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By **Lion Hirth**, Potsdam-Institute for Climate Impact Research, Vattenfall GmbH

Falko Ueckerdt, Potsdam-Institute for Climate Impact Research

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By Lion Hirth, Potsdam-Institute for Climate Impact Research, Vattenfall GmbH
Falko Ueckerdt, Potsdam-Institute for Climate Impact Research

Summary

Energy and climate policies are usually seen as measures to internalize externalities. However, as a side effect, these policies redistribute 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 real world policy debates. This paper compares the redistribution effects of two major electricity policies: support schemes for renewable energy sources, and CO2 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 leave consumers better off even if they bear the costs of subsidies. In the case of CO2 pricing, we find that while suppliers as a whole benefit even without free allocation of emission certificates, large amounts of producer surplus are redistributed between different types of producers. These findings are derived from an analytical model of electricity markets, and a calibrated numerical model of the Northwestern European integrated power system. Our findings imply that a society with a preference for avoiding large redistribution might prefer a mix of policies, even if CO2 pricing alone is the first best climate policy in terms of allocative efficiency.

Keywords: Carbon Tax, Emission Trading, Redistribution, Consumer Surplus, Producer Surplus, Wind Power Generation, Electricity Market Modelling

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Address for correspondence:

Lion Hirth
Potsdam-Institut für Klimafolgenforschung
Telegrafenberg 31
14473 Potsdam
Germany
Phone: +49 30 81824032
E-mail: lion.hirth@pik-potsdam.de

Redistribution Effects of Energy and Climate Policy: The Electricity Market

Lion Hirth*[#], Falko Ueckerdt*

* Potsdam-Institute for Climate Impact Research.
[#] Vattenfall GmbH.

Abstract – Energy and climate policies are usually seen as measures to internalize externalities. However, as a side effect, these policies redistribute 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 real world policy debates. This paper compares the redistribution 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 leave consumers better off even if they bear the costs of subsidies. In the case of CO_2 pricing, we find that while suppliers as a whole benefit even without free allocation of emission certificates, large amounts of producer surplus are redistributed between different types of producers. These findings are derived from an analytical model of electricity markets, and a calibrated numerical model of the Northwestern European integrated power system. Our findings imply that a society with a preference for avoiding large redistribution might prefer a mix of policies, even if CO_2 pricing alone is the first best climate policy in terms of allocative efficiency.

Index Terms – Carbon tax, Emission trading, Redistribution, Consumer surplus, Producer surplus, Wind power generation, Electricity market modeling

1. Introduction

Two major new policies were implemented in the European power sector during the last decade. Many countries have introduced support schemes for renewable electricity, such as feed-in-tariffs, certificate trading, or investment subsidies. As a consequence, the share of renewables in electricity generation has been growing rapidly, from 13% in 1997 to 17% in 2008. According to official targets, the share of renewables in EU electricity consumption shall reach 60-80% in 2050. The second major policy shift was the introduction of CO_2 pricing in the power sector via the EU emission trading scheme in

Lion Hirth, Potsdam-Institut für Klimafolgenforschung, Telegrafenberg 31, 14473 Potsdam, Germany. lion.hirth@pik-potsdam.de, +49(30)81824032.

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2005. During the last seven years, the 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 have and will continue to affect the profits of previously-existing 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 otherwise would not have been there. These additional generators decrease the wholesale electricity price below the level it would have been otherwise. For example, wind power reduces the price whenever it is windy by shifting the supply curve (merit-order curve) to the right. This reduces the income and thus the profits of existing generators. Consumer surplus increases due to lower electricity prices. 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 higher costs. 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.

In this paper, we model and quantify the redistribution effects of renewable support policies and CO_2 pricing. Following a dual methodological approach, we apply an analytical (theoretical) and a numerical (empirical) model. We distinguish two sectors: Conventional 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. 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 tariff, certificate trading, investment grants) and is in this sense quite general. We use wind power as an example for a subsidized renewable electricity source, but all findings apply to solar power and other zero marginal-cost technologies as well.

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 of 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 while increasing the profits of nuclear plants dramatically. Overall, electricity generators benefit from carbon pricing even without free allocation of emission permits.

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

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 combined effects of both policies. Section 7 concludes.

2. Literature Review

This paper aims at connecting two branches of literature that have discussed distributive effects of climate and energy policies from quite different angles. The first branch focuses on the depressing effect of renewables generation on the electricity price, which has been termed "merit-order effect" by Sensfuß (2007). The second branch discusses the impact of carbon pricing on consumer surplus and producer rents, sometimes labeled "windfall profits".

