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IMPACT OF RENEWABLES DEPLOYMENT ON THE CO2 PRICE AND THE CO2 EMISSIONS IN THE EUROPEAN ELECTRICITY SECTOR

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Abstract

As of 2005, electricity generators in Europe operate under the European Union Emission Trading System (EU ETS). At the same time, European Member States have launched support mechanisms to stimulate the deployment of renewable electricity sources (RES-E). RES-E injections displace CO2 emissions within the sectors operating under the EU ETS and they reduce the demand for European Union Allowances (EUAs), therefore reducing the EUA price. This paper presents the results of an ex-post analysis to quantify the impact of RES-E deployment on the EUA price and CO2 emissions in the Western and Southern European electricity sector during the period from 2007 to 2010. This study shows that the CO2 displacement from the electricity sector to other ETS sectors due to RES-E deployment can be up to more than 10 % of historical CO2 emissions in the electricity sector. The EUA price decrease caused by RES-E deployment varies between zero and multiple times the historical EUA price.

Keywords

RES-E deployment CO2 emissions EU ETS.

1. Introduction

As of 2008, European Union (EU)-wide binding targets for CO_2 emissions and deployment of renewable energy sources (RES) exist. The EU aims to reduce greenhouse gas (GHG) emissions with 20 % by 2020 compared to 1990, which is equivalent to a 14 % reduction of GHG emissions compared to 2005. All large industrial installations, including power plants, are subject to a CO_2-emission cap set by the European Union Emission Trading System (EU ETS), equivalent to a reduction of GHG emissions with 21 % by 2020 compared to 2005 emission levels (European Commission, 2010a). At the same time, the EU pursues a 20 % share of renewable energy sources in final energy consumption by 2020 with a 10 % share of renewable energy specifically in the transport sector. To achieve these targets, the EU imposes binding targets to each Member State (European Commission, 2010c). A 10 % RES share target for the transport sector implies that the electricity sector and/or the heating sector will end up with a RES share above 20 % in 2020.

Launched in 2005, the EU ETS is the first and largest cap and trade mechanism in the world for CO_2 emissions (Ellerman and Joskow, 2008)[1]. It sets a cap on the total amount of CO_2 emitted by installations operating under the EU ETS. Within the cap, participants receive, buy or sell emission permits, also referred to as European Union allowances (EUAs). A participant can sell allowances and reduce its emissions when the market price for allowances is higher than the CO_2 abatement cost of its last emitted ton CO_2. Vice versa, a participant can buy allowances when the EUA market price is lower than its own marginal CO_2 abatement cost. Currently, the EU ETS covers almost half of the EU's CO_2 emissions and 40 % of the EU's GHG emissions (European Commission, 2010b). The electricity sector represents around 60 % of the CO_2 emissions covered by the EU ETS (Neuhoff et al., 2011).

Unlike European CO_2 mitigation policy, where electricity generation is subject to one Europe-wide system[2], European policy with regard to electricity from renewable energy sources (RES-E) is much more diffuse. Each Member State is free to choose its own incentives to stimulate deployment

[1] The EU ETS was launched before the 2020 targets were set.

[2] National fossil fuel taxes are not considered as a policy instrument to reduce CO_2 emissions.

of RES-E. One can distinguish two main types of support mechanisms. The first type covers quantity-based mechanisms. In quantity regulation, consumers or suppliers have the obligation to redeem tradable green certificates (TGC) which can be gathered by producing renewable electricity or by purchasing them on the market. The second type of support mechanisms are price-regulated mechanisms. In price regulation, a fixed financial payment per unit of generated renewable energy is awarded to the generator. Feed-in tariffs (FIT) and feed-in premiums (FIP) are price-regulated mechanisms. Besides these two types of regulation, policy makers can set up additional measures to make investments in renewables more attractive, e.g. through R&D grants, fiscal incentives and tendering (Ecofys, 2011).

The electricity market, the EU ETS and RES-E deployment are linked in multiple ways as shown in figure 1. Both the EU ETS and RES-E deployment influence CO_2 emissions from electricity generators. The EU ETS caps CO_2 emissions of all ETS sectors, including the electricity sector, and puts a price on the emission of CO_2. The generation of CO_2-free electricity from renewable sources due to RES-E support schemes reduces CO_2 emissions needed to satisfy electricity demand. As the aggregated CO_2 emissions of all installations operating under the EU ETS are set, RES-E deployment does not cause a reduction in CO_2 emissions but it displaces CO_2 emissions within the ETS sectors - both within the electricity sectors itself and between the electricity sector and other ETS sectors.

The reduction in demand for EUAs due to generation from RES-E translates into a lower EUA price. The other way around, the EU ETS reduces the need for RES-E support mechanisms. By putting a price on CO_2 emissions, the EU ETS narrows the cost gap between renewable technologies and conventional technologies. The latter effect is however much smaller than the first effect.

This paper deals with CO_2 displacement and EUA price reductions caused by RES-E deployment. Although electricity price effects are not considered further in this paper, electricity price interdependencies are briefly mentioned in this paragraph for the sake of completeness. The EU ETS increases electricity prices as generators take the CO_2-emission cost into account in the marginal electricity generation cost, regardless of how they were acquired, i.e. grandfathered or bought. Allowances have a market value and thus represent an opportunity cost for the generators. The effect of RES-E deployment on electricity prices is ambiguous. On the one hand, wholesale electricity prices are lowered because of the low marginal generation cost of renewable

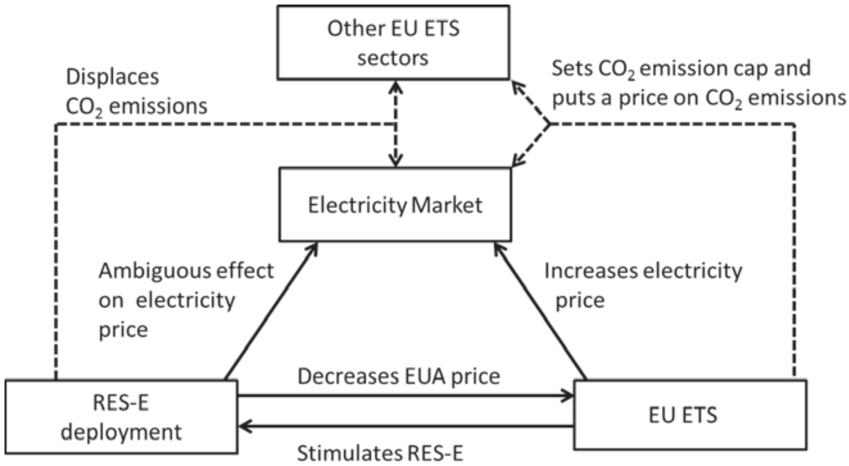


Figure 1: Schematic presentation of the interdependencies between the European electricity market, the EU ETS and RES-E deployment. Solid lines indicate price interdependencies, dotted lines indicate CO_2 interdependencies. Figure results from elaboration of the authors based on del Río González (2007).

power plants. On the other hand, the cost of RES-E support schemes is often passed on to the customer in the form of higher tariffs. RES-E deployment also influences electricity prices indirectly by decreasing the EUA price. Hence RES-E causes a decrease in wholesale electricity prices but the effect on final electricity prices is less clear.

