ & - \sum_{l \in L} \sum_{w \in W} av_{r,l,a,w} \cdot \sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot \alpha_{t,r,l,f,a,w}) \geq 0 \\ & \perp I_{t,r,f,a} \geq 0 \qquad \forall t,r,f,a,w.\end{aligned} \tag{4}$$

[10] The dual variable of the capacity constraint ($\alpha_{t,r,l,f,a,w}$) is zero unless the capacity constraint is binding.

[11] Under a feed-in tariff system or quota w/out market integration, renewable technologies with lower variable costs than the offered feed-in tariff/certificate price generate electricity at full available capacity at all times. If the offered feed-in tariff is equally high as the variable costs, the first-order condition for electricity generation is then fulfilled for zero to maximal generation (no unique solution). To force the model to reach an unique solution, negligible increasing variable costs are modeled. Hence, the first-order condition with regard to electricity generation is actually: $dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (-pl_{a,w} \cdot \phi_{t,r,l,w} - bf \cdot fit_t - bp \cdot (\phi_{t,r,l,w} + bo_t) - bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}) + (vc_{t,a} + epsilon \cdot S_{t,r,l,f,a,w})) + \alpha_{t,r,l,f,a,w} + bb_a \cdot h_l \cdot \beta_{t,r,f,a,w} \geq 0$.

Arbitrageur's maximization problem: linkage between model regions

Model regions are linked by introducing an arbitrageur, as described in Traber and Kemfert (2013), who takes advantage of different price levels across regions. Modeling an arbitrageur, rather than allowing producers to export electricity to another region, is purely due to computational reasons (reducing the amount of variables). The pay-off function of the arbitrageur Π_{ARB} can be written as shown in (5a) to (5c). Line (5a) defines the revenues gained from trading electricity across regions ($\mathrm{E}_{t,r,l,r',w}$), considering transmission losses ($\mathrm{lo}_{r,r'}$). Transmission losses are assumed to be linear, depending on the average distance between regions. Transmission capacities ($\mathrm{fp}_{t,r,r'}$) are restricted as defined in (5b). Line (5c) is the typical non-negativity constraint.

$$\max_{E_{t,r,l,r',w}} \Pi_{ARB} = \sum_{t\in T} dr_t \cdot tr_t \cdot pr_w \cdot \tag{5a}$$

$$\sum_{r\in R}\sum_{l\in L}\sum_{r'\in R}\sum_{w\in W} ((h_l \cdot pr_w \cdot (\phi_{t,r',l,w} \cdot lo_{r,r'} - \phi_{t,r,l,w}) \cdot E_{t,r,l,r',w})$$

$s.t.$

$$E_{t,r,l,r',w} - fp_{t,r,r'} \leq 0 \qquad (\chi_{t,r,l,r',w}) \qquad \forall t,r,l,r',w. \tag{5b}$$

$$E_{t,r,l,r',w} \geq 0 \tag{5c}$$

The Karush-Kuhn-Tucker condition from the Lagrangian $\mathcal{L}_{ARB}$ of the arbitrageur's maximization problem with regard to electricity transports is shown in Equation 6. The arbitrageur transports electricity between two regions if the market price of the import region accounting for transmission losses is greater than or equal to the market price in the export region plus the congestion fee ($\chi_{t,r,l,r',w}$). The congestion fee is zero until the transmission line operates at full capacity.

$$\begin{aligned} \frac{\partial \mathcal{L}_{ARB}}{\partial E_{t,r,l,r',w}} : \quad & -dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (lo_{r,r'} \cdot \phi_{t,r',l,w} - \phi_{t,r,l,w}) + \chi_{t,r,l,r',w} \\ & \perp E_{t,r,l,r',w} \geq 0 \qquad \forall t,r,l,r',w. \end{aligned} \tag{6}$$

Transmission system operator's maximization problem

The transmission system operator monitors the curtailment of fluctuating renewable generation. Due to the renewable support, renewable producers may generate electricity even if the market price is zero. The wholesale price drops to zero if the regional electricity demand is met and transfer capacities, as well as storage capacities, are operating at their capacity limit. In practice, transmission system operators order renewable generators to reduce their generation (e.g., turning wind turbines) in the event of such a situation. However, in some support schemes, renewable producers still receive the subsidy payment despite the needed curtailment.

From a modeling perspective, there is no difference between a transmission operator absorbing the electricity surplus and renewable-based producers reducing generation. Renewable curtailment ($M_{t,r,l,w}$) is modeled by giving the transmission system operator an incentive to take care of surplus electricity in these situations. The transmission system operator receives the price difference between the defined minimum electricity price ($\bar{\phi} \leq 1.0 \cdot E^{-5}$) and the actual wholesale price per curtailed unit. In other words, the transmission system operator increases the electricity demand until the wholesale price increases to the defined minimum. Given no further restrictions, the transmission system operator's profit is zero in all possible scenarios as the price difference converges to zero in the equilibrium ($\bar{\phi} - \phi_{t,r,l,w} = 0$). It is important to note that electricity generators receive the renewable subsidy for their generation. The resulting profit function is stated in Line (7a). Line (7b) is the typical non-negativity constraint.

$$\max_{M_{t,r,l,w}} \Pi_{TSO} = \sum_{t \in T} dr_t \cdot tr_t \cdot pr_w \cdot \left[\sum_{r \in R} \sum_{l \in L} (h_l \cdot pr_w \cdot \left(\bar{\phi} - \phi_{t,r,l,w}\right) \cdot M_{t,r,l,w}) \right] \tag{7a}$$

$$s.t.$$

$$M_{t,r,l,w} \geq 0 \tag{7b}$$

The Karush-Kuhn-Tucker condition from the Lagrangian $\mathcal{L}_{TSO}$ of the transmission system operator's maximization problem with regard to renewable curtailment ($M_{t,r,l,w}$) is shown in Equation 8. From a modeling perspective, the transmission system operator absorbs electricity (or in other words, increases electricity demand) as long as the wholesale price is below the defined limit ($\bar{\phi} \leq 1.0 \cdot E^{-5}$) for the electricity price.