Modeling exercises for 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 (Munksgaard & Morthorst 2008) are less conclusive. Under emission trading, wind support additionally decrease electricity prices via its lowering influence on the CO_2 price (Rathmann 2007). 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 & Denny (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 (2012) stresses the effect on producer profits and the "missing money" to finance capital costs from short-term profits. Wissen & Nicolosi (2008) and MacCormack et al. (2010) emphasize that the merit-order effect is only a short-term or "transient" phenomenon, since any long-term equilibrium requires capital costs to be recovered. While some of these papers acknowledge that economic surplus is redistributed from producers to consumers, 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, the 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 & Neuhoff 2005) and for North-West 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.

Our work contributes to the literature in three ways. First, while many of the existing publications touch upon on a wide range of topics, we focus on redistribution effects. Specifically, we estimate effects at different levels of policy intervention, and we comprehensively account for redistributive flows between all actors such that they consistently add up to zero. Second, the existing literature discusses either renewables deployment policies *or* CO_2 pricing. To the best of our knowledge, this paper is the first to analyze redistribution effects of both types of policies within one consistent framework. This newly developed framework uses the long-term equilibrium as a benchmark to evaluate both policies. Finally, 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.

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 redistribution effects induced by climate and energy policy. The numerical model quantifies redistribution flows for North-Western 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 displace 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 lifetimes 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" approach). 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 is given while in the short term there is a stock of sunk investments. While profits are zero in the LTE, they are typically positive in the short-term equilibrium (STE). 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 cost. In other words, in the STE previously-existing (incumbent) generators are able to extract rents from their sunk investments. These rents 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

[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 labelled 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.

believe the short term as defined here is an appropriate assumption to analyze moderate shocks to European power systems on a time horizons of 3 to 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 (Figure 1). We assume that the power market is in its LTE before policies are introduced. Then we switch the 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 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 then compared. 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.

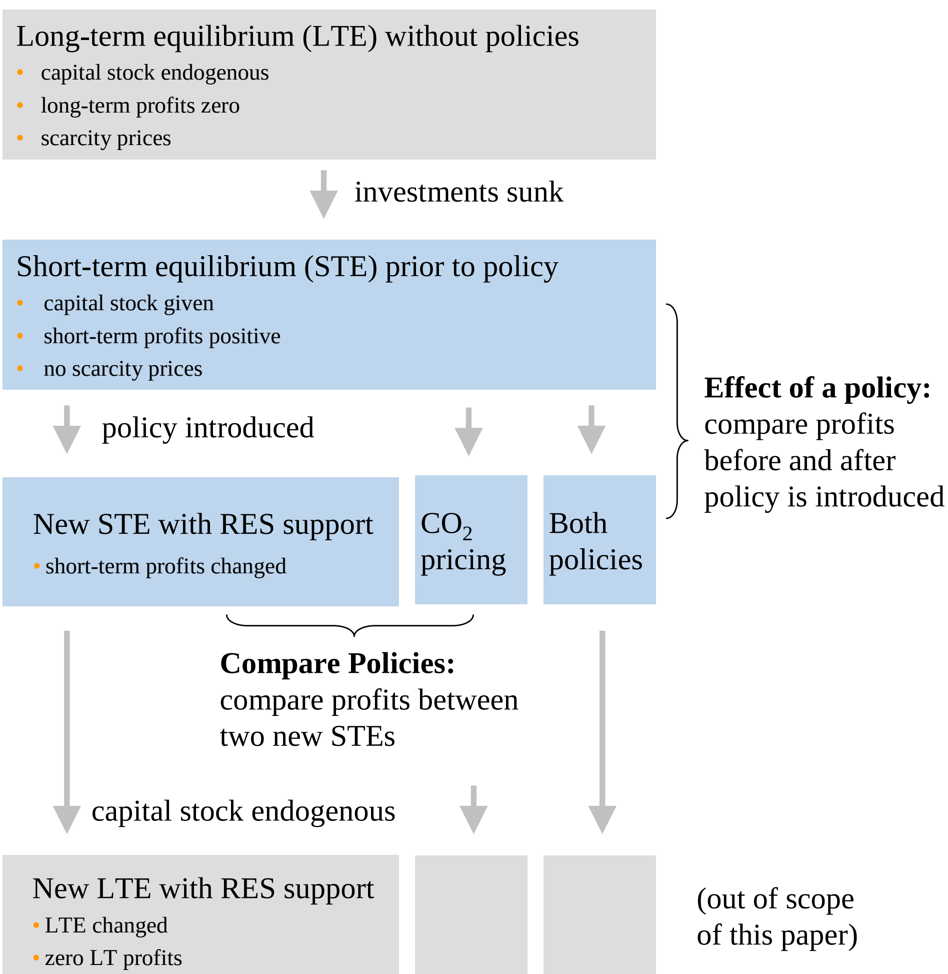

Figure 1: This framework allows to consistently studying different policies with an analytical and a numerical model. Starting from a long-term equilibrium with no policy, two short-term equilibriums (STE) are compared: the STE prior to policy with a STE with a newly introduced policy.

