
The Impact of EU ETS Price Variations on Germany's Electricity Production Mix



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Electricity Market, Electricity Mix Modeling, Simulation Study, Cournot Competition, EU ETS Certificate Price, Feed-In Tariffs.

Elektrizitätsmarkt, Strommix-Modellierung, Simulationsstudie, Cournot Wettbewerb, EU ETS Zertifikatspreise, Einspeisetarife.



Motivated by the initiation of the third EU ETS trading period in January 2013, this paper examines the effects of EUA price variations on the electricity mix. We focus on the German electricity market, since it is one of the most important EU electricity markets. In this context, we formulate a simulation model for the scenario years 2011, 2020, and 2030 as MCP and compute results utilizing GAMS. Our results indicate that the ability of EUAs to influence the production mix starts at EUA price levels that have not often been observable in the EU ETS until today (i.e. $> €25-35/\text{ton}$) and that in order to reach Germany's future RES-E target shares, EUA price levels of €40 (2020) and €45 (2030) are sufficiently high enough according to our model.



Motiviert durch die Einführung der dritten EU ETS Handelsperiode in 2013, beschäftigt sich dieser Artikel mit den Effekten von EUA Preisschwankungen auf die Zusammensetzung der Stromerzeugung. Wir konzentrieren uns hierbei auf den deutschen Elektrizitätsmarkt als wichtigsten und größten Elektrizitätsmarkt innerhalb der EU. In diesem Zusammenhang erstellen wir ein auf MCP basierendes Simulationsmodell für die Jahre 2011, 2020 und 2030 und ermitteln die Ergebnisse mittels GAMS. Unsere Ergebnisse zeigen, dass EUAs erst ab einem Preis von ca. €25-35/Tonne CO₂ den Elektrizitätsmix wesentlich beeinflussen. Des Weiteren ist ein CO₂ Preisniveau von €40 (2020) bzw. €45 (2030) notwendig, um die deutschen Ziele in Folge des EEG zu erreichen.



1. Introduction and Regulatory Background

The electricity sector is one of today's most important industrial sectors. Electricity is a basic human need in modern societies of developed countries and its role is becoming increasingly more important in developing countries. However, with fossil fuels still being

the main primary energy source for electricity production all over the world, greenhouse gas (GHG) emissions are polluting the planet at an ever-increasing rate, which is why political and economic discussions focus on the environmental issues of the electricity sector.

Feasible options to decrease the share of carbon-emitting energy sources and increase the share of renewables are of major importance, and many experts consider the approach of pricing GHG emissions (i.e. of increasing the marginal production costs of carbon-emitting energy sources by pricing their GHG emissions per ton) as the best way to reach this goal. Since the marginal production costs of most renewable energy sources are still higher than those of traditional CO₂-emitting energy sources, this approach would increase the competitiveness of green primary energy sources and help them overcome the current economic advantage of traditional CO₂-emitting energy sources.

Consequently, the European Union Emission Trading System (EU ETS) was enacted in 2003 in the wake of the Kyoto Protocol. Based on a cap and trade system, EU member states establish national limits on GHG emissions via what is being referred to as National Allocation Plans (NAPs). Subsequently, CO₂ certificates (i.e. emission allowances (EUAs)) are being auctioned (or allocated for free) and factories, power plants as well as other installations subject to these NAPs may either reduce their emissions or buy EUAs at the market to ensure their right to continue emitting GHGs.

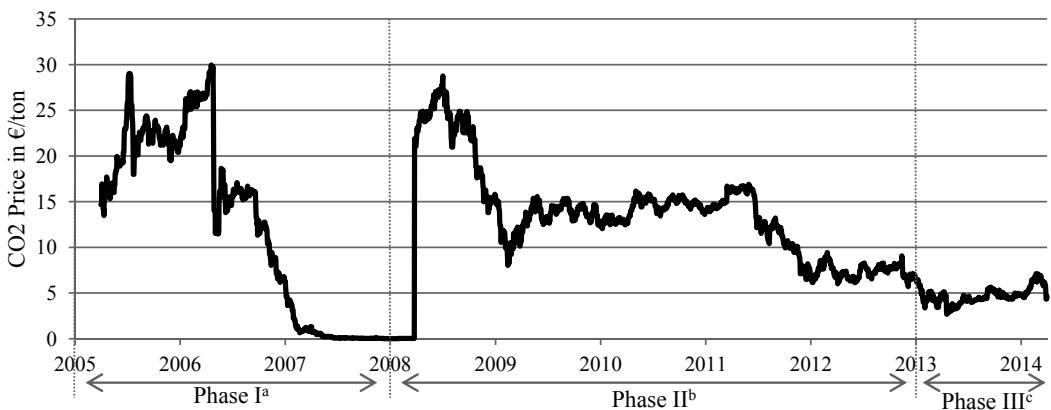


Figure 1: 2005 – 2014 EEX Carbon Index (Carbix)

a Mean: 12.24; Std.Dev.: 9.94; Max.: 29.95; Min.: 0.01

b Mean: 13.01; Std.Dev.: 5.72; Max.: 28.75; Min.: 0.01

c Mean: 4.75; Std.Dev.: 0.89; Max.: 7.11; Min.: 2.68

Figure 1 displays the development of EUA prices at the European Energy Exchange (EEX¹). Two trading periods of EUAs have already passed. The first trading period spanned from 2005 until the end of 2007: 95% of all emission allowances were allocated for free, while only 5% were subject to auctions. Due to an excess of supply² of EUAs as well as the fact that they could not be carried forward into the second trading period, a

1 Auctioned emission certificates are traded via several commodity exchanges in Europe, e.g. the European Energy Exchange (EEX), the Intercontinental Exchange (ICE) and the Norwegian Nord Pool (amongst others).