$$\frac{\partial \mathcal{L}_{TSO}}{\partial M_{t,r,l,w}} : \quad \phi_{t,r,l,w} - \bar{\phi} \geq 0 \quad \perp M_{t,r,l,w} \; \geq 0 \qquad \forall t, r, l, w. \tag{8}$$

Market clearing conditions

In addition to the derived first-order conditions of the European electricity producer, the arbitrageur and the transmission system operator, three market clearing conditions define the equilibrium of the market. Equation 9 ensures that the hourly regional electricity demand ($\mathrm{d}_{t,r,l}$) is satisfied by domestic or foreign electricity supply. Electricity demand is assumed to be price inelastic as real-time elasticity of electricity demand seems to be rather low.[12] The charging of storages ($\mathrm{P}_{t,r,l,f,a,w}$) and renewable curtailment ($\mathrm{M}_{t,r,l,w}$) increase the fixed electricity demand at the specific load level.

$$\begin{aligned} d_{t,r,l} + \sum_{f \in F} \sum_{a \in B} (P_{t,r,l,f,a,w}) + M_{t,r,l,w} - \sum_{f \in F} \sum_{a \in A} (S_{t,r,l,f,a,w}) \\ - \sum_{r' \in R} (lo_{r,r'} \cdot E_{t,r,l,r',w}) + \sum_{r' \in R} (E_{t,r',l,r,w}) = 0 \quad \phi_{t,r,l,w} \ \mathit{free} \qquad \forall t, r, l, w. \end{aligned} \tag{9}$$

Equation 10 is the market clearing condition for the green certificate market. When renewables are subsidized by a quota obligation, this condition defines the demanded RES-E generation and sets a market price for green certificates (ψ_t). The demanded renewable target refers to the total renewable generation in all regions (Europe-wide). It is important to note that a higher renewable generation than demanded leads to certificate prices equal to zero. Moreover, curtailed energy does not contribute to the renewable generation target.

$$\begin{aligned} \sum_{r \in R} \sum_{l \in L} \sum_{f \in F} \sum_{a \in Q} (h_l \cdot S_{t,r,l,f,a,w}) - \sum_{r \in R} \sum_{l \in L} (h_l \cdot M_{t,r,l,w}) \\ -qu_t \cdot \sum_{r \in R} \sum_{l \in L} (h_l \cdot d_{t,r,l}) \geq 0 \quad \perp \psi_{t,w} \geq 0 \qquad \forall t, w. \end{aligned} \tag{10}$$

Equation 11 is the market clearing condition for the capacity reserve market. It ensures that a politically defined amount of securely available capacity ($\mathrm{dp}_{t,r}$) is installed in each region. Given limited cross-border transmission capacities, the almost simultaneous occurrence of peak loads across Europe and the need for regional flexible generation to control the grid frequency, it is unclear to what extent capacities in other regions are able to contribute to the securely available capacity. Thus, it is assumed that only regional power plants can participate in the regional capacity reserve markets.

$$\begin{aligned} \sum_{a \in A} \left(ca_a \cdot \left(ec_{t,r,f,a} + \sum_{t' \in T} (bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}) \right) \right) - dp_{t,r} \geq 0 \\ \perp \omega_{t,r} \geq 0 \qquad \forall t, r. \end{aligned} \tag{11}$$

[12]Price elasticity of demand is defined as the percentage change in quantity demanded given a one percent change in price ($\eta = \frac{dQ/Q}{dP/P}$). Empirical data on real-time elasticity of electricity demand can be found in Lijesen (2007).

The model is defined by the first-order conditions (2 - 4) and restrictions (1h - 1k) of the European electricity producer; the first-order condition (6) and the restrictions (5b - 5c) of the arbitrageur, the first-order condition (8) and the restriction (7b) of the transmission system operator as well as the market clearing conditions (9 - 11). Modeling eight regions and ten technologies up to 2070 in ten year time steps, the model contains of about 32,000 variables/constraints. The PATH solver tends to not converge when modeling a renewable policy. Hence, the solution of the system with no support is always used as a first starting point. Then, tariffs or quotas are increased over up to 100 iterations, each time using the previous solution as new starting point.

3.2. Assumptions

The model results are based on many assumptions including the regional electricity demand development, net transfer capacities between regions, existing power plants, technical and economic parameters for power plant investments and fuel and CO_2 prices. It is clear that the scenario setting chosen for this analysis is only one possible development and should not be interpreted as a forecast. The assumptions are based on several databases such as IEA (2011), Prognos/EWI/GWS (2010), ENTSO-E (2011) and EWI (2011).

Net electricity demand

The scenarios assume a similar demand development as described in EWI (2011). Yearly net electricity demand is assumed to increase in all regions until 2050. A strong increase, 0.7-1.95 % per year, is assumed until 2020, in particular due to the further economic development in Southern Europe. In the long term, growth rates are assumed to decrease to 0-1.35 % per year, among others, due to the application of energy efficient technologies. Two load levels (base and peak) are modeled based on the structure of the load duration curve in 2009 (ENTSO-E, 2011). In the scenarios, peak load is defined as the average of the 10 % highest electricity load levels. The demand structure, referring to the ratio between peak and base load, is assumed to remain as in 2009. Thus, base demand (l_1) occurs in 7970 hours and peak demand (l_2) in 790 hours each year. Table 2 depicts the two assumed load levels, absolute peak demand and the resulting annual electricity consumption for each region from 2020 to 2050.