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 framework is to our knowledge a novel approach. An alternative to our short term / long term dichotomy is to model the system's adaptation to shocks dynamically in several steps (Nicolosi 2012, Färber et al. 2012, Short et al. 2011, Prognos AG et al. 2010). However, such scenario analysis typically features a multitude of dynamic shocks that makes it very hard to identify the effect of a specific policy. Moreover, 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.

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.

To develop a qualitative understanding of the major effects of these policies it is sufficient to model two generation technologies, labeled "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). In both models a perfect market is assumed where producers act fully competitive and with perfect foresight on complete markets. Hence, the cost-minimizing solution is equivalent to the market equilibrium. Electricity demand is perfectly price-inelastic and deterministic. All fees and taxes are assumed to be specific and remain constant. Externalities are assumed to be absent. We model energy-only markets with marginal pricing.

We extend a classical method from power economics (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 (Figure 2a, b, 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.

[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.

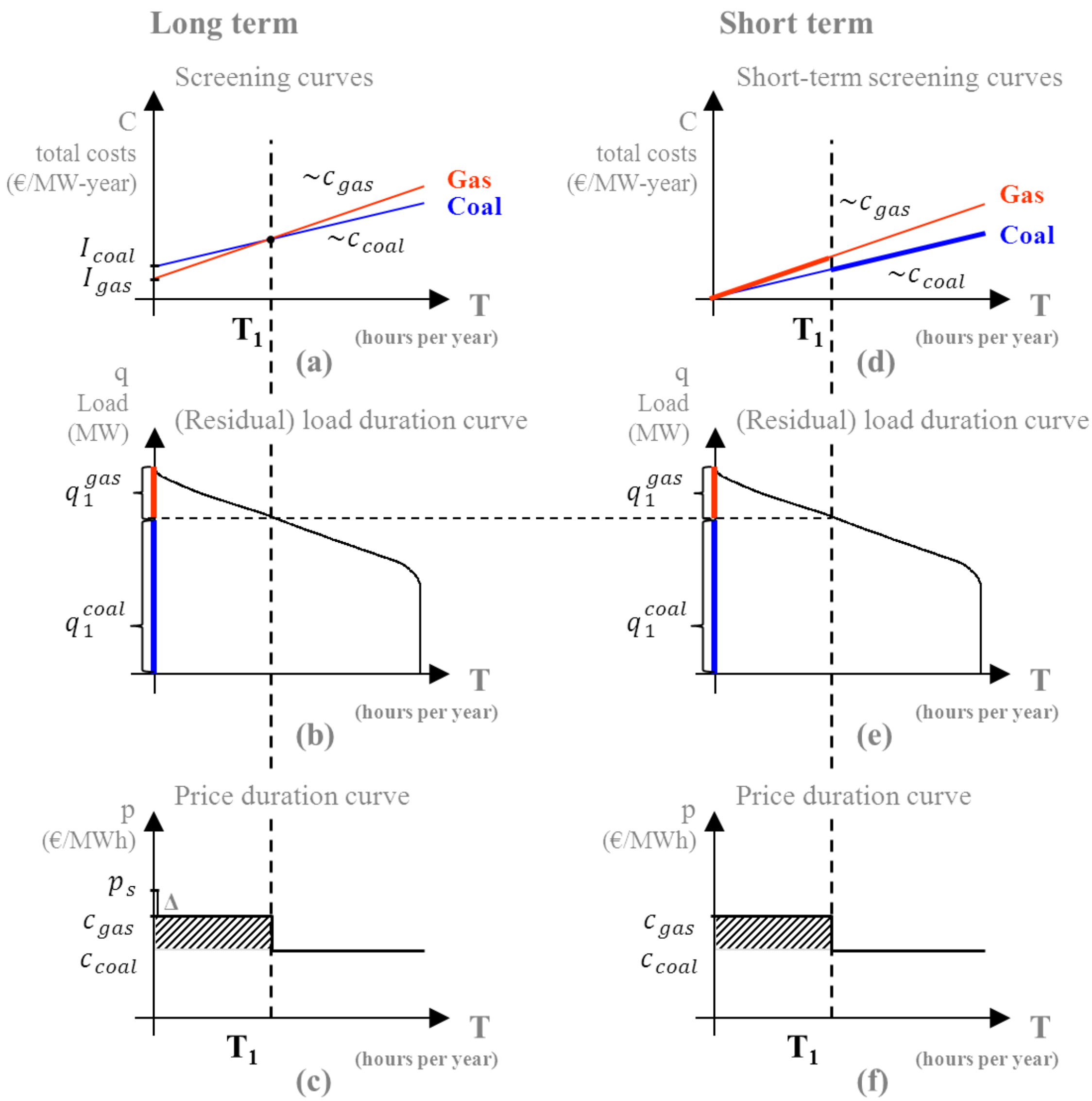

Figure 2: Long-term equilibrium (left) and short-term equilibrium (right) described by screening curves (a,d), load duration curve (b,e), and price duration curve (c,f). In the short term, screening curves do not contain investment costs and the price duration curve does not contain scarcity prices p_s.