The EU ETS and RES-E deployment are both important pillars of the EU policy regarding electricity generation. A review of the existing literature shows that a lot of work has been done on the topic of electricity generation under the EU ETS and with RES-E deployment. However, at the time of writing, no ex-post analysis is available. As the EU ETS and RES-E deployment are rather recent phenomena, literature on the topic is mainly aiming to outline prospective scenarios. Hindsberger et al. (2003) and Unger and Ahlgren (2005) perform ex-ante analyses to quantify the impact of renewable electricity generation on the CO_2 emission cost.

Today, after some years of electricity generation with RES-E deployment, it is imperative to assess the effective impact of this policy instrument. This paper aims to quantify, for the period 2007 to 2010, the impact of RES-E deployment on the EUA price and on CO_2 emissions in the Western and Southern European electricity sector. As the impact of RES-E deployment is partly determined by the EU ETS, this paper closely considers the EU ETS as well.

This paper differs from the existing literature in two aspects. First, this study focuses on both RES-E deployment and the EU ETS, unlike much of the literature in which the effect of only one policy instrument is examined and the other instrument is not considered. Delarue and D'haeseleer (2008) and Delarue et al. (2010) solely address the effect of EU ETS on CO_2 emissions in the European electricity sector. Jensen and Skytte (2002) examines the interdependencies between the power sector and the green certificate market. Second, the conclusions presented in this paper result from a quantitative analysis based on an extended simulation model of the European electricity market. Research results presented in the existing literature often follow from theoretical qualitative descriptions or theoretical quantitative models. Examples of papers applying the first approach are Boots et al. (2001), Morthorst (2001) and Sorrell et al. (2003) whereas Jensen and Skytte (2003), Rathmann (2007) and De Jonghe et al. (2009) apply the second approach.

The methodology applied to achieve the aim of this paper is discussed in section 2. Section 3 deals with the simulation model. Subsequently, the simulation results are presented in section 4. Finally, conclusions are drawn in section 5.

2. Methodology

This section deals with the methodology used to quantify the impact of RES-E deployment on the EUA price and CO_2 emissions in the electricity sector. The analysis covers the period 2007 - 2010 and includes 12 European Union Member States (EU MS) in Western and Southern Europe[3]. Only the electricity sectors in these 12 EU MS are represented in the model. All the other sectors operating under the EU ETS and the electricity sectors in countries which are not considered, are not taken into account. These sectors are further referred to as *non-modeled ETS sectors*. Electricity from wind energy, photovoltaic energy and bio-energy - biogas and biomass - is considered as renewable electricity due to RES-E support schemes. These

[3]Austria, Belgium, Denmark, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, the United Kingdom.

forms of renewable electricity are supported by all European Member States (Ecofys, 2011).

2.1. Analysis plan

The amount of CO_2 emissions emitted in the electricity sector and the EUA price are interdependent. An EUA price change translates into a change in CO_2 emissions in the electricity sector and vice versa. As only part of the EU ETS is considered in the analysis, it is impossible to properly model the full interdependency. Therefore, CO_2 emissions in the electricity sector and the EUA price are considered independent of one another in the first part of the analysis. In a first step, the EUA price is considered as an invariable parameter and the CO_2 emissions in the electricity sector vary according to the presence of RES-E deployment. This assumption is referred to as *ETS-price assumption*. In a second step, the aggregated CO_2 emission of the modeled electricity sectors is considered as an invariable parameter and the EUA price varies according to the presence of RES-E deployment. This assumption is referred to as *ETS-cap assumption*. These first two steps can be seen as extreme cases. In a final step, the results of the previous steps are taken together to determine the actual impact of RES-E deployment on the EUA price and on the CO_2 emissions in the electricity sector.

2.1.1. ETS-price assumption

According to the ETS-price assumption, the EU ETS is modeled as an exogenous and invariable EUA price imposed on electricity generators. In this case, RES-E deployment causes CO_2 displacement between the modeled electricity sectors and other ETS sectors but it does not reduce the EUA price. This assumption corresponds to a situation in which CO_2 abatement in the non-modeled ETS sectors is possible without additional cost at the current EUA price. As this is not the case in reality, the CO_2 displacement due to RES-E deployment starting from this assumption is an outer limit of the impact of RES-E deployment on the CO_2 emissions in the electricity sector.

2.1.2. ETS-cap assumption

According to the ETS cap assumption, the EU ETS is modeled as an exogenous CO_2 emission cap imposed on the electricity generators. Within this emission cap, the trade mechanism determines the EUA price. The introduction of RES-E deployment decreases this EUA price but does not cause

CO_2 displacement from the electricity sector to other ETS sectors as emissions are capped. This assumption corresponds to a situation in which CO_2 abatement in the non-modeled ETS sectors is impossible. As this is not the case in reality, the EUA price reduction due to RES-E deployment starting from this assumption is an outer limit of the impact of RES-E deployment on the EUA price.

2.1.3. Combination of both assumptions

The ETS-price assumption and the ETS-cap assumption sketch two extreme cases. In reality, RES-E deployment affects CO_2 emissions and the EUA price at the same time, which corresponds to a situation in which CO_2 abatement in the non-modeled ETS sectors is possible at non-zero additional cost. The extreme assumptions, however, define the range in which the actual impact of RES-E deployment on both CO_2 emissions in the electricity sector and the EUA price is situated.

2.2. Analysis tool: scenario analysis

The analysis tool is a scenario analysis performed with a newly developed simulation model of the electricity market. Two different scenarios are considered:

- *OBS scenario.* The observed scenario represents the actual market outcome as observed in the period from 2007 to 2010. In the OBS scenario, both the EU ETS and RES-E deployment are in place.
- *NORES scenario.* In the NORES scenario, only the EU ETS is in place and RES-E generation due to RES-E support schemes is set to zero. EU ETS can be modeled according to:
  - the ETS-price assumption, i.e. as an invariable EUA price.
  - the ETS-cap assumption, i.e. as an exogenous CO_2 emission cap.

First, the impact of RES-E deployment on *CO_2 emissions* in the electricity sector is determined as the difference in CO_2 emissions between the NORES scenario, starting from the ETS-price assumption, and the OBS scenario. The EUA price is considered to be the same in both scenarios and equal to the historical observed EUA price. Second, the impact of RES-E deployment on the *EUA price* is determined as the difference in EUA price between the NORES scenario, starting from the ETS-cap assumption, and the OBS scenario. The CO_2 emission cap is considered to be the same in both scenarios and equal to the historical observed aggregated CO_2 emission. The difference between the ETS-cap assumption and the ETS-price assumption is only reflected in the NORES scenario. The OBS scenario reproduces historical data, regardless whether the EU ETS is perceived as a price mechanism or as a quantity mechanism.

2.3. Scope of the analysis

12 European Member States are incorporated in the analysis: Austria, Belgium, Denmark, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain and the United Kingdom. These countries are part of the EU ETS and have at the same time significant RES-E injections due to RES-E support schemes. From 2007 to 2010, 91 % of the supported RES-E generation in EU-27 originated from Member States represented in this analysis. Further in this paper, these countries are referred to as MS12.

