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Abstract

Incentives for the development of renewable energy have increasingly become an instrument of climate policy, that is, as a means to reduce GHG emissions. This research analyzes the German experience in promoting renewable energy over the past decade to identify the ex-post cost of reducing CO2 emissions in the power sector through the promotion of renewable energy, specifically, wind and solar. A *carbon surcharge* and an *implicit carbon price* due to the renewable energy incentives for the years 2006-2010 are calculated. The carbon surcharge is the ratio of the net cost of the renewable energy over the CO2 emission reductions resulting from actual renewable energy injections. The net cost is the sum of the costs and cost savings due to these injections into the electric power system. The implicit carbon price is the sum of the carbon surcharge and the EUA price and it can be seen as a measure of the CO2 abatement efficiency of the renewable energy incentives. Results show that both the carbon surcharge and the implicit carbon price of wind are relatively low, on the order of tens of euro per tonne of CO2, while the same measures for solar are very high, on the order of hundreds of euro per tonne of CO2.

Keywords

Renewables incentives, wind energy, solar energy, abatement cost, EU ETS.

1 Introduction

In adopting the Climate and Energy Package in 2009, the European Union (EU) made the promotion of Renewable Energy (RE) a distinct element of climate policy. As stated in the first of the ninety-seven whereas's in the Renewable Energy Directive (2009/28/EC),

> "the increased use of energy from renewable sources [...] constitutes an important part of the package of measures needed to reduce greenhouse gas emissions and comply with the Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC), and other further Community and international greenhouse gas emission reduction commitments beyond 2012."

As for the Emissions Trading System (ETS), a companion measure in the Climate and Energy Package, the Renewable Energy Directive implies an additional incentive to increase the RE share and thereby reduce greenhouse gas emissions below what they would otherwise be. Unlike the ETS, the additional incentive is not uniform throughout the EU. Instead, each member state is expected to develop a national "support scheme" to ensure achievement of that member states' share of the EU-wide target of a 20% share of gross energy consumption from RE sources by 2020. Those support schemes can take various forms, but all provide some extra incentive that can be seen as comparable to the carbon price created by the ETS. It is only natural then to ask: what is the real price paid by consumers to abate CO2 emissions? And what is the implicit CO2 abatement cost embodied in these RE support schemes?

To respond to these questions, we estimate the *carbon surcharge* and the *implicit carbon price* associated with RE incentives (REI). The carbon surcharge measures the additional cost to reduce CO2 emissions in the power sector over and above the carbon price resulting from the EU ETS. The implicit carbon price is the sum of the carbon price and the carbon surcharge, thereby providing an estimation of the CO2 abatement efficiency of the REI. This paper calculates the carbon surcharge and the implicit carbon price for wind and solar energy in Germany for the years 2006-2010. Germany is the member state that has played as large a role as any in the expansion of RE in the EU. The German Renewable Energy Act (EEG), which came into force in 2000, defined a system of feed-in tariff (FIT) for all renewable technologies that triggered an impressive growth of wind and solar capacity. Wind capacity grew more than four-fold from 6 GW in 2000 to 27 GW in 2010, solar capacity more than twenty-fold from 76 MW in 2000 to 17 GW in 2010 (BMU, 2012).

The *carbon surcharge* is calculated as the ratio of the net cost of RE over the CO2 emission reductions due to the RE injections into the electric power system. For the quantity of CO2 abated as a result of injections of wind and solar energy for the years 2006-2010, we use the estimates of Weigt et al. (2012) calculated using a deterministic unit commitment model of the German electricity system. Most of the paper is devoted to estimate the net cost of renewable. This is the sum of the costs and cost savings associated with the use of RE in generating electricity. Other benefits -whether they are expressed as energy security, innovation, jobs, non-CO2 emissions, etc.- are not included, nor are costs associated with transmission and distribution.

Our analysis is restricted to the impact of RE on the power sector. When we refer to emissions abatement, we always mean the reduction of CO2 emissions in the German electricity generation system. Actually, because of the EU ETS cap on these emissions, increasing RE in the German electricity sector does not reduce the EU-wide CO2 emissions. Instead, emissions reduction in the German electricity sector is displaced to other ETS sectors in Germany and in other EU member states. Hence, the carbon surcharge should not be considered as the total CO2 abatement cost due to the injection of RE[1] but as an estimate of how much German consumers have paid to reduce CO2 emissions in the German power sector in addition to what is already paid as a result of the EU ETS.

We define the *implicit carbon price* of the REI as the sum of the carbon surcharge plus the average carbon price paid in the EU ETS by conventional generators. This can be seen as the hypothetical carbon price that would make RE economic or, in other words, as an estimation of the equivalent total carbon price being paid when we think of REI as a carbon instrument alone (without EU ETS). The relative efficiency of the REI as an instrument to reduce CO2 emissions can be obtained by comparing the implicit carbon price with the hypothetical EUA price that

[1]The total CO2 abatement cost due to the injection of RE can be seen as infinity since total ETS emissions are capped.

would exist without the REI. In this work, we do not attempt to estimate the effect of the REI on the EUA price. Still, a comparison of the implicit carbon of the REI with estimates of what the EU ETS price might be without the REI provides robust preliminary results.

Our paper is the first, to our knowledge, to estimate the cost of RE to abate CO2 emissions from an ex-post point of view. There is a number of studies that have analyzed the costs and benefits of renewable generation from an ex-ante point of view (e.g. Denny and O'Malley (2007) for Ireland, Dale et al. (2004) for UK, Holttinen (2004) for Nordic countries, DEWI et al. (2005) for Germany). Some of them, such as Holttinen (2004) and DEWI et al. (2005), have also estimated the cost to reduce CO2 emissions resulting from the injection of the RE into the power system. DEWI et al. (2005) estimated the "CO2 avoidance cost" of wind energy, which is the equivalent of our carbon surcharge. It compares the net cost and CO2 emissions the system would have in 2007, 2010 and 2015 between two scenarios: the first one with the future wind capacity remaining the same as in 2003, and second one with a larger wind capacity that is developed thanks to the RE support scheme. Results depend on the assumptions made for the fuel and carbon prices. With a carbon price in the range of €5-10 per tCO2, the estimated annual CO2 avoidance cost of wind in the years 2007 and 2010 goes from a minimum of €56.6/tCO2 to a maximum of €168.0/tCO2. The results from these works are difficult to compare because of the different methodologies, data and scenarios analyzed (Holttinen et al., 2011).

Regarding ex-post analyses using historical data, the research on the costs and benefits of RE into the power system has mostly focused on the impact of RE on the electricity price (e.g. Sensfuß et al. (2008) for Germany, Sáenz de Miera et al. (2008), Gelabert et al. (2011) for Spain, Jónsson et al. (2010) for Denmark). The analyses show that the injection of RE reduces the wholesale price of electricity, often called the merit order effect, and that the savings can be large enough to exceed the total annual expenditure for FIT, as was the case for Germany in 2006 (Sensfuß et al., 2008). Others (Gelabert et al., 2011) have found that, although present initially, the merit order effect disappears over time. We do not assess the benefits of RE from their impact on the electricity price, as we directly estimate the costs and benefits of RE from the analysis of the power generation costs. However, in section 2 we explain how the benefits of RE that we take into account relate with the merit order effect. There is also a substantial amount of literature available - both theoretical and empirical - on renewable incentives. The focus of the empirical studies is mostly on the comparison of the different support schemes and in their effectiveness to promote the deployment of renewable technologies (Lipp, 2007; Fouquet and Johansson, 2008; Steinhilber et al., 2011), but not on the cost to reduce CO2 emissions.

In contrast to these studies, our paper is the first, to our knowledge, to estimate the cost of REI to abate CO2 emissions from an ex-post point of view. We do not asses the benefits of RE in terms of impact on the electricity price, but we directly estimate the costs and benefits of RE by analysing the power generation costs. However in section 2 we explain how the benefits of RE that we take into account relate with the merit order effect.

In the remainder of the paper, section 2 provides a categorization and general discussion of the costs and cost savings associated with the use of wind and solar energy. Section 3 describes in detail the methodology used to estimate these costs and cost savings. Section 4 presents the results and a sensitivity analysis. Section 5 concludes.

2 Costs and cost savings of renewable generation

This section briefly describes the six cost and cost saving components taken into account in calculating the cost of abating CO2 emissions by promoting wind and solar energy in the electricity sector. We also discuss why the merit order effect is not one of these components. The included components are associated with the cost of generation behind the busbar, that is, excluding the cost that may be incurred in connecting these generating sources to the grid, as well as any costs or cost savings associated with congestion in the operation of the transmission and distribution system. Finally, as stated earlier, other possible benefits from the use of RE related to energy security, non-CO2 related emissions, or jobs are also excluded. The cost components that are included are the remuneration to generators, additional balancing cost and additional cycling costs. The cost savings components are the cost savings from the avoided fossil fuel use and carbon costs, and those from added generating capacity.

An important aspect of the costs of wind and solar energy is intermittency, which includes two independent aspects: non-controllable variability and partial unpredictability (Pérez-

Arriaga and Batlle, 2012). Every power plant, including fossil fuel generation, is variable and unpredictable to a certain degree, but wind and solar power plants present these characteristics at a much higher level. The unpredictability of wind and solar energy could be expected to increase the cost of balancing the electric power system, while its variability has an impact on cycling cost.

2.1 Remuneration to generators

Producers of renewable generation are remunerated at a rate that is on average higher than the price at which the electricity they produce could be sold in the wholesale market. This higher remuneration can take various forms. In the case of Germany, it takes the form of guaranteed FITs or fixed prices whose costs are charged to consumers. Many studies that analyze the cost of renewable generation focus on the generation cost, which in the case of RE consists almost entirely of the initial capital cost and the return on the initial investment. While many have commented on the extent to which this cost has been declining, cost data on actual capital outlays are not available for either renewable or competing fossil generation. A more accessible metric is the price paid for the output, which can be expected to cover all relevant costs in well-functioning markets, as well as extra profit and unanticipated losses in some instances. The payments to producers are real expenditures and they are the starting point for devising any relevant metric of cost. In the case of the German FIT, payments are front-loaded and we explain in the subsequent methodology section how we avoid over-stating this cost in the early years of the RE program, by equalizing the annual remuneration along lifetime of the power plants.

2.2 Additional cycling costs

Cycling refers to the operations of conventional plants required to respond to load variations and cycling cost is the cost related to them (Lefton et al., 1997). The increase of energy from intermittent generation reduces the demand for conventional thermal generation and may cause the output of those plants to vary more than would otherwise be the case. This increases cycling costs (Pérez-Arriaga and Batlle, 2012). Firstly, fossil fuel plants could have more start-ups and shut-downs of production, implying an increase of start-up and ramping costs. Secondly, because of the decrease in the demand for thermal generation, conventional power plants tend to work at a lower capacity factor than the one designed for maximum efficiency. Thirdly, the increase of the cycling activity accelerates component failure and increases maintenance costs. The increase of cycling costs is higher especially when more cycling is required to fossil units that were designed for base-load operation (Troy et al., 2010).

2.3 Additional balancing cost

The electric system needs supply and demand to be exactly balanced at all times. The balancing operation refers to the actions undertaken by the TSO to ensure that demand is equal to supply in and near real time. Due to sudden disturbances, such as unanticipated fluctuations of load or electric short circuits, the system operators must make relatively small adjustments with respect to the scheduled dispatching. The balancing is made by purchasing services from generators or adjustable loads whose costs are paid by consumers in the electricity retail price. The system balancing reserve is the provision of capacity the system operator can deploy for balancing the system in real time. The unexpected fluctuations of intermittent generation increase the variation of supply in the short-term. This implies more balancing operations as well as additional system balancing reserves (Milligan et al., 2010). The amount of the additional balancing cost due to intermittent generation depends on many factors such as the level of wind and solar penetrations, the quality of weather forecast, the flexibility of the existing generation portfolio, the balancing market rule.[2] With regard to wind, a number of studies have been carried out on the balancing cost. Results indicate that the additional reserve requirement, as a proportion of the wind capacity installed, tends to be relatively small and that the additional balancing cost is about a few euro per MWh of wind energy, also for high wind penetration (Gross et al., 2006; Holttinen et al., 2011; IEA, 2011). This is because short run fluctuations of wind energy are comparable with other variations of supply and demand (Gross et al., 2006).

[2]Some studies under balancing cost also include the loss of efficiency in the use of existing conventional generation in the medium term due to the additional cycling cost (Holttinen et al., 2011).

