Energy Policy 62 (2013) 934–947

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

# Redistribution effects of energy and climate policy: The electricity market ☆

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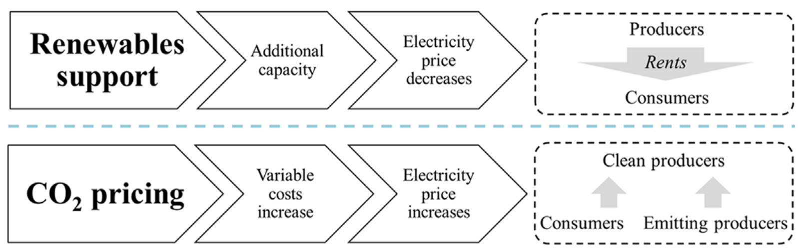
## HIGHLIGHTS

- $CO_2$ pricing and renewables support have strikingly different impacts on rents.
- Carbon pricing increases producer surplus and decreases consumer surplus.
- Renewable support schemes (portfolio standards, feed-in tariffs) do the opposite.
- We model these impacts theoretically and quantify them for Europe.
- Redistribution of wealth is found to be significant in size.

## GRAPHICAL ABSTRACT




Renewable support redistributes economic surplus from incumbent producers to consumers.
$CO_2$ pricing does the opposite, but affects carbon-intensive and low-carbon technologies differently.

## ARTICLE INFO

*Article history:*
Received 11 January 2013
Accepted 17 July 2013
Available online 7 August 2013

*Keywords:*
Redistribution
Emission trading
Renewable energy

## ABSTRACT

Energy and climate policies are usually seen as measures to internalize externalities. However, as a side effect, the introduction of these policies redistributes wealth between consumers and producers, and within these groups. While redistribution is seldom the focus of the academic literature in energy economics, it plays a central role in public debates and policy decisions. This paper compares the distributional effects of two major electricity policies: support schemes for renewable energy sources, and $CO_2$ pricing. We find that the redistribution effects of both policies are large, and they work in opposed directions. While renewables support transfers wealth from producers to consumers, carbon pricing does the opposite. More specifically, we show that moderate amounts of wind subsidies can increase consumer surplus, even if consumers bear the subsidy costs. $CO_2$ pricing, in contrast, increases aggregated producer surplus, even without free allocation of emission allowances; however, not all types of producers benefit. These findings are derived from an analytical model of electricity markets, and a calibrated numerical model of Northwestern Europe. Our findings imply that if policy makers want to avoid large redistribution they might prefer a mix of policies, even if $CO_2$ pricing alone is the first-best climate policy in terms of allocative efficiency.



## 1. Introduction

Two of the major new policies that have been implemented in European, American, and other power markets during the last years are support for renewable energy generators and $CO_2$ pricing. Many countries have introduced support schemes for renewable electricity, such as feed-in-tariffs or renewable portfolio standards. As a consequence, the share of renewables in electricity generation has been growing rapidly (REN21, 2013; OECD/IEA,

☆We would like to thank Wolf-Peter Schill, Catrin Jung-Draschil, Reinhard Ellwanger, Gustav Resch, Michael Jakob, Daniel Klingenfeld, Robert Pietzcker, Schifferhof Uckermark, Sophia Ruester, Sebastian Schwenen, Thomas Präßler, Theo Geurtsen, Robert Brecha, Ottmar Edenhofer, and five anonymous reviewers for helpful comments. All remaining errors are ours. Earlier versions of this paper were published as FEEM Working Paper 2012.071 and presented at the Enerday, IEW, and EEM conferences. The findings, interpretations, and conclusions expressed herein are those of the authors and do not necessarily reflect the views of Vattenfall or the Potsdam-Institute.

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http://dx.doi.org/10.1016/j.enpol.2013.07.055

2013). In the European Union, it increased from 13% in 1997 to 17% in 2008, in Germany, from 4% to 23% within the last two decades. According to official targets, the share of renewables in EU electricity consumption shall reach 60–80% by 2050. The second major policy was the introduction of a price for $CO_2$. In Europe $CO_2$ pricing was implemented via an emission trading scheme in 2005, and several countries, regions, and states have followed. During the last 8 years, the European carbon price has fluctuated between zero and 30 €/t, with official expectations of prices between 100 €/t and 300 €/t by 2050.[1]

These new policies affect the profits of previously-existing (incumbent) electricity generators. More general, they redistribute economic surplus between producers and consumers and between different types of producers and consumers. Support policies bring renewable capacity in the market that decreases the wholesale electricity price below the level it would have been otherwise. For example, wind power has low variable costs and reduces the wholesale electricity price whenever it is windy. Lower electricity prices reduce the profits of existing generators and increase consumer surplus. If subsidy costs are passed on to consumers, the net effect on consumer surplus is ambiguous a priori.

$CO_2$ pricing increases the variable costs of carbon-emitting plants. Whenever such generators are price-setting, $CO_2$ pricing increases the electricity price. Low-carbon plants like nuclear and hydro power benefit from higher prices without having to pay for emission. Carbon-intensive generators like lignite, in contrast, see their profits reduced because costs increase more than revenues. Consumer surplus is reduced due to higher electricity prices, and increased if they receive the income from $CO_2$ revenues. Again the net effect on consumers is ambiguous.

Policy can impact producer rents only in the short term. In the long-term equilibrium, assuming perfect and complete markets, profits are always zero. Only if a market features some sort of inertia, and newly introduced policies are not fully anticipated, the policy impacts profits. We believe power markets to fulfill these two conditions.

In this paper, we model and quantify the redistribution effects of renewable support policies and $CO_2$ pricing, using an analytical (theoretical) and the numerical (empirical) model EMMA. We distinguish two sectors: incumbent generators with sunk investments, and electricity consumers. State revenues and expenditures are assumed to be passed on to consumers as lump-sum payments. Generators are further distinguished by technology, since the effect of $CO_2$ pricing on generators depends on their carbon intensity and the effect of renewable subsidies depends on their capital intensity. Disaggregating consumers could yield important insights, but is beyond the scope of this paper (see for example Neuhoff et al., 2013). Markets are assumed to be competitive, thus profits are zero in the long term. The modeling approach is valid for different types of $CO_2$ pricing (emission trading, carbon tax) and different types of renewables support (feed-in tariffs, renewable portfolio standards with or without certificate trading, investment grants, tax credits) and is in this sense very general. We use wind power as an example for a subsidized renewable electricity source, but all arguments apply to solar power and other zero marginal-cost technologies as well.

In our quantitative assessment of Northwestern Europe we find that the redistribution effects of both policies are large. Overall, wind support distributes surplus from producers to consumers and carbon pricing does the opposite. Wind support transfers enough producer rents to consumers to make those better off even if they pay the costs of subsidies. Wind support reduces the profits of base load generators more than those of peak load generators. $CO_2$ pricing reduces the profits of coal-fired generators, leaves those of gas plants largely unaffected, and increasing the rents of nuclear plants dramatically. As a group, electricity generators benefit from carbon pricing even without free allocation of emission permits.

We acknowledge that power markets feature a number of externalities that we ignore in this study. While $CO_2$ pricing has the clear objective of internalizing the costs of climate change, policy makers have put forward a multitude of motivations for renewable support. This paper does not assess these motivations, does not take into account externalities, and does not provide a cost–benefit analysis of these two policies or evaluates them against each other. Rather, our goal is merely to point out their peculiar effects regarding the redistribution of wealth. We focus here on the impact of two policies separately, and the joint impact. Interactions with existing or new policies, such as energy efficiency, are beyond the scope of this paper.

The next section reviews the literature. Section 3 presents the analytical framework and introduces the models. Section 4 discusses the effects of wind support, Section 5 those of carbon pricing, and Section 6 the compound effects of both policies. Section 7 concludes.

## 2. Literature review

Redistributive impacts of climate and energy policy have become a major topic in economics research during the last years. Redistributive flows between jurisdiction, between generations, and between resource owners vs. resource consumers have received much attention; see for example Bauer et al. (submitted for publication) on resource owners. Edenhofer et al. (2013) provides a broader survey of the issue. This paper adds to this literature by analyzing redistribution between firms and consumers via the electricity market.

Focusing on the narrower field of electricity policies, the present paper builds on three branches of the literature on implications of policy instruments: the “merit-order” literature, the “windfall profit” literature, and the “policy interaction” literature. The first branch focuses on the depressing effect of renewables generation on the electricity price, which has been termed “merit-order effect”. The second branch discusses the impact of carbon pricing on consumer and producer surplus, where increasing producer rents are sometimes labeled “windfall profits”. The third branch discusses the interaction between these two policies.