Switzerland is also included in the analysis in order to build a complete model of the Western and Southern European electricity market, although it is not part of the EU ETS and does not join in the renewable energy target of the EU. Therefore, Switzerland is considered as a *dummy country*, meaning that in every scenario electricity in Switzerland is generated in absence of the EU ETS but with RES-E injections.

The analysis covers the period from January 1 2007 till December 31 2010. During this time range, the electricity sector was subject to changes in electricity demand, conventional generation capacity and generation from renewables due to RES-E support schemes. Aggregated annual electricity demand in MS12 grew from 2,406 TWh in 2007 to 2,482 TWh in 2010. This equates to an average demand growth of 0.8 % per year. Five countries represent 85 % of total electricity demand, i.e. Germany (24 %), France (20 %), the United Kingdom (15 %), Italy (14 %) and Spain (12 %). The largest change in the conventional power plant portfolio is the increase of combined cycle capacity with 18 GW during the considered period. Installed cogeneration capacity increased from 85 GW in 2007 to 89 GW in 2010. Other conventional generation capacity remained more or less constant.

Electricity generation from supported renewable energy sources increased significantly over the period 2007-2010 (see figure 2). Wind energy generation increased from 99 TWh in 2007 to 136 TWh in 2010, solar energy generation rose from 4 TWh in 2007 to 20 TWh in 2010 and electricity generation from biomass and biogas increased from 52 TWh to 70 TWh. Wind energy is the most important supported RES-E, generating 62 % of the supported renewable electricity from 2007 to 2010. Biomass and biogas fired power plants generate 32 % of supported renewable electricity during this period and solar energy contributes only 6 %. However, solar energy is the renewable energy source with the largest relative growth in generation, increasing with more than a factor 5 in four years. Wind energy shows the largest absolute growth, increasing produced electricity with 37 TWh from 2007 to 2010. Germany and Spain are by far the largest producers of supported renewable electricity. In 2010, Germany is responsible for 34 % and Spain for 23 % of the supported renewable electricity in the model.

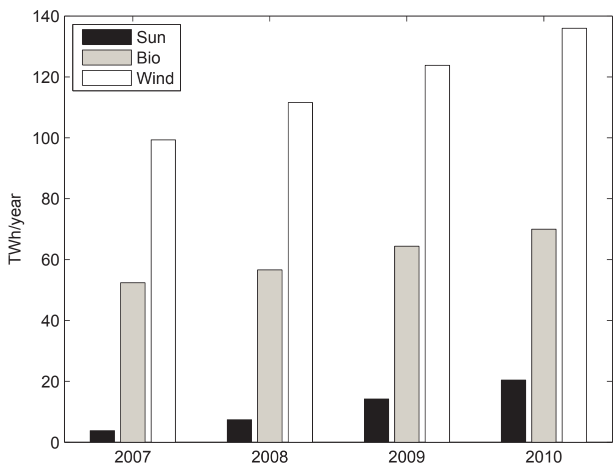


Figure 2: Evolution of renewable electricity generation in MS12 due to support schemes (EURELECTRIC, 2010).

The period 2007-2010 can be divided in three subperiods based on the EUA price and fuel prices (see figure 3). The first subperiod covers 2007, which is characterized by a very low EUA price and steadily increasing fuel prices. The second subperiod starts at the beginning of 2008 and runs till mid-2009. Early 2008, the EUA price and fuel prices show a strong upsurge to peak mid-2008. Subsequently, the EUA price and fuel prices fall dramatically due to economic recession to stabilize in the first half of 2009. The third subperiod runs from mid-2009 to the end of 2010 and is characterized by a stable EUA price on an average price level of 14 EUR/tCO_2 and slowly

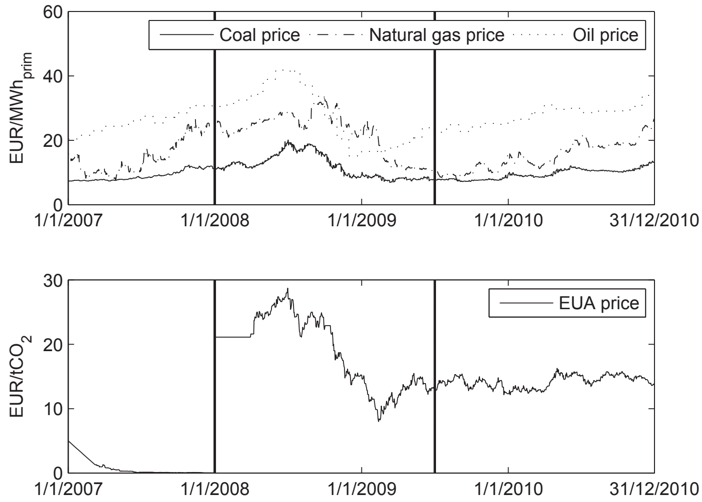


Figure 3: Evolution of fuel prices and the EUA price. Subperiods run from January 1, 2007 till December 31, 2007; January 1, 2008 till June 30, 2009 and July 1, 2009 till December 31, 2010. The coal price is a quarterly future, the gas price is day ahead, the oil price is a monthly future and the EUA price is the spot price (EEX, 2011; ICE, 2011; Powernext, 2011; APX-ENDEX, 2011; Nord Pool, 2011; Index Mundi, 2011; BlueNext, 2011).

increasing fuel prices.

3. Simulation model

The scenario analysis is performed with an electricity generation simulation model, specifically built for the purpose of this study. The model allows to simulate electricity generation in the countries incorporated in the analysis from 2007 to 2010. Two settings are possible with regard to RES-E deployment - with or without RES-E deployment - and two with regard to the EU ETS - EUA price or CO_2 emission cap. This way, all required scenarios and assumptions described in the previous section can be simulated. The model returns hourly generation of each power plant type in each country, hourly CO_2 emissions of each power plant type in each country, hourly electricity price in each country and hourly cross border transmission.

The model considers only short term operational aspects. This implies that the conventional power plant portfolio is assumed to be the same in absence of RES-E deployment.

3.1. Description

The model is based on the principle of overall operational cost minimization. The demand for electricity is considered inelastic. The model has one objective function, i.e. to minimize total generation and transmission cost. The electrical network is modeled as a trade-based network in which neighboring countries are connected through an interconnection with limited capacity.

The model is formulated as a linear programming problem in the General Algebraic Modeling System (GAMS, Brooke et al. (2008)) and solved using the CPLEX solver (ILOG Inc, 2007). The input and output of the linear optimization problem is processed in Matlab. As a full year optimization is not solvable in one model run, each year is divided and solved in weekly blocks, which are then attached to each other.

All the power plants of the same type and same rated efficiency are grouped per country and considered as one effective power plant with a set of characteristics and a power output ranging from zero to the installed capacity. The efficiency of a power plant type is considered to be the rated efficiency, independently from the load level[4]. 19 different power generating technologies are incorporated in the model. To ensure an accurate analysis, the installed capacity coal fired power plants and the installed capacity gas fired combined cycle power plants are each divided in three groups with different rated efficiency. This results in 23 different types of effective power plants per country represented in the model.