2.4 Fuel cost saving

From the perspective adopted in this paper, the fixed price paid in Germany for RE generation buys a joint product: electricity and CO2 abatement. Priority access to the grid, not to mention near-zero variable costs of generation, means that when available renewable generation nearly always displaces conventional fossil fuel generation, typically either coal or natural gas. The cost of the fossil fuel required to generate the electricity thus displaced is a cost saving since it is what would be paid out to produce the same amount of electricity. Consequently, it must be subtracted from the payment to generators to isolate the additional cost for abating CO2 emissions. This cost saving depends on the quantity and prices of the coal or natural gas not purchased, but figuring out what is displaced when wind or solar generation is injected into the grid is not easy. In this paper, the quantity and type of fossil fuel combustion avoided is taken from the simulations of the German electricity system for the years 2006-10 performed by Weigt et al. (2012). The quantities of each fuel displaced are those indicated by the difference between the scenario calibrated to replicate observed load and injections with the counterfactual scenarios in which the only change is that the RE injections are taken away. The quantities thus indicated are multiplied by the fuel prices, to determine the fuel cost savings, or more broadly, what would have been the cost of generating an amount of electricity equal to the RE injection. Since natural gas prices are always higher than coal prices, cost savings are greater per MWh of displaced natural gas generation than for coal generation. The fuel prices are exogenous and therefore not affected by the reduction in fuel demand occasioned by RE injections. The price for oil, coal and gas are now determined in the global market, and this variation of demand in Germany is assumed not to be significant in the global market.

2.5 Carbon cost saving

Carbon cost savings are determined in the same manner as the fuel cost savings, that is, as the difference in quantities between the calibrated observed simulation and the appropriate counterfactual, using typical emission factors for the fossil fuel combustion avoided and actual average monthly allowance prices. In contrast to fuel cost savings, carbon cost savings are greater for displaced coal generation than for natural gas generation since the emissions avoided by displaced coal generation are higher than for natural gas. Carbon prices are also treated as exogenous, but the assumption that these prices are not significantly affected by RE injections in Germany is subject to serious challenge. We treat the carbon price as exogenous because of the absence of reliable estimates of the effect of RE injections on the carbon price.

2.6 Capacity saving

Developing renewable generation increases generation capacity in the system, although not by the same amount as equivalent fossil-fuel generating capacity since intermittent generation does not provide the same degree of reliability. Nevertheless, the equivalent amount of avoided dispatchable capacity is not zero since on average the amount of fossil generation required is less. Hence some conventional capacity could be retired or, alternatively, less conventional capacity would need to be built in the future. The capacity credit is the amount of conventional capacity that can be displaced by intermittent plants while preserving the same level of system security and is generally expressed as a percentage of the installed capacity of intermittent generators (Gross et al., 2006). The capacity cost saving consists of the fixed cost of building or maintaining the conventional capacity no longer needed as a result of the capacity credit. There is a large literature on wind energy addressing this issue (see Gross et al. (2006), Giebel (2005), IEA (2011) for a comparison of studies). Results show that the capacity credit depends on many factors such as the quantity and distribution of wind, the level of energy storage, the network system; its value differs from country to country. If calculated as percentage of installed capacity, it tends to decrease with penetration of wind energy. Previous studies agree that the capacity credit is never zero, but that it can be small.

An important concept related to capacity credit, and often used to calculate the cost of wind generation, is back-up capacity. This is the conventional capacity reserve that would make wind generation as reliable as an equivalent amount of conventional dispatchable capacity. Back-up capacity is complementary to the capacity credit: the lower the capacity credit, the higher is the required back-up capacity. (Gross (2006) shows the analytic relation between the back-up cost and the capacity saving.) The relationship between the capacity credit and back-up capacity cost can be illustrated by a simple example. Imagine a system that is anticipating additional load that would require 100 MW of conventional dispatchable capacity. If one starts with building 100 MW of wind capacity, then the cost of the required back-up capacity must be added. In nearly all instances, the required back-up capacity will be less than 100 MW. Alternatively, one can start with 100 MW of dispatchable capacity, then add wind capacity, and determine how much less dispatchable capacity would be needed because of the added wind capacity. The analysis presented in this paper takes the latter approach as more appropriate when wind is added to an existing system with adequate conventional capacity to meet demand, as is the case in Germany. The cost savings results either from some existing capacity that no longer needs to be maintained or from new capacity that will not have to be built to meet anticipated demand.

2.7 Merit order effect

The merit order effect is the reduction of wholesale electricity price as result of the RE injections, which is sometimes argued as a cost savings that should be counted against the subsidy paid for RE (Sensfuß et al., 2008). Fig. 1 presents a stylized representation of the effect of injecting RE energy into the electricity system and it is used to explain why the savings resulting from the merit order effect is not included.

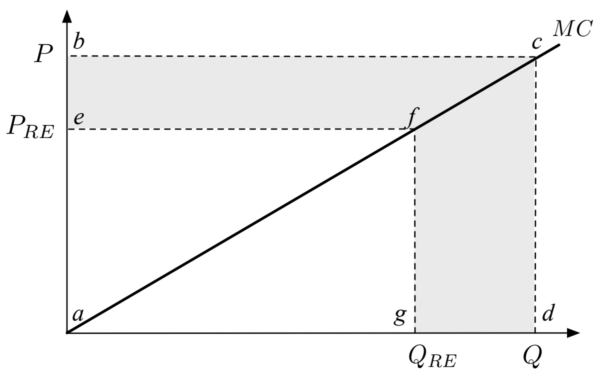

Figure 1: merit order effect. *MC*: marginal cost of conventional generators; $Q(Q_{RES})$: demand of electricity from conventional generators without(with) renewable energy in the system; $P(P_{RES})$: price of electricity without(with) renewable energy in the system.

The line *MC* represents an approximation of the dispatch order of conventional generation plants on a typical electrical system in which those with the lowest variable or marginal cost are dispatched ahead of high variable cost plants. Absent injections of wind or solar generation, the generation demanded of this set of plants, would be Q, the wholesale price for electricity, P, and the amount paid to generators in the wholesale market, *abcd*. Of this amount, *acd* represents variable costs incurred in the generation of Q electricity while *abc* is the producer's surplus or infra-marginal rent from which capital and other fixed costs are recovered. When wind or solar generation is injected into this system, the demand upon these generators is reduced to Q_{RE}, the price commensurately to P_{RE}, and the amount paid to these generators, to *aefg*. The difference in payments to displaced generators is the shaded area of Fig. 1. Of this reduced payment, one component consists of real costs not incurred, *gfcd* representing avoided variable/fuel costs, while the other component, *bcfe* representing infra-marginal rent, is an avoided payment to generators for the fixed costs of the capacity in service.

The *gfcd* component is identical in concept to the fuel cost savings discussed in section 2.4 above. The *bcfe* component is a transfer payment, which may or may not be passed on to final consumers depending on the regulations governing the prices paid by final consumers and provisions for maintaining unused capacity on line. For instance, if the regulatory system guarantees the recovery of fixed costs for generators and *abcd* is the amount that fully compensates generators for fixed and variable costs of existing capacity, then payments for fixed costs must increase with increased RE injections. Alternatively, if the recovery of fixed costs is not guaranteed, the loss incurred by generators will lead to the retirement of existing unused capacity or a higher threshold price for building new capacity. In fact, the loss of this infra-marginal rent is the origin of the debate about the need for capacity markets or alternative capacity payments to maintain sufficient dispatchable capacity to meet load in the presence of intermittent generation. These capacity payments reflect the difference between the capacities that could be retired if RE generation were fully dispatchable and that which can be retired notwithstanding intermittency. The capacity credit discussed in section 2.6 above captures the cost savings for the capacity that is no longer needed and can be retired.

In our cost accounting, we do not include the infra-marginal rent component of the merit order effect since either it will not be realized at the retail level because of regulatory treatment or some other arrangement will be devised to maintain sufficient capacity to meet demand at all times. Moreover, the capacity credit captures whatever savings in fixed-cost compensation are to be achieved as a result of reduced capacity needs. Our treatment is much simpler than including the full merit order effect and then estimating substitute capacity payments. We start from the point that however adequate the current system of compensation to generators without RE may be, equivalent compensation will need to be maintained in one form or another for all capacity except that represented by the capacity credit.

3 Methodology

In this session we present the methodology used to calculate the carbon surcharge and the implicit carbon price. We first define the carbon surcharge and the implicit carbon price and how they are related to the costs and cost savings described in the previous section. Subsequently we present in detail how we calculate all the costs and cost savings for the German case.

We calculate the annual REI carbon surcharge (*CaS*) for the years 2006-2010 by comparing the annual costs of renewables and the emissions in generating electricity in two scenarios: the historical scenario, which we call observable scenario (*OBS*), and the counterfactual scenario where we suppose that no RE was injected into the system (*NoRES*). More precisely, *CaS* is given by the net cost of renewable (*NC*) divided by the CO2 emission reduction due to the injection of renewable energy (*A*) in a given year. The net cost of renewable, *NC*, is the sum of all the annual costs and benefits (which are in the form of cost savings) resulting from the injection of renewable energy into the power system and can be seen as the sum of three components. The first is the total remuneration earned from generating electricity from renewable energy (*Rem*), which accounts for the direct cost of the REI. The second is the difference between the total costs of producing electricity from conventional generators (*TC*) in the *OBS* scenario and the same cost in the *NoRES* scenario: $TC(OBS) - TC(OBS)$. This takes into account only the impact of RE on the short-term cost of generating electricity from conventional generation, as we consider the same conventional capacity in the *OBS* and *NoRES* scenario. The third component is the capacity saving (*CapSav*) which comprises the impact of RE on the capital cost of conventional generation. The CO2 emission reduction due to the injection of renewable energy, *A*, is given by the difference in the total emissions between the *OBS* scenario ($E(OBS)$) and the

NoRES scenario ($E(NoRES)$). In formulas, we have:

$$CaS = \frac{NC(OBS)}{A} = \frac{Rem + (TC(OBS) - TC(NoRES)) - CapSav}{A} \tag{1}$$

where

$$\begin{aligned} A &= E(NoRES) - E(OBS)\,, \\ TC(OBS) &= TFC(OBS) + TCC(OBS) + TCyC(OBS) + TBC(OBS)\,, \\ TC(NoRES) &= TFC(NoRES) + TCC(NoRES) + TCyC(NoRES) + TBC(NoRES)\,. \end{aligned} \tag{2}$$

TC is given by the sum of the total fuel cost (TFC), the total carbon cost (TCC), the total cycling cost ($TCyC$) and the total balancing cost (TBC). The fuel cost saving ($FCSav$) and carbon cost saving ($CCSav$) are given by the difference in the total fuel costs and total carbon costs between the *OBS* and *NoRES* scenario. The additional cycling cost ($ACyC$) and the additional balancing cost (ABC) as the difference in the total cycling cost and total balancing cost between the *NoRES* and *OBS* scenario. The definition of the costs and the savings are such that they are all positive and the net cost is given by the sum of the costs minus the savings:

$$CaS = \frac{Rem + AdCyC + AdBC - FCSav - CCSav - CapSav}{A}\,, \tag{3}$$

where

$$\begin{aligned} FCSav &= TFC(NoRES) - TFC(OBS)\,, \\ CCSav &= TCC(NoRES) - TCC(OBS)\,, \\ AdCyC(OBS) &= TCyC(OBS) - TCyC(NoRES)\,, \\ AdBC(OBS) &= TBC(OBS) - TBC(NoRES)\,. \end{aligned} \tag{4}$$

Regarding the carbon price, we do not consider any interaction between the EU ETS and the REI: we simply use as EUA prices in the *NoRES* scenario the same prices as those in the

OBS scenario. Thus $TCC(OBS) = \overline{P}_{obs} * E(OBS)$ and $TCC(NoRES) = \overline{P}_{obs} * E(NoRES)$, where $\overline{P}_{obs}$ is the historical average carbon price paid by fossil fuel generators, and $CCSav = \overline{P}_{obs} * A$. In Appendix A, we have extended the methodology to include the change of the EUA price due to the interaction between the REI and the EU ETS. It shows that the effect on the carbon surcharge is ambiguous. For example, a higher EUA price will increase the carbon surcharge by reducing the emission abatement due to the RE injection, but it will also decrease it because a higher carbon price implies higher fuel cost saving and carbon cost savings. We did not make any attempt to empirically estimate these effects, for the reason that we can find no modeling that provides an estimate of the EU-wide reduction in demand for allowances due to RE policy and estimation of the relationship between changes in demand for EUAs and the effect on price. Effectively, we treat the observed EUA price as if it were a fixed annual tax.

The implicit carbon price (*ICP*) is equal to the carbon surcharge, as defined in Eq. (3), plus the average carbon price $\overline{P}_{obs}$, or equivalently is given by calculating the carbon surcharge without considering the carbon cost saving in the net cost:

$$ICP = \frac{Rem + AdCyC + AdBC - FCSav - CapSav}{A} = CCSav + \overline{P}_{obs}\,. \tag{5}$$

The *ICP* can be seen as an estimation of the implicit abatement cost of the REI, that is the cost of abating CO2 when we think of the REI as a carbon instrument alone, or, in other word, as the hypothetical carbon price that would recover the cost of RE. Appendix B provides a proof for the German case when the carbon price is the same in the (NoRES) scenario as in the (OBS) scenario.