Attracting additional investments in (renewable) generation capacity depresses the electricity price below the level it would have been otherwise. Because the size of the drop depends on the shape of the merit-order curve, Sensfuß (2007) has termed this the “merit-order effect”. A number of papers model the price impact theoretically and numerically. Modeling exercises for the Nordic countries (Unger and Ahlgren, 2005), Germany (Sensfuß et al., 2008) and Spain (De Miera et al., 2008) indicate that the additional supply of electricity from wind power reduces the spot price so much that consumers are better off even if they have to bear the subsidy costs. Results for Denmark are less conclusive (Munksgaard and Morthorst, 2008). Based on a theoretical model, Fischer (2010) finds that the sign of the price impact depends on the relative elasticity of supply of fossil and renewable generation. MacCormack et al. (2010) find the merit-order effect to be larger when conventional generators have more market power because both the additional supply and the uncertainty introduced by wind power reduce the incentive to withhold capacity. While these studies apply numerical models, O′Mahoney and Denny (2011)

[1] 2050 targets are taken from the Energy Roadmap 2050 (European Commission, 2011).

and Gil et al. (2012) use regression analyses. Confirming model results, they find that both in Ireland and Spain the merit-order effect outweighs the subsidy costs for consumers. Mount et al. (2012) stresses the effect on producer profits and the "missing money" to finance capital costs from short-term profits. Wissen and Nicolosi (2008) and MacCormack et al. (2010) emphasize that the merit-order effect is only a short-term or "transient" phenomenon, since in the long-term equilibrium prices need to include capital costs. While the literature has collected an impressive amount of evidence, most of these papers are not explicit that the price is reduced by redistributing wealth from incumbent producers to consumers, and none accounts comprehensively for all redistribution and efficiency effects.

The second branch of literature deals with the redistribution effects of carbon taxes and emission trading schemes. Most of these studies are written in the context of discussions of different allocation rules for emission allowances. Typically, they model the impact of allocation rules on profits, and to what extent $CO_2$ costs can be passed through to consumers. A well-known result is that in the case of grandfathering large windfall profits for producers occur that are paid by consumers, for example reported by Bode (2006) and Sijm et al. (2006). Some authors find that the aggregated power generation sector benefits even if allowances are fully auctioned. This is shown for the UK (Martinez and Neuhoff, 2005) and for Northwestern Europe (Chen et al., 2008). Similarly, Burtraw et al. (2002) report for the US that only 9% of all allowances would need to be grandfathered to preserve total producer profits when introducing $CO_2$ certificates. In addition, Burtraw and Karen (2008) find that a number of US-electricity generators would benefit from emission trading even under full auctioning.

Finally, there is an established branch of the literature that discusses the interaction between $CO_2$ pricing and renewables support. It is found that these concurrent policies partly offset each other, in the sense that a more stringent renewable target reduces the $CO_2$ prices, and a more stringent $CO_2$ target reduces the prices of tradable green certificates (Unger and Ahlgren, 2005; Tsao et al., 2011). A perverse consequence is that more renewable support increases the supply of the most emission-intensive generators (Böhringer and Rosendahl, 2010). Because of lower allowance prices, wind support decreases electricity prices not only via the power market, but also via the carbon market (Rathmann, 2007). These publications focus on certificate markets, but do not compare both policies regarding their effect on the power market.

To the best of our knowledge, this is the first paper that comprehensively and consistently models and compares the redistribution effects of renewables support and $CO_2$ pricing. While previous studies do report effects on prices and sometimes on profits, they do not report consumer and producer surplus. We comprehensively account for all redistributive flows between actors such that they consistently add up. A newly developed framework that uses the long-term equilibrium as a benchmark is used to evaluate both policies consistently. This innovation is the main contribution to the literature.

Furthermore, combining an analytical with a numerical model allows us tracing the causal mechanisms as well as providing quantitative estimates where theoretical results are ambiguous. To the best of our knowledge, this is the first paper to provide an analytical model of redistribution via the electricity market. In addition, we allow for endogenous investment, a key gap in the literature identified by Tsao et al. (2011).

Finally, our numerical power market model takes into account a large number of technical side constraints and the intermittent character of wind power. This is crucial not only for quantifications, but also to understand the different impact on types of generating technologies.

## 3. Methodology

This section introduces the two models and outlines the framework in which we apply both models. The analytical model is meant to generate insights into the causal mechanisms of policy-induced redistribution effects. The numerical model EMMA quantifies redistribution flows for Northwestern European countries and provides results where analytical findings are ambiguous. Both models are applied within the same consistent framework that uses the long-term equilibrium as a starting point to compare the short-term impacts of both policies.

### 3.1. Framework

In a long-term equilibrium (LTE) on perfect and complete markets with free entry, profits (rents, producer surplus) are zero.[2] If a market features some sort of inertia and newly introduced policies are not fully anticipated, a policy shock displaces the system from its LTE. Only during the transition towards a new LTE the policy might change profits and thereby redistribute producer surplus to or from other actors. As MacCormack et al. (2010) put it, redistribution of producer surplus is a "transient phenomenon" that vanishes once the system has converged to the new LTE. In the power market, inertia is substantial due to long life times and building times of power plants and other infrastructure.

In this paper, we distinguish two time perspectives with corresponding market equilibriums: the "long term" and the "short term". In the long term, the amount and type of capacity is a choice variable that is decided upon by producers ("green field" model). In the short term, producers take the existing capital stock as given at zero costs (but are allowed to additionally invest). In both the long and the short term, producers face production decisions.[3] In other words, in the long term no capital stock is given while in the short term there is a stock of sunk investments. While long-term profits are zero in the LTE, short-term profits are positive in the short-term equilibrium (STE). Short-term profits are needed to repay capital costs. This is possible because there is no free entry that could drive down short-term profits to zero, since entrants had to build new capacity and pay the corresponding capital expenditures. In other words, in the STE previously-existing generators are able to extract rents from their sunk investments, which are used to finance capital costs. While both long term and short term are analytical concepts that never describe a real market entirely correctly, we believe the short term as defined here is a useful assumption to analyze moderate shocks to European power systems on a time horizon of 3–15 years.

In this research project, we exploit these two concepts to construct a framework that allows comparing the distribution effect of different policies consistently (Fig. 1). We assume that the power market is in its LTE before policies are introduced. Then we switch perspective and derive the STE by taking the previously derived capacity as given. Then a policy is introduced exogenously and unexpectedly that shifts the system to a new STE. We define

[2] Positive long-term profits would attract new investments that drive down prices to the point where profits disappear. Vice versa, negative profits would lead to disinvestment, driving up prices until negative profits vanish.

[3] Note that according to this definition, the capital stock is not fixed in the short term, but additional investments are possible. Others (Hirth, 2012; MacCormack et al., 2010) have labeled this the "medium term" and apply the term "short term" to a situation where the capital stock is fixed without the possibility of additional investments.

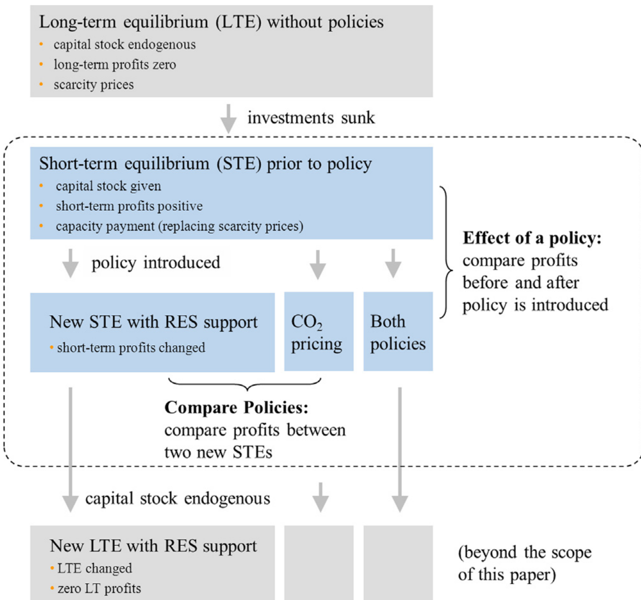


**Fig. 1.** This framework allows to consistently studying different policies with an analytical and a numerical model. Starting from a long-term equilibrium with no policy, two short-term equilibriums (STE) are compared: the STE prior to policy with a STE with a newly introduced policy.

the redistributive effect of that policy as the difference of short-term profits and consumer surplus between these two STEs. To compare two policies, they are independently introduced starting from the same STE, and the redistribution effects of the policies are consequently compared. Income from scarcity pricing is assumed to remain constant, for example due to capacity payments. The new LTE that would emerge after some time is not of interest for this paper. This framework features two properties that are necessary to compare redistribution effects of different policies:

1. The same benchmark is used for both policies.
2. All changes in short-term rents are strictly caused by policy changes.

While deriving the long-term equilibrium is a standard methodology in the power economics literature, using the resulting capacity mix to evaluate policies in a short-term equilibrium is to our knowledge a novel approach, which we regard as significant innovation. An alternative to our short term/long term dichotomy is to disregard adjustments of the capital stock, potentially overestimating the impact of policies (Sensfuß et al., 2008; Chen et al., 2008; Böhringer and Rosendahl, 2010; Tsao et al., 2011). Another alternative is to model the system′s adaptation to shocks dynamically over time (Prognos and GWS, 2010; Short et al., 2011; Nicolosi, 2012; Färber et al., 2012). However, such scenario analysis typically features a multitude of dynamic shocks that makes it very hard to identify the effect of a specific policy. Consequently, this scenario literature does not provide results of the distributional impact of individual policies. More fundamentally, the starting points of these studies are usually chosen in a way that the market is off its equilibrium in the first place, meaning that changes in rents are not only caused by policy changes, but simply by adjustment process towards the equilibrium. While the scenario literature can provide projection of rents, it is not helpful to disentangle individual drivers and evaluate specific policies.