The objective function is

$$min \left(\sum_{i,j,t} MC_{i,j,t} * gen_{i,j,t} + \sum_{j,j_2,t} |cbt_{j,j_2,t}| * TC \right) \tag{1}$$

with i the type of power plant, j the country and t the time. $MC_{i,j,t}$ is the marginal generation cost of a power plant type in EUR/MWh, $gen_{i,j,t}$ the generated electricity in MWh/h, $cbt_{j,j_2,t}$ the cross border transmission in MWh/h from country j_2 to country j and TC the transmission cost in

[4]As power plants are grouped on technology basis, load dependence of efficiency is not considered in the model.

EUR/MWh[5]. The marginal generation cost follows from

$$MC_{i,j,t} = \frac{FP_{t,j}}{\eta_i} + \frac{EF_i * EUA\_price_t}{\eta_i} \tag{2}$$

with $FP_{t,j}$ the fuel price in EUR/MWh$_{prim}$, EF_i the emission factor of the power plant type in tCO$_2$/MWh$_{prim}$, η_i the rated efficiency of the power plant type and EUA_price_t the EUA price in EUR/tCO$_2$ if applicable.

The solution of the objective function has to satisfy the following constraints:
Demand constraint:

$$\forall j, t \quad \sum_i gen_{i,j,t} + \sum_{j_2} cbt_{j,j_2,t} = dem_{t,j} - rel_{t,j} + char_{t,j} \tag{3}$$

Power constraint:

$$\forall i, j, t \quad 0 \leq gen_{i,j,t} \leq cap_{i,j} * AF_{i,j} \tag{4}$$

Cross border transmission constraints:

$$\forall j, j_2, t \quad |cbt_{j,j_2,t}| \leq NTC_{j,j_2} \tag{5}$$

$$\forall j, j_2, t \quad cbt_{j,j_2,t} = -cbt_{j_2,j,t} \tag{6}$$

Ramping constraints:

$$\forall j, j_2, t \quad gen_{i,j,t} \leq gen_{i,j,t-1} + cap_{i,j} * RF_{i,j} \tag{7}$$

$$\forall j, j_2, t \quad gen_{i,j,t} \geq gen_{i,j,t-1} - cap_{i,j} * RF_{i,j} \tag{8}$$

with $dem_{t,j}$ the electricity demand in MWh/h, $rel_{t,j}$ and $char_{t,j}$ respectively the releasing rate and charging rate of the dual storage unit in MWh/h, $cap_{i,j}$ the installed capacity of the power plant type in MW, $AF_{i,j}$ the availability factor of the power plant type, NTC_{j,j_2} the net transfer capacity from country j_2 to j in MW and $RF_{i,j}$ the ramping factor of the power plant type.

Dual storage is implemented in the cost minimization based on Wood and Wollenberg (1996). Dual storage units consume electricity to store energy.

[5]A small transmission cost is imposed to the model in order to roughly calibrate cross border transmission.

The dual storage units considered in the model are water-pumping units. The energy content of a water-pumping unit at the end of the simulation must be equal to the initial energy content. Besides, maximum and minimum charging rate, releasing rate and energy content must be respected at all times. This results in four additional constraints:

Energy balance constraint:

$$\forall j \quad \sum_t rel_{t,j} = \sum_t char_{t,j} * \eta \tag{9}$$

Power and energy content constraints:

$$\forall t, j \quad 0 \leq rel_{t,j} \leq cap\_dual\_storage_j \tag{10}$$

$$\forall t, j \quad 0 \leq char_{t,j} \leq \frac{cap\_dual\_storage_j}{\eta} \tag{11}$$

$$\forall t, j \quad 0 \leq pump\_energy_{t,j} \leq pump\_energy\_max_j \tag{12}$$

with $cap\_dual\_storage_j$ the installed storage capacity in MW, $pump\_energy\_max_j$ the maximum energy content of the water-pumping unit in MWh, $pump\_en_{t,j}$ the energy content in MWh and η the total efficiency of the water-pumping unit. The releasing efficiency and charging efficiency are assumed to be the same. The energy content of the water-pumping unit is given by

$$\forall j, t \quad pump\_en_{t,j} = pump\_en_{t-1,j} + char_{t,j} * \sqrt{\eta} - \frac{rel_{t,j}}{\sqrt{\eta}} \tag{13}$$

A CO_2 emission cap constraint is added in a scenario with a CO_2 emission cap imposed on the electricity sector. The exogenous EUA price EUA_price_t is then set to zero.
CO_2 emission cap constraint:

$$\sum_{i,j,t} \frac{gen_{i,j,t} * EF_i}{\eta_i} \leq CO_2\_cap \tag{14}$$

with CO_2_cap the CO_2 emission cap in tCO_2/year. The CO_2 emission cost in this case is derived as the dual of the CO_2 emission cap constraint.

In a scenario without the EU ETS, the EUA price is set to zero and the CO_2 emission cap constraint is not considered. In a scenario without RES-E deployment, renewable capacity due to support schemes is set to zero.

The modeling of renewable power generation and power generation through cogeneration requires a specific approach. Unlike conventional power plants, the power output of renewable power plants and cogeneration plants is often not driven by electricity demand but by other factors such as meteorological conditions or heat demand. Wind power, photovoltaic power, geothermal power and power from cogeneration are implemented as negative loads. This means that generation from these power sources is subtracted from the electricity demand. Wind energy, photovoltaic energy and bio-energy are modeled based on historical generation data in order to accurately study the impact of RES-E deployment. Hydro energy from run-of-river plants is not modeled as a negative load but incorporated in the cost minimization.

Single storage is also modeled as a demand correction. Single storage units are power plants where energy is stored without electricity consumption, e.g. a water dam. Single storage units are mainly used as seasonal storage and tend to smoothen out the electricity demand on an annual basis.

3.2. Input data

Three different types of input data are required. A scenario is needed, consisting of a year, a setting for the EU ETS and a setting for RES-E deployment, data per country and overall data. The data sources of the model are listed in appendix.

3.3. Calibration and validation

The model is calibrated in order to match the simulation results in the OBS scenario with historical observed data. The calibration of the model consist of 5 steps:

1. The hourly demand data from ENTSO-E are scaled to match peak demand data and aggregated demand data from EURELECTRIC. Wind data, cogeneration profiles and solar profiles were scaled so that the sum of the hourly produced electricity from these sources matches the aggregated EURELECTRIC data. This is needed to overcome the deviation between different data sources.
2. Generation of power plant types whose power output is independent from RES-E injections or the presence of the EU ETS, is set to historical generation levels. In this work, this is assumed to be the case for nuclear power plants, lignite fired plants, wind power plants, photovoltaic power plants, biomass and biogas power plants, run-of-river

plants, power plants based on waste, electric energy from cogeneration units, geothermal power plants and single storage units. This can be done as the generation of these power plant types is the same in all scenarios - or is zero for wind energy, photovoltaic energy and bio-energy in a scenario without RES-E deployment.