The rest of the section presents in detail how we calculated the annual costs and cost savings of wind and solar energy in Germany for the period 2006-2010.

3.1 Remuneration to generators

The relevant law in Germany (EEG) provides producers of RE a 20-year guaranteed FIT (in addition to generation in the year of installation), which is different for wind and solar energy. Power producers of wind energy receive an initial high tariff for a period ranging from a minimum of 5 years up to 20 years, and a final low tariff (about 60% lower) for the remaining period.[3] The length of the initial period depends on the characteristics of the power plant. Plant-specific data on how long the producers receive the high tariff are not available, but according to the 2011 EEG-Progress Report published by the German government (BMU, 2011), more than half of the power plants receive the initial tariff payment over 20 years and more than three-quarters at least for 15 years. The level of the initial and final tariffs depends on the year of installation of the turbines and both are annually reduced by a fixed percentage. For example, wind energy generated by on-shore power plants installed in 2010, is remunerated by an initial and final FIT that are 1% lower than for the energy generated by the power plants installed in 2009.

With regard to FIT for solar energy, producers receive a fixed tariff for 20 years. For the period 2000-2003, the level was the same for all solar power plants; from 2004 on, it depends on the characteristics and location of the installation. As for wind, the levels of solar FIT for new installed capacity are annually reduced by a fixed percentage. The levels and the annual reductions of solar and wind FIT were first defined in year 2000 and subsequently revised in 2004, 2009 and recently in 2011. Table 1 shows the levels of FIT for new installed capacity for the period 2000-2010 (EEG, 2000, 2004, 2009). It also shows the total annual FIT expenditure, that is, the total amount spent annually for solar and wind FIT.[4] All FIT are nominal.

Since the FIT diminishes in value over time both in nominal and real terms, taking the amount paid for the FIT in a given year would make wind and solar energy appear more expensive in the first years of activities, when the payments are relatively generous, and cheaper in the following years. Consequently, the structure of payments over time requires some equalization to avoid over- and understating cost in the early and later years of the facilitie life. We do so in the following way for all capacity installed in a given year.

First, we assume a 25-year lifetime for all solar and wind power plants (IEA/NEA, 2010) and estimate remuneration for each vintage based on observed wind or solar generation in each

[3]The minimum length of the initial period is 5 years for on-shore power plants, 9 years for off-shore power plants commissioned before year 2004, and 12 years for off-shore power plants commissioned afterwards.

[4]Data for the total annual expenditure are provided by the German TSOs: www.eeg-kwk.net/de/EEG_Jahresabrechnungen.htm.

Wind		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
On-shore	IT [¢/kWh]	9.10	9.10	8.96	8.83	8.70	8.53	8.36	8.19	8.02	9.20	9.11
	FT [¢/kWh]	6.19	6.19	6.10	6.01	5.50	5.39	5.28	5.18	5.07	5.02	4.97
Off-shore	IT [¢/kWh]	9.10	9.10	8.96	8.83	9.10	9.10	9.10	9.10	8.92	15.00	15.00
	FT [¢/kWh]	6.19	6.19	6.10	6.01	6.19	6.19	6.19	6.19	6.07	3.50	3.50
Expenditure	[Bn€]			1.44	1.70	2.30	2.44	2.73	3.51	3.56	3.39	3.34

Solar		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Minimum rate	[¢/kWh]	50.62	50.62	48.09	45.68	45.70	43.42	41.24	39.18	37.22	31.94	28.43
Maximum rate	[¢/kWh]	50.62	50.62	48.09	45.68	57.40	54.53	51.80	49.21	46.75	43.01	39.14
Expenditure	[Bn€]			0.08	0.15	0.28	0.68	1.18	1.60	2.22	3.16	5.09

Table 1: wind and solar FIT. *IT*: initial tariff; *FT*: final tariff. *Expenditure*: total annual expenditure for wind and solar FIT. The level of the solar FIT depends on the capacity and location of the solar plant and ranges between the *Minimum rate* and *Maximum rate*. All the data are in nominal value. Sources: for the level of the FIT, elaboration from EEG (2000, 2004, 2009); for the expenditures data are provided by the German TSOs. To our knowledge there are no data publicly available on the total expenditure for wind and solar FIT for the period 2000-2001.

year through 2010 assuming equal annual capacity factors for each in-service vintage and based on an assumed capacity factor for the remaining years of activity of that vintage.[5] Then, that stream of payments is discounted at the fixed rate of 7% and summed to get an initial Net Present Value (NPV) of all the remunerations.[6] Finally, the resulting NPV is converted into a mortgage-like equal annual remuneration by redistributing it over 25 years. We assume that all the installations built before year 2000 (about 4GW for wind and 32MW for solar) were commissioned in year 2000.[7] The equalized remuneration for all turbines in a given year consists of the sum of the equalized payments to each vintage of capacity in service that year. For example, the equalized remuneration for year 2006 is given by the sum of the annualized payments of the vintages built between 2000 and year 2006 because all capacity constructed from 2000 is still in activity in 2006. All remunerations are calculated in €(2011) in order to take into account inflation. For the period 2000-2011 the average annual historical CPI rate of the German Federal Statistical Office is used (see table 15),[8] while from 2012 we assume a constant rate of 2% (the average annual inflation in Germany in 1990-2011 was 2.17%).

[5] We assume that all capacity is installed on the first of January.

[6] The existing literature on cost of generation electricity generally uses a cost of capital between 5% and 10% (IEA/NEA, 2010).

[7] This assumption is justified because the capacity built before year 2000 was low compared to the capacity constructed between 2000 and 2010 (especially with regard to solar energy), and because the EEG gives FIT also to power plants built before 2000 as if they were commissioned in 2000.

[8] www.destatis.de.

Table 2 shows the annually installed wind and solar capacities and the amount of electricity generated. For the period from 2010 to the end of the lifetime of the plants, we assume that all power plants have the same capacity factor equal to 18.0% for wind and 8.1% for solar, as the average capacity factors in 2006-2010.

Wind		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Total capacity	[GW]	6.1	8.8	12.0	14.6	16.6	18.4	20.6	22.2	23.8	25.7	27.2
Installed capacity	[GW]	1.7	2.7	3.2	2.6	2.0	1.8	2.2	1.6	1.6	1.9	1.5
Wind electricity	[TWh]	9.5	10.5	15.8	18.7	25.5	27.2	30.7	39.7	40.6	38.7	37.8
Off-shore electricity	[GWh]										38	174

Solar		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Total capacity	[MW]	76	186	296	435	1105	2056	2899	4170	6120	9914	17320
Installed capacity	[MW]	44	110	110	139	670	951	843	1271	1950	3794	7406
Solar electricity	[GWh]	64	76	162	313	556	1282	2220	3075	4420	6583	11683

Table 2: *Total capacity*: total installed capacity; *Installed capacity*: annual installed capacity; *Wind electricity*: total final electricity produced by wind energy; *Off-shore electricity*: total final electricity produced by off-shore wind energy; *Solar electricity*: total final electricity produced by solar energy. Source: BMU (2012).

The price of electricity paid to wind and solar energy depends on the level of FIT for the first 20 years of activity, after that power plants receive remuneration from selling electricity into the market. We assume that the market price of electricity is €50/MWh in real terms (average electricity price 2006-2011 was €47.7/MWh). Due to inflation, the real level of the FIT decreases annually. If it goes below the assumed electricity price, the power producers sell electricity in the market. In other words, producers receive at least €50/MWh of energy generated.

With regard to FIT for wind energy, for the period 2000-2010 our assumption is that all wind power plants received the initial high FIT.[9] For the years after 2010, it is assumed that 50% of power plants receive the initial high tariff for 20 years and the other 50% for 15 years. In addition to this scenario, which is called *Medium FIT*, section 4.2 shows results for two other FIT scenarios. Regarding FIT for solar energy, we assume that the average FIT earned by all newly installed solar capacity in its first year of activity would be the same for all 20 years. Additionally details on the calculation are in Appendices C and D. In section 4.2 we present

[9]For the years 2002-2010, the difference between the total annual wind remuneration based on this assumption and the total historical expenditures for FIT of table 1 is no higher than 0.5%.

results for scenarios with different assumptions regarding cost of capital, future inflation rate, cost of electricity and level of FIT.

Table 3 shows the results for the equalized remuneration and the total annual expenditures for FIT for wind and solar energy for the period 2006-2010. For wind, the results refer to the *Medium FIT* scenario. The level of remuneration to generators increases over the years with the increase of wind and solar capacity and our equalized remuneration is always lower than the actual annual expenditures for FIT, except in 2010 for wind when the wind capacity factor was especially low. Actual annual expenditure for FIT depends on the amount of RE generated, and therefore on the actual capacity factor in contrast to the lifetime average capacity factor assumed in the calculation of equalized remuneration. While the wind capacity factor was lower in 2010 (15.9%), it was higher in 2007 and 2008 (20.43% and 19.43%). Consequently, in table 3 equalized remuneration is lower than the expenditure for FIT in 2007-2008 and higher in 2010.

Wind		2006	2007	2008	2009	2010
Expenditure for FIT	[M€]	2979	3737	3696	3512	3419
Equalized remuneration	**[M€]**	**2684**	**2873**	**3056**	**3291**	**3486**
%		90%	77%	83%	93%	102%

Solar		2006	2007	2008	2009	2010
Expenditure for FIT	[M€]	1282	1702	2303	3266	5207
Equalized remuneration	**[M€]**	**966**	**1351**	**1893**	**2882**	**4503**
%		75%	79%	82%	88%	86%

Table 3: wind and solar generation costs. *Expenditure for FIT*: total annual expenditure for the wind and solar FIT (cf. table 1). *Equalized remuneration*: annual equalized remuneration. *%*: percentage of *Equalized remuneration* vs. *Expenditure for FIT*. Data are in M€(2011).

3.2 Fuels cost saving and carbon cost saving

For the estimation of the fuel cost saving and carbon cost saving we make use of the model of Weigt et al. (2012). This is a deterministic unit commitment model of the German electricity market for the period 2006-2010. The model minimizes total generation costs, including start-up cost, on an hourly time frame and it is calibrated to reproduce observed yearly generation by fuel. The generation cost and the hourly demand, as well as technical parameters, are exogenous while the electricity price and the dispatching schedule are endogenous. Perfect competition and perfect foresight of load and RE injections are assumed. The model dataset uses detailed information on all conventional facilities in Germany with more than 100 MW generation capacity by plant and fuel types, and aggregated information for smaller power plants. Data come from VGE (2005, 2006, 2009), Umweltbundesamt (2011), Eurelectric (2010) and company reports. Marginal generation costs consist of fuel and emission costs. Natural gas and coal prices are exogenous and assumed not to be significantly affected by the reduction in demand occasioned by RE injections in the German electricity system. Average monthly fuel prices for oil, gas, and coal are used and they come from the Federal Office of Economics and Export Control (BAFA, 2011). In all scenarios the EU ETS carbon price is exogenous and equal to the historical values. The carbon prices used are monthly average EUA prices from the European Energy Exchange (EEX). Data for start-up cost and shut-down times come from DENA (2005), Schröter (2004). The model considers differences in plant efficiencies due to the different lifetime of the plants as in Schröter (2004), but does not take into account efficiency losses resulting from a lower utilization due to renewable injection. Demand level accounts for import and export and is based on data from ENTSO-E (2011). Data for hourly wind input are provided by the four German network operators. Data for solar and biomass injections are not available for the full time frame and an average monthly profile has been estimated based on the hourly injection levels provided for the East German region by the TSO 50Hertz Transmission. Consequently, the model accounts for the high variability of wind injection but not for solar variations. Biomass is running with a relative constant profile. The model has been calibrated by modifying the marginal generation costs of coal and gas plants and the availability factors. For more details see Weigt et al. (2012).

Table 4 presents the total annual CO2 emissions and the fuel and carbon costs in the *OBS*, *No Wind* and *No Solar* scenarios. Fuel cost consists of the expenditure for buying fuels for coal, gas, nuclear and lignite generation. The total annual CO2 emissions reduction, fuel cost saving and carbon cost saving are calculated by taking the values of the emissions and costs in the *No Wind* and *No Solar* scenarios and subtracting those in the *OBS* scenario.