### 3.2. Analytical model

This subsection introduces a stylized cost-minimizing analytical model of the electricity market and derives the LTE and the STE. We show that long-term profits are zero while in the STE producers are able to extract short-term rents from their sunk investment. Policies are assessed in Sections 4.1 and 5.1.

To develop a qualitative understanding of major effects it is sufficient to model two generation technologies, which we label “gas” and “coal” power. Dynamic aspects like ramping constraints and electricity storage are neglected, as well as heat and reserve market requirements, international trade, and grid constraints. These details are taken into account in the numerical model (Section 3.3). Both models assume fully competitive and complete markets with perfect foresight. Hence, the cost-minimizing solution is equivalent to the market equilibrium. Electricity demand is perfectly price-inelastic. All fees and taxes are assumed to be specific and remain constant. Externalities are assumed to be absent.

We extend a classical method from power economics (Stoughton et al., 1980; Grubb, 1991; Stoft, 2002; Green, 2005) that uses screening curves, a load duration curve[4] (LDC), and a price duration curves (PDC) that is derived from the first two (Fig. 2a–c). A screening curve represents the total costs per kW-year of one generation technology as a function of its full load hours. Its $y$-intercept is the annuity of investment costs and the slope equals the variable costs. The LDC shows the sorted hourly load of one year starting with the highest load hour. A price duration curve shows the sorted hourly prices of one year starting with the highest price. This model allows the representation of the two policies we aim to analyze: wind support[5] reshapes the LDC, while $CO_2$ pricing pivots the screening curves. Before introducing policies in Sections 4 and 5, the LTE and the STE are derived in the following. For a more detailed model description and an alternative application see Ueckerdt et al. (2012).

We first derive the cost-minimal long-term capacity mix and dispatch, then show that profits for all plants are zero in the cost minimum, and finally explain that this is the unique market equilibrium. Cost-minimal capacities and generation can be derived by projecting the intercepts of the screening curves on the LDC. The LDC is then horizontally divided. Each part of load is covered by the technology with the least-cost screening curve for the respective range of full load hours. Gas power plants are cost effective at lower full load hours (peak load) due to their low fixed-to-variable-cost ratio. Coal power plants cover base load. Hereby optimal capacities and dispatch of plants are determined. The PDC is derived from the equilibrium condition that the price equals the variable costs of the marginal plant, except in the one hour of the year when capacity is scarce. In this peak hour scarcity prices $p_s$ occur.

We now show that gas plants earn zero profit. Unless capacity is scarce, the electricity price is set by the variable costs of the marginal plant. Hence, operating gas plants are always price-setting (Fig. 2c). To recover capital costs, gas plants need to demand a scarcity price $p_s$. Under perfectly inelastic demand, this is only possible in exactly one hour of the year, since at any other point in time there is some capacity available that would supply electricity if the price would rise above variable costs.

$$p_s = c_{gas} + \Delta \tag{1}$$

$$\Delta = I_{gas} \tag{2}$$

[4] For the illustrations we use hourly data for German power demand in 2009 (ENTSO-E).

[5] We use quarter hourly feed-in data from German TSOs for 2009.

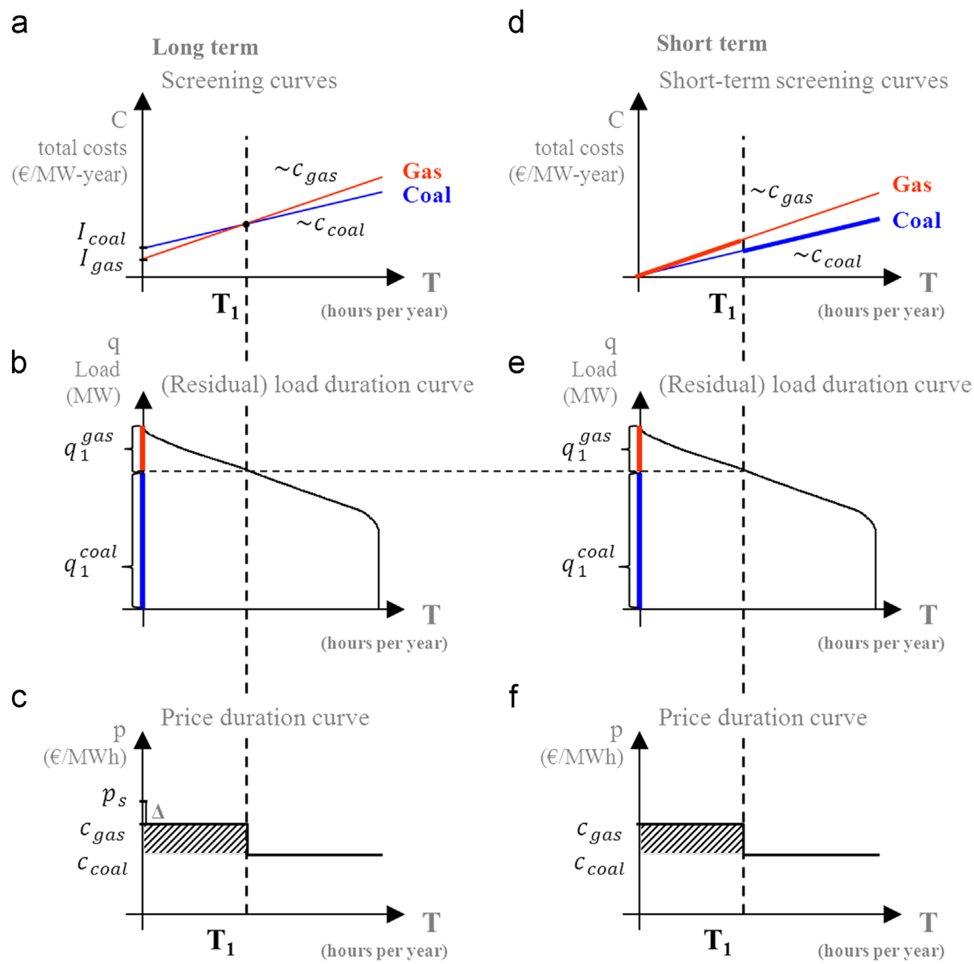


**Fig. 2.** Long-term equilibrium (left) and short-term equilibrium (right) described by screening curves (a, d), load duration curve (b,e), and price duration curve (c,f). In the short term, screening curves do not contain investment costs and the price duration curve does not contain scarcity prices $p_s$.

The markup $\Delta$ on specific (per MWh) variable costs $c_{gas}$ can only be chosen to exactly cover the investment specific (per MW) cost $I_{gas}$. A gas power plant cannot further increase the scarcity price to make profit because other gas power plants would enter the market and bid lower prices until the rent vanishes. Hence, the scarcity price implies zero profits for gas power plants.

We now show that for the optimal capacity mix the scarcity price leads to zero profits also for coal power plants. At the intersection of the screening curves in Fig. 2a it holds:

$$c_{coal}T_1 + I_{coal} = c_{gas}T_1 + I_{gas} \tag{3}$$

$$\Leftrightarrow I_{coal} = (c_{gas} - c_{coal})T_1 + I_{gas} \tag{4}$$

$$\overset{(2)}{\Rightarrow} I_{coal} = (c_{gas} - c_{coal})T_1 + \Delta \tag{5}$$

The right hand side of the last equation is the annual income of one unit of coal capacity in the optimal capacity mix as indicated by the shaded area under the price duration curve (Fig. 2c). Hence, market income exactly covers the specific investment costs of coal capacity if the capacity mix is cost-minimal. One scarcity price leads to zero profits for both gas and coal power plants at the optimal capacity mix.

We now explain why this solution is the unique long-term market equilibrium. Let us assume the system's capacities deviate from their optimal values. Substituting gas for coal capacity would increase the width of the shaded area in Fig. 2c, resulting in profits for coal plants. Additional coal generators have an incentive to enter the market until profits vanish. Substituting coal for gas capacity would lead to negative profits and market exit. A decrease of total generation capacity would lead to profits via scarcity prices and subsequent market entry. An increase of total generation capacity would make scarcity pricing impossible, causing exit of suppliers. Thus the cost-minimal capacity mix and the corresponding PDC is the unique LTE. To conclude, in the long-term equilibrium load is covered at least costs and all power plants earn zero profits. This result can be generalized to more than two technologies.

In the following we define short-term profits and show that they are positive in the STE, as defined in Section 3.1. In the short term, capacities from the long-term equilibrium are given. Investment costs for those existing plants are sunk and hence short-term screening curves only contain variable costs and no investment costs (Fig. 2d). Coal is the least-cost technology at all full load hour values; however, its capacity is limited. The optimal dispatch does not change compared to the long-term equilibrium. Total capacity is not scarce and thus there is no scarcity price (Fig. 2f). We assume the "missing money" due to lacking scarcity prices is transferred to generators via other mechanisms, for example a capacity payment. Hence, gas plants sell electricity at marginal costs whenever they operate and do not earn any profits. On the other hand, coal power plants generate short-term profits when gas is price-setting. The specific rent per MW (shaded area in Fig. 2f) needs to be multiplied by the coal capacity $q_1^{coal}$ to calculate the absolute short-term producer rent $R_1^{coal}$:

$$R_1^{coal} = (c_{gas} - c_{coal})T_1 q_1^{coal} \tag{6}$$

In contrast to the LTE, where profits are zero, in the short term some producers can extract short-term rents from their sunk investment.