3. A small transmission cost of 0.50 EUR/MWh is imposed to do a rough calibration of international transmission.
4. An additional constraint is added to calibrate peak power plant types, i.e. gas turbines units and internal combustion units. The constraint imposes a minimum generation level on the peak power plant types. Otherwise, peak power plant types are never used as no unscheduled unavailabilities occur. The minimum production level is set to leave open the possibility that peak power plants produce more in scenarios without RES-E deployment.
5. In a final step, generation of coal fired power plants and gas fired combined cycle power plants is calibrated by adjusting rated efficiency of these power plant types, correcting fuel prices and changing power plant availabilities. Coal power plants and gas fired combined cycle power plants have one out of three possible efficiencies, i.e. 32 %, 36 % and 40 % for coal power plants and 45 %, 48 % and 51 % for gas fired combined cycle power plants. The total installed capacity is divided per country over the different efficiency levels in a way that departure from historical generation data is reduced and a logic evolution of the average efficiency is induced. To correct for the underproduction of coal power plants in 2009 and 2010 in the uncalibrated model, the coal price of EEX is replaced by the coal price of ICE, which was slightly lower at that time. The overproduction of gas fired combined cylce power plants during the same years in the uncalibrated model is reduced by increasing the natural gas price with 15 % from March 20 2009 to March 19 2010. The availability of coal power plants and combined cycle power plants is adjusted per country, ranging from 60 % to 100 %.

A comparison of the OBS scenario of the calibrated model with historical generation data shows that simulated generation from nuclear power plants, lignite fired power plants, run-of-river power plants and supported RES-E sources matches historical generation (see table 1). Generation from coal fired power plants is underestimated by the model with 1.3 % to 5.3 % and generation from gas fired power plants is underestimated with 0.5 % to 2.9 %.

The reason for generation of both power plant types being underestimated is that dual storage is barely used in the model. Therefore less electricity generation is needed.

As the model reproduces historical electricity generation with an acceptable accuracy, simulated CO_2 emission data are accurate as well.

[TWh/year]	Nucl.	Coal	Lign.	Gas	Oil	RoR	RES	CHP	Stor.
2007									
historical	741	397	158	405	36	116	153	398	141
simulated	741	392	158	399	36	116	153	390	82
2008									
historical	739	358	148	437	34	119	174	399	146
simulated	739	343	148	428	37	119	174	399	86
2009									
historical	743	357	143	432	31	103	198	414	154
simulated	743	338	143	430	33	103	198	415	97
2010									
historical	747	357	137	419	27	125	227	429	166
simulated	747	341	137	407	27	125	227	435	100

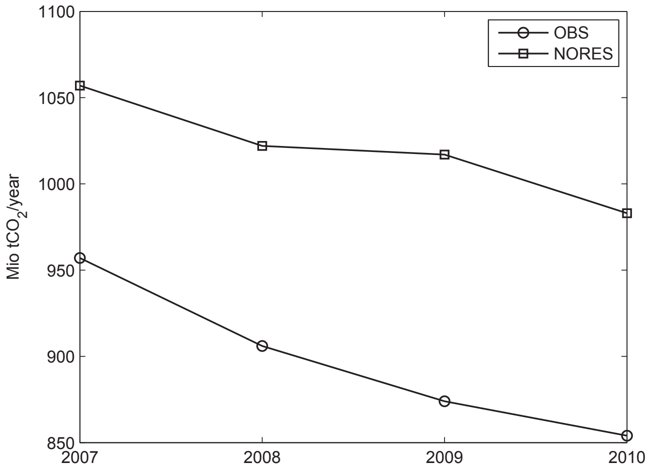
Table 1: Historical electricity generation and simulated electricity generation. Aggregated annual data for MS12.

4. Simulation results

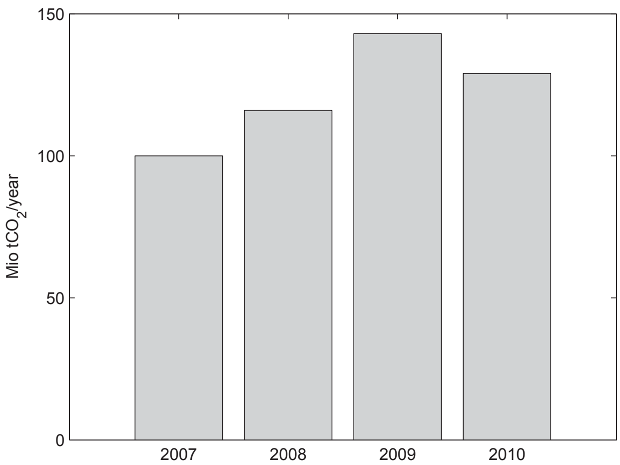
4.1. Outer limit of impact on CO_2 emissions

This section discusses the impact of RES-E deployment on CO_2 emissions in the electricity sector. The impact of RES-E deployment is expressed in terms of CO_2 displacement from the modeled electricity sector to non-modeled ETS sectors. The results presented in this section are based on the ETS-price assumption. This implies that the CO_2 displacement presented in this section is an outer limit for the actual CO_2 displacement caused by RES-E deployment.

Figure 4a shows CO_2 emissions in the electricity sector in the MS12. It is evident that a scenario without RES-E deployment (NORES scenario) results in higher CO_2 emissions in the electricity sector than the historical scenario (OBS scenario). Figure 4b shows the CO_2 displacement due to RES-E deployment from the modeled electricity sector to the non-modeled ETS



(a) CO_2 emissions



(b) CO_2 displacement

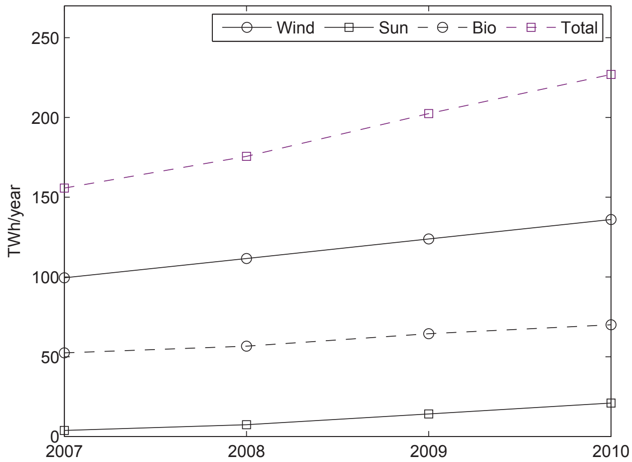
Figure 4: Annual CO_2 emissions in the modeled electricity sector and annual CO_2 displacement from the modeled electricity sector to non-modeled ETS sectors. Data for MS12.

sectors. This CO_2 displacement follows from the difference in CO_2 emissions between the NORES scenario and the OBS scenario.

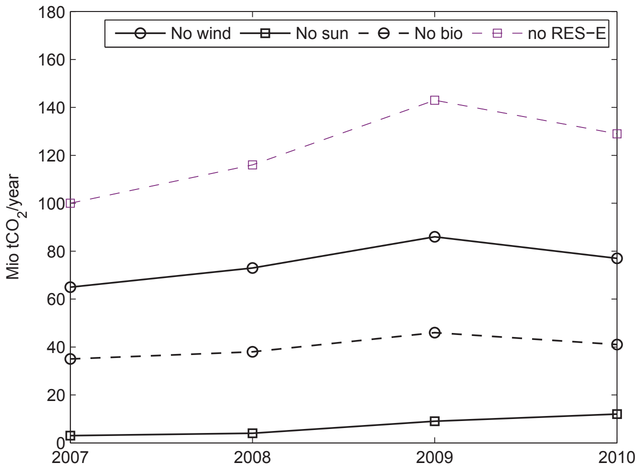
In 2007, total CO_2 displacement due to RES-E deployment is 100 million tCO_2 or 10 % of historical CO_2 emissions. In 2008, 116 million tCO_2 or 13 % of historical CO_2 emissions is displaced. In 2009 and 2010, respectively 143 million tCO_2 or 16 % of historical CO_2 emissions and 129 million tCO_2 or 15 % of historical CO_2 emissions is displaced.