2 Evidence for an over-allocation of EUAs within this period was for example found by Ellerman/Buchner (2008) or Ellerman/Joskow (2008).

decline of CO₂ prices started in 2006, leading towards certificate values of close to zero. Following *Ellerman/Joskow* (2008) the main goal of establishing a cap and trade infrastructure to meet future Kyoto-Protocol requirements was achieved with the trial period until the end of the first trading period which lead to CO₂ emission reductions in Germany (see e.g. *Delarue et al.* 2008; *Ellerman/Feilhauer* 2008). The second trading period started in 2008 and lasted until December 2012. Here, at least 90% of certificates were apporobated by the European Commission for free and 10% were subject to auctions. In combination with the decreasing cap (less allowances than emissions in 2008), price increases were observable with a peak EUA price of €27/ton of CO₂ in July 2008. *Vennmans* (2012) found that price volatility at the end of the second trading period could be mitigated due to certificates being able to be carried forward into the third trading period. For the start of the third trading period at the beginning of 2013, the European Union agreed upon several major changes in the EU ETS in order to increase regulatory impact and enable EU member states to actually reach their GHG reduction targets.³

In Europe, CO₂-related research is primarily focused on analyzing the effectiveness of the EU ETS in its first two trading periods. Empirical research revealed for example that EUA price developments play an important role for the stock performance of utility portfolios in general (*Oberndorfer* 2009; *Veith et al.* 2009) and that carbon risks are asymmetrically distributed among specific utility companies (*Koch/Bassen* 2012). *Keppler/Cruciani* (2010) provided an empirical estimate of EUA-related welfare effects on electricity producers during the first trading period and also highlighted their asymmetric distribution among specific firms. Under the assumption of no fuel switching, i.e. without changes in the electricity production mix, the authors found that the planned replacement of EUA grandfathering by full auctioning in 2013 (see footnote 3) will significantly decrease the welfare of carbon-intensive electricity producers while still allowing carbon-free electricity producers to generate a surplus.

This paper contributes to the existing literature by examining possible influences of EUA prices on the electricity production mix by means of a simulation model. The analysis focuses on the German electricity market. The simulation model is calibrated on basis of German market data from 2011 and is run for three scenario years, 2011 (base scenario), 2020 and 2030. For 2020 and 2030 we adapt electricity production capacities and other input variables in line with the estimations provided in a study by the Engiwirtschaftliches Institut (EWI) in 2012.

Our results indicate that the establishment of the EU ETS and thus of CO₂ as scarce resource enables regulators to influence the electricity production mix. Interestingly, the ability of EUAs to influence the production mix only starts at EUA price levels that have not often been observable in the EU ETS until today (i.e. > €25-35). In order to reach Germany's future RES-E target shares, EUA price levels of €40 (2020) and €45 (2030) are high enough according to our model. The single most important policy implication of our study is the conclusion that a well-functioning EU ETS seems to be a necessity. First, to ensure increasing RES-E and decreasing non-RES-E investments in the years to come and

³ One of the most prominent changes is the proposed replacement of EUA grandfathering for the electricity production sector. According to Directive 2009/29/EC of the European Union (Premises (19)) full auctioning of CO₂ allowances should be the rule for electricity production from 2013 onwards. Apart from the electricity sector, EUA auctioning is supposed to increase to 20% in 2013 and will be continuously being stepped up to 70% by 2020.

second, as a result, to enable Germany to reach its renewable electricity policy goals in 2020 and 2030.

The remaining paper is organized as follows: In section two we describe the model framework and the underlying dataset. In section three we present the simulation results and show how EUA prices affect the energy mix. The last section summarizes the main findings and concludes.

2. Simulation Model

Following *Andersson/Bergman* (1995), *Kopsakangas-Savolainen* (2003) or *Bremberger et al.* (2012), we implement a General Algebraic Modeling System (GAMS) simulation model⁴ based on the mixed complimentary problem (MCP) and Cournot competition (companies face competition in quantities). Several articles (e.g. *Hogan* 1997; *Borenstein/Bushnell* 1999; *Borenstein et al.* 1999; *Willems* 2002; *Metzler et al.* 2003; *Hobbs et al.* 2005; *Smeers* 2009) suggest the Cournot competition approach to model electricity sector characteristics⁵. Moreover, *Tanaka* conducted a study in 2009 of the Japanese wholesale electricity market (as a transmission-constrained Cournot market), using the systematics of MCP for his simulation.

This setting allows us to analyze the impact of EUA price variations (i.e. EU ETS certificate on carbon emissions) on the electricity generation mix (i.e. the fuel mix). Our simulation model is based on the reference year 2011. Furthermore, we also run simulation models and forecast results for the years 2020 and 2030. These years were chosen since various interesting regulatory changes are bound to influence the electricity generation mix in Germany until then. Examples are the German nuclear power phase-out, which will be completed by 2022 (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety 2011), or the German roadmap for increasing the share of renewable energy sources for electricity generation (RES-E), which schedules Germany to reach thresholds of 35% RES-E and 50% RES-E by 2020 and 2030, respectively (Federal Ministry of Justice 2008).