### 3.3. Numerical model

To relax some of the assumptions of the analytical model, the calibrated Northwestern European numerical electricity market model EMMA has been developed. As the analytical model, it is deterministic, has an hourly resolution, assumes perfect and complete markets and can be used to derive both the LTE and the STE. However, it provides more details, such as a wider set of generation technologies, electricity storage, and international trade, features a large set of technical constraints, and accounts for fixed O&M costs. These features are discussed briefly in the following paragraphs. Equations are discussed in Hirth (2012) and the source code as well as input date are available under creative common license via Hirth (2013).

Generation is modeled as seven discrete technologies with continuous capacity: one fluctuating renewable source with zero marginal cost and exogenous dispatch (wind), five thermal technologies with economic dispatch (nuclear, lignite, hard coal, combined cycle and open cycle gas turbines), and electricity storage (pumped hydro). Dispatchable plants produce when the price is above their variable cost. The electricity price is the shadow price of demand, which is the marginal cost of increasing demand in a certain hour. This guarantees that the prices in the long-run equilibrium are consistent with the zero-profit condition for generators. Investments in all generation technologies is possible, but in the short-term nuclear investments are disregarded due to their long implementation time. Fixed O&M costs are taken into account, such that existing plants might be decommissioned for economic reasons after a policy shock.

In power systems, a large number of technical constraints affect the dispatch of plants. A few of the most important ones are implemented as side conditions in EMMA. A share of the thermal capacity is modeled as combined heat and power plants that sell heat as well as electricity. These plants are forced to run, even if prices are below their variable costs. Ancillary services such as regulating power are modeled as a spinning reserve requirement that forces dispatchable capacity equivalent to 20% of the yearly peak demand to be online at any point of time. While internal grid constraints are ignored, cross-border flows are limited by net transfer capacities.

Demand as well as wind generation time series are based on empirical 2010 data. Using historical time series ensures that crucial correlations across space, over time, and between parameters are captured. The model is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, and France. The model is linear, written in GAMS and solved by Cplex. It has been back-tested with historical data and is able to replicate dispatch decisions as well as prices in a satisfactory manner. Cost and technical parameters are consistent with empirical data, and were chosen such that today's capacity mix is roughly replicated in the long-term equilibrium (Fig. 3).

Both the analytical and the numerical model do not take into account internal grid investments and balancing power. Large-scale renewables deployment probably increases both grid and balancing costs (Hirth and Ziegenhagen, 2013), which we do not account for.

Similar market models have been used by DeCarolis and Keith (2006), Doherty et al. (2006), Olsina et al. (2007), Lamont (2008), Bushnell (2010), and Green and Vasilakos (2011) to numerically estimate long-term equilibriums of power markets. However, these authors do not discuss the short term nor distribution issues.

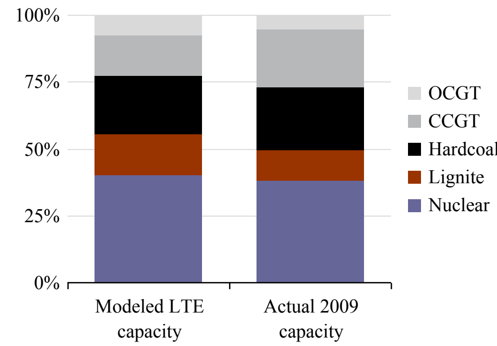


**Fig. 3.** Model long-term equilibrium capacity mix versus historical capacity mix in 2009 for the model region. The modeled LTE capacity mix resembles quite closely to the observed data.

## 4. Wind support

This section presents analytical and numerical model results of the redistribution effects of wind support schemes. As explained in Section 3.1, it is assumed that the electricity market is in its long-term equilibrium prior to the introduction of wind support, and effects take place in the short term. Distributional effects emerge because costs for the existing capital stock are regarded as sunk. Support policies are not modeled explicitly, but implicitly by exogenously increasing the amount of wind power. The costs of wind support are then calculated ex post as the gap between full costs and market income, assuming a perfect policy design that does not leave any rents to wind generators.

Renewable support policies have the effect of pushing additional low-variable cost capacity into the market relative to the long-term equilibrium. As a consequence, wind power replaces high-variable cost gas power plants when it is windy. Hence, during some hours coal is setting the price instead of gas power plants that become extra-marginal. In those hours the electricity price is reduced. In all other hours the electricity price remains unchanged. This implies that wind support never increases short-term rents of any existing generators. The reduction of producer rents leads to gains in consumer surplus. In addition, consumers are assumed to bear the economic costs of wind subsidies. The net effect of wind support on consumer surplus is thus a priori ambiguous and depends on the relative size of redistribution of producer surplus to the costs of subsidizing wind power.

### 4.1. Analytical results

Fig. 4 compares the short-term equilibrium of the electricity market prior (left) and after (right) the introduction of wind power. The left hand side is identical to the right hand side of Fig. 2. Additional wind capacity has no effect on the cost structure of dispatchable generators, thus the short-term screening curves do not change (a, d) and dispatchable capacity remains the same (capacity bars in c and d are identical). However, residual load (load net of wind generation) is reduced during windy hours, shifting the RLDC downwards (b, e). The RLDC also becomes steeper because load during the peak hour of the year remains virtually unchanged.[6] The amount of energy generated in dispatchable plants, the integral under the RLDC, is reduced. Thus full load hours of all dispatchable plants are reduced: existing capacity is utilized less – this is why Nicolosi (2012) calls the impact of wind on the RLDC the "utilization effect". Most importantly, the

[6] This is the case when the renewable technology has a comparable small capacity credit like wind power in Europe.

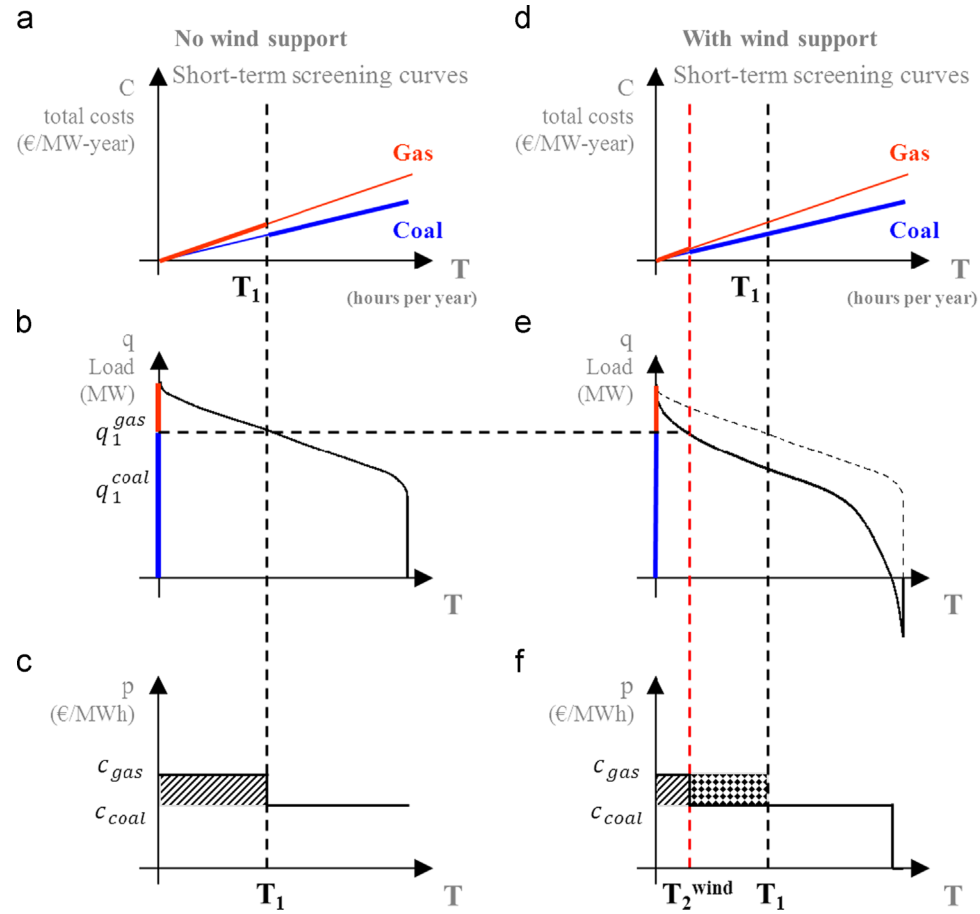


**Fig. 4.** Short-term screening curves, load duration curves, price duration curves without (left) and with wind support (right). Wind changes the residual load duration curve (b, e). Producer rents decrease with wind support (checkered area equals the reduction of specific coal rents).

PDC is shifted (c, f) to lower prices, because the number of hours where gas is price-setting is diminished.