The same analysis can be done for each type of supported RES-E separately. Over the considered period, generation of all types of supported RES-E increased (see figure 5a). The impact of wind energy, solar energy and bio-energy on CO_2 emissions in MS12 is presented in figure 5b. The impact on emissions is determined as the increase in CO_2 emissions in the electricity sector when generation from this particular RES-E is removed. The impact on emissions follows the same pattern as the amount of RES-E injections, although some variations are noticeable. From 2008 to 2009, RES-E injections increased by 12 % whereas the CO_2 abatement due to these injections increased by 27 %. The larger CO_2 abatement per injected unit of renewable energy is due to a smaller gap in marginal generation cost between coal power plants and gas power plants. In 2008, the average marginal generation cost of a coal power plant is 2.7 EUR/MWh lower than the marginal generation cost of a gas power plant whereas in 2009, this cost gap is narrowed to on average 1.2 EUR/MWh. Consequentely, relatively more coal power plants are pushed out of the merit order by RES-E injections in 2009, resulting in a larger impact on CO_2 emissions. In 2010, the impact of RES-E injections decreases as the gap in marginal generation cost between coal power plants and gas power plants increases again.

CO_2 displacement is the direct consequence of changes in fuel shares caused by RES-E deployment. Figure 6 shows the gas share and coal share in MS12 in the different scenarios. RES-E injections decrease the coal share and the gas share in MS12 with 0.9 to 4.1 %-points and 4.1 to 8.3 %-points, respectively. RES-E injections have a larger effect on the gas share than on the coal share. RES-E replaces conventional generation starting with the most expensive generating power plant, being most of the time natural gas fired power plants.

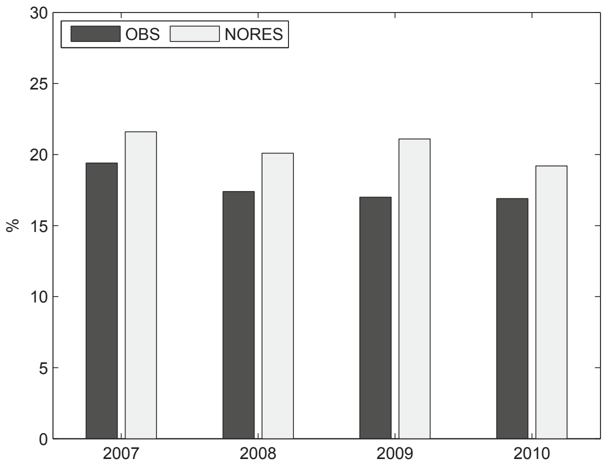


(a) RES-E injections

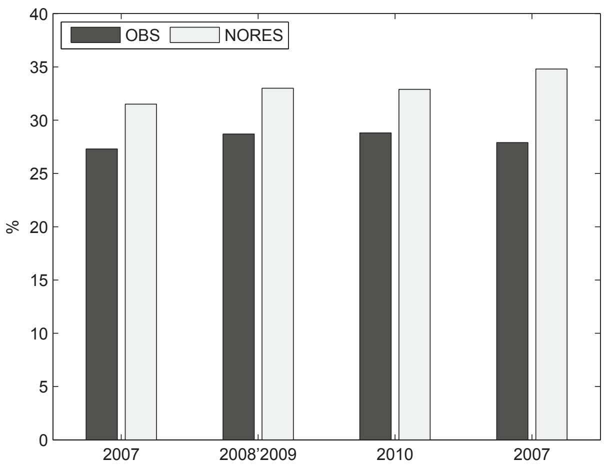


(b) CO_2 emission increase

Figure 5: Historical RES-E injections from wind energy, bio-energy and solar energy and the impact of these RES-E injections on CO_2 emissions expressed as the increase in CO_2 emissions compared to the OBS scenario. Data for MS12.



(a) Coal share



(b) Gas share

Figure 6: Coal share and gas share in electricity generation in MS12, starting from the ETS-price assumption.

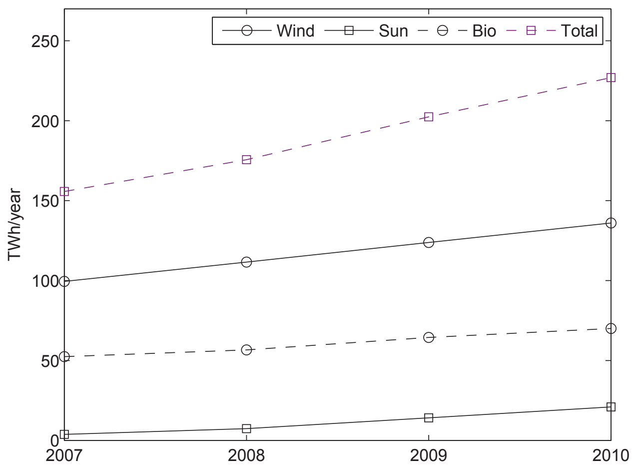
4.2. Outer limit of impact on the EUA price

This section discusses the impact of RES-E deployment on the EUA price. The impact of RES-E deployment is expressed in terms of a reduction in EUA price. The results presented in this section are based on the ETS-cap assumption, implying that the EUA price reduction presented in this section is an outer limit for the actual EUA price reduction caused by RES-E deployment.

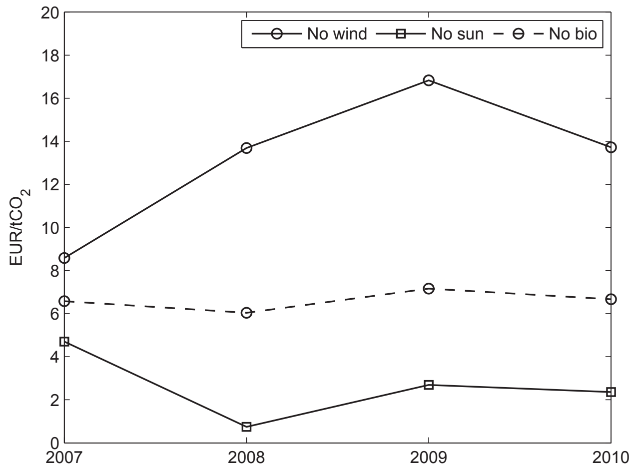
To limit CO_2 emissions in the electricity sector to historical emission levels in absence of RES-E injections, the EUA price should be significantly higher. In 2007, an average EUA price of 15 EUR/tCO_2 is needed while the historical EUA price is only 0.79 EUR/tCO_2. In 2008 an increase in average EUA price from 22 EUR/tCO_2 to 68 EUR/tCO_2 is required and in 2010 an increase in average EUA price from 14 EUR/tCO_2 to 474 EUR/tCO_2 is needed. In 2009, historical CO_2 emissions cannot be reached without RES-E injections. This translates mathematically into an infinite EUA price. In summary, the simulation results indicate that RES-E injections due to support schemes reduce the EUA price by maximum 15 EUR/tCO_2 in 2007, 46 EUR/tCO_2 in 2008 and 460 EUR/tCO_2 in 2010. In 2009, RES-E injections were needed to reach the historical CO_2 emission level.