Wind			2006	2007	2008	2009	2010
CO2 emissions	*OBS*	[MtCO2]	307	318	297	282	287
	No Wind	[MtCO2]	329	344	329	312	314
CO2 emission reduction		**[MtCO2]**	**22**	**26**	**32**	**30**	**27**
Fuel cost	*OBS*	[M€]	10621	10622	13875	10423	11111
	No Wind	[M€]	11726	12104	15718	11705	12433
Fuel cost saving		**[M€]**	**1105**	**1482**	**1843**	**1281**	**1322**
Carbon cost	*OBS*	[M€]	5302	192	5090	3733	4276
	No Wind	[M€]	5651	221	5513	4121	4668
Carbon cost saving		**[M€]**	**350**	**29**	**422**	**388**	**393**

Solar			2006	2007	2008	2009	2010
CO2 emissions	*OBS*	[MtCO2]	307	318	297	282	287
	No Solar	[MtCO2]	308	320	301	287	295
CO2 emission reduction		**[MtCO2]**	**2**	**2**	**4**	**5**	**7**
Fuel cost	*OBS*	[M€]	10621	10622	13875	10423	11111
	No Solar	[M€]	10719	10739	14080	10649	11519
Fuel cost saving		**[M€]**	**98**	**117**	**205**	**226**	**407**
Carbon cost	*OBS*	[M€]	5302	192	5090	3733	4276
	No Solar	[M€]	5327	193	5168	3795	4386
Carbon cost saving		**[M€]**	**26**	**1**	**78**	**63**	**110**

Table 4: total annual CO2 emission reduction, fuel cost saving and carbon cost saving due to wind and solar energy. Data are in nominal value.

3.3 Additional start-up cost

Regarding cycling costs, we restrict our analysis only to the start-up cost, which is the cost of the additional fuel needed to start-up the plant, because the model of Weigt et al. (2012) does not consider other cycling costs.[10] As it was done for fuel cost saving, we calculate the additional start-up cost due to wind(solar) as the difference of start-up costs in the *OBS* scenario and *No Wind*(*No Solar*) scenario, table 5. First we notice that, in most of the years, the start-up costs

[10]The model considers start-up restrictions for coal and lignite fired steam plants of several hours downtime while gas turbines have no start-up restrictions. It also assumes that all plants can technically be shut down after one hour of operation, and does not consider externally defined minimum run-time.

are lower in the observed scenario than in the scenarios without wind and solar energy. In these years, plants continuing in service always do experience greater start-up costs when we inject RE, but there are just fewer plants starting up and shutting down when intermittent generation is present. This result probably also reflects the assumption of perfect foresight with respect to the intermittent RE injections, which would allow for an optimal utilization of the existing generation fleet. Second, we see that the start-up costs in all scenarios are always much lower than the avoided fossil fuel cost (less than 2%), and consequently the additional cycling cost are much lower than the fuel cost saving. Also the other cycling costs, such as ramping cost, are always much lower than the avoided fuel cost, at least one order of magnitude smaller (Van den Bergh et al., 2013), and we can infer that our results would not change much if all cycling costs could be added to our analysis.

Wind		2006	2007	2008	2009	2010
start-up cost	*OBS*	173	156	212	199	207
	No Wind	178	169	217	197	203
Additional start-up cost		**-5**	**-13**	**-5**	**2**	**4**

Solar		2006	2007	2008	2009	2010
start-up cost	*OBS*	173	156	212	199	207
	No Solar	175	159	213	209	207
Addition start-up cost		**-2**	**-3**	**-1**	**-9**	**0**

Table 5: Additional start-up cost due to wind and solar energy. Data are in nominal value.

3.4 Additional balancing cost for wind

The model of Weigt et al. (2012) considers perfect foresight of load and RE and cannot be used to estimate balancing cost. However, a number of studies have examined the additional balancing cost for wind energy. Estimations are in the order of €1-4/MWh of wind energy for wind penetrations up to 20% (Holttinen, 2008).[11] GreenNet project estimates a cost of Germany of €2 per MWh of wind energy with a 10% wind penetration by comparing the system operational costs in a simulation model run with stochastic wind power forecasts and in the same model where the equivalent wind production is predictable and constant (Meibom

[11] In the period 2006-2010 wind penetration in Germany did not exceed 7%.

et al., 2006). We use this value for our assessment of the balancing cost. Our goal is not so much an accurate calculation of the additional balancing cost as it is an estimation of its order of magnitude in comparison with other costs and cost savings. Table 6 shows the balancing cost for wind.

Wind		2006	2007	2008	2009	2010
Balancing cost per MWh of wind energy	[€/MWh]	2	2	2	2	2
Wind energy generated	[TWh]	31	40	41	38	36
Additional balancing cost	**[M€]**	**61**	**79**	**81**	**77**	**76**

Table 6: additional balancing cost for wind. Data are in M€(2011).

3.5 Wind capacity saving

In order to estimate the capacity benefit we must estimate how much, when and which kind of conventional capacity is displaced because of the additional wind generation. This kind of assessment would require a detailed analysis of the development of the German system in the next years, which goes beyond the scope of this study. We will therefore estimate the capacity benefit for wind only, based on results from existing literature and on simple and transparent assumptions. As for the additional balancing cost, our goal is not so much an accurate calculation of the capacity saving as it is an estimation of its order of magnitude in comparison with other costs and cost savings. As shown in section 4.2 the magnitudes concerning solar energy are such that the capacity credit will have little bearing on the final abatement cost.

In order to estimate the cost savings for wind from capacity no longer required, we assume that the capacity installed up to 2010 would provide a credit of 7%. One study (DENA, 2005) shows a capacity credit of 6-8% in Germany for a wind capacity of 14.5GW, while a capacity of 36GW would have a capacity credit of 5-6%. Considering that in 2010 there was a wind capacity of 27GW, a 7% capacity credit is a realistic value. We assume that these cost savings from all wind capacity built before 2010 are realized in 2015. This means that in Germany, in 2015 the constructed conventional capacity will be lower by 7% of the wind capacity installed in the period 2000-2010 than it would be otherwise. We suppose that the wind capacity credit will substitute 70% of coal and 30% of gas. Coal is displaced more than gas because wind power plants need flexible gas-fired generation to cope with wind fluctuations. In order to make an estimation of the economic benefit, we calculate the savings in capital cost and fixed O&M cost of the conventional plants displaced by the wind capacity credit. For the O&M cost, we consider all the years when wind generators are active (envisaging the lifetime of a wind turbine of 25 years). For example, in 2006 about 2GW of wind capacity was installed which will last up to 2031. This wind capacity provides a capacity credit of 120MW. As a result, we assume that in 2015, investment in 84MW of coal capacity and 36MW of gas capacity will not be needed and that from 2015 to 2031 the corresponding fixed O&M costs will not be spent because of the wind power plants installed in 2006. As is done for the equalized remuneration to generators, the NPV of these savings is calculated by discounting and summing them up to the year of installation of the wind capacity at a 7% cost of capital. Subsequently, we annualize them over the lifetime of the wind power plant by redistributing the NPV in a 25 years mortgage using the same interest rate to spread this cost savings over all the tons of CO2 abated over the life of the turbine. Finally, the total cost savings for a given year is provided by the sum of the mortgage rates of the capacity in service in that year. For overnight cost, data are from NEA (2011) (€1978/kW for coal and €883/kW for gas in €(2011)), as to fixed O&M cost, data derive from EIA (2010) (€29/kW for coal and €11/kW for gas in €(2011)). We consider a capacity factor of 85% both for coal and gas (IEA/NEA, 2010). Table 7 shows the cost savings due to the capacity credit and the components due to the avoided capital and O&M cost. The increase of these cost savings over the years reflects the increase of wind capacity. We do not estimate the balancing cost and capacity saving for solar energy, but in the sensitivity analysis we show that their impact on the final result would be minor.

Wind	2006	2007	2008	2009	2010
Capital cost saving	95	106	117	130	142
O&M cost saving	10	12	13	15	16
Capacity saving	**106**	**117**	**130**	**145**	**158**

Table 7: wind capacity saving. *Capital cost saving*: annualized capital cost saving; *O&M cost saving*: annualized fixed O&M cost saving; *Capacity saving*: sum of *Capital cost saving* and *O&M cost saving*. Data are in M€(2011).

4 Results and comments

This section presents the results of our analysis. Section 4.1 presents and comments on the carbon surcharge and implicit carbon price of the REI for wind and solar technologies while sections 4.2 and 4.3 discuss the robustness of these results. Section 4.2 presents the impact on the final results of the assumptions made to calculate the different costs and benefits, with particular attention to remuneration to generators. Section 4.3 discusses the inclusion of the learning rate on our methodology.

4.1 Carbon surcharge and implicit carbon price

Table 8 shows annual *carbon surcharges* and annual *implicit carbon prices* as a result of the injection of wind and solar energy into the power system in euro per tCO2. The net cost is given by the sum of the costs minus cost savings. The carbon surcharge for wind(solar) is the net cost for the year divided by CO2 emission reduction, which is the simulated quantity of CO2 emissions reduced by the injection of wind(solar) energy in that year. The implicit carbon price is given by the net cost without carbon cost saving divided by CO2 emission reduction. *Average* is the average annual CO2 abatement costs weighted over CO2 emission reductions. For wind energy, results are for the *Medium FIT* scenario. Figs. 2 and 3 show the costs and cost savings graphically per tCO2 abated and per MWh of wind(solar) energy injection, respectively. Costs are above zero, cost savings are below and the black bar indicates the carbon surcharge in Fig. 2 and the net cost per MWh of wind(solar) energy in Fig. 3. All data are in €(2011).

Three main results can be drawn.

1. There is a large disparity among different costs and cost savings. Equalized remuneration to generators is by far the largest cost; the additional start-up cost and the balancing cost represent just a few percentage of it. Fuel cost savings are the largest savings while carbon cost savings and the capacity savings are much lower although not irrelevant. Fig. (2) clearly shows that net costs are mostly determined by the remuneration to generators and the fuel cost savings. The other costs and benefits are much smaller (start-up costs are too small to appear in the figures). Note that the vertical scale for the cost of solar energy

Wind		2006	2007	2008	2009	2010	Average
Equalized remuneration	[M€]	2684	2873	3056	3291	3486	
Additional start-up cost	[M€]	-6	-14	-5	2	4	
Additional balancing cost	[M€]	61	79	81	77	76	
Fuel cost saving	[M€]	1204	1578	1913	1326	1352	
Carbon cost saving	[M€]	381	31	438	402	402	
Capacity saving	[M€]	106	117	130	145	158	
Net cost	[M€]	1050	1212	651	1498	1654	
CO2 emission reduction	[MtCO2]	22	26	32	30	27	
Carbon surcharge	**[€/tCO2]**	**47**	**47**	**21**	**51**	**62**	**45**
Implicit carbon price	**[€/tCO2]**	**64**	**48**	**34**	**64**	**77**	**57**

Solar		2006	2007	2008	2009	2010	Average
Equalized remuneration	[M€]	966	1351	1893	2882	4503	
Additional start-up cost	[M€]	-2	-3	-1	-10	0	
Fuel cost saving	[M€]	107	124	212	234	417	
Carbon cost saving	[M€]	28	1	81	65	113	
Net cost	[M€]	829	1223	1599	2574	3973	
CO2 emission reduction	[MtCO2]	2	2	4	5	7	
Carbon surcharge	**[€/tCO2]**	**552**	**627**	**439**	**557**	**547**	**537**
Implicit carbon price	**[€/tCO2]**	**571**	**627**	**461**	**571**	**562**	**552**

Table 8: annual carbon surcharge and annual implicit carbon price for wind and solar energy. *Equalized remuneration*: see table 3; *Additional start-up cost*, *Fuel cost saving*, *Carbon cost saving* and *CO2 emission reduction*: see table 4; *Capacity saving*: see table 7; *Balancing cost*: see table 6; *Net cost*: sum of all the costs minus the savings; *Carbon surcharge*: *Net cost* divided *CO2 emission reduction*; *Implicit carbon price*: *Net cost* without *Carbon cost saving* divided *CO2 emission reduction*; *Average*: annual average *Carbon surcharge* and *Implicit carbon price* weighted over CO2 emission reductions. Data are in €(2011).

is different than that for wind energy because of the significantly higher remuneration to solar generators.