The effect of wind support on incumbent generators is determined by the shift of the PDC. The short-term rents of gas plants remain zero even though less energy is generated, because they are price-setting whenever they operate. In contrast, coal power plants earn profits when gas is price-setting. Hence, coal power plants lose because the number of hours when gas is price-setting is reduced. The reduction of coal rents equals the change of total producer rents. The dotted area in Fig. 4f shows the loss of the specific (in € per MW) rent of coal capacity: $(c_{gas}-c_{coal})(T_1-T_2)$. The absolute decrease of $R_1^{coal}$ (in €) is given by the coal capacity $q_1^{coal}$ times the specific loss.

$$R_1^{coal}-R_2^{coal}=q_1^{coal}(c_{gas}-c_{coal})(T_1-T_2) \tag{7}$$

The last factor depends on the deployment of renewable capacity while the others are constant: The shift of the PDC to lower prices drives redistribution due to renewable support.

A strong analytical result is that the rents of incumbent generators never increase due to wind support policies. Rents of the base load technology (coal) decrease, while rents of the peak load technology (gas) remain unchanged. The total effect is proportional to the reduction of hours in which gas is price-setting. Consumer rents increase by that amount minus the costs of wind support. The net effect on consumer surplus is ambiguous.

### 4.2. Numerical results

In the following, EMMA is used to derive additional details and quantifications in three directions. Firstly, redistribution flows are quantified and shown to be significant in size. Secondly, a wider set of dispatchable generation technologies is modeled, such that loosing and winning generators can be identified more specifically. Finally, the costs of optimal wind subsidies are estimated, and it is shown that for moderate amounts of wind power the net effect on consumer surplus is positive.

In the long-term equilibrium wind is absent, thus all incumbent generators are conventional. Table 1 presents the changes in producer and consumer surplus caused by an exogenous increase of the wind share from 0% to 30% of electricity consumption. Results are given per MWh of total annual consumption to facilitate comparison.[7] Short-term rents of conventional generators are in average reduced by 22 €/MWh. Nuclear rents almost vanish, coal rents are reduced by 80%, and gas rents by 70%. As indicated by the analytical model base load generators lose most, since their income is reduced during a relatively high share of hours.

The effect on electricity consumers is displayed in Table 1b. Consumers save 28 €/MWh in electricity expenditures, because 22 €/MWh are transferred from producers, and 6 €/MWh are saved due to lower fuel costs. On the other hand, consumers pay slightly more for heat, ancillary services, and grid fees. In addition, they have to bear the costs of incentivizing wind investments, which is 18 €/MWh. In sum, they receive a net benefit of 7 €/MWh. In other words, at 30% penetration rate the merit-order effect is larger than the cost increase due to wind subsidies. Despite wind power

[7] Thus results can be interpreted as normalized to a total electricity consumption of one MWh.

**Table 1**
(a–c) Changes in short-term surplus of producers and consumers, and system costs changes when increasing wind penetration from zero to 30% (€/MWh). Previously existing generators lose, while gross benefits for consumers via the electricity price are larger than costs of subsidies, thus overall consumer surplus increases.

| **Incumbent producers** (€/MWh) | | **Consumers** (€/MWh) | | **System costs** (€/MWh) | |
|---|---|---|---|---|---|
| Nuclear rents | −13 | Electricity market | +28 | Decrease in producers surplus | 22 |
| Coal rents | −9 | Heat market | −2 | Increase in consumer surplus | 7 |
| Gas rents | −1 | AS market | −0.1 | | |
| | | Interconnectors | −0.2 | | |
| | | $CO_2$ taxes | / | | |
| | | Wind subsidies | −18 | | |
| Producer surplus | −22 | Consumer surplus | +7 | Increase in system costs | 15 |

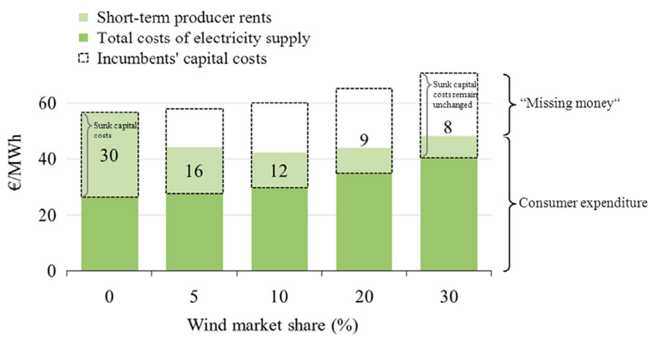


**Fig. 5.** Rents and costs at different wind penetration rates. Numbers label short-term producer rents (light green). The sum of the colored bars is consumer expenditure. With increasing wind penetration, producer rents are transferred to consumers. At 10% wind market share, short-term consumer surplus is maximal. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

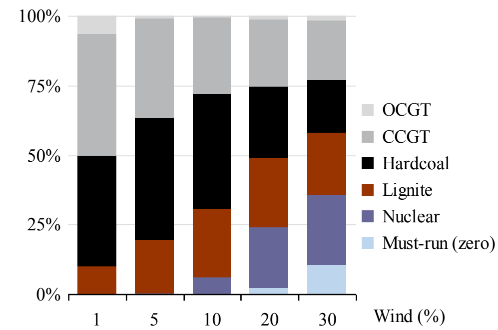


**Fig. 6.** Share of hours in which different technologies are price-setting. With higher wind penetration, the share of base load technologies increases. At 20% wind and above, prices drop to zero, when must-run constraints become binding.

being inefficient, pushing it into the market reduces net consumer costs by transferring surplus from producers. This is consistent with the findings of previous studies (Unger and Ahlgren, 2005; De Miera et al., 2008; Sensfuß et al., 2008; O′Mahoney and Denny, 2011; Gil et al., 2012).

System costs, the sum of negative surpluses, increase by 15 €/MWh (Table 1c). This is the net economic cost of wind power, ignoring all externalities.

The redistribution flows are economically highly significant: The surplus redistributed from producers to consumers due to wind subsidies is larger than the efficiency effect of this policy. Short-term profits are 30 €/MWh prior to the policy shock, thus they are reduced by more than 70%. Total long-term costs of electricity are 78 €/MWh, thus the loss in producer surplus is about 28% of total revenues of the industry.

Fig. 5 displays the costs of electricity supply and short-term producer rents at wind penetration rates between 0% and 30%. While total costs of electricity supply increase when more wind capacity is added to the system, incumbents' profits continuously fall. The latter effect is larger than the former, such that consumer expenditures are reduced. At a penetration rate of 10% consumers benefit the most. Prior to the policy shock, short-term rents were just sufficient to cover capital costs. Decreasing short-term producer rents are not sufficient to cover fixed costs ("missing money"). Conventional generators do not earn their expected rate of return, and might go bankrupt. Nonetheless, the "missing money" result does *not* imply that capacity payments are needed to restore allocative efficiency or secure supply. In our framework, energy-only markets with scarcity pricing provide sufficient incentives for new investments – it is only previously existing investments that are expropriated.

Fig. 6 shows how the price-setting technology shifts when adding more wind capacity to the system. This mechanism transfers producer rents to consumers via lower prices. As derived in Section 4.1, the additional capacity causes generators with lower variable costs to set the price more often. Without wind, gas plants set the price in 50% of all hours, and hard coal during most of the remaining time. At 30% wind penetration, the price drops to zero in 10% of all hours, and in an additional 50% of the hours the base load technologies lignite and nuclear set the price.

### 4.3. Findings and discussion

Several findings emerge from our analytical and numerical analysis of redistribution effects of wind support policies. Triggering significant amounts of wind investments will always reduce the electricity price. This implies a redistribution of surplus from incumbent generators to consumers. Thus wind support policies can be seen as a mechanism to transfer rents from producers to consumers. This is possible only if investments are sunk. Transfers are large relative to system cost effects and relative to other benchmarks. Base load generators lose relatively more than peak load generators. At moderate penetration rates (up to at least 30%) consumers benefit even if they pay the wind subsidies. Consumer surplus is maximized at around 10% wind share. Other types of renewables such as offshore wind power and solar power are more costly than onshore wind. Subsidizing those technologies could have a negative net effect on consumers, since the costs of subsidies might be larger than redistributed producer rents.

## 5. $CO_2$ pricing

This section presents analytical and numerical model results of the redistribution effects of carbon pricing. As in Section 4, we do not model the carbon policy explicitly, but just its consequence: the existence of a $CO_2$ price signal. The price of $CO_2$ could be implemented via a price or a quantity instrument, both forms are equivalent in the present models. It is assumed that neither emission rights are allocated freely to emitters nor is there any other compensatory transfer to generators.

Carbon pricing increases the variable costs of $CO_2$-emitting plants. This increases the electricity price whenever these technologies are marginal generators. In all other hours, the electricity price remains unchanged. This implies that carbon pricing never decreases the short-term rents of carbon-free generators, while the effect on emitting generators depends on their relative carbon intensity and their location in the merit order. The increase in average electricity price leads to losses in consumer surplus. However, consumers are assumed to receive the revenue from carbon pricing as a lump-sum transfer. The net effect of pricing carbon on consumer surplus is thus a priori ambiguous.

### 5.1. Analytical results

In this subsection we will show that the net effect on producers as a whole depends on the initial generation mix and the $CO_2$ price level.