Table 2: Electricity loads [GW] and annual (net) electricity demand [TWh]

			ATCH	BNL	FR	GER	IB	IT	SCAN	UK
2020	l_1	GW	15.5	26.0	57.7	68.0	42.1	43.2	48.0	49.4
	l_2	GW	21.5	33.6	83.2	90.2	56.1	57.2	67.6	69.5
	dp	GW	23.7	37.0	91.5	99.2	61.8	62.9	74.4	76.5
	annual	TWh	140.2	233.9	525.4	613.6	379.5	389.8	435.8	448.4
2030	l_1	GW	16.5	27.7	61.5	70.1	48.4	42.1	51.2	52.6
	l_2	GW	22.9	35.8	88.7	92.9	64.6	56.1	72.1	74.1
	dp	GW	25.2	39.4	97.5	102.2	71.0	61.8	79.3	81.6
	annual	TWh	149.4	249.3	560.1	632.1	436.6	379.5	464.6	478.0
2040	l_1	GW	17.5	29.4	65.2	70.1	55.4	48.4	54.3	55.8
	l_2	GW	24.3	38.0	94.1	92.9	73.9	64.6	76.5	78.7
	dp	GW	26.8	41.8	103.5	102.2	81.3	71.0	84.1	86.5
	annual	TWh	158.5	264.5	594.3	632.1	499.8	436.6	492.9	507.1
2050	l_1	GW	18.5	31.1	68.9	70.1	63.1	55.4	57.3	58.9
	l_2	GW	25.7	40.1	99.3	92.9	84.3	73.9	80.7	83.0
	dp	GW	28.3	44.2	109.2	102.2	92.7	81.3	88.8	91.3
	annual	TWh	167.4	279.3	627.4	632.1	569.6	499.8	520.4	535.4

Remark: Austria-Switzerland (ATCH); BeNeLux (BNL); France (FR); Germany (GER); Iberian Peninsula (IB); Italy (IT); Scandinavia (SCAN) and United Kingdom (UK).

Technologies and generation costs

The model includes conventional, renewable and storage technologies. The regional existing power plant fleet is based on the power plant database of the Institute of Energy Economics at the University of Cologne. Power plant data including net capacity, efficiency factors and location has been collected from a multitude of different sources (including company reports and Platts database 2012). Table 3 gives an overview of the technical and economic parameters of the modeled technologies. The assumptions are based on different databases such as IEA (2011), Prognos/EWI/GWS (2010) and EWI (2011). Additionally, it is assumed that lignite-fired power plants emit 0.406 t CO_2 /MWh_{th}, hard-coal plants 0.335 t CO_2 /MWh_{th} and natural gas-fired plants 0.201 t CO_2 /MWh_{th}.

Table 3: Technical and economic parameters of generation technologies

Technology	FOM costs [EUR_{2010}/kWa]	Lifetime [a]	Efficiency (η_{load}) [%]	Capacity factor [%]
Nuclear	97	60	33.0	85
Lignite	43	40	42.5	87
Hard-coal	36	40	47.0	87
CCGT	28	30	57.0	87
OCGT	17	20	27.0	87
Pump-Storage	12	100	87.0 (83.0)	70
CAES-Storage	10	30	86.0 (81.0)	50
Hydro resevoir and river	12	100	-	50
Biomass	120	30	40.0	85
Photovoltaics	30	20	-	0
Wind onshore	41	20	-	5
Wind offshore	150	20	-	5

Compared to today, investment costs of renewable technologies, and particularly of photovoltaics, are assumed to decrease significantly until 2050. To determine the annual capital costs, as described in line (1g) of the electricity producer's maximization problem, a technology-independent interest rate of 10 % is assumed. Table 4 shows the assumed development of investment costs for the different technologies.

Due to the limited potential, hydro reservoirs, run-of-river and pump storage facilities are not considered as an investment option. Investments in nuclear power plants are restricted to the countries already using nuclear power today. Moreover, total regional nuclear capacity is bounded by today's existing capacity. In Germany, nuclear power generation is prohibited due to the nuclear phase-out starting from 2020 (actually planned for 2022). Furthermore, fuel bounds apply for lignite and biomass plants. Additionally, regional wind and solar capacities are bounded by regional space potentials.

Table 4: Investment costs of technologies [EUR_{2010}/kW]

	2020	2030	2040	2050
Nuclear	3,300	3,300	3,300	3,300
Lignite	1,850	1,850	1,850	1,850
Hard-coal	1,500	1,500	1,500	1,500
CCGT	950	950	950	950
OCGT	400	400	400	400
CAES-Storage	850	850	850	850
Biomass (gas)	2,400	2,400	2,400	2,400
Biomass (solid)	3,000	3,000	3,000	3,000
Photovoltaics	1,300	950	800	750
Wind onshore	1,350	1,150	1,100	1,100
Wind offshore	3,150	2,950	2,850	2,800

The fluctuating feed-in of wind and solar technologies is approximated by different availability factors at each load level, as shown in Table 5. At each load level, a low and high wind and solar availability is modeled based on the empirical data of 2007-2010, in total four dispatch situations.[13] The low availability represents the 30 % quantile and the high value represents the 70 % quantile at the respective load level. Varying regional renewable conditions are reflected by different full load hours. In addition, uncertainty concerning annual full load hours of wind and solar technologies is represented by a low-average-high wind (solar) year. In the low (high) wind year, full load hours are 20 % lower (higher) than in the average year. The negative correlation between wind and solar power is approximated by assuming 10 % higher (lower) full load hours of solar technologies in the low (high) wind year. It is further assumed that the average weather year w_2 occurs with a probability of 60 % and the weather years w_1 and w_3 with a probability of 20 %.