2.1. Model Outline

The output (X) of a single electricity supplier (f) is defined as the sum of electricity produced utilizing different primary energy sources. In particular we distinguish between hydro (X_{hydro}), wind (X_{wind}), solar (X_{solar}), biomass ($X_{biomass}$), nuclear (X_{nuc}), gas (X_{gas}), hard coal (X_{hard}), and brown coal (X_{brown}). $X(f)$ represents the total electricity output of a single electricity supplier:

4 In line with *Bremberger et al.* (2012), the *Andersson/Bergman* model is expanded in order to include Germany's ownership unbundling framework.

5 According to *Martin* (1993, cited in *Smale et al.* 2006) the Cournot model can be seen as the standard model in the area of competition policy simulation for oligopolies where the cost structure contains both fixed and marginal costs. *Smale et al.* (2006) further elaborate that for example the Bertand model cannot be applied to simulate industries where fixed costs are part of the cost structure. Cournot competition thus seems to be the most suitable model in the context of electricity market simulations (see also *Schmidtchen/Bier* 2006; *von Hirschhausen et al.* 2007; and *Willems et al.* 2009 for additional insights).

$$X(f) = X_{hydro}(f) + X_{wind}(f) + X_{solar}(f) + X_{biomass}(f) + X_{nuc}(f) + X_{gas}(f) + X_{hard}(f) + X_{brown}(f); \quad (1)$$

for $f = 1, 2, \dots, F$

The sum of individual company supplies corresponds to the total supply of electricity (S_E):

$$S_E = \sum_{f=1}^F X(f); \quad \text{for } f = 1, 2, \dots, F \quad (2)$$

Since we distinguish eight different types of primary energy sources, we also specify eight different marginal cost functions. Hydro-powered electricity production includes reservoir and run-of-river power plants, and yields the following marginal cost function:

$$\frac{\partial C_{hydro}}{\partial X_{hydro}}(f) = c_{hydro} + \lambda_{hydro}(f); \quad \text{for } f = 1, 2, \dots, F \quad (3)$$

c_{hydro} denotes the operating costs of run-of-river power plants. λ_{hydro} stands for the shadow price of stored water, i.e. it can intuitively be seen as implying a firm-specific scarcity rent of reservoir power plants (as outlined in *Bremberger et al. 2012*)

The marginal costs for the remaining renewable electricity sources (i.e. onshore and offshore wind, solar, and biomass) evolve as constant operating costs and are represented by c_{wind_on} , c_{wind_off} , c_{solar} , and $c_{biomass}$, respectively:

$$\frac{\partial C_{wind_on}}{\partial X_{wind_on}}(f) = c_{wind_on}; \quad \text{for } f = 1, 2, \dots, F \quad (4)$$

and

$$\frac{\partial C_{wind_off}}{\partial X_{wind_off}}(f) = c_{wind_off}; \quad \text{for } f = 1, 2, \dots, F \quad (5)$$

and

$$\frac{\partial C_{solar}}{\partial X_{solar}}(f) = c_{solar}; \quad \text{for } f = 1, 2, \dots, F \quad (6)$$

and

$$\frac{\partial C_{biomass}}{\partial X_{biomass}}(f) = c_{biomass}; \quad \text{for } f = 1, 2, \dots, F. \quad (7)$$

Similar to these functions, also the marginal cost function for nuclear electricity generation is:

$$\frac{\partial C_{nuc}}{\partial X_{nuc}}(f) = c_{nuc}; \quad \text{for } f = 1, 2, \dots, F. \quad (8)$$

c_{nuc} stands for the operating costs of nuclear powered electricity production.

Fossil-fueled power plants are producing CO₂ emissions in the production process of electricity. Consequently, EUA prices have to be considered in the respective marginal cost function. As different fossil fuel technologies produce different amounts of CO₂ emissions per MWh, the price per ton of CO₂ has to be converted into specific marginal costs per MWh. Category-specific conversion factors are used for this purpose.

The marginal cost function for gas-fired electricity production is:

$$\frac{\partial C_{gas}}{\partial X_{gas}}(f) = (c_{gas} + cf_{gas} \cdot p_{CO2}) + a_{gas} \cdot \left(\frac{X_{gas}(f)}{K_{gas}(f)} \right)^\sigma; \quad (9)$$

for $f = 1, 2, \dots, F$.

c_{gas} represents minimal operating costs and cf_{gas} the respective conversion factor for gas power plants, which is multiplied by the price per ton of CO₂ (p_{CO2}) to establish respective CO₂ costs in gas power plants ($cf_{gas} \cdot p_{CO2}$). $a_{gas} \cdot \left(\frac{X_{gas}(f)}{K_{gas}(f)} \right)^\sigma$ represents a markup on the unit costs that is applied in case more expensive gas power technologies enter the production process. With a_{gas} representing the difference between minimal and maximal operating costs for gas power plants, the second part of the marginal cost function again ensures exponential cost increases according to capacity utilization, where $X_{gas}(f)$ represents the produced amount and $K_{gas}(f)$ the installed capacity in gas power plants. Consequently, σ is greater than one.

The marginal cost function for electricity production from hard coal is modeled as follows:

$$\frac{\partial C_{hard}}{\partial X_{hard}}(f) = (c_{hard} + cf_{hard} \cdot p_{CO2}) + a_{hard} \cdot \left(\frac{X_{hard}(f)}{K_{hard}(f)} \right)^\sigma; \quad (10)$$

for $f = 1, 2, \dots, F$.

c_{hard} represents the operating costs of the cheapest production type in this category and respective CO₂ costs in hard coal-fired power plants are given by ($cf_{hard} \cdot p_{CO2}$), with cf_{hard} symbolizing the respective conversion factor for hard coal-fired power plants. The second part is designed in the same way as for gas power plants, which guarantees an exponential increase in marginal costs when capacity utilization is increasing. The parameter a_{hard} represents the difference between minimal and maximal operating costs in hard coal-fired power plants, $X_{hard}(f)$ gives the produced amount and $K_{hard}(f)$ the installed capacity in hard coal-fired power plants.