Fig. 7 shows short-term screening curves for different $CO_2$ prices. Fig. 7a displays a price of zero and is identical to Fig. 2b. With higher carbon prices, the variable costs of emitting technologies increase and thus the short-term screening curves pivot around their vertical intercepts. This effect induces changes of short-term profits. Six qualitatively different $CO_2$ price regimes can be identified (Fig. 7a–f):

(a) Without $CO_2$ pricing costs and rents are $(c_{gas}-c_{coal})T_1q_1^{coal}$ as derived in Section 3.
(b) An increasing $CO_2$ price causes the screening curve of coal to pivot faster than the screening curve of gas. Coal rents decrease in proportion to the decreasing variable cost gap $(c_{gas}-c_{coal})$, while capacities as well as dispatch remain unchanged.
(c) At a sufficiently high $CO_2$ price, the two screening curves coincide.[8] Capacities remain unchanged, and dispatch is arbitrary since both technologies feature identical variable costs. Total producer rents are zero because the price always equals the variable costs.
(d) Further increasing the $CO_2$ price increases the variable costs of coal above those of gas. The coal screening curve is steeper and above the gas curve. While capacities remain unchanged, now the dispatch changes ("dispatch fuel switch"): gas plants now cover base load. While coal plants do not earn any profits, gas plants generate rents when coal power plants are price-setting.
(e) At an even higher $CO_2$ price, the screening curve of coal touches the screening curve of new gas power plants even though the latter also contains investment costs.[9] At this point, new base load gas is as expensive as old base load coal ("investment fuel switch"). The rents of gas power plants reach a maximum.
(f) At higher $CO_2$ prices, the end of the short-term coal screening curve lies above the long-term gas screening curve. Now, it is efficient to replace coal plants that operate with full load hours higher than $T_2$ by new gas plants.[10] Only old gas plants generate rents. These rents remain at the level they reached in (e). This regime is further discussed in the remainder of this subsection and shown in Fig. 9.

Fig. 8 summarizes the development of short-term rents (in €) of coal and gas power plants when the carbon price increases. It illustrates that rents shift from coal power plants to gas power plants. The change of total producer rents (coal and gas) depends on the initial capacity mix of coal and gas, as we formally show later this section.

In detail we discuss regime (f) because it includes a multitude of relevant policy-induced effects. Fig. 9 compares the short-term equilibrium of the electricity market prior (left) and after (right) the introduction of a carbon price. The short-term screening curves in Fig. 9a and d change according to the development illustrated in Fig. 7f. Variable costs of coal are above those of gas, thus the coal screening curve is above the gas curve for existing plants. The dispatch is transposed: coal is shifted to peak load, existing gas power plants cover base load (Fig. 9e). Coal rents vanish, while incumbent gas plants generate profits when coal is price-setting (Fig. 9f).

Moreover investments in new gas power plants are profitable because screening curves of new gas power plants and existing coal power plants intersect (Fig. 9d). All coal power plants that would operate at full load hours higher than $T_2$ are replaced. The remaining coal power plants operate at lower full load hours. New gas plants are assumed to have the same efficiency parameters as old plants, thus the dispatch of old and new gas does not need to be distinguished.

Hence all gas plants have the same specific income (in € per MW) indicated by the shaded area (Fig. 9f): $(c_{coal}^{CO_2}-c_{gas}^{CO_2})T_2$. The absolute rents (in €) of old gas are derived by multiplying with the old gas capacity:

$$R_2^{gas}=(c_{coal}^{CO_2}-c_{gas}^{CO_2})T_2q_1^{gas} \tag{8}$$

$T_2$ is given by the intersection of new gas power plants and existing coal power plants intersect:

$$c_{coal}^{CO_2}T_2=c_{gas}^{CO_2}T_2+I_{gas} \tag{9}$$

When inserting this into Eq. (8) and it follows:

$$R_2^{gas}=I_{gas}q_1^{gas} \tag{10}$$

Total gas rents $R_2^{gas}$ depend only on the fixed costs of gas investments and their initial capacity. They do not further increase with growing $CO_2$ price. This is one of our major analytical results. One MW of existing gas capacity receives short-term rents that exactly equal the costs of constructing new capacity. Thus the sunk nature of capital can be understood as entrance barrier that allows investors to generate profits.

To calculate the total effect of carbon pricing on the total producer rents we need to calculate the coal rent before the policy. When the $CO_2$ price is zero coal power plants earn their maximum rent $R_1^{coal}$ this can be calculated by inserting Eq. (4) into Eq. (6):

$$R_1^{coal}=(I_{coal}-I_{gas})q_1^{coal} \tag{11}$$

Now we compare total producer rents (the sum of coal and gas plants), assuming realistically that coal plants are twice as capital intensive as gas plants ($I_{coal}=2I_{gas}$). Thus from Eqs. (10) and (11) it can be followed that the change in total producer rents (in €)

[8] The short-term screening curves coincide at a carbon price of 65 €/t $CO_2$, assuming fuel costs of 25 €/$MWh_{th}$ (gas) and 12 €/$MWh_{th}$ (coal), efficiencies of 48% (gas) and 39% (coal), carbon intensities of 0.24 t/$MWh_{th}$ (gas) and 0.32 t/$MWh_{th}$ (coal).

[9] This happens at about 80 €/t $CO_2$, with the same efficiency assumptions and investment costs of 100 €/kWa (gas).

[10] It is assumed that new gas power plants have the same costs and the same efficiencies as old ones.

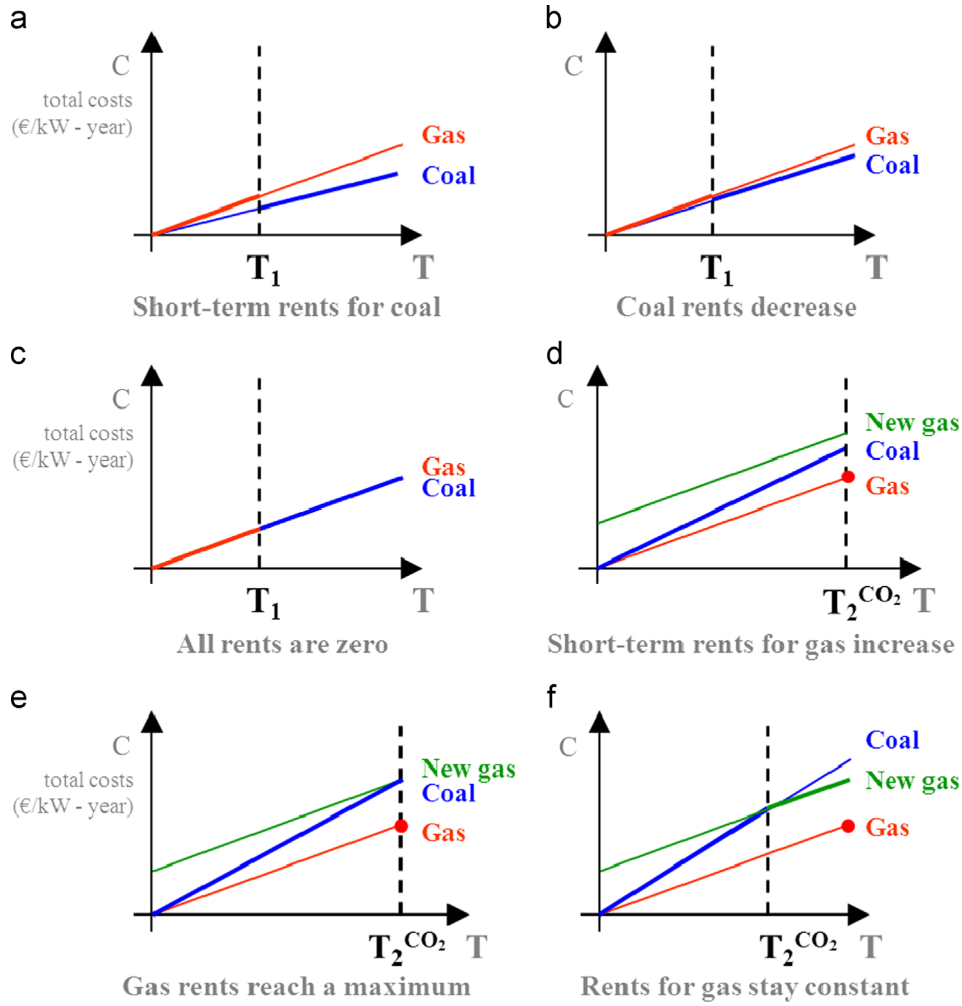


**Fig. 7.** Short-term screening curves for coal and gas power plants. The $CO_2$ price increases from figure a to f, and thus the short-term screening curves pivot further around their vertical intercepts. Six qualitatively different $CO_2$ price levels can be identified.