Table 5: Availability of fluctuating renewables for $w_1/w_2/w_3$ [% or MW/MW$_{inst.}$]

		base		peak		
		low	high	low	high	full load hours
Solar						
	ATCH	5/5/4	23/21/19	1/1/1	11/10/9	1155/1050/945
	BNL	5/4/4	19/17/15	1/1/1	6/6/5	963/875/788
	FR	4/3/3	28/26/23	2/2/1	12/11/10	1320/1200/1080
	GER	5/4/4	20/18/16	1/1/1	9/8/7	1018/925/833
	IB	4/4/3	34/31/28	3/3/2	18/16/14	1595/1450/1305
	IT	4/3/3	33/30/27	3/3/2	17/15/14	1540/1400/1260
	SCAN	5/4/4	17/16/14	0/0/0	2/2/2	880/800/720
	UK	4/4/3	19/17/16	1/1/1	6/5/5	946/860/774
Wind onshore						
	ATCH	10/12/15	20/24/29	2/2/3	26/33/39	1280/1600/1920
	BNL	12/15/18	32/40/47	9/12/14	36/45/54	1920/2400/2880
	FR	12/15/18	29/37/44	13/16/20	35/44/53	1840/2300/2760
	GER	11/13/16	23/28/34	6/8/9	21/26/31	1440/1800/2160
	IB	13/16/19	21/27/32	10/13/15	27/34/41	1520/1900/2280
	IT	10/12/15	16/20/24	8/9/11	21/26/31	1140/1425/1710
	SCAN	7/9/11	41/51/61	15/18/22	45/56/67	2160/2700/3240
	UK	16/19/23	44/55/66	17/21/26	42/52/63	2600/3250/3900
Wind offshore						
	BNL	21/26/31	53/66/79	23/29/35	46/57/69	3200/4000/4800
	FR	17/21/26	41/51/61	25/31/37	40/50/60	2560/3200/3840
	GER	19/24/29	40/50/61	17/21/25	28/35/42	2560/3200/3840
	IB	14/17/21	23/28/34	14/17/21	24/30/36	1600/2000/2400
	IT	12/15/19	20/25/31	12/16/19	22/27/33	1440/1800/2160
	SCAN	27/34/40	45/56/68	30/37/45	53/67/80	3200/4000/4800
	UK	17/21/25	49/61/73	27/34/41	41/51/62	2880/3600/4320

Remark: Austria-Switzerland (ATCH); BeNeLux (BNL); France (FR); Germany (GER); Iberian Peninsula (IB); Italy (IT); Scandinavia (SCAN) and United Kingdom (UK).

The assumed fuel prices are based on international market prices and transportation costs to the power plants. The price for hard coal is assumed to increase from 11.9 EUR$_{2010}$/MWh$_{th}$ in 2010 to

[13] The assumed full load hours are based on hourly wind speeds and solar radiation from EuroWind (2011).

12.7 EUR_{2010}/MWh_{th} in 2050. For domestic lignite a constant price of 1.4 EUR_{2010}/MWh_{th} is assumed. Despite the current excess supply and low prices of natural gas, a significant increase up to 25.3 EUR_{2010}/MWh_{th} is assumed for the long term. The price for biomass is assumed to increase up to 37.5-85.1 EUR_{2010}/MWh_{th}. In addition to the modeled renewable target, an increasing tax on CO_2 emissions of up to 20.0 EUR_{2010}/t CO_2 in 2050 is assumed. Table 6 shows the assumed development of fuel prices for thermal power plants in the scenarios.

Table 6: Fuel [EUR_{2010}/MWh_{th}] and CO_2 prices [EUR_{2010}/t CO_2]

	2020	2030	2040	2050
Nuclear	3.3	3.3	3.3	3.3
Lignite	1.4	1.4	1.4	1.4
Hard-coal	11.5	11.7	12.2	12.7
Natural gas	18.2	22.3	23.7	25.3
Biomass	0.1-27.7-67.2	0.1-34.9-72.9	0.1-35.1-78.8	0.1-37.7-85.1
CO_2 price [EUR_{2010}/t CO_2]	15.0	17.5	20.0	20.0

Net transfer capacities

Due to computational constraints, only a limited number of regions can be modeled. Within each region, limited transmission capacities cannot be considered. Hence, in all modeled scenarios a substantial increase of transmission capacities in Europe is assumed. For example, grid extensions have to be large enough within the United Kingdom to transport large amounts of wind energy along the northern and western coastlines to central England.

However, the model considers transfer restrictions between model regions based on net transfer capacities. In the scenarios, a similar extension of cross-border transmission capacities as described in EWI (2011) is assumed. In 2050, total cross-border capacities are assumed to be more than five times as large as today's levels. Table 7 lists assumed net transfer capacities between model regions.

Table 7: Assumed net transfer capacities between model regions [GW]

		2020	2030	2040	2050
Austria-Switzerland (ATCH)	France (FR)	3.0	3.0	3.0	3.2
Austria-Switzerland (ATCH)	Germany (GER)	3.2	3.2	3.2	5.9
Austria-Switzerland (ATCH)	Italy (IT)	1.4	1.4	2.4	5.0
BeNeLux (BNL)	France (FR)	3.2	3.2	4.2	4.2
BeNeLux (BNL)	United Kingdom (UK)	1.0	1.0	1.0	1.0
BeNeLux (BNL)	Germany (GER)	3.9	5.8	5.8	6.7
BeNeLux (BNL)	Scandinavia (SCAN)	0.7	2.8	2.8	2.8
France (FR)	United Kingdom (UK)	2.6	3.6	3.6	3.6
France (FR)	Germany (GER)	3.1	3.1	3.1	3.1
France (FR)	Iberian Peninsula (IB)	1.2	3.5	3.5	4.7
France (FR)	Italy (IT)	2.4	3.0	3.0	4.0
Germany (GER)	Scandinavia (SCAN)	2.1	2.6	4.2	14.2
Scandinavia (SCAN)	United Kingdom (UK)	0.0	1.4	1.4	1.4

3.3. Simulation results

In this section, the model results for the scenario with *'no renewable support'*, as well as the renewable policies *'feed-in tariff'*, *'fixed bonus'* and *'renewable quota obligation'* to achieve a renewable share of 60 % in 2050 (2020: 30 %, 2030: 40 % and 2040: 50 %) are presented. First, the development of the electricity market based on the capacity and generation mix as well as the prices (wholesale, renewable and capacity) are presented. Second, the financial risk for renewable-based electricity producers under the different policies is analyzed by comparing the variance in profits. All numerical data can be found in Tables 8 and 9.