The marginal cost function for electricity production from brown coal is⁶:

$$\frac{\partial C_{brown}}{\partial X_{brown}}(f) = c_{brown} + cf_{brown} \cdot p_{CO2}; \quad \text{for } f = 1, 2, \dots, F. \quad (11)$$

c_{brown} stands for the operating costs in brown coal power plants, cf_{brown} represents the conversion factor between prices per ton of CO₂ (p_{CO2}) and CO₂ production costs per MWh in brown coal power plants.

⁶ In line with Wissel *et al.* (2008) we do not model a capacity dependent component for brown coal.

In addition to modeling the market's electricity producers, we simulate consumers by utilizing a linear demand function for electricity (D_E). The inverse demand function⁷ is given by:

$$P_E = a + b \cdot D_E. \quad (12)$$

P_E represents the current market price of electricity. The parameters a and b are determined via the assumed price elasticity of demand (ϵ), the electricity base price and electricity demand.⁸

In line with *Bremberger et al.* (2012), we include P_{net} , which represents the transportation costs⁹ for each unit supplied. The existing regulatory regime is ownership unbundling. We model the profit function of an electricity producer as follows:

$$\Pi(f) = P_E \cdot X(f) - C(f) - P_{net} \cdot X(f); \text{ for } f = 1, 2, \dots, F. \quad (13)$$

Profit ($\Pi(f)$) is given by adding revenues ($P_E \cdot X(f)$) and subtracting generation ($C(f)$) and transportation costs ($P_{net} \cdot X(f)$). The respective cost function $C(f)$ has to be inserted according to the primary energy source used in the production process, while P_{net} and P_E represent unit prices.

The model further allows explicitly modelling feed-in tariffs. In our framework, feed-in tariffs are paid for renewable electricity produced in wind, solar and biomass power plans in 2011. The respective profit function of an electricity producer earning feed-in tariffs (FI) is given by:

$$\Pi_{FI}(f) = P_{FI} \cdot X(f) - C(f) - P_{net} \cdot X(f); \text{ for } f = 1, 2, \dots, F. \quad (14)$$

P_{FI} represents the feed-in tariff instead of the price for electricity paid on the market.

Thus, the mixed profit function of a producer owning both electricity generation facilities covered by feed-in tariffs as well as not covered by feed-in tariffs is given by:

$$\Pi_{Mixed}(f) = \Pi(f) + \Pi_{FI}(f); \text{ for } f = 1, 2, \dots, F. \quad (15)$$

All market players are profit maximizers, thus, we transform the profit functions according to their first order conditions (FOC).

2.2. Market Data

The simulation model for the different scenarios (2011, 2020, and 2030) is calibrated on basis of empirical data from Germany, which represents the most important European electricity market. All data refers to the year 2011 in which the spot price of electricity reached an average value of €51,11/MWh in 2011 (European Energy Exchange – EEX),

⁷ Consequently, the demand for electricity takes the following form: $D_E = 1 / b \cdot P_E - a / b$.

⁸ For a detailed derivation see *Bremberger et al.* (2012).

⁹ In 2012 the German grid system was operated by four main network operators (TransnetBW GmbH, Tennet TSO GmbH, Amprion GmbH, and 50Hertz Transmission GmbH) and it is not possible to obtain a unique regulated grid tariff. Hence, we analyzed the fees of each of the four network operators (data was provided by the German network operators) and use an average fee over all network operators for our simulation. The grid tariff is usually a transitory item for generators, however it is explicitly modeled in our simulation while demand charges are neglected.

with a minimum of €13,63/MWh and maximum of €68,30/MWh. We use an electricity price starting value of €42,15/MWh for the simulations, which establishes the ten percent quantile of the observed prices. As reported by AGEB (2012), the domestic electricity demand in Germany was 608,50 TWh for the year 2011, which we adjusted in order to account for the limited availability of primary energy source data on German power plants.¹⁰ The following sections provide an overview of the simulation input data for the German electricity mix, the marginal costs of production, the price elasticity of demand and EUA price variations.

2.2.1. Electricity Production Mix

The electricity production mix consists of hydro, on- and offshore wind, solar, biomass, nuclear, gas, hard and brown coal. Six electricity producers in our simulation represent companies that are actually operating in the German market. Four of these are in line with the market players presented in *Bremberger et al.* (2012). In contrast to *Bremberger et al.* (2012) however, who based their simulation on 2008 data, the German electricity production mix drastically changed between 2008 and 2011, mostly due to Germany's nuclear power phase-out enacted in the wake of the nuclear catastrophe of Fukushima in 2010. As a result, the installed capacities of the four biggest market players were reduced while the share of renewable energy sources increased, developments resulting in Germany's electricity production facilities being increasingly wide-spread and often local or privately owned. The data on German power plants provided by the German Federal Network Agency shows that as of December 2011 57.10% of the total installed capacity is not being owned by or ascribed to one of the six biggest players in the market. Hence, the remaining market share is split among numerous fringe players created to accommodate for the local and privately owned electricity production facilities mentioned above.