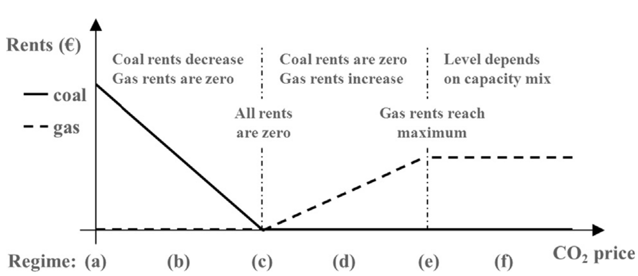


**Fig. 8.** Rents of gas and coal power plants change with increasing $CO_2$ price. Six regimes (a–f) can be distinguished. Coal rents decrease to zero, while gas rents increase to a maximum level. The gas rents in regime (e and f) could be above or below the coal rents in (a), depending on the initial capacity mix (see result derived below).

depends only on the initial capacity mix:

$$R_2^{gas} - R_1^{coal} = I_{gas}(q_1^{gas} - q_1^{coal}) \tag{12}$$

If there is more low-carbon gas than carbon-intensive coal capacity in the initial mix the total producer rents will increase with high $CO_2$ prices. This is a surprisingly simple condition and one of our main analytical model results.

To conclude, increasing the $CO_2$ price leads to redistribution flows between the two producers. The initial rents of coal power plants vanish. Rents of gas power plants occur after a certain threshold and increase up to a certain level that is determined by the rental capital costs of new gas plants. The resulting change of the total producer rents depends on the $CO_2$ price and the initial mix of existing capacity.

In this analytical model, it requires both very high $CO_2$ prices and more initial gas than coal capacity to increase total producer rents. If we add a low-carbon base load technology like nuclear power to the model, it can be shown that $CO_2$ pricing increases producer rents under a much wider set of parameters. While these results are not shown analytically due to space constraints, they are discussed in the following subsection.

### 5.2. Numerical results

Table 2 presents the changes in producer and consumer surplus caused by an exogenous increase of the carbon price from zero to 100 €/t as modeled in EMMA. A $CO_2$ price of 100 €/t has a similar system cost impact as supporting wind power to reach a market share of 30% and is in that sense a similarly “strong” policy intervention. The surprising result: despite full auctioning, overall short-term producer rents increase. This is one of our major numerical results.

Nuclear power, while not being affected on the cost side, gains from increased electricity prices and can more than double short-term profits. On the other hand, coal plants lose most of their short-term profits. Gas rents increase their initially low profits by

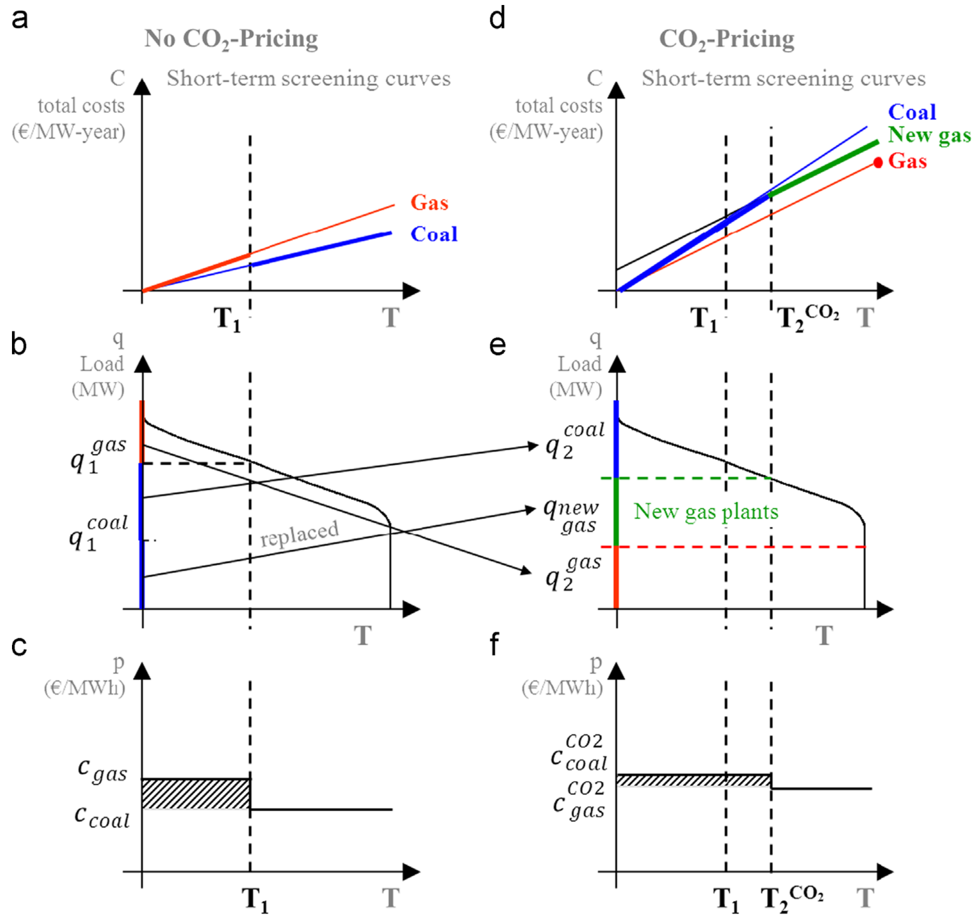


**Fig. 9.** Short-term screening curves, load duration curves, price duration curves without (left) and with $CO_2$ pricing (right). Coal rents disappear, while gas rents appear. New gas power plants are built.

**Table 2**
(a–c) Changes in short-term surplus of producers and consumers, and system costs changes when increasing the $CO_2$ price from zero to 100 €/t (€/MWh). Producers gain and consumers lose.

| **Incumbent producers** (€/MWh) | | **Consumers** (€/MWh) | | **System costs** (€/MWh) | |
|---|---|---|---|---|---|
| Nuclear rents | +21 | Electricity market | −43 | Increase in producer surplus | 12 |
| Coal rents | −10 | Heat market | −6 | Decrease in consumer surplus | 29 |
| Gas rents | +0 | AS market | −0 | | |
| | | Interconnectors | −0 | | |
| | | $CO_2$ taxes | +20 | | |
| | | Wind subsidies | / | | |
| Producer surplus | +12 | Consumer Surplus | −29 | Increase in system costs | 17 |

15%. If large-scale new nuclear investments would be possible in the short run, nuclear profits would be limited by new investments. The finding that overall producer rents increase is consistent with some previous studies, for example Martinez and Neuhoff (2005) and Chen et al. (2008).

Consumers have to pay 43 €/MWh more for electricity, and have to bear higher costs for district heating, ancillary services, and grids as well. On the other hand, they receive a lump-sum carbon revenues of 20 €/MWh. Overall, consumer surplus is reduced by 29 €/MWh. System costs increase by 17 €/MWh.

As in the case of wind support, the transfers between economic actors due to carbon pricing are large in size. The surplus redistributed from consumers to producers is larger than the efficiency effect of this policy. Short-term profits are 30 €/MWh prior to the policy shock, thus they are increased by about 40%. In contrast to wind support and as indicated by the analytical model, carbon pricing also leads to massive redistribution between different generation technologies, from carbon intensive to low-carbon generators. According to our estimates, nuclear power plants more than double their profits.

If emission allowances would be allocated freely to producers instead of being auctioned, this would increase producer rents by another 20 €/MWh. Thus the rents generated by increasing spot prices are of the same order of magnitude as the rents generated from entirely free allocation. This is surprising, since free allocation is widely discussed as a transfer mechanism, and the electricity market received much less attention in the public and academic debate.

Not only a carbon price of 100 €/t, but also lower price cause significant transfers. Fig. 10 displays the costs of electricity, suppliers' expenditures for $CO_2$, and short-term producer rents at carbon prices between zero and 100 €/t. The sum of these three components equals consumer expenditure for electricity. Short-term producer rents increase continuously, driven by increased nuclear profits. Recall that the effect of $CO_2$ pricing on total producer rents was found to be dependent on the initial capacity mix in Section 5.1. Empirically, the increasing rents of low-carbon producers overcompensate for decreasing rents of carbon-intensive generators, because of the significant amount of installed nuclear power in the long-term equilibrium derived in Section 3.3. In contrast to the effect of wind support consumer expenditures continuously increase even if revenues from the carbon market are transferred to the consumers.

In contrast to wind support, carbon pricing has very different effects across countries: because of large existing nuclear capacity in France, producer rents double when introducing a $CO_2$ price of 100 €/t. At the same time they remain constant in Germany, because of the large carbon-intensive incumbent lignite fleet. This dependency of the capital mix on the overall producer rents empirically confirms a qualitative result of the analytical model.

Fig. 11 compares the merit-order curve without a $CO_2$ price with that at 100 €/t. The change in the merit-order curve is the fundamental reason for income transfers from consumers to producers via higher electricity prices. At high carbon prices, lignite plants would have higher variable costs than hard coal and CCGTs, but due to economic reasons they are decommissioned. The underlying reason for nuclear to increase short-term profits is that carbon pricing drives up the gap between nuclear and fossil plants. As in Fig. 9f, the carbon price is high enough to incentivize new investments, in this case lignite CCS, CCGTs, and wind power.