Effects on the electricity mix

If no renewable support mechanism is in place, the capacity mix remains relatively similar to today. Base-load generation takes place in nuclear (limited as per political assumption) and lignite power plants (limited due to fuel availability). The assumed increasing electricity demand is mainly met by additional hard-coal power plants. Open cycle gas turbines are installed as back-up capacities, which only achieve about 600-700 full load hours per year but are nonetheless profitable because of the capacity payments. A few investments in wind turbines (onshore at the most favorable sites in the United Kingdom) take place in 2040 due to the assumed capital cost reduction as well as increasing CO_2 and fuel prices of conventional plants. These investments in wind turbines are profitable without any subsidies. Given the increasing electricity demand, the share of renewable generation, mainly in already existing hydro plants, decreases to about 15-17 % in 2050. Annual generation from fluctuating renewables differs between years and is balanced by conventional technologies (mainly gas-fired plants). As a result, wholesale prices of electricity vary throughout the weather years. However, the effect is rather small in the scenario with no renewable support due to the limited deployment of these technologies. Moreover, electricity prices rise in all regions up to 2050 due to the assumed increase in electricity demand as well as CO_2 and fuel prices. Price differences across regions tend to decrease due to the further development of the European transmission network and the increase in demand (both assumptions).[14] Regional capacity prices range from 39 to 87 EUR_{2010}/kWa.[15] Given the scenario assumptions, open-cycle gas turbines are the cheapest option to provide additional securely available capacity.

Under all renewable policies, the achievement of a 60 % renewable share of the total electricity generation in 2050 (2020: 30 %, 2030: 40 % and 2040: 50 %) leads to a stepwise reduction in traditional base-load capacities such as nuclear and hard-coal power plants.[16] The remaining non-renewable generation is provided mostly by combined and open cycle gas turbines due to decreasing full load hours of conventional plants and a more favorable operating/capital cost ratio. In 2020, the demanded RES-E generation is provided by hydro facilities (about 50 %) and onshore wind turbines (about 40 %). In the long term, the renewable generation is more technologically and geographically diversified: offshore wind in the United Kingdom and the Benelux (about 25 %); onshore wind in France, United Kingdom and Germany (about 25 %); solar power plants in Italy, Spain and France (about 25 %); hydro in Scandinavia and Austria (about 20 %) and biomass in Germany, France and Italy (about 5 %). Electricity prices (wholesale) decrease over time due to the price lowering effect of renewable energies (merit order effect). Large wind and solar capacities, a result of subsidies, push the merit order to the right as marginal costs of these technologies are negligible. Hence, technologies with lower marginal costs are price setting in more hours. In 2050, wholesale prices are about 25 % lower than in the scenario with no renewable support. In the policy scenarios, the increase in intermittent generation, has a large influence with respect to generation, electricity prices and renewable curtailment due to the large deployment of wind and solar technologies.

Under a *'feed-in tariff'* policy, the renewable electricity mix is simply optimized based on levelized costs of electricity. Operators of non-subsidized technologies (nuclear, conventional and storages) react to the

[14]Long-term price differences occur in spatial markets when technologies with marginal cost differences are available in only some regions and transport capacities are limited (or significant transport losses/costs apply). A few such resources exist in the European power sector: large hydro facilities (Austria, Switzerland and Scandinavia), large nuclear capacities (France) and lignite-fired plants (Germany).

[15]The common capacity price of 74 EUR_{2010}/kWa represents the annualized fixed costs of an open cycle gas turbine over 20 years. Particularly remarkable is the capacity situation in Germany in 2020. Due to the phase-out of nuclear power in Germany (the scenarios assume no nuclear power in 2020), substantial investments in securley available capacities are needed. In 2030, these capacities have been commissioned and old wind and solar capacities (capacities that were built under the feed-in tariff support before 2012 and reached their technical lifetime before 2030) are replaced by coal capacities. Therefore, the capacity situation is less tense in 2030 compared to 2020. As a result, capacity prices are high in 2020 and relatively low in 2030.

[16]The renewable policies are designed such that the last capacity to achieve the renewable target can remunerate its capital costs. The resulting feed-in tariffs, bonus payments and certificate prices are depicted in Table 9.

higher or lower annual renewable generation. Thus, electricity generation, renewable curtailment, electricity prices and electricity transports vary among weather years depending on the availability of wind and solar generation. Reaching the renewable target through feed-in tariffs reduces the sectoral welfare[17] by about 217 bn. EUR_{2010} compared to the scenario with *'no renewable support'*.

The hourly and regional price signals under a *'fixed bonus'* policy lead to a more efficient mix of renewable capacities. Given limited cost-efficient electricity storage options, the value of electricity depends on a specific point in time. When integrating the hourly price signal into renewable support mechanisms, investors consider the hourly value of electricity and compare it to the production profiles of technologies with intermittent power generation, rather than simply minimize levelized costs of electricity. Reaching the renewable target through a fixed bonus policy reduces the sectoral welfare by about 194 bn. EUR_{2010} compared to the scenario with *'no renewable support'*.