The same analysis can be done for each type of supported RES-E type separately. Figure 7a gives an overview of the historical RES-E injections in MS12 and figure 7b shows the impact on the EUA price of each type of supported RES-E. The EUA price impact is determined as the increase in EUA price when generation from this particular RES-E is removed starting from the OBS scenario. It becomes clear that the larger the amount of RES-E injections, the larger the impact on the EUA price. The sum of the EAU price increases in absence of each RES-E type separately does not equal the total EUA price increase in absence of all supported RES-E injections. The impact of RES-E injections on the EUA price is hence a nonlinear effect.

RES-E deployment also induces a change in fuel shares (see figure 8). Gas shares are increased with 10.7 to 18.9 %-points and coal shares are decreased with 4.4 to 10.6 %-points when RES-E injections are removed. As the CO_2 intensity of gas fired power plants is lower than the CO_2 intensity of coal fired power plants, RES-E injections are replaced as much as possible with gas fired power plants. Besides, gas fired power plants also replace some of the original coal based generation to compensate for the extra CO_2 emissions needed to replace RES-E injections. 2009 is not included in figure 8 as the historical emissions in the modeled electricity sector cannot be reached without RES-E

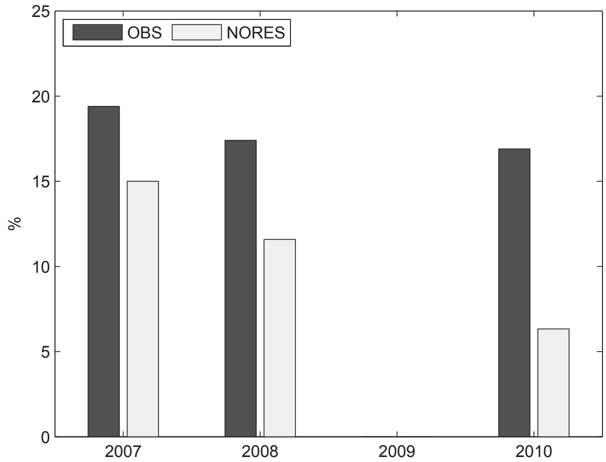


(a) RES-E injections

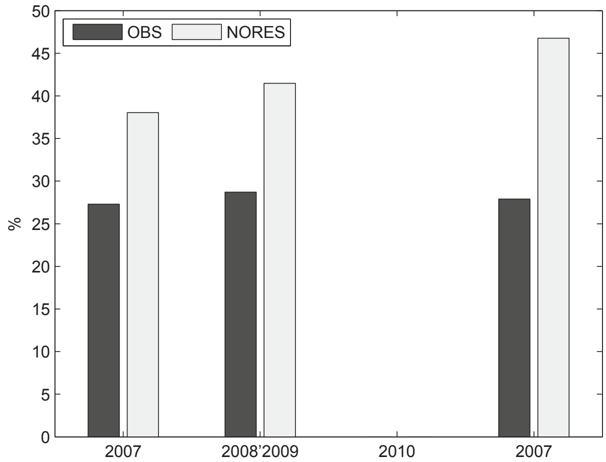


(b) EUA price increase

Figure 7: Historical RES-E injections from wind energy, bio-energy and solar energy and the EUA price increase in absence of these RES-E injections. Data for MS12.



(a) Coal share



(b) Gas share

Figure 8: Coal share and gas share in electricity generation in MS12, starting from the ETS-cap assumption. 2009 data is not available as the NORES scenario is not feasible in 2009.

injections. Note the difference between figure 8 and figure 6. Figure 6 shows the fuel shares starting from the ETS-price assumption. As CO_2 emissions of the modeled electricity sector are not capped according to that assumption, both gas fired generation and coal fired generation replace RES-E injections in the NORES scenario. On the other hand, figure 8 shows the fuels shares staring from the ETS-cap assumption, meaning that CO_2 emissions from the modeled electricity sector are capped. Hence gas fired generation replaces the RES-E injections in the NORES scenario while coal fired generation reduces.

4.3. Combined impact

So far, the electricity sector is considered, consecutively, starting from the ETS-price assumption and starting from the ETS-cap assumption. According to the first assumption, the impact of RES-E deployment is expressed as an outer limit of CO_2 displacement between the modeled electricity sectors and the non-modeled ETS sectors. According to the ETS-cap assumption, the impact of RES-E deployment is expressed as an outer limit of the EUA price change. The combination of both assumptions defines the range in which the actual impact of RES-E deployment is located.

Table 2 summarizes the results presented in section 4.1 and in section 4.2. The outer limit of the CO_2 displacement caused by RES-E deployment follows from the difference in CO_2 emissions between the NORES scenario under the ETS-price assumption and the OBS scenario. Analogously, the outer limit of the EUA price impact follows from the difference in EUA price between the NORES scenario under the ETS-cap assumption and the OBS scenario.

Figure 9 gives an overview of possible combinations of CO_2 displacement and EUA price changes due to RES-E deployment. The x-axis shows the increase in EUA price when supported RES-E injections are removed, starting from the OBS scenario. The y-axis shows the corresponding CO_2 displacement from the non-modeled ETS sectors to the modeled electricity sectors when supported RES-E injections are removed. CO_2 displacement at zero EUA price increase corresponds to the ETS-price assumption (see points P in figure 9) and EUA price increase at zero CO_2 displacement corresponds to the ETS-cap assumption (see points C in figure 9). The curves between these extrema are determined by simulating the NORES scenario with different constant EUA prices imposed on the electricity generators. Note that CO_2 displacement only refers to CO_2 emissions shifted from the

	OBS scenario	NORES scenario	
		ETS-price	ETS-cap
2007			
CO_2 emissions [Mio tCO_2]	957	1057	957
EUA price [EUR/tCO_2]	0.79	0.79	15.01
2008			
CO_2 emissions [Mio tCO_2]	906	1022	906
EUA price [EUR/tCO_2]	22.06	22.06	67.56
2009			
CO_2 emissions [Mio tCO_2]	874	1017	874
EUA price [EUR/tCO_2]	13.15	13.15	infinite
2010			
CO_2 emissions [Mio tCO_2]	854	983	854
EUA price [EUR/tCO_2]	14.31	14.31	474.25

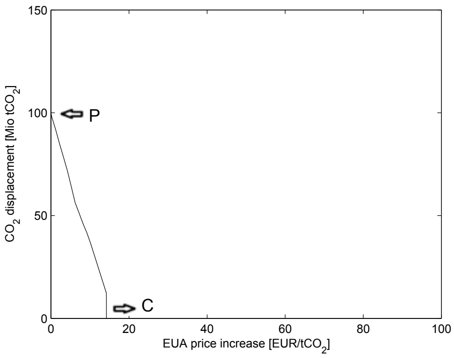
Table 2: Overview of the aggregated annual CO_2 emissions in MS12 and the year average EUA price.

non-modeled ETS sectors to the modeled electricity sectors. Emissions displaced within the modeled electricity sector itself can be determined as the difference between the CO_2 displacement from the non-modeled ETS sectors in the ETS-price assumption (point P) and the actual CO_2 abatement from the non-modeled ETS sectors.