2.2.2. Marginal Costs of Production

Figure 2 highlights the marginal costs (in €/MWh) of the various electricity production techniques, in line with *Wissel et al.* (2008). The marginal costs encompass cost components for the fuel of primary energy sources, operating costs, and corresponding EUA price influences.¹¹ The impact of EUA prices on the marginal costs of electricity production depends mainly on the primary energy source used and its effectiveness. Thus, EUA prices do not influence the marginal production costs of different primary energy sources to the same extent.

We let EUA prices vary within a range of €5 to 160 (see below for details). CO₂ certificate values of €5, 80, and 160 are presented in *Figure 2* in order to illustrate the impact of EUA prices on the marginal cost structure of fossil fuels.

10 The power plant report from the German Federal Network Agency (2012) features German plants with capacities greater than 10 MW only. As a result, the report highlights a total electricity production capacity of 466.90 TWh (versus German production capacities of 614.50 TWh reported by AGEB 2012). Therefore, we downscale the data of domestic electricity demand (German Federal Network Agency 2012), resulting in the simulation model being predicated on a domestic electricity demand in Germany of 462.34 TWh and installed electricity production capacity of 466.90 TWh.

11 Since we are simulating specific points in time (i.e. the years 2011, 2020, 2030) and are taking Germany's power plant portfolio as given, capital costs can be considered sunk and, thus, are neglected in our marginal cost analysis.

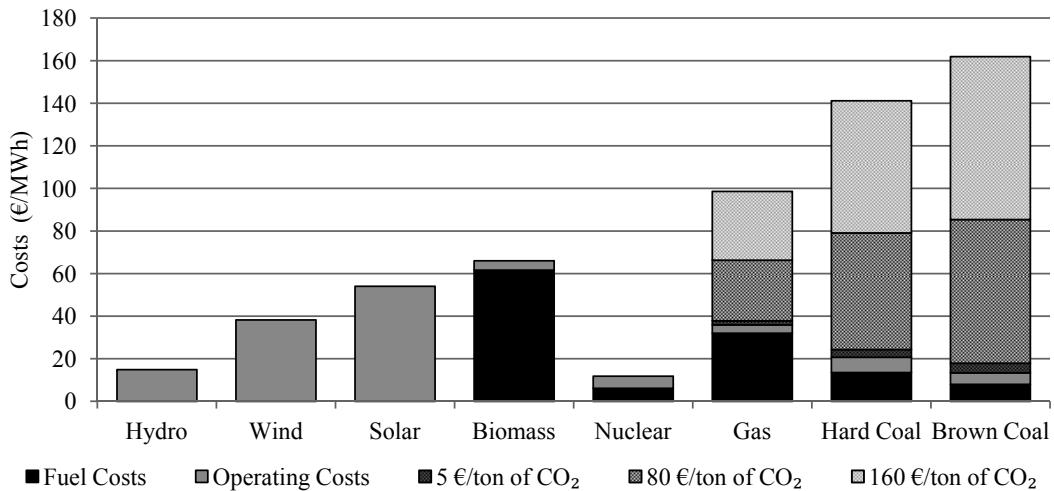


Figure 2: Marginal Costs of Primary Energy Sources (Source: Based on Wissel et al. 2008)

2.2.3. Price Elasticity of Demand

Our simulation model warrants that the price elasticity of demand is given as an exogenous parameter. *Bohi* (1981) for example studied the short-run elasticity for aggregate electricity demand and found the elasticity to range between -0.03 and -0.54. For the long-term elasticity he observed results varying from -0.45 to -2.1. *Lafferty et al.* (2001) provide an extensive overview of the results of several studies focusing on the price elasticity of demand under time-of-use pricing (i.e. off-peak and peak demand as well as residential and business consumer demand). The results of these studies vary within a range of -0.02 to -2.57. In line with the results of *Filippini* (1999) and NIEIR (2004), we assume a price elasticity of demand of -0.35.

2.2.4. EUA Prices

Since 2005, EUAs have been traded at the EEX. Until the end of the second trading period in 2012, the EEX carbon index (Carbix) had reached minimum and maximum values of €0.01 and 29.95. In order to be able to analyze how CO₂ price dynamics impact electricity prices and the electricity mix, we allow EUA prices to vary in a range of €5 to 160 (in €5 steps). This CO₂ price range covers the historical price trend pattern of the Carbix as well as the CO₂ price range found by *Bernard/Vieille* (2009). In addition, this EUA price range leaves some scope for further increase in EUA prices, as CO₂ certificates will become an increasingly scarce production factor in the future.

2.2.5. Synopsis: Simulation

As already mentioned, we use the GAMS simulation model to compute the impact of EU ETS certificate prices on the electricity production mix for the reference year of 2011, as well as for 2020 and 2030. For 2011, we refer to the power plant report from the German Federal Network Agency to model the installed electricity production capacity. Following the assumptions about the impact of various developments (i.e. German nuclear power

phase-out, roadmap for increasing the share of RES-E) made by EWI (2012), we adapt the installed electricity generation capacity parameters (total and per primary energy source) for the simulation of 2020 and 2030. As a result, the RES-E share of installed capacity (in MWh) increases by 11 percentage points until 2020 and by 20 percentage points until 2030, both on the basis of the RES-E share in 2011, while the shares of non-RES-E decreases accordingly.

In order to accommodate for Germany's 2011 regulatory framework for RES-E, we implement the feed-in tariff regime in force, where RES-E producers receive a guaranteed price and electricity suppliers are obligated to source all available renewable electricity (renewables obligation). For both 2020 and 2030 we model the German electricity market without a feed-in tariff regime, mostly since current developments strongly indicate the expiration of the tariff system currently in place. While the simulation of 2011 thus incorporates two factors promoting the deployment of RES-E (i.e. feed-in tariffs and the EU ETS), in 2020 and 2030 the EU ETS is the only regulatory setting in place.