2. There is a large difference between the carbon surcharge for wind and solar energy. While the carbon surcharge cost for wind is of the order of tens of €/tCO2, for solar it is of the order of hundreds of €/tCO2. Fuel cost savings per tCO2 are similar for wind and solar energy, being slightly higher for solar than for wind since solar energy is generated only during the day and displaces mostly gas when peak demand occurs, while wind is active day and night and it displaces cheaper coal as well as gas. What drives the difference between wind and solar is the remuneration: the annual equalized remuneration per MWh is much higher for solar than for wind, as shown in Fig. 2. This reflects the higher level of solar FIT, see table 1. Comparing these results with the historical annual average

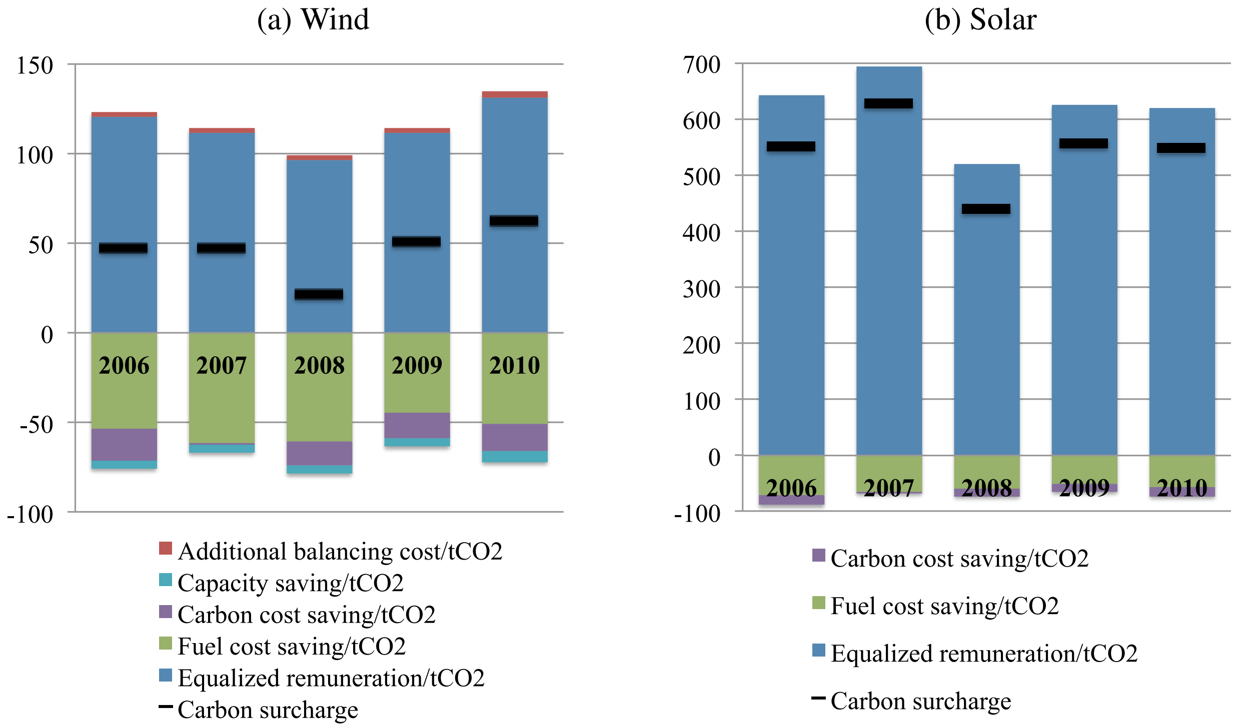

Figure 2: (a) costs and cost savings of wind energy per tCO2 abated. (b) costs and cost savings of solar energy per tCO2 abated. Costs are positive numbers, cost savings are negative numbers. Data are in €(2011)/tCO2.

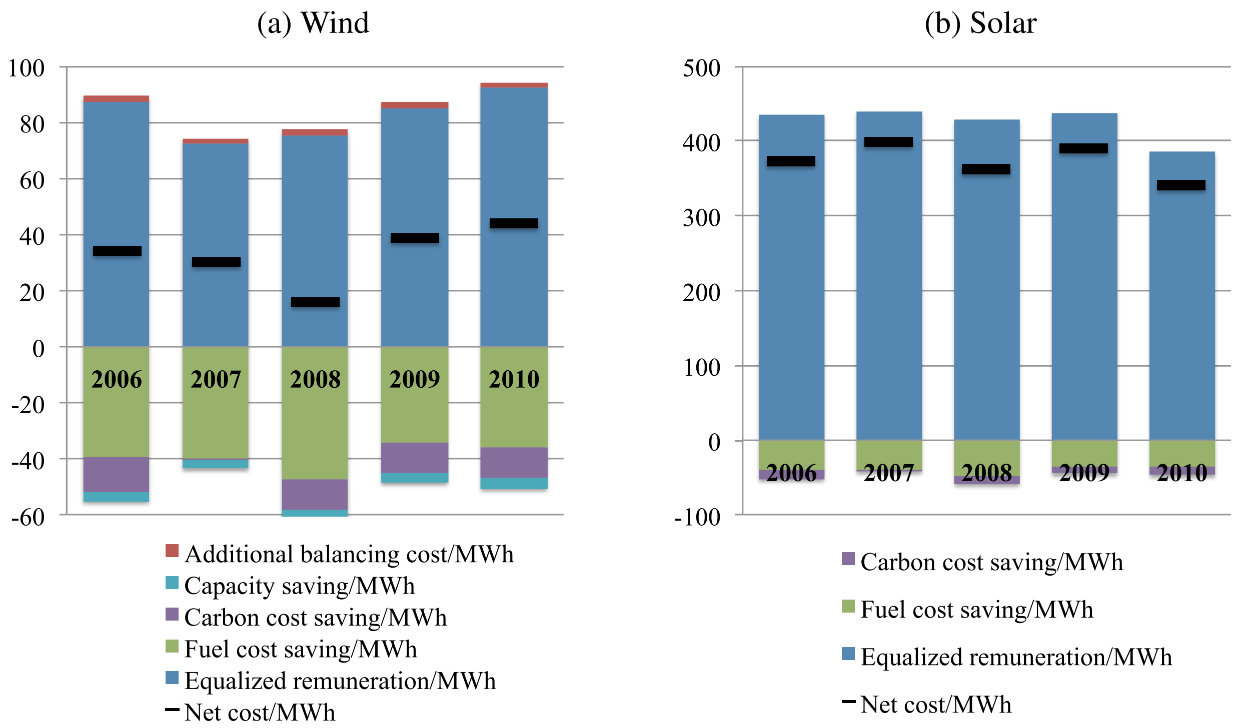

Figure 3: (a) costs and cost savings of wind energy per MWh of wind energy generated. (b) costs and cost savings of solar energy per MWh of solar energy generated. Costs are positive numbers, cost savings are negative numbers. Data are in €(2011)/MWh.

EU ETS carbon price (table 9) the carbon surcharges of wind tend to be higher than EUA prices but of the same order of magnitude (the price of allowances reached levels of €30/tCO2 in April 2006). On the other hand, the implicit carbon prices for solar were always much above the prices for the EUA. Similar results can be observed for the annual implicit carbon prices. The implicit carbon price for wind is, on average, 20% higher than the carbon surcharge, but it remains always on the order of tens of €/tCO2. For solar the difference between the implicit carbon price and the carbon surcharge is very small, on average of 3%. If the implicit carbon price is compared with the historical annual average EU ETS carbon price, the result is the same as for the comparison with the carbon surcharge. Note, however, that it may be considered more meaningful to compare the REI implicit carbon price with the hypothetical EUA price that it would have been in the absence of the REI. In the absence of good empirically based estimates of the price-quantity relationship, we might assume for the sake of illustration that the effect was so high that the German RE injections would have decreased the EUA price by 50%. If so, the annual average EUA price would have been at maximum no more than €40/tCO2. The same conclusion would be reached: the implicit carbon price of wind tends to be higher than the annual EUA prices but of the same order of magnitude, while the implicit carbon price for solar is always much above any realistic EUA price.

	2006	2007	2008	2009	2010	Average
EUA	18.9	0.7	12.4	13.6	14.7	10.7

Table 9: average annual EUA price. Source: EEX. Data are in €(2011)/tCO2.

3. The carbon surcharge and the implicit carbon price can change considerably from year to year, particularly for wind where variations by a factor of two can be observed. These changes in net cost mostly reflect changes in annual fuel cost saving and carbon cost saving, which are correlated with the variations of fossil fuel prices and the carbon prices. Fig. (4 - a) presents wind fuel cost saving per MWh of wind energy and the annual average price of coal, gas and oil. Fig. (4 - b) shows carbon cost saving per tCO2 and the annual average EUA price. In contrast, the remuneration to generators is relatively constant. The year 2008 is the one with the lowest values for the carbon surcharge and the implicit

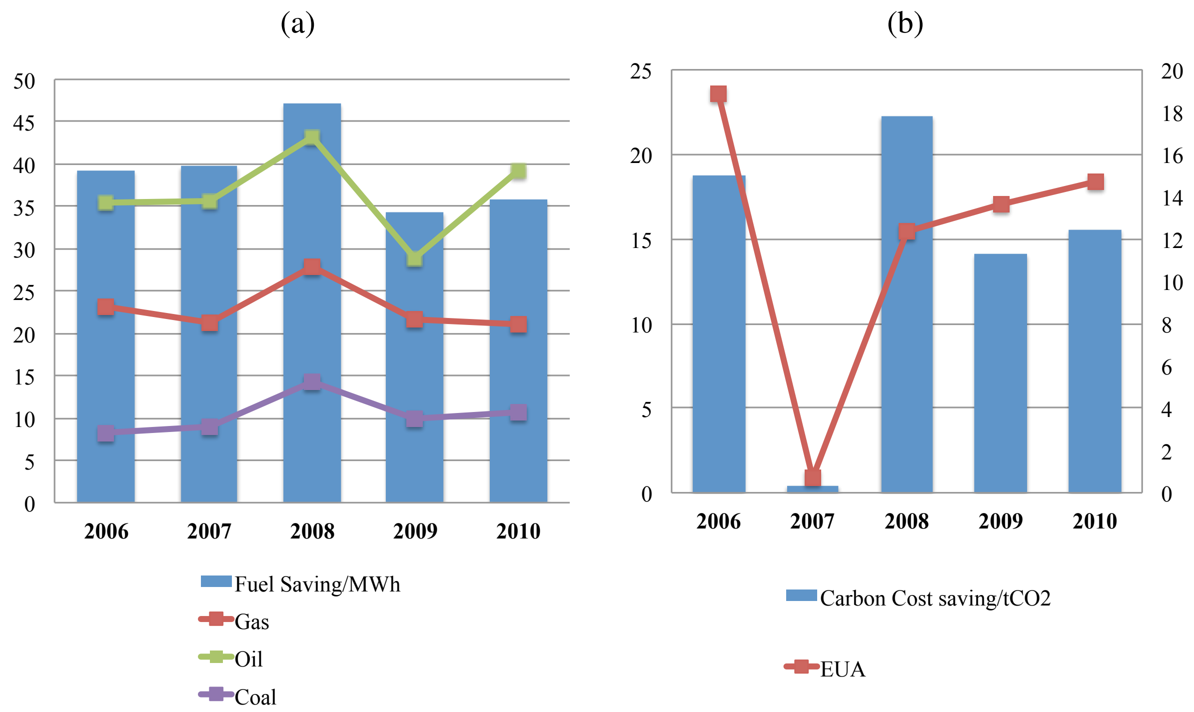

Figure 4: (a) wind fuel cost saving per MWh of wind energy generated and annual average fossil fuel prices, data are in €(2011)/MWh. Source for fuel prices: BAFA (2011). (b) wind carbon cost saving per MWh of wind energy and EUA average annual price, data are in €(2011)/tCO2. Source for carbon price: EEX.

carbon price, due to a combination of high fossil fuel prices and, with regard to wind energy, a high annual capacity factor.

4.2 *Sensitivity analyses*

The results presented in section 4.1 refer to the base case scenario that considers a 2% future rate of inflation, €50/MWh future electricity price and a 7% cost of capital. The results for wind are from the *Medium FIT* scenario where 50% of power plants are assumed to receive the initial high tariff for 20 years and the remaining 50% for 15 years. Table (10) shows the annual carbon surcharges for wind under different assumptions regarding the remuneration to generators. In the *High FIT* scenario we suppose that all the power plants receive the high tariff for 20 years, and all the power plants installed from the year 2009 receive the extra bonus.[12] In the *Low FIT* scenario we suppose that 50% of power plants receive the high tariff for 20 years, 25% for 15 years and, for the remaining 25%, 5 years for on-shore power plants and 12

[12]From 2009 there is a technological bonus of ¢0.5/kWh for on-shore wind, and ¢2/kWh for off-shore wind.

years for off-shore power plants . Table 10 shows that the carbon surcharges for wind do not considerably differ under these scenarios. On average, they go from a minimum of €39/tCO2 in the *Low FIT* scenario with 5% cost of capital, up to a maximum of €51/tCO2 in the *High FIT* scenario with 10% cost of capital. Results under different scenarios are very close to each other because most of the variations in remuneration affect future revenues, which are discounted.

Wind		2006	2007	2008	2009	2010	Average
	Low FIT	44	45	18	48	59	42
Base case	***Medium FIT***	**47**	**47**	**21**	**51**	**62**	**45**
	High FIT	49	49	22	53	65	47
	Low FIT	46	46	20	50	61	44
1% inflation	*Medium FIT*	48	48	22	53	65	46
	High FIT	51	51	24	55	68	49
	Low FIT	43	43	17	46	57	40
€40/MWh electricity price	*Medium FIT*	45	45	19	49	60	43
	High FIT	48	48	21	52	64	45
	Low FIT	50	50	23	54	66	48
€70/MWh electricity price	*Medium FIT*	51	51	24	55	67	49
	High FIT	52	51	25	56	68	50
	Low FIT	41	42	16	44	55	39
5% cost of capital	*Medium FIT*	43	43	18	47	58	41
	High FIT	47	47	21	51	62	45
	Low FIT	50	50	22	52	64	47
10% cost of capital	*Medium FIT*	51	51	24	55	67	49
	High FIT	54	54	26	57	69	51

Table 10: carbon surcharge of wind under different scenario regarding remuneration to generators; *1% inflation*: 1% future rate of inflation after 2011 inflation; *€40/MWh electricity price*: €40/MWh future electricity price; *€70/MWh electricity price*: €70/MWh future electricity price; *5% cost of capital*: cost of capital of 5%; *10% cost of capital*: cost of capital of 10%. Results presented in section 4.1 are for the Base case - *Medium FIT* scenario. Data are in €(2011)/tCO2.