Under a *'renewable quota obligation'* without the option of banking and borrowing, the renewable target is expected to be reached in all weather years. Hence, more renewable energies and a greater mix of technologies are deployed, allowing the target to be achieved even in weather years with low generation from fluctuating renewables. Due to the stochastic generation of wind and solar capacities, green certificate prices vary significantly between weather years. As wind power is the dominant renewable technology (and hence largely deployed under the scenario assumptions), certificate prices are low or even zero in high wind years (w_3). In the low wind year (w_1), green certificate prices are relatively high due to the utilization of more costly biomass technologies. Moreover, certificate prices are greater than short-term marginal costs if an additional capacity must be built in order to achieve the renewable target within the specific period. Thus, expecting the renewable target to be reached in every single year increases the policy costs and reduces sectoral welfare. Given the scenario assumptions, reaching the renewable target through a renewable quota obligation, reduces the sectoral welfare by about 213 bn. EUR_{2010} compared to the scenario with *'no renewable support'*.

[17] Within the electricity market model, total welfare is defined as the sum of the producer profit, arbitrageur surplus and the consumer surplus (differences in electricity costs given fixed electricity demand) under the consideration of renewable and capacity payments. Given this definition of sectoral welfare, potential benefits of renewable policies such as fewer emissions, positive employment effects and lower imports of fossil fuels are not considered. Thus, the welfare effect of all modeled renewable policies is, by definition, negative compared to the *'no support scenario'*.

Table 8: Overview of model results I – capacities and annual generation in Europe for weather years $w_1/w_2/w_3$

		Net capacities [GW]				Net generation (adjusted by curtailment) [TWh]			
		2020	2030	2040	2050	2020	2030	2040	2050
'no subsidy'	Nuclear	104	79	118	132	771/771/771	583/583/583	874/874/874	978/978/978
	Hard-coal	82	158	223	257	626/626/624	1207/1207/1207	1702/1702/1702	1955/1955/1937
	Lignite	18	18	18	18	140/140/140	140/140/140	140/140/140	140/140/140
	Natural gas	289	295	241	242	1065/1051/1040	1007/1007/1007	346/314/283	243/211/196
	Storages	33	33	33	33	14/14/14	14/14/14	14/14/14	14/14/14
	Wind	39	1	50	50	64/81/97	3/4/4	130/163/195	130/163/195
	Solar	24	5	0	0	29/26/24	7/7/6	0/0/0	0/0/0
	Biomass	15	8	2	2	20/20/20	15/15/15	14/14/14	14/14/14
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					18/18/18	14/14/14	16/17/18	15/16/17
'feed-in tariff'	Nuclear	104	79	19	6	749/731/731	559/548/516	131/131/132	47/47/47
	Hard-coal	82	47	43	52	596/572/541	333/319/312	309/309/294	295/304/297
	Lignite	17	17	18	17	128/128/128	131/131/128	136/136/136	127/127/124
	Natural gas	281	389	498	545	820/785/758	1150/1070/997	1318/1207/1111	1090/978/911
	Storages	33	33	33	33	15/14/14	17/21/21	21/21/21	19/18/19
	Wind	147	273	345	510	315/394/454	528/660/792	682/853/1023	1094/1271/1426
	Solar	24	165	434	618	29/26/24	236/220/205	640/582/524	832/756/681
	Biomass	17	10	4	2	86/86/86	43/43/43	14/14/14	14/14/14
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					28/30/32	37/40/43	49/52/55	61/63/65
'fixed bonus' or *'renewable quota (perf. BaB)'*	Nuclear	104	79	35	23	771/761/747	583/583/567	260/260/260	168/168/168
	Hard-coal	82	39	33	36	578/555/526	298/277/268	230/230/230	235/186/193
	Lignite	18	18	18	18	135/135/135	140/140/136	139/140/140	140/136/134
	Natural gas	282	398	497	547	795/753/723	1100/1020/954	1374/1273/1180	1178/1076/1002
	Storages	33	33	33	33	14/14/17	14/14/18	16/14/15	14/15/22
	Wind	157	273	321	424	330/412/495	528/660/792	604/756/907	930/1163/1395
	Solar	24	178	400	589	29/26/24	277/252/227	596/542/487	803/730/657
	Biomass	15	8	2	3	84/81/81	43/43/42	14/14/14	21/21/21
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					28/30/33	38/41/44	45/48/51	56/60/62
'renewable quota (no BaB)'	Nuclear	104	79	43	31	750/737/731	583/583/567	320/320/320	231/231/231
	Hard-coal	82	38	29	37	569/559/539	264/247/245	186/197/194	175/232/200
	Lignite	18	18	18	18	135/135/135	140/140/136	136/136/136	140/140/136
	Natural gas	280	398	477	506	759/786/759	1059/1045/984	1199/1188/1146	1026/959/1020
	Storages	33	33	33	33	14/14/17	14/14/18	19/20/20	16/14/18
	Wind	171	259	314	373	358/448/524	506/632/759	583/729/875	772/965/1158
	Solar	24	220	456	640	29/26/24	343/312/281	663/603/543	853/776/698
	Biomass	16	10	19	38	119/32/20	75/14/14	141/55/21	281/165/50
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					30/30/32	40/41/44	50/50/51	60/60/60

Remark: Total net electricity generation varies among weather years and scenarios due to differing electricity exchanges (transportation losses) and storage utilizations (storage losses).