3. Simulation Results

Figure 3 presents the development of the electricity production mix in percentages of the total output for 2011. Recall, EUA prices vary in a range of €5 to €160. Due to the feed-in tariff system and the renewables obligation, all renewable energy sources are being used at their maximum capacity levels, regardless of the EUA price. The two important RES-E future target shares already mentioned above (35% of overall demand in 2020 and 50% in 2030, see for example Federal Ministry of Economics and Technology/Federal Ministry for the Environment, Nature Conservation and Nuclear Safety 2010) are highlighted as dotted lines on the primary x-axis as well. We observe that the RES-E target shares are already attainable in 2011, however, the achievement of the objectives is only made possible by drastic EUA price level increases. According to the model, the EUA price has to reach values of €60 and €140, in order to enable Germany to achieve the RES-E targets of 35% and 50% by 2011.¹² Consequently, increasing EUA prices lead to higher marginal production costs of CO₂-emitting primary energy sources and, thus, the consumer's demand for electricity as well as the share of fossil energy sources in the total mix declines. This development is accompanied by an increasing share of RES-E in the total energy mix, since EUA price hikes have no impact on their marginal costs and are thus essentially increasing the competitiveness of renewable energy sources.

Overall, at an EUA price of roughly €25, we find first indications of change concerning both total electricity production as well as electricity mix. This is due to the fact that up to this point, the marginal costs of RES-E are higher than the marginal costs of carbon-emitting energy sources (including the respective EUA price share). Therefore, at this price level, brown coal, as primary energy source with the highest carbon intensity per MWh, starts to see a persistent decline in its use for electricity generation. At an EUA price of €75, brown coal finally completely ceases to be an option for electricity production, while hard coal (due to its slightly lower CO₂ intensity) continues to be used until CO₂ certificate prices reach a value of €100. At this point, renewable energy sources are only supple-

12 Due to the low share of installed renewable electricity sources, these results are only obtainable by massive reductions in total electricity output. At an EUA price of €60 (€140), only 344.6 TWh (244.7 TWh) of electricity are produced, while at an EUA price of €5, total output is given by 443.2 TWh.

mented by nuclear (not impacted by EUA price variations) as well as natural gas-fired electricity production, the fossil fuel source with the lowest carbon emissions.

The total output (dashed line) shows a piecewise linear pattern, strongly correlated with the decreasing shares of brown and hard coal, i.e. the two high carbon intensity energy source for electricity production. As soon as the decline of brown coal starts at a CO₂ price of €25, we observe a strong downward sloping development in total output that only lessens immediately after both brown coal and hard coal exiting the electricity mix. From this EUA price level onwards (€100), only a slight decrease in total electricity output is noticeable until the upper boundary CO₂ price of €160 is reached.

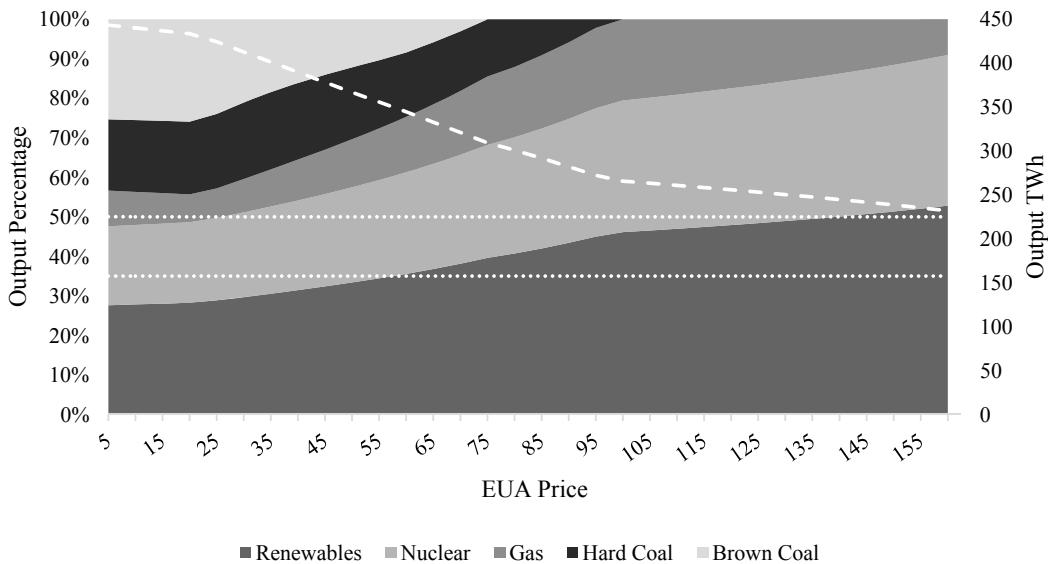


Figure 3: 2011, Electricity Production Mix / Feed-In Tariff Regime

This figure displays the German electricity production mix in percentages of total output depending on varying EUA price levels between €5 and €160. The two dotted lines indicate RES-E target shares of 35% and 50% respectively, while the dashed line represents total electricity output in TWh on the secondary x-axis.