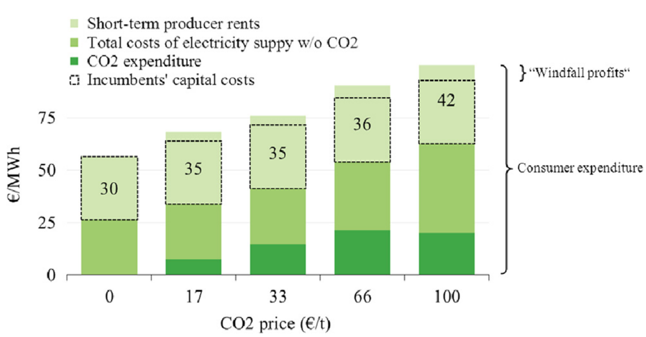


**Fig. 10.** Rents and costs at different $CO_2$ prices. Numbers label short-term producer rents (light green). The sum of the colored bars is consumer expenditure, but $CO_2$ expenditure of fossil plants (dark green) is recycled to consumers via lump-sum payments. Short-term rents increase with higher carbon prices over and above what is needed to recover capital costs ("windfall profits"). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

### 5.3. Findings and discussion

The findings from modeling short-term effects of carbon pricing analytically and numerically can be summarized as follows. Even without free allocation of emission permits, pricing carbon can increase the surplus of electricity producers. If that is the case or not, depends on the initial capacity mix prior to the policy shock. Specifically, if the infra-marginal capacity is mainly low-emitting, producers as a whole benefit and consumers lose (via increasing electricity prices). If the infra-marginal capacity is mainly carbon intensive, producers lose and consumers can benefit (via tax or auction revenues).

At realistic cost parameters and under the given European electricity mix, numerical model results show increasing overall producer rents at carbon prices of up to 100 €/t. Even at a moderate carbon price of 17 €/t, profits increase by almost 20% under full auctioning. Furthermore, this policy induces large transfers from carbon-intensive to low-carbon generators. The overall gain in producer surplus is large, in the same order of magnitude as the transfer due to free allocation of emission permits. Furthermore, the different initial capacity mixes in European countries lead to significant cross-border transfers, the largest flowing from coal-intensive Germany to nuclear-intensive France.

## 6. Policy mix

Comparing the two policy instruments with respect to their redistribution effect reveals a striking difference. While the system cost effect of each policy as well as the size of redistribution between consumers and producers is comparable in size, the directions of flows are opposite. $CO_2$ pricing transfers economic surplus from consumers to producers while wind support does the opposite. Moreover, $CO_2$ pricing leads to dramatic profit transfers from carbon-intensive to low-carbon producers, while wind support policies make all incumbent producers lose.

It is plausible to assume that policy makers try to avoid transferring surplus to conventional generators. Indeed, during the last years there have been fierce debates on "excessive returns" and "windfall profits" in the context of emission trading and renewables support schemes in several countries. On the other hand, reducing generators' short-term rents too much might leave them in a situation where they cannot pay back their sunk investments and go bankrupt, which might be undesirable from a policy maker's perspective as well. Given that $CO_2$ pricing increases producer rents and wind subsidies reduce them, a mix

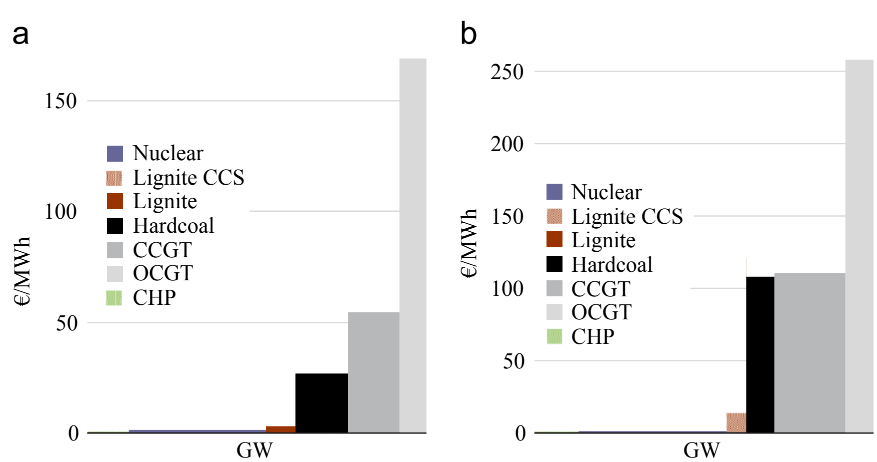


**Fig. 11.** (a) and (b) The merit-order curve of dispatchable plants without carbon pricing (left) and at 100 €/t $CO_2$. The $y$-axis shows bidding price that takes into account start-up costs.

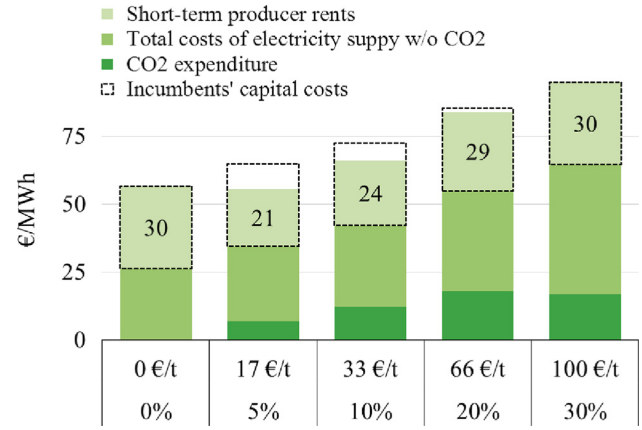


**Fig. 12.** Rents and costs with a mix of policies. The policy mix represents a path which leaves rents roughly unchanged.

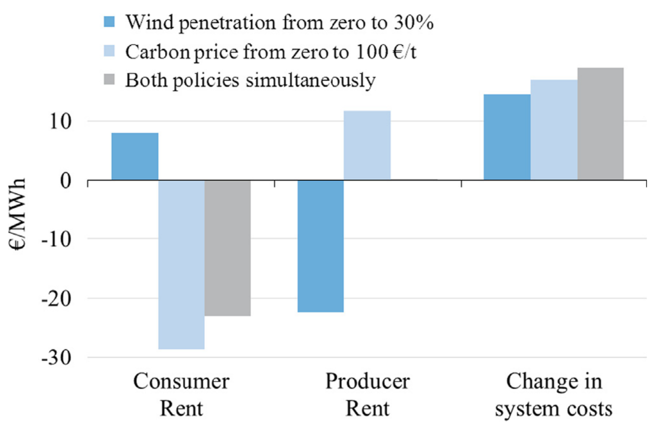


**Fig. 13.** Change in consumer rent, producer rent, and system costs due to wind support (30%), carbon pricing (100 €/t) and a combination of the two policies. A policy mix reduced the impact on profits virtually to zero.

of both instruments allows mitigating $CO_2$ emissions without changing conventional generators' rents too much. Figs. 12 and 13 display the compound effect of a mix of both policies. For example, introducing a $CO_2$ price of 100 €/t and a wind target of 30% simultaneously leaves conventional rents virtually unchanged.

## 7. Conclusion

This paper discusses wealth redistribution between producers and consumers caused by carbon pricing and renewable support via the electricity market. We have developed a framework to consistently evaluate both policies and have applied both a theoretical and an empirical model to it.

We find that redistribution flows are large relative to the system cost impact of these policies. The two policies induce diametrically opposed redistribution flows: renewable support transfers rents from consumers to producers, while $CO_2$ pricing does the opposite. In the case of renewables support, transfers are large enough to make consumers benefit from moderate levels of wind subsidies even if they pay for subsidies. Suppliers as a group benefit from carbon pricing, even if they pay for emission allowances, but there are large transfers from carbon intensive to low-carbon generators.

In the economic literature on power markets and electricity policy, energy and climate policies have the primary purpose of internalizing external effects. Distributional consequences are seldom the focus of academic research and usually only briefly discussed in the literature. In real world policy making, in contrast, redistribution effects are often hotly debated. Given the size of transfers, we find, this is not surprising.

Furthermore, our findings help explaining two stylized facts of energy policy: the attitude of certain actors towards specific policies, and the existence of a mix of policies in many countries. Our findings suggest that conventional generators should push for carbon pricing, while consumers should prefer renewable support. These attitudes can indeed be found in current European debates on energy policy.

It is often found that carbon pricing is the first-best climate policy. The existence of renewable support policies is often explained with other externalities like learning spill-overs. We offer an alternative interpretation of this policy mix: undesirable distributional consequences might prevent the implementation of carbon pricing alone and additionally require renewable support. Specifically, we show that combining carbon pricing with renewables support allows policy makers to keep producer rents unchanged. In general, understanding redistribution effects helps policy makers designing a policy mix that reduces implementation barriers.

Future research could expand the analysis in five directions: First, redistribution between jurisdictions is important for policy making. This could be analyzed specifically in the context of heterogeneous national policies. Second, the interaction of redistributive effects of renewables support and $CO_2$ pricing with existing and new policies merits attention. Third, we have not touched upon redistribution between different consumer groups and between producing firms (not only fuels), which certainly matters. Forth, we have ignored the efficiency impact of both policies in terms of internalization of externalities. Examining the potential trade-off between efficiency and redistribution would be interesting. Finally, our assumption on perfect power markets could be relaxed, and redistribution under market power analyzed.

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