Table 9: Overview of model results II – wholesale, capacity and RES-E prices for weather years $w_1/w_2/w_3$

		Wholesale prices [EUR_{2010}/MWh]				Capacity price [EUR_{2010}/kWa]			
		2020	2030	2040	2050	2020	2030	2040	2050
'no subsidy'	ATCH	46/43/42	66/54/51	67/55/55	65/62/59	69	69	68	68
	BNL	45/42/42	65/53/50	71/55/53	62/59/55	74	72	74	74
	FR	43/41/41	67/54/51	70/54/52	60/57/53	73	72	74	74
	GER	48/45/44	70/57/53	69/54/55	62/61/56	87	39	74	72
	IB	45/45/42	64/55/56	70/56/58	65/61/59	53	61	63	74
	IT	51/47/47	67/53/57	68/54/57	62/59/55	63	60	74	74
	SCAN	48/45/45	68/54/50	67/54/54	61/58/56	74	74	74	74
	UK	44/42/41	67/54/50	70/54/51	60/57/53	74	74	74	74
	RES-E price	0/0/0	0/0/0	0/0/0	0/0/0				
'feed-in tariff'	ATCH	44/43/43	66/53/51	74/58/54	51/47/45	69	70	71	72
	BNL	44/42/42	68/52/50	73/56/48	33/28/28	74	74	74	74
	FR	41/40/40	58/36/32	56/38/34	61/48/45	73	74	74	74
	GER	48/45/44	68/54/52	73/59/54	43/43/43	80	57	74	74
	IB	45/45/45	40/28/28	53/38/35	67/50/50	49	74	74	74
	IT	49/48/47	63/54/54	70/55/52	62/58/58	63	68	74	74
	SCAN	29/26/22	65/49/32	73/59/50	27/22/4	74	74	74	74
	UK	41/38/38	68/53/48	72/56/48	71/59/53	74	74	74	74
	RES-E price	89/89/89	105/105/105	119/119/119	131/131/131				
'fixed bonus' or *'renewable quota (perf. BaB)'*	ATCH	44/42/42	66/54/51	74/57/53	63/50/42	70	69	71	71
	BNL	44/42/41	66/52/50	73/57/54	62/39/31	74	74	74	74
	FR	39/37/31	64/45/32	67/52/42	71/50/39	74	74	74	74
	GER	52/44/44	68/54/52	73/57/54	61/48/41	80	57	74	73
	IB	45/44/42	68/51/44	59/45/40	72/52/50	58	74	74	74
	IT	51/47/47	61/53/53	70/55/52	70/55/57	65	74	74	74
	SCAN	31/29/28	65/49/33	73/57/49	57/36/31	74	74	74	74
	UK	41/38/38	68/53/48	73/56/48	77/52/38	74	74	74	74
	RES-E price	55/55/55	57/57/57	64/64/64	87/87/87				
'renewable quota (no BaB)'	ATCH	41/43/43	55/57/51	58/53/60	52/51/61	70	70	71	71
	BNL	41/42/47	56/56/50	67/56/61	51/49/56	74	74	74	74
	FR	38/33/31	51/48/34	58/41/43	51/50/64	74	74	74	74
	GER	42/45/51	58/58/52	64/56/63	51/50/56	81	55	74	74
	IB	45/45/42	57/49/46	59/39/39	52/51/71	53	74	74	74
	IT	45/48/50	48/56/53	58/55/62	59/53/75	66	74	74	74
	SCAN	29/27/23	55/52/34	65/54/62	48/48/50	74	74	74	74
	UK	41/38/38	57/56/50	67/55/51	61/53/63	74	74	74	74
	RES-E price	272/27/0	283/0/0	274/33/0	288/47/0				

Remark: Austria-Switzerland (ATCH); BeNeLux (BNL); France (FR); Germany (GER); Iberian Peninsula (IB); Italy (IT); Scandinavia (SCAN) and United Kingdom (UK).

Investment risks under the analyzed renewable policies

To measure the financial risk of renewable-based electricity producers due to weather uncertainty, we analyze the variance in profits of investments in different renewable energies. For this purpose, we calculate annual revenues for the different weather years of an average wind turbine, photovoltaic system and biomass plant in Europe (average based on all modeled regions). We pick 10,000 different combinations of revenues considering the given weather probabilities over the technical lifetime (sampling with replacement) and subtract total capital as well as fixed operating and maintenance costs. Table 10 depicts the resulting variance in profits for each renewable policy.

The general idea of a renewable subsidy is that the payment that renewable-based electricity producers receive, should cover the extra costs for renewable generation compared to conventional power generation. However, as discussed in Bergek and Jacobsson (2010), technology-neutral payments (as modeled in this analysis) allow some technologies to achieve additional rents, often referred to as *'windfall or swindle profits'* (Verbruggen, 2008). Within the model environment, renewable-based electricity producers are able to achieve additional rents from low-cost renewable technologies with limited fuel (e.g., low cost biomass) or space potential (e.g., onshore wind).[18] Thus, the expected profit of the analyzed investments (average over all countries) is positive under all renewable policies. The data shows that the expected profit differs depending on the renewable policy, which makes it difficult to compare the investment risks. However, the effect of the different policies on the variance in profits is so large for most technologies that the effects seem to be clear.

Table 10: Variance in profits depending on the renewable policy [$TEUR_{2010}$/MW]

			Min	25%-Qu	Mean	Median	75%-Qu	Max	Var
Wind onshore	2020	FIT	198	404	426	427	450	657	$1.2 \cdot 10^4$
		Bo/quota (perf. BaB)	246	382	396	397	412	492	$5.2 \cdot 10^3$
		Quota (no BaB)	-110	408	581	566	745	2,588	$6.0 \cdot 10^5$
	2030	FIT	166	259	269	269	280	373	$2.5 \cdot 10^3$
		Bo/quota (perf. BaB)	188	224	227	227	230	244	$2.1 \cdot 10^2$
		Quota (no BaB)	-91	90	167	162	231	989	$1.0 \cdot 10^5$
	2040	FIT	86	126	131	131	135	176	$4.7 \cdot 10^2$
		Bo/quota (perf. BaB)	94	117	119	120	122	136	$1.1 \cdot 10^2$
		Quota (no BaB)	-12	72	99	97	122	380	$1.2 \cdot 10^4$
Wind offshore	2040	FIT	34	104	112	112	119	189	$1.4 \cdot 10^3$
		Bo/quota (perf. BaB)	56	95	101	101	107	155	$7.4 \cdot 10^2$
		Quota (no BaB)	-76	61	101	97	139	571	$3.4 \cdot 10^4$
PV	2030	FIT	90	120	123	123	126	156	$2.5 \cdot 10^2$
		Bo/quota (perf. BaB)	51	89	94	94	99	140	$5.3 \cdot 10^2$
		Quota (no BaB)	-109	33	102	99	168	849	$8.9 \cdot 10^4$
	2040	FIT	57	70	71	71	73	85	$4.7 \cdot 10^1$
		Bo/quota (perf. BaB)	36	49	50	50	52	65	$4.7 \cdot 10^1$
		Quota	-40	35	59	57	80	321	$1.1 \cdot 10^6$
Biomass	2020	FIT	138	138	138	138	138	138	0
		Bo/quota (perf. BaB)	80	160	176	175	191	397	$5.4 \cdot 10^5$
		Quota (no BaB)	-2,675	-435	301	224	954	9,406	$1.0 \cdot 10^9$
	2030	FIT	112	112	112	112	112	112	0
		Bo/quota (perf. BaB)	46	128	144	143	158	350	$5.0 \cdot 10^5$
		Quota	-937	-152	159	129	437	3,861	$1.8 \cdot 10^8$