In contrast to the 2011 simulation, it has to be noted that no feed-in tariffs are considered in this scenario and that the total level of installed capacities and the resulting electricity output is lower across EUA price variations in 2020, in line with the assumptions about the development of the German electricity mix made in the EWI study (see *Figure 4*). This is caused by Germany's nuclear power phase-out, and the resulting lower nuclear power share in the electricity mix. Together with the increased installed capacity of RES-E in contrast to 2011, an elevated share of renewable electricity is thus observable throughout the simulation results.

Even at the lowest possible EUA price of €5, hydropower, wind power and solar are used for electricity production at full capacity, thereby partly offsetting the impact on total electricity output by the decrease of nuclear electricity production in comparison to 2011. Biomass enters the production mix at a EUA price of €35 and reaches its full capacity at an EU ETS certificate price of €50. €35 is also the EUA price level where changes in total electricity production as well in the electricity mix become apparent, and with even higher

EUA prices, brown and hard coal-fired electricity production exhibit the same downward trends as in 2011, exiting the mix at a CO₂ price of €90 (brown coal) and €115 (hard coal) respectively.

Starting at an EUA price of €40, the government target for 2020 of a RES-E share of 35% is met. It is most interesting to note that in contrast to the 2011 findings, a far lower EUA price level is sufficient to accomplish this goal and that at the same time the impact of the respective EUA price on total output seems to be negligible (370.6 TWh at EUA price of €5 vs. 360.7 TWh at EUA price of €40). At an EUA price of €75, the RES-E target for 2030 is met (albeit at a far lower total electricity output of 294.5 TWh). Natural gas and nuclear power are the only non-renewables that are part of the electricity mix regardless of the EUA price.

The total output (dashed line) shows again a piecewise linear pattern, strongly correlated with the decreasing shares of brown and hard coal. The decline of brown coal picks up at a CO₂ price of €35 and is accompanied by a rather strong downward sloping development in total output. Again, immediately after both brown coal and hard coal exit the electricity mix, total output stabilizes and only declines indiscernibly until the EUA high price of €160.

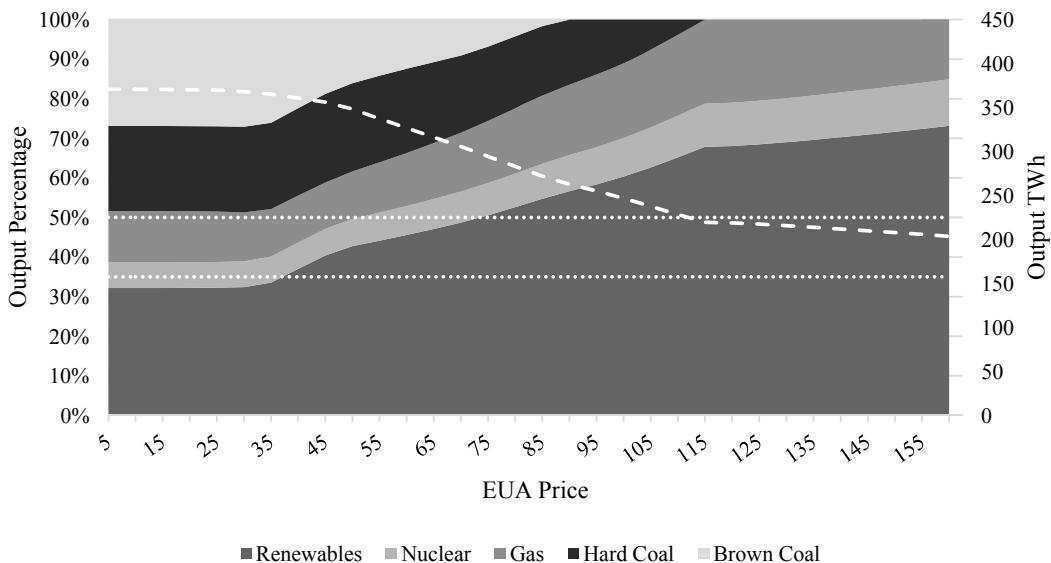


Figure 4: 2020, Electricity Production Mix / No Feed-In Tariff Regime

This figure displays the German electricity production mix in percentages of total output depending on varying EUA price levels between €5 and €160. The two dotted lines indicate RES-E target shares of 35% and 50% respectively, while the dashed line represents total electricity output in TWh on the secondary x-axis.

For 2030, again no feed-in tariffs are considered in the simulation. Total levels of installed capacities and the resulting electricity output are lower than in 2020, as given by the EWI study (see *Figure 5*). In this scenario, nuclear power is no longer part of the German power plant portfolio.

Now, even at the lowest possible EUA price of €5, all renewable energy sources for electricity production are run at full capacity. At an EUA price of €30 total electricity produc-

tion as well electricity mix changes become apparent, with firstly the share of brown coal and hard coal beginning to diminish and secondly both exiting the mix at an EUA price of €90 (brown coal) and €115 (hard coal).

Even at the minimum EUA price of €5, the 2020 target for the RES-E share of 35% is met, while the RES-E target for 2030 (50% RES-E) is accomplished at €45. Total electricity output is only slightly diminished at this price level in contrast to the base CO₂ price of €5 (i.e. 345.4 TWh vs. 363.2 TWh). In line with previous results, natural gas is still part of the electricity mix regardless of the EUA price, due to its low carbon intensity. Total electricity output (dashed line) shows again a piecewise linear pattern, strongly correlated with the decreasing shares of brown and hard coal.