Table 11 shows the annual carbon surcharge of wind under different assumptions regarding the capacity credit, it presents two extreme cases of 0% and 20% capacity credit, in addition to the base case of a 7% capacity credit. The higher the capacity credit, the greater the cost savings, and the lower the carbon surcharge. Average annual carbon surcharge is €54/tCO2 with 0% capacity credit and €43/tCO2 with 20% capacity credit. This analysis confirms the result that, even if wind capacity benefit is not irrelevant to determine carbon surcharge, its impact is not predominant.

Wind	2006	2007	2008	2009	2010	Average
0% capacity credit	62	46	32	62	74	54
7% capacity credit	**47**	**47**	**20**	**50**	**62**	**44**
20% capacity credit	50	35	23	50	60	43

Table 11: carbon surcharge with different values of capacity credit. Results presented in section 4.1 are with 7% capacity credit. Data are in €(2011)/tCO2.

Table 12 shows the annual carbon surcharge for solar under different assumptions regarding the remuneration to generators. Also for solar, results do not differ considerably from the base case scenario. They range from a minimum average carbon surcharge of €521/tCO2 in the scenario with 5% cost of capital up to €562/tCO2 in the scenarios with 10% cost of capital.

We did not calculate the capacity saving and the additional balancing cost for solar, however their impact on the final results would be very small. To show it, we assume that solar energy has the same additional balancing cost and capacity saving as wind in absolute term, that is the same values shown in table 8. This is a large overestimation as the total solar capacity is about two thirds of wind capacity, and solar capacity factor is less than half with respect to wind capacity factor. Nevertheless, under these generous conditions the average solar annual carbon surcharge would only increase of less than 7% if we added the additional abatement cost and would decrease of less than 4% if we added capacity saving, remaining on average always around €500/tCO2.

All sensitivity analyses performed show that the annual carbon surcharges for wind remain of the order of few tens of €/tCO2, while the annual carbon surcharges for solar remain of the order of hundreds of €/tCO2.

4.3 Learning effect

A frequent argument in favor of subsidies for the development of RE development is the learning effect: future costs will be less because of learning-by-doing from today's subsidized deployment. We have not included this potential cost savings because of the strong required assumption that the future cost savings can be attributed to the deployment in one specific country

Solar	2006	2007	2008	2009	2010	Average
Base case	**552**	**627**	**439**	**557**	**547**	**537**
1% inflation	568	647	456	582	576	561
€0/MWh electricity price	546	620	433	550	539	530
€40/MWh electricity price	551	625	438	556	545	536
€70/MWh electricity price	554	629	441	560	550	540
5% cost of capital	534	608	424	540	530	521
10% cost of capital	578	655	460	583	572	562

Table 12: carbon surcharge of solar under different scenarios regarding remuneration to generators; *1% inflation*: 1% future rate of inflation after 2011 inflation; *€40/MWh electricity price*: €40/MWh future electricity price; *€70/MWh electricity price*: €70/MWh future electricity price; *5% cost of capital*: cost of capital of 5%; *10% cost of capital*: cost of capital of 10%. Results presented in section 4.1 are for the Base case scenario. Data are in €(2011)/tCO2.

when learning is notoriously international. There is, in addition, another attribution problem: to which vintage(s) should future cost savings be attributed? Alternatively, when are learning effects from a particular investment exhausted and how are they realized over time?

Also to be noted is that the level of remuneration to RE generators in Germany assumes a considerable degree of cost reduction over time as shown in table 1. For wind, the level of the initial FIT decreased from ¢9.10/kWh in 2000 to ¢8.02/kWh in 2008, or by almost 12% in nominal terms. In real terms the FIT declined by 23% at an annual rate of about 3.3%. It is evident from the various adjustments in the initial tariff and the rate of decline over the years, that the regulator has had a hard time getting this right. Still, even after the notable adjustment in 2009, when the initial FIT was increased by 15% to ¢9.20/kWh, the real level of the initial FIT was 12% lower than the 2000 level, for a real rate of decrease in remuneration of about 1.5% per annum. For solar the decrease was much higher: the highest tariff went from ¢50.62 /kWh in 2000 down to 28.43/kWh in 2010, more than 30% in nominal terms, and 24% in real terms with an annual rate of 13%. Both for solar and wind, the reduction of FIT will continue in the next years.

If the attribution problems can be overlooked, and the reduction in the level of German FIT for new RE capacity can be only credited to the learning effect due to the construction of the past capacity in Germany, a methodology similar to that employed for calculating the equalized remuneration to generators can be used to estimate the impact of the learning effect. This can be done by first estimating the lifetime revenues for all the capacity build from 2000 to 2020 and then discounting all revenues and redistributing them annually per quantity of RE electricity produced as if all electricity produced by all capacity build in the period 2000-2020 would have been paid the same amount. In other words, remuneration is equalized not only along the lifetime of a given installation as before, but also along the capacity build in different years. In this way we reduce the annual equalized remuneration of the past capacity by effectively credited it with the benefit of the lower payments for future capacity due to the expected FIT reduction. In order to estimate future payments, assumptions need to be made about the quantity of capacity build in the future and how much the electricity produced by this capacity will be paid. The following estimates are based on scenarios provided by the German government when available, or on optimistic assumptions regarding the RE development and FIT decrease. For solar, a 3.5GW annual capacity increase from 2013 with a 11% annual FIT reduction is indicated by the reference scenario of the last amendment of the EEG (EEG, 2012). For wind, a 1.5% annual FIT reduction is projected (EEG, 2012), and we assume an annual increase of wind capacity of 2.5 GW (average new annual capacity in 2006-2010 was 1.7GW). We also assume that from 2011 only 20% of new wind capacity will have high FIT for 20 years, while 30% will have high FIT for 15 years and 50% for 5 years. For all the other parameters (such as power plant lifetime, capacity factors, cost of capital etc.) the same assumptions used in section 3.1 are maintained. When the resulting learning effects are attributed to the period 2006-2010, the average carbon surcharges are €36/tCO2 for wind and €290/tCO2 for solar (€45/tCO2 and €537/tCO2 respectively without learning effects) while for the implicit carbon prices are €48/tCO2 for wind and €306/tCO2 for solar (€57/tCO2 and €552/tCO2 respectively without learning effects). For wind, the decrease in cost is just of few euro per tCO2, while for solar, because of the much higher projected FIT reduction, the decrease is almost 50%. However this does not change the basic conclusion: the carbon surcharge and implicit carbon price of REI are in the tens of euro per tCO2 for wind, and of the order of hundreds of euro per tCO2 for solar, higher than the observed price of CO2 in the EU ETS even if the learning effect is included.

5 Conclusions

This paper analyses CO2 abatement cost due to wind and solar energy in Germany for the years 2006-2010. We calculated the REI annual carbon surcharge as the ratio of the net cost of RE over the CO2 emission reductions attributed to RE, and the implicit carbon price of the REI as the sum of carbon surcharge plus the average annual price in the EU ETS paid by conventional generators. For wind, the carbon surcharge for the period 2006-2010 is on average €45/tCO2 and the implicit carbon price is €57/tCO2. These are higher than the historical EU ETS carbon price but of the same order of magnitude. In contrast, for solar, the annual carbon surcharges and the implicit carbon prices are very high, the average for 2006-2010 is €537/tCO2 for the first and €552/tCO2 for the latter, much above any possible realistic carbon price. The main cost component is the remuneration to generators determined by the FIT. In comparison, the additional start-up cost and balancing cost are quite small, if not negligible. The main cost saving comes from the avoided fuel cost of the electricity generation displaced by the RE. The other cost saving components -the carbon cost saving and the capacity benefit- are smaller but not irrelevant, particularly in the case of wind. The carbon surcharge and implicit carbon price have changed considerably over the years due to variations in fossil fuels prices, carbon price and the amount of generated RE. The year 2008 is the one with the lowest values due to a combination of high fossil fuel prices and, with regard to wind energy, a high annual capacity factor. Under several sensitivity analyses, the carbon surcharge and the implicit carbon price of REI always remain of the order of few tens €/tCO2 for wind energy, while for solar energy are always of the order of hundreds of €/tCO2.

Our study suggests that if we look at RE only as a climate instrument, and at REI only as a policy to abate CO2 emissions in the power sector, the German support for wind energy has induced a reduction of CO2 emissions at a cost generally higher than the historically observed EUA price, but on the same order of magnitude. On the contrary, supporting solar energy through deployment incentives has proven to be a very expensive way of reducing CO2 emissions.

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Appendices

A Impact of the interaction between the REI and the EU ETS on the carbon surcharge

The REI carbon surcharge (*CaS*) in section 3 is calculated by comparing the cost of renewables and emissions in two scenarios: the historical scenario (*OBS*) and a counterfactual scenario where we suppose that no RE was injected into the power system (*NoRE*). In the estimation of *CaS* the interaction between the RE and the EU ETS has not been taken into account: the EUA prices used in the *NoRE* scenario are the same prices as those in the OBS scenario. This appendix shows how the carbon surcharge would change if the interaction between the REI and the EU ETS is considered. In the absence of RE, the average carbon price in the EU ETS paid by conventional generators ($\overline{P}_{noRE}$) would have been higher than the observed one ($\overline{P}_{obs}$): $\overline{P}_{noRE} \geq \overline{P}_{obs}$. This increase of the carbon price would have an impact on the net cost of RE, as well as on the total emissions, and thus on the estimation of the carbon surcharge. CaS_{int} is the carbon surcharge calculated by considering the impact of the interaction between the RE and the EU ETS. It is given by comparing the cost of renewables and the emissions between the *OBS* scenario and the counterfactual scenario without RE and with the carbon price affected by the reduction of the RE, which is labeled $NoRES_{int}$.

$$CaS_{int} = \frac{Rem - (TC(OBS) + TC(NoRE_{int})) - CapSav}{A_{int}} = \frac{Rem - FCSav_{int} - CCSav_{int} - CapSav}{A_{int}}, \tag{6}$$

where

$$\begin{aligned}
TC(OBS) &= TFC(OBS) + TCC(OBS), \\
TC(NoRE_{int}) &= TFC(NoRE_{int}) + TCC(NoRE_{int}), \\
FCSav_{int} &= TFC(NoRE_{int}) - TFC(OBS), \\
CCSav_{int} &= TCC(NoRE_{int}) - TCC(OBS), \\
TCC(OBS) &= \overline{P}_{obs} * E(OBS), \\
TCC(NoRE_{int}) &= \overline{P}_{noRE} * E(NoRE_{int}), \\
A_{int} &= E(NoRE_{int}) - E(OBS).
\end{aligned} \tag{7}$$

For the sake of simplicity the cycling cost and balancing costs are neglected in this analysis, as they are marginal if not negligible in comparison with the other costs. *Rem* and *CapSav* in CaS_{int} are the same than in *CaS* because the remuneration for RE and the deployment of RE capacity depends on the REI, and not not the carbon price.

The difference between CaS_{int} and CaS (Eq. 3) is:

$$CaS_{int} - CaS = Rem\left(\frac{1}{A_{int}} - \frac{1}{A}\right) + \left(\frac{FCSav}{A} - \frac{FCSav_{int}}{A_{int}}\right) + \left(\overline{P}_{obs} - \overline{P}_{NoRE}\right)\frac{E(NoRE_{int})}{A_{int}} \tag{8}$$

The increase of carbon price in the $NoRE_{int}$ scenario with respect to *NoRE* scenario, would induce a shift of production from coal to gas in $NoRE_{int}$ with respect to the *NoRE* and thus an increase of the fossil fuel cost ($FCSav_{int} \geq FCSav$) and decrease in emissions ($E(NoRE_{int}) \leq E(NoRE)$). This also implyes $A_{int} \leq A$. Hence the first term in the RHS of Eq. (8) is always positive, while the second and third terms are always negative. Thus the effect of the interaction on the RE and the EU ETS on the carbon surcharge is ambiguous. On the one hand it tends to increase the carbon surcharge because it decreases the emission abatement due to the RE injection, on the other hand it tends to decrease the carbon surcharge because higher carbon price implies higher fuel cost saving and carbon cost saving.