The analytical analysis in Section 2 indicates that market integration may actually reduce the financial risk of investments in technologies with negatively correlated fluctuations in production and wholesale/certificate prices.

Effect of market integration (fixed bonus compared to feed-in tariffs)

In the scenarios, wholesale prices vary between weather years due to the different feed-in from intermittent renewables. As wind energy is largely deployed in the scenarios, wholesale prices are typically lower in years with large feed-in from wind producers. However, considering that annual generation from intermittent renewables ranges from 2000 TWh to 2500 TWh (the difference represents about 10 % of the annual demand) in 2050, wholesale prices remain relatively stable. This implies a rather low slope of the supply function on the power market. Concerning the analytical example in Section 2, this refers to the case on the left side of Figure 2. Thus, wind energy producers actually face negatively correlated fluctuations in production and

[18] One should keep in mind that the additional rents highly depend on the assumed potential for these technologies. Given the scenario assumptions, onshore wind remains the cheapest renewable option, followed by low-cost biomass technologies. Thus, investments in these technologies are highly profitable due to the technology-neutral incentives.

wholesale prices. Hence, the variance in profits is substaintially lower (about 60-90 %) for investments in wind power under a fixed bonus incentive than under a feed-in tariff policy.

The effect is reversed for investments in solar or biomass technologies, as wholesale prices are positively correlated with energy generation. As a result, variances in profits are larger than under a feed-in tariff policy. For solar technologies, the model assumes that annual full load hours are negatively correlated to wind energy generation. As annual full load hours are in reality not perfectly negatively correlated to wind generation, the increasing effect of market integration on the variance in profits is likely to be overestimated by the model. Furthermore, Table 10 depicts the variance for an average investment in a photovoltaic system (over all regions). In regions with large solar capacities (e.g., Southern Europe), wholesale prices react more to the availability of solar energy rather than wind energy. Thus, investors in photovoltaics on the Iberian Peninsula face a similar variance in profits under a feed-in tariff or bonus support.

Effects of a renewable quota obligation without banking and borrowing

The simulation indicates highly volatile prices of green certificates due to the fluctuations in wind and solar generation. This implies that the supply curve of renewable power generation is very steep. As marginal generation costs of wind and solar technologies are negligible, certificate prices become zero in years with large feed-in from wind and solar technologies (if banking and borrowing is not allowed). In years with limited feed-in from intermittent technologies, certificate prices are determined by the long-run marginal costs of wind and solar technologies and thus certificate prices are relatively high.

Because certificate prices vary significantly among weather years in the analyzed scenario, the price effect is relatively large compared to the fluctuations in electricity generation. Thus, the financial risk of investments in all renewable energies is higher under a quota obligation (without the option of banking and borrowing) compared to feed-in tariffs and bonus incentives. However, this remains the extreme case, as the renewable target has to be achieved in every single year independently of the availability of wind and solar technologies. An appropriate banking and borrowing mechanism may be able to reduce the price volatility considerably and, as such, reduce the financial risk of green electricity producers.

4. Conclusion

In recent years, many countries have implemented policies to incentivize renewable power generation. The analysis shows that renewable-based electricity producers face different risks under the various policies. The effect of weather uncertainty on the financial risk of green electricity producers is not obvious and depends on the function of the supply curve of dispatchable plants. The numerical simulation indicates a risk lowering effect of market integration for wind energy producers but higher risks for solar and biomass suppliers. Furthermore, all renewable-based electricity producers face larger variances in profits under a European renewable quota obligation when banking and borrowing is not an option.

It is an ongoing debate as to if and how renewable energies should be promoted in Europe once the envisaged national renewable targets of the National Renewable Energy Action Plans in 2020 have been achieved. Following the discussion of a European renewable quota after 2020, the analysis indicates the importance of an appropriate banking and borrowing mechanism to reduce the risk for producers in light of a greater penetration of stochastic wind and solar generation. Moreover, national renewable quotas, as opposed to a European quota, would be even more affected by fluctuations in intermittent renewable generation and could thus be questioned as the appropriate instrument to promote renewable energies.

The analysis neglects a few important aspects: First, we concentrate on the effect of weather uncertainty under various renewable policies. However, weather is obviously not the only source for uncertainty. Thus, it would be interesting to analyze the effect of other uncertainties on the investment risk under the different policies. Second, the analysis assumes risk-neutral investors, but Ehrenmann and Smeers (2011) show that the risk-neutral analysis may miss a shift towards less capital-intensive technologies that may result from risk aversion. This is particularly interesting due to the capital intensity of most renewable technologies. Third, it would be desirable to explicitly model the policy option of the 'banking and borrowing' of certificates as an instrument to reduce the investment risk under a renewable quota obligation. In particular, determining how long banking periods would have to be in order to significantly reduce the investment risks would be an interesting research question.

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