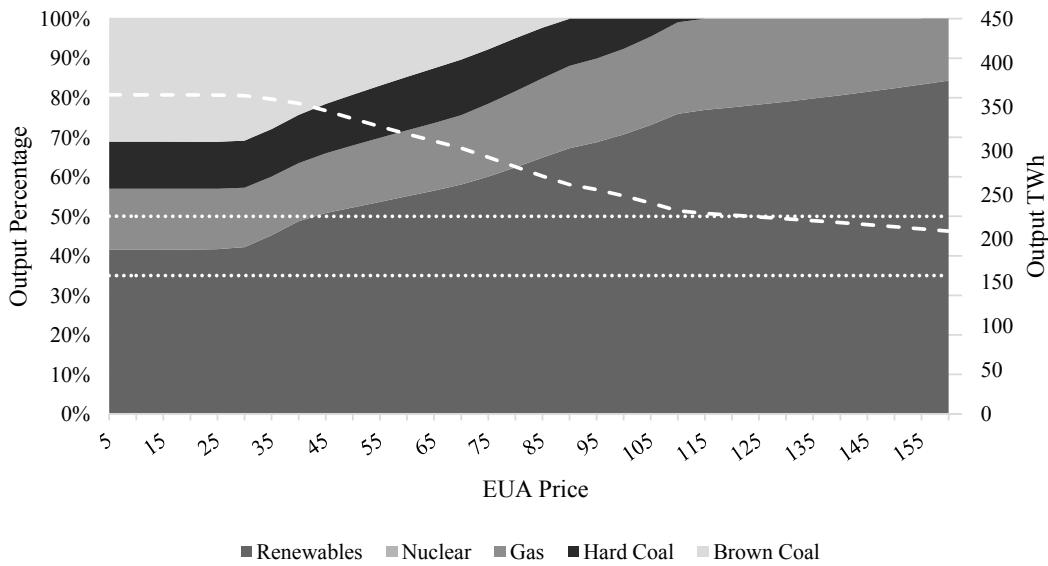


Figure 5: 2030, Electricity Production Mix / No Feed-In Tariff Regime

This figure displays the German electricity production mix in percentages of total output depending on varying EUA price levels between €5 and €160. The two dotted lines indicate RES-E target shares of 35% and 50% respectively, while the dashed line represents total electricity output in TWh on the secondary x-axis.

4. Conclusions

Motivated by the initiation of the third EU ETS trading period in January 2013, this paper examines the effects of EUA price variations on the electricity mix. We focus on the German electricity market, since it is one of the most important EU electricity markets and since various interesting regulatory changes (i.e. specific government-set RES-E targets for 2020 and 2030, feed-in tariff and nuclear power phase-out by 2020 and 2022) are bound to affect Germany in the years to come.

Our findings suggest that the establishment of CO₂ as scarce resource (i.e. through introduction of the EU ETS) enables regulators and policymakers to influence the electricity production mix. Low EUA prices result in an electricity mix with a high share of fossil-fueled energy sources, whereas higher EUA prices (i.e. starting at roughly €25-35) lead to an increased share of renewable electricity in the electricity mix. This price level is in line

with related research as e.g. *Martinsen et al.* (2007) also report CO₂-reducing efforts of German electricity producers to start gaining importance at a price of approximately €30. Moreover, several studies take EUA prices starting at a level of €30 as their basis for the assessment of the effects of EU ETS certificates in different European industries (for a good overview see for example *Venmans* 2012).

On overall, it is interesting to note that the ability of EUAs to influence the production mix only really seems to pick up at EUA price levels that have (as of yet) not often been observable in the EU ETS (i.e. > €25-35). We attribute this lack in higher EUA prices to the grandfathering system that has been in place in the European Union in the last two EUA trading periods, where 90% to 95% of all emission allowances were allocated for free. In our simulations, no grandfathering scheme is modeled, thus indicating that higher EUA prices, for example reached by a full auctioning system, are indeed crucial for the success of the EU ETS in increasing the RES-E market share. In 2020 and 2030, EUA price levels of €40 and €45 are sufficiently high to ensure that Germany reaches its respective RES-E targets of 35% and 50%, respectively.

As previously mentioned, one of the major factors distinguishing our simulation of the years 2011, 2020 and 2030 from each other, is that while we implement both, a feed-in tariff structure with renewables obligation and the EU ETS for 2011, we only model the EU ETS for both 2020 and 2030 due to the indications that the feed-in tariff scheme might expire sometime in the years to come. Nonetheless, the EU ETS alone has enough regulatory impact in order to enable Germany to reach the 2020 and 2030 RES-E targets by its own, while at the same time not requiring CO₂ price levels that seem unrealistic from today's point of view.

The most important policy implication of our study is that a well-functioning EU ETS seems to be a necessity to firstly ensure increasing RES-E and decreasing non-RES-E investments and secondly, as a result, enable Germany to reach its renewable electricity policy goals in 2020 and 2030. With a view to current EUA price levels (see *Figure 1*) and the low mean CO₂ price of only €4,75 during the present trading phase since the start of 2013, the issues hampering market development seem to be exerting increasing pressure on prices in contrast to previous trading phases. The European Union seems to have identified a number of market problems with the current implementation of the EU ETS and directive 2009/29/EC was intended as a first step towards mending the situation. Among various other smaller changes, it also determines a new auctioning mechanism (full auctioning of CO₂ allowances should be the rule for electricity production from 2013 onwards, i.e. abolishment of grandfathering scheme) as well as the demolition of National Allocation Plans in favor of a new and EU-wide Allocation Plan of EUAs. This is expected to help and increase the market competitiveness of RES-E in contrast to non-RES-E by allowing EUA prices to reach higher levels than were observable until now.

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