B The implicit carbon price of the REI

This appendix shows that the implicit carbon price as defined in Eq. (5) is a good estimation (difference lower than 5%) of the CO2 abatement cost of the REI, that is labeled *AC*, when we assume that REI is the only climate instrument. *AC* can be calculated by comparing the cost of renewables and emissions in generating electricity in two hypothetical scenarios: the scenarios with and without RE with both scenarios without any carbon price. These two scenarios are labeled $(RE, NoETS)$ and $(NoRE, NoETS)$. The REI in the $(RE, NoETS)$ and $(NoRE, NoETS)$ scenarios are the same as in the *OBS* scenario.

$$AC = \frac{Rem + (TC(NoRE, NoETS) - TC(RE, NoETS)) - CapSav}{E(NoRE, NoETS) - E(RE, NoETS)}. \tag{9}$$

Note that there are no carbon costs in $TC(NoRE, NoETS)$ and $TC(RE, NoETS)$ because we suppose that the carbon price is zero in both scenarios. *Rem* and *CapSav* in Eq. (9) are the remuneration and the capacity saving calculated in the scenario with RE and without EU ETS. They are equal to those of Eq. (3) because the remuneration for RE and the deployment of RE capacity, depends only on the REI and not on the carbon price. Weigt et al. (2012) have shown that, in Germany for the period 2006-2010, there is an interaction in the emission abatement between the injection of RE and the EU ETS: the CO2 abatement induced by the presence of both the carbon price and the injection of RE is on average higher than sum of the CO2 abatement due only to RE plus the CO2 abatement due only to the EU ETS. However this interaction tends to be very small and their model shows that:

$$E(NoRE, NoETS) - E(RE, NoETS) \simeq E(NoRE) - E(OBS), \tag{10}$$

$$TFC(NoRE, NoETS) - TFC(RE, NoETS) \simeq TFC(NoRE) - TFC(OBS), \tag{11}$$

where *OBS* and *NoRE* are the scenarios described in section 3, with the EUA prices in *NoRES* scenario equal to those in the *OBS* scenario. The average differences between the LHS and RHS for the years 2006-2010 of Eq. (10) is -4% and of Eq. (11) is 2%. These values refer to the injection of all RE coming from wind, solar and biomass. The value for the injection of only wind energy or only solar energy would be smaller given the lower penetration. If these numbers are assumed also for wind and solar, the difference between the *ICP* defined in Eq. (5) and the implicit CO2 abatement cost of the REI of Eq. (9) would be less than 2% for wind and less than 4% for solar. Including the variation of cycling cost and balancing costs due to the absence of the carbon price, would only marginally change these results because these costs are small if not negligible in comparison to the other costs and benefits.

C Wind equalized remunerations

This appendix shows in detail the calculations of the equalized remuneration for wind energy in the *Medium FIT* scenario. Table 13 shows the estimated annual electricity produced by each vintage of capacity from year 2000 to year 2010. The years in the first horizontal axis represent the years of installation, while the ones in the first vertical axis are the years of production. Each column shows the annual energy produced in 25 years (the assumed lifetime of wind power plants) by the capacity installed in the year marked in the first row. The entries in the rows are calculated in the following way: for the period 2000-2010 we allocate the historical annual electricity generated by wind (shown in table 2) to power plants installed in different years by assuming an equal annual capacity factor for all power plants. As from 2010 until the end of the lifetime of the power plants a constant capacity factor of 18% is assumed.

Table 14 shows the annual real price of electricity for wind power plants that receive the initial high FIT for 20 years. As before, the years in the first horizontal axis are the years of installation of the power plant, while the ones in the first vertical axis are the years of production. Results take into account inflation: the annual historical CPI rate of the German Federal Statistical Office is used up to 2011 (table 15),[13] from 2012 we assume a constant rate of 2%. All results are in €(2011). Each column shows the annual electricity price paid to wind energy

[13]www.destatis.de.

generated by the capacity installed in the year marked in the first row; the values are calculated by inflating the nominal annual level of FIT (table 1) for the first 20 years of activity. For the last 5 years of activity, and when the real level of FIT goes below the assumed market price of €50/MWh, the power producers sell electricity at the market price. Table 16 is analogous to table 14 but refers to power plants which receive the initial high FIT only for 15 years.

Table 17 shows the annual remunerations in the *Medium FIT* scenario (where we suppose that 50% of power plants receive the initial FIT for 20 years and 50% for 15 years). Each column shows the annual remuneration to wind power plants installed in the year marked in the first row. Each entry of table 17 is given by multiplying the corresponding entry of table 13 by 0.5 times the sum of the corresponding entries in tables 14 and 16. Table 18 shows the annualized remuneration for each vintage of capacity from year 2000 to year 2010. In order to calculate it we discount the remunerations in the columns of table 13 at the fixed rate of 7% to the first year of activity, sum them up to obtain the initial NPV, and redistribute the NPV through a 25-year mortgage using the same interest rate. The years 2009 and 2010 show the sum of the annualized remuneration for on-shore and off-shore wind. The total equalized remuneration of a given year consists of the sum of the annualized payment for the capacities in service in that year. For example, the equalized remuneration of year 2008 is given by summing up all the annualized remuneration from 2000 to 2008 because all capacity build from 2000 is still in activity in 2008.

	On-shore											Off-shore	
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2009	2010
2000	9.5												
2001	7.3	3.2											
2002	8.0	3.5	4.3										
2003	7.8	3.4	4.2	3.4									
2004	9.4	4.1	5.0	4.0	3.1								
2005	9.0	3.9	4.8	3.9	3.0	2.6							
2006	9.1	4.0	4.8	3.9	3.0	2.6	3.3						
2007	10.9	4.7	5.8	4.7	3.6	3.2	3.9	2.9					
2008	10.4	4.5	5.5	4.5	3.4	3.0	3.7	2.7	2.8				
2009	9.2	4.0	4.9	3.9	3.0	2.7	3.3	2.4	2.5	2.8		0.04	
2010	8.4	3.7	4.5	3.6	2.8	2.4	3.0	2.2	2.3	2.6	2.1	0.04	0.1
2011	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2012	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2013	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2014	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2015	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2016	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2017	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2018	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2019	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2020	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2021	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2022	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2023	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2024	9.6	4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2025		4.2	5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2026			5.1	4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2027				4.1	3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2028					3.2	2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2029						2.8	3.4	2.5	2.6	3.0	2.3	0.04	0.1
2030							3.4	2.5	2.6	3.0	2.3	0.04	0.1
2031								2.5	2.6	3.0	2.3	0.04	0.1
2032									2.6	3.0	2.3	0.04	0.1
2033										3.0	2.3	0.04	0.1
2034											2.3		0.1

Table 13: assumed annual energy generated by wind power plants installed in different years. Data are in TWh.

	On-shore											Off-shore	
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2009	2010
2000	10.8												
2001	10.7	10.7											
2002	10.6	10.6	10.4										
2003	10.5	10.5	10.3	10.2									
2004	10.2	10.2	10.1	9.9	9.8								
2005	10.1	10.1	9.9	9.8	9.6	9.4							
2006	9.9	9.9	9.8	9.6	9.5	9.3	9.1						
2007	9.6	9.6	9.5	9.4	9.2	9.0	8.9	8.7					
2008	9.5	9.5	9.4	9.3	9.1	8.9	8.8	8.6	8.4				
2009	9.4	9.4	9.3	9.2	9.0	8.9	8.7	8.5	8.3	9.6		15.6	
2010	9.3	9.3	9.2	9.0	8.9	8.7	8.5	8.4	8.2	9.4	9.3	15.3	15.3
2011	9.1	9.1	9.0	8.8	8.7	8.5	8.4	8.2	8.0	9.2	9.1	15.0	15.0
2012	8.9	8.9	8.8	8.7	8.5	8.4	8.2	8.0	7.9	9.0	8.9	14.7	14.7
2013	8.7	8.7	8.6	8.5	8.4	8.2	8.0	7.9	7.7	8.8	8.8	14.4	14.4
2014	8.6	8.6	8.4	8.3	8.2	8.0	7.9	7.7	7.6	8.7	8.6	14.1	14.1
2015	8.4	8.4	8.3	8.2	8.0	7.9	7.7	7.6	7.4	8.5	8.4	13.9	13.9
2016	8.2	8.2	8.1	8.0	7.9	7.7	7.6	7.4	7.3	8.3	8.2	13.6	13.6
2017	8.1	8.1	8.0	7.8	7.7	7.6	7.4	7.3	7.1	8.2	8.1	13.3	13.3
2018	7.9	7.9	7.8	7.7	7.6	7.4	7.3	7.1	7.0	8.0	7.9	13.1	13.1
2019	7.8	7.8	7.7	7.5	7.4	7.3	7.1	7.0	6.8	7.9	7.8	12.8	12.8
2020	5.0	7.6	7.5	7.4	7.3	7.1	7.0	6.9	6.7	7.7	7.6	12.6	12.6
2021	5.0	5.0	7.4	7.2	7.1	7.0	6.9	6.7	6.6	7.5	7.5	12.3	12.3
2022	5.0	5.0	5.0	7.1	7.0	6.9	6.7	6.6	6.5	7.4	7.3	12.1	12.1
2023	5.0	5.0	5.0	5.0	6.9	6.7	6.6	6.5	6.3	7.3	7.2	11.8	11.8
2024	5.0	5.0	5.0	5.0	5.0	6.6	6.5	6.3	6.2	7.1	7.0	11.6	11.6
2025		5.0	5.0	5.0	5.0	5.0	6.3	6.2	6.1	7.0	6.9	11.4	11.4
2026			5.0	5.0	5.0	5.0	5.0	6.1	6.0	6.8	6.8	11.1	11.1
2027				5.0	5.0	5.0	5.0	5.0	5.8	6.7	6.6	10.9	10.9
2028					5.0	5.0	5.0	5.0	5.0	6.6	6.5	10.7	10.7
2029						5.0	5.0	5.0	5.0	5.0	6.4	5.0	10.5
2030							5.0	5.0	5.0	5.0	5.0	5.0	5.0
2031								5.0	5.0	5.0	5.0	5.0	5.0
2032									5.0	5.0	5.0	5.0	5.0
2033										5.0	5.0	5.0	5.0

Table 14: annual real prices of electricity paid to wind energy from power plants installed in different years and receiving the high FIT for 20 years. Data are in ¢(2011)/kWh.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Annual inflation rate	1.45	1.98	1.40	1.04	1.67	1.56	1.58	2.29	2.63	0.31	1.14	2.30

Table 15: Average annual inflation rate. Source: German Federal Statistical Office, www.destatis.de.

	On-shore											Off-shore	
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2009	2010
2000	10.8												
2001	10.7	10.7											
2002	10.6	10.6	10.4										
2003	10.5	10.5	10.3	10.2									
2004	10.2	10.2	10.1	9.9	9.8								
2005	10.1	10.1	9.9	9.8	9.6	9.4							
2006	9.9	9.9	9.8	9.6	9.5	9.3	9.1						
2007	9.6	9.6	9.5	9.4	9.2	9.0	8.9	8.7					
2008	9.5	9.5	9.4	9.3	9.1	8.9	8.8	8.6	8.4				
2009	9.4	9.4	9.3	9.2	9.0	8.9	8.7	8.5	8.3	9.6		15.6	
2010	9.3	9.3	9.2	9.0	8.9	8.7	8.5	8.4	8.2	9.4	9.3	15.3	15.3
2011	9.1	9.1	9.0	8.8	8.7	8.5	8.4	8.2	8.0	9.2	9.1	15.0	15.0
2012	8.9	8.9	8.8	8.7	8.5	8.4	8.2	8.0	7.9	9.0	8.9	14.7	14.7
2013	8.7	8.7	8.6	8.5	8.4	8.2	8.0	7.9	7.7	8.8	8.8	14.4	14.4
2014	8.6	8.6	8.4	8.3	8.2	8.0	7.9	7.7	7.6	8.7	8.6	14.1	14.1
2015	5.7	8.4	8.3	8.2	8.0	7.9	7.7	7.6	7.4	8.5	8.4	13.9	13.9
2016	5.6	5.6	8.1	8.0	7.9	7.7	7.6	7.4	7.3	8.3	8.2	13.6	13.6
2017	5.5	5.5	5.4	7.8	7.7	7.6	7.4	7.3	7.1	8.2	8.1	13.3	13.3
2018	5.4	5.4	5.3	5.2	7.6	7.4	7.3	7.1	7.0	8.0	7.9	13.1	13.1
2019	5.3	5.3	5.2	5.1	4.7	7.3	7.1	7.0	6.8	7.9	7.8	12.8	12.8
2020	5.0	5.2	5.1	5.0	4.6	4.5	7.0	6.9	6.7	7.7	7.6	12.6	12.6
2021	5.0	5.0	5.0	4.9	4.5	4.4	4.3	6.7	6.6	7.5	7.5	12.3	12.3
2022	5.0	5.0	5.0	4.8	4.4	4.3	4.2	4.2	6.5	7.4	7.3	12.1	12.1
2023	5.0	5.0	5.0	5.0	4.3	4.2	4.2	4.1	4.0	7.3	7.2	11.8	11.8
2024	5.0	5.0	5.0	5.0	5.0	4.2	4.1	4.0	3.9	3.9	7.0	2.7	11.6
2025		5.0	5.0	5.0	5.0	5.0	4.0	3.9	3.8	3.8	3.8	2.7	2.7
2026			5.0	5.0	5.0	5.0	5.0	3.8	3.8	3.7	3.7	2.6	2.6
2027				5.0	5.0	5.0	5.0	5.0	3.7	3.7	3.6	2.5	2.5
2028					5.0	5.0	5.0	5.0	5.0	3.6	3.5	2.5	2.5
2029						5.0	5.0	5.0	5.0	5.0	3.5	5.0	2.5
2030							5.0	5.0	5.0	5.0	5.0	5.0	5.0
2031								5.0	5.0	5.0	5.0	5.0	5.0
2032									5.0	5.0	5.0	5.0	5.0
2033										5.0	5.0	5.0	5.0

Table 16: annual real prices of electricity paid to wind energy from power plants installed in different years and receiving the high FIT for 15 years. Data are in ¢(2011)/kWh.