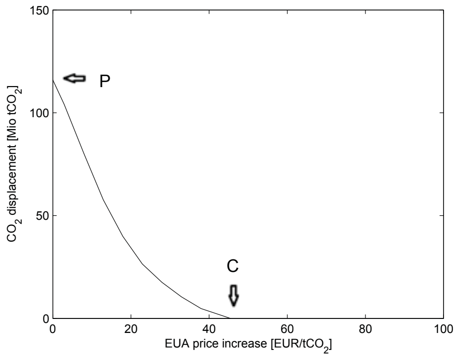
The larger the amount of historical RES-E injections, the larger the range of possible EUA price increases and CO_2 displacements if these RES-E injections are removed. In 2007, total RES-E injections are 156 TWh, in 2008 176 TWh, in 2009 202 TWh and in 2010 226 TWh.

Figure 9 is only valid at the historical CO_2 emission cap imposed by the EU ETS on all ETS sectors. If this emission cap would change, the OBS scenario, which is the reference point with which the impact of RES-E deployment is compared, would change as well and hence figure 9 is no longer valid.

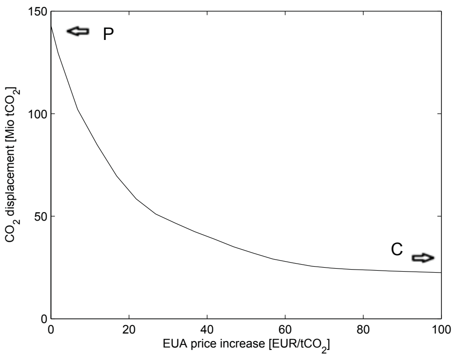
The intersection of figure 9 with the marginal abatement cost curve (MACC) of the non-modeled ETS sectors, starting at the historical EUA price, gives the actual impact of RES-E deployment. This can be understood as follows: consider figure 9d, an EUA price increase of 20 EUR/tCO_2 corresponds to a CO_2 displacement of about 50 million tCO_2 from the non-modeled ETS sectors to the modeled electricity sectors. If this point would



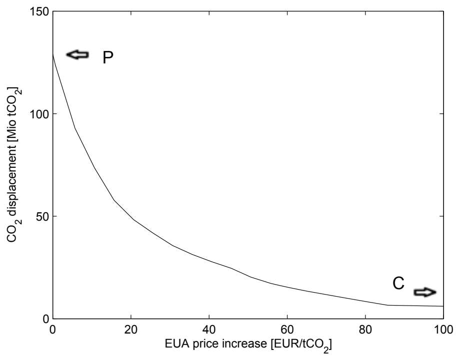
(a) 2007



(b) 2008



(c) 2009



(d) 2010

Figure 9: Possible impact of RES-E deployment on the EUA price and CO_2 displacement from the non-modeled ETS sectors to the modeled electricity sectors when RES-E injections are removed, starting from the OBS scenario.

represent the actual impact of RES-E deployment, it means that the non-modeled ETS sectors reduce their emissions with about 50 million tCO_2 extra due to an EUA price increase of 20 EUR/tCO_2. Put differently, an increase in CO_2 emissions in the modeled electricity sectors with about 50 million tCO_2 when supported RES-E injections are removed, corresponds to an EUA price increase of 20 EUR/tCO_2 needed to displace these emissions from the non-modeled ETS sectors to the modeled electricity sectors. Due to this EUA price increase, about 79 million tCO_2 is displaced within the electricity sectors itself. This 79 million tCO_2 is determined as the difference in CO_2 displacement according to the ETS-price assumption (i.e. 129 million tCO_2) and the actual CO_2 abatement in this example (i.e. about 50 million tCO_2).

If CO_2 abatement in the non-modeled ETS sectors is possible at low cost, the aggregated MACC of the non-modeled ETS sectors intersect figure 9 close to point P. If CO_2 abatement in the non-modeled electricity sector is only possible at high cost, the aggregated abatement curve of the non-modeled ETS sectors intersect figure 9 close to point C.

5. Conclusion

This paper studies the impact of RES-E deployment on the EUA price and the CO_2 emissions in the European electricity sector. The analysis covers 12 EU Member States in Southern and Western Europe during the period from 2007 to 2010. Within the CO_2 emission cap set by the EU ETS, RES-E deployment releases CO_2 emissions in the electricity sector and displaces part of these CO_2 emissions within the electricity sector itself and part from the electricity sector to other ETS sectors. As such, RES-E deployment lowers the demand for EUAs and thus reduces the EUA price.

First, the outer limit of the CO_2 displacement between the modeled electricity sector and the non-modeled ETS sector is determined. The simulation results show that without RES-E injections due to support schemes, the CO_2 emissions in the electricity sector would be up to 10 % higher in 2007, 13 % in 2008, 16 % in 2009 and 15 % in 2010. Subsequently, this paper determines the outer limit of the EUA price decrease due to the introduction of RES-E deployment. The simulation results indicate that RES-E injections due to support schemes reduce the EUA price by maximum 15 EUR/tCO_2 in 2007, 46 EUR/tCO_2 in 2008 and 460 EUR/tCO_2 in 2010. In 2009, RES-E injections were needed to reach the historical CO_2 emission level. Finally, all possible combinations of CO_2 displacement and EUA price change between the outer limits are defined. The intersection of these curves with the MACC of the non-modeled ETS sectors give the actual impact of RES-E deployment on the EUA price and the CO_2 emissions in the electricity sector.

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Appendix

The electricity generation system used in the model is based on data presented by EURELECTRIC (2010) and specified for each year. The used power plant characteristics are taken from Voorspools (2004).

Hourly electricity demand data originates from ENTSO-E (2011) for the countries on the European mainland, from EirGrid (2011) for Ireland and from the National Grid Company (2011) for the United Kingdom. These original demand data are adapted to take into account neglected import/export between countries included in the model and countries excluded of the model.

The hourly wind energy production is taken from national TSO's EirGrid (2011), REN (2011), REE (2011), Terna (2011), Amprion (2011), EnBW Transportnetze AG (2011), 50 Hz (2011), Tennet (2011), Energinet.dk (2011) and Elia (2011). The wind production in Luxembourg, Switzerland, the United Kingdom, France, Austria and the Netherlands is obtained as the capacity weighted average of wind production in the neighboring countries. The cogeneration profile is based on Voorspools (2004). The multiplication of the installed cogeneration capacity and the cogeneration profile gives the hourly electricity generation from cogeneration plants. The solar profile is based on data from the Photovoltaic Geographical Information System (2011). The multiplication of the installed photovoltaic capacity and the solar profile gives the hourly electricity generation from photovoltaic installations.

Day ahead natural gas prices are taken from APX-ENDEX (2011), Nord Pool (2011), Powernext (2011), EEX (2011) and ICE (2011). Quarterly coal futures are taken from EEX (2011) and ICE (2011). The Brent monthly future, available on Index Mundi (2011), is used as oil price. The price for lignite, uranium, biomass and biogas is considered as constant. Finally, the EUA price originates from BlueNext (2011) and the NTC data from ENTSO-E (2011).

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