	On-shore											Off-shore	
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2009	2010
2000	1032												
2001	785	342											
2002	849	369	444										
2003	818	356	428	340									
2004	957	417	501	398	303								
2005	910	396	476	379	288	247							
2006	905	394	473	377	286	246	298						
2007	1052	458	551	438	333	286	347	251					
2008	990	431	518	412	313	269	326	236	235				
2009	865	376	452	360	274	235	285	206	205	270		6	
2010	783	341	410	326	248	213	258	187	186	244	191	6	21
2011	875	381	458	364	277	238	288	209	208	273	214	6	20
2012	858	373	449	357	272	233	283	204	204	267	210	6	20
2013	841	366	440	350	266	228	277	200	200	262	205	5	20
2014	824	359	431	343	261	224	272	196	196	257	201	5	19
2015	679	352	423	336	256	219	266	193	192	252	197	5	19
2016	666	290	415	330	251	215	261	189	188	247	194	5	18
2017	653	284	342	323	246	211	256	185	184	242	190	5	18
2018	640	278	335	266	241	207	251	182	181	237	186	5	18
2019	627	273	328	261	198	203	246	178	177	233	182	5	17
2020	481	268	322	256	195	169	241	174	174	228	179	5	17
2021	481	209	316	252	193	167	205	171	170	224	175	5	17
2022	481	209	255	249	191	165	202	148	167	219	172	5	16
2023	481	209	255	206	189	163	200	146	147	215	169	4	16
2024	481	209	255	206	159	161	198	144	145	180	165	3	16
2025		209	255	206	159	139	196	143	143	177	140	3	11
2026			255	206	159	139	173	141	142	175	138	3	11
2027				206	159	139	173	127	140	173	136	3	11
2028					159	139	173	127	129	171	135	3	11
2029						139	173	127	129	148	133	2	11
2030							173	127	129	148	117	2	7
2031								127	129	148	117	2	7
2032									129	148	117	2	7
2033										148	117	2	7
2034											117		7

Table 17: annual remunerations for wind energy in the *Medium FIT* scenario. Data are in M€(2011).

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Annualized remuneration	827	353	426	339	258	219	263	189	183	235	195
Equalized remuneration	827	1179	1606	1944	2202	2421	2684	2873	3056	3291	3486

Table 18: *Annualized remuneration*: annualized remuneration of every vintage of wind capacity from year 2000 to year 2010. *Equalized remuneration*: sum of the annualized remunerations of all capacity in service. Data are in M€(2011).

D Solar equalized remunerations

This appendix shows in detail the calculations of the equalized remuneration for solar energy. Table 19 shows the assumed electricity produced by each vintage of capacity from year 2000 to year 2010. It is calculated similarly to the corresponding table for wind (table 13). The entries on the rows are calculated in the following way: for the period 2000-2010 we allocate the historical annual electricity generated by solar (cf. table 2) assuming a constant annual capacity factor; from 2010 to the end of the lifetime of the power plants we assume a constant fixed capacity factor of 8.14%.

Table 20 shows the annual real price of electricity paid to solar energy. Results take into account inflation and are in €(2011). Each column shows the annual electricity price paid to solar energy generated by power plants installed in the year marked in the first row. Solar energy producers receive a constant FIT for 20 years. Until 2003 there was a single level of FIT for all solar facilities, while, from 2004 onwards, the level depends on the capacity and location of the power plant. There are no data on the average level of FIT for solar power plants since 2004, but we can make use of the historical data on the total expenditure of solar FIT (available from 2002, cf. table 1) to estimate it. For power plants built in the period 2000-2001, we assume that they receive a FIT as in table 1 and we apply it for 20 years. As from year 2002, we estimate the average FIT as follows: we take the annual total expenditure of solar FIT, we subtract the assumed expenditure of FIT for power plants installed the years before by assuming annual constant capacity factor, and we divide the result by the assumed total energy produced by the facilities installed that year as in table 20. For example the average FIT for the power plants build in 2002 is estimated by subtracting to the 2002 annual expenditure of solar FIT, which is M€95 in €(2011) (cf. table 1), the quantity paid to the installations built in 2000 and 2001 assuming constant capacity factor (that is given by the sum of the first two elements of the third row of table 19 times the corresponding elements of table 20), and dividing it by 60GWh (the third element of the third row in table 19).

Table 21 shows the annualized payment for each vintage of capacity from year 2000 to year 2010. Each entry in table 21 is given by multiplying the corresponding entry in table 19 with the entry in table 20. Table 22 shows the annualized remuneration and the total equalized remuneration. It is calculated similarly to table 18.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	64										
2001	31	45									
2002	42	60	60								
2003	55	79	79	100							
2004	38	55	55	70	337						
2005	47	69	69	87	418	593					
2006	58	84	84	106	513	728	646				
2007	56	81	81	102	494	701	622	937			
2008	55	79	79	100	484	687	609	918	1408		
2009	50	73	73	92	445	631	559	843	1294	2517	
2010	51	74	74	94	452	641	569	857	1315	2559	4995
2011	54	78	78	99	478	678	601	906	1390	2705	5281
2012	54	78	78	99	478	678	601	906	1390	2705	5281
2013	54	78	78	99	478	678	601	906	1390	2705	5281
2014	54	78	78	99	478	678	601	906	1390	2705	5281
2015	54	78	78	99	478	678	601	906	1390	2705	5281
2016	54	78	78	99	478	678	601	906	1390	2705	5281
2017	54	78	78	99	478	678	601	906	1390	2705	5281
2018	54	78	78	99	478	678	601	906	1390	2705	5281
2019	54	78	78	99	478	678	601	906	1390	2705	5281
2020	54	78	78	99	478	678	601	906	1390	2705	5281
2021	54	78	78	99	478	678	601	906	1390	2705	5281
2022	54	78	78	99	478	678	601	906	1390	2705	5281
2023	54	78	78	99	478	678	601	906	1390	2705	5281
2024	54	78	78	99	478	678	601	906	1390	2705	5281
2025		78	78	99	478	678	601	906	1390	2705	5281
2026			78	99	478	678	601	906	1390	2705	5281
2027				99	478	678	601	906	1390	2705	5281
2028					478	678	601	906	1390	2705	5281
2029						678	601	906	1390	2705	5281
2030							601	906	1390	2705	5281
2031								906	1390	2705	5281
2032									1390	2705	5281
2033										2705	5281
2034											5281

Table 19: assumed annual energy generated by solar capacity installed in different years. Data are in GWh.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	60.4										
2001	59.3	59.3									
2002	58.4	58.4	57.5								
2003	57.8	57.8	56.9	53.0							
2004	56.9	56.9	56.0	52.1	58.4						
2005	56.0	56.0	55.1	51.3	57.5	61.4					
2006	55.2	55.2	54.3	50.5	56.6	60.5	57.9				
2007	53.9	53.9	53.0	49.4	55.3	59.1	56.6	52.8			
2008	52.5	52.5	51.7	48.1	53.9	57.6	55.1	51.4	48.2		
2009	52.4	52.4	51.5	48.0	53.7	57.4	54.9	51.3	48.0	46.0	
2010	51.8	51.8	50.9	47.4	53.1	56.8	54.3	50.7	47.5	45.4	38.5
2011	50.6	50.6	49.8	46.4	51.9	55.5	53.1	49.6	46.4	44.4	37.7
2012	49.6	49.6	48.8	45.4	50.9	54.4	52.1	48.6	45.5	43.5	36.9
2013	48.7	48.7	47.9	44.6	49.9	53.3	51.0	47.6	44.6	42.7	36.2
2014	47.7	47.7	46.9	43.7	48.9	52.3	50.0	46.7	43.8	41.9	35.5
2015	46.8	46.8	46.0	42.8	48.0	51.3	49.1	45.8	42.9	41.0	34.8
2016	45.8	45.8	45.1	42.0	47.0	50.3	48.1	44.9	42.1	40.2	34.1
2017	44.9	44.9	44.2	41.2	46.1	49.3	47.2	44.0	41.2	39.4	33.4
2018	44.1	44.1	43.4	40.4	45.2	48.3	46.2	43.2	40.4	38.7	32.8
2019	43.2	43.2	42.5	39.6	44.3	47.4	45.3	42.3	39.6	37.9	32.1
2020	5.0	42.4	41.7	38.8	43.4	46.4	44.4	41.5	38.9	37.2	31.5
2021	5.0	5.0	40.9	38.0	42.6	45.5	43.6	40.7	38.1	36.4	30.9
2022	5.0	5.0	5.0	37.3	41.8	44.6	42.7	39.9	37.3	35.7	30.3
2023	5.0	5.0	5.0	5.0	40.9	43.7	41.9	39.1	36.6	35.0	29.7
2024	5.0	5.0	5.0	5.0	5.0	42.9	41.1	38.3	35.9	34.3	29.1
2025		5.0	5.0	5.0	5.0	5.0	40.2	37.6	35.2	33.7	28.5
2026			5.0	5.0	5.0	5.0	5.0	36.8	34.5	33.0	28.0
2027				5.0	5.0	5.0	5.0	5.0	33.8	32.4	27.4
2028					5.0	5.0	5.0	5.0	5.0	31.7	26.9
2029						5.0	5.0	5.0	5.0	5.0	26.4
2030							5.0	5.0	5.0	5.0	5.0
2031								5.0	5.0	5.0	5.0
2032									5.0	5.0	5.0
2033										5.0	5.0
2034											5.0

Table 20: annual real prices of electricity paid to solar energy from capacity installed in different years. Data are in ¢(2011)/kWh.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	39										
2001	18	27									
2002	24	35	35								
2003	32	46	45	53							
2004	22	32	31	36	197						
2005	27	38	38	44	240	364					
2006	32	46	46	54	290	440	374				
2007	30	44	43	51	273	414	352	495			
2008	29	42	41	48	261	395	336	472	679		
2009	26	38	38	44	239	362	307	433	622	1157	
2010	27	38	38	44	240	364	309	435	625	1163	1925
2011	27	40	39	46	248	376	319	449	646	1202	1989
2012	27	39	38	45	243	369	313	440	633	1178	1950
2013	26	38	38	44	238	362	307	432	621	1155	1912
2014	26	37	37	43	234	355	301	423	608	1132	1874
2015	25	37	36	42	229	348	295	415	597	1110	1837
2016	25	36	35	42	225	341	289	407	585	1088	1801
2017	24	35	35	41	220	334	283	399	573	1067	1766
2018	24	35	34	40	216	328	278	391	562	1046	1731
2019	23	34	33	39	212	321	272	383	551	1026	1697
2020	3	33	33	38	208	315	267	376	540	1005	1664
2021	3	4	32	38	203	309	262	369	530	986	1631
2022	3	4	4	37	200	303	257	361	519	966	1599
2023	3	4	4	5	196	297	252	354	509	947	1568
2024	3	4	4	5	24	291	247	347	499	929	1537
2025		4	4	5	24	34	242	340	489	911	1507
2026			4	5	24	34	30	334	480	893	1478
2027				5	24	34	30	45	470	875	1449
2028					24	34	30	45	70	858	1420
2029						34	30	45	70	135	1392
2030							30	45	70	135	264
2031								45	70	135	264
2032									70	135	264
2033										135	264
2034											264

Table 21: annual remunerations for solar energy. Data are in M€(2011).

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Annualized remuneration	25	35	35	41	217	333	281	385	542	989	1620
Equalized remuneration	25	60	94	136	353	685	966	1351	1893	2882	4503

Table 22: *Annualized remuneration*: annualized remuneration of every vintage of solar capacity from year 2000 to year 2010. *Equalized remuneration*: sum of the annualized remunerations of all capacity in service. Data are in M€(2011).

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