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 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 with higher capacity costs and lower variable costs 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 (Figure 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.

$$p_s = c_{gas} + \Delta \tag{1}$$
$$\Delta = I_{gas} \tag{2}$$

The markup Δ on specific (per MWh) variable costs c_{gas} can only be chosen to exactly cover the investment specific (per MW) costs 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 Figure 2a it holds:

$$c_{coal}T_1 + I_{coal} = c_{gas}T_1 + I_{gas} \tag{3}$$
$$\Leftrightarrow \qquad I_{coal} = (c_{gas} - c_{coal})T_1 + I_{gas} \tag{4}$$
$$\overset{(2)}{\Rightarrow} \qquad I_{coal} = (c_{gas} - c_{coal})T_1 + \Delta \tag{5}$$

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 (Figure 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 of the width of the shaded area in Figure 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 in the STE, as defined in section 3.1, they are positive. 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 (Figure 2d). Coal is the least-cost technology at all full load hour values. However, it cannot cover the total load, because its capacity is constrained. The optimal dispatch does not change compared to the long-term equilibrium. Total capacity is not scarce and thus there is no scarcity price (Figure 2f). 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 Figure 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, a calibrated numerical model of the North-Western European electricity market 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 costs. These features are discussed briefly in the following paragraphs and in more detail in (Hirth 2012).

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. An energy-only market is modeled. 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 in the STE.

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 the model. 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 North-Western 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 (Figure 3).

Long-term equilibriums of power markets have been estimated numerically by Lamont (2008), Bushnell (2010), and Green & Vasilakos (2011), but these authors do not discuss the short term nor distribution issues.

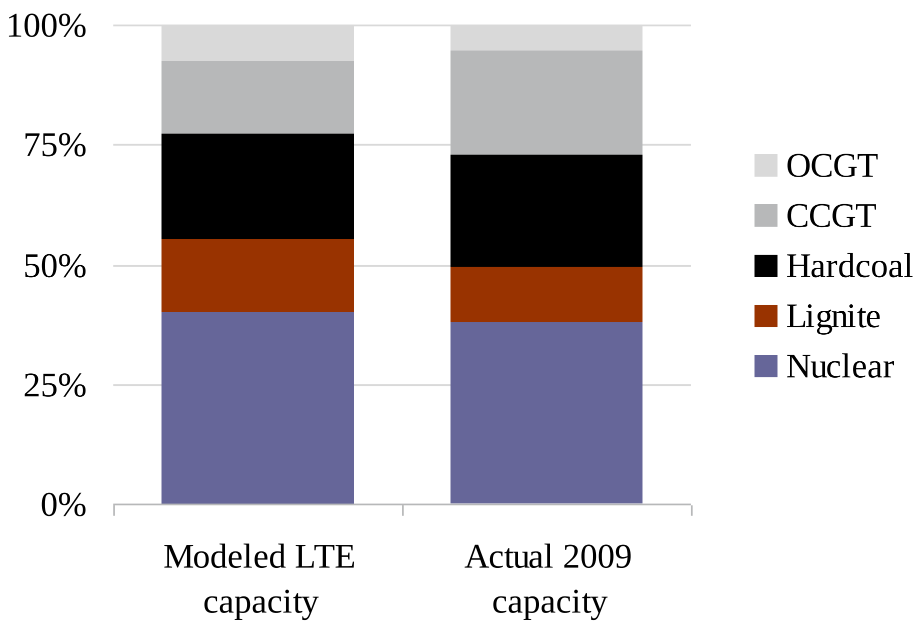

Figure 3: Model long-term equilibrium dispatchable capacity mix versus historical capacity mix in 2009 for the model region. The modeled LTE capacity mix, which is used as a starting point for policy analysis, resembles quite closely to the observed data. Wind power is too expensive to be built.

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.

4.1. Analytical Results

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. With inelastic demand the reduction of producer rents equals 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.

Figure 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 Figure 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 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 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. This is because gas power plants 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 checkered area in Figure 4f shows the loss of the specific (per MW) rent of coal capacity: $(c_{gas} - c_{coal})(T_1 - T_2)$. The absolute decrease of R_1^{coal} is given by the coal capacity q_1^{coal} times the specific loss.

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

Only the last factor depends on the deployment of renewable capacity: The shift of the PDC to lower prices mainly drives redistribution due to renewable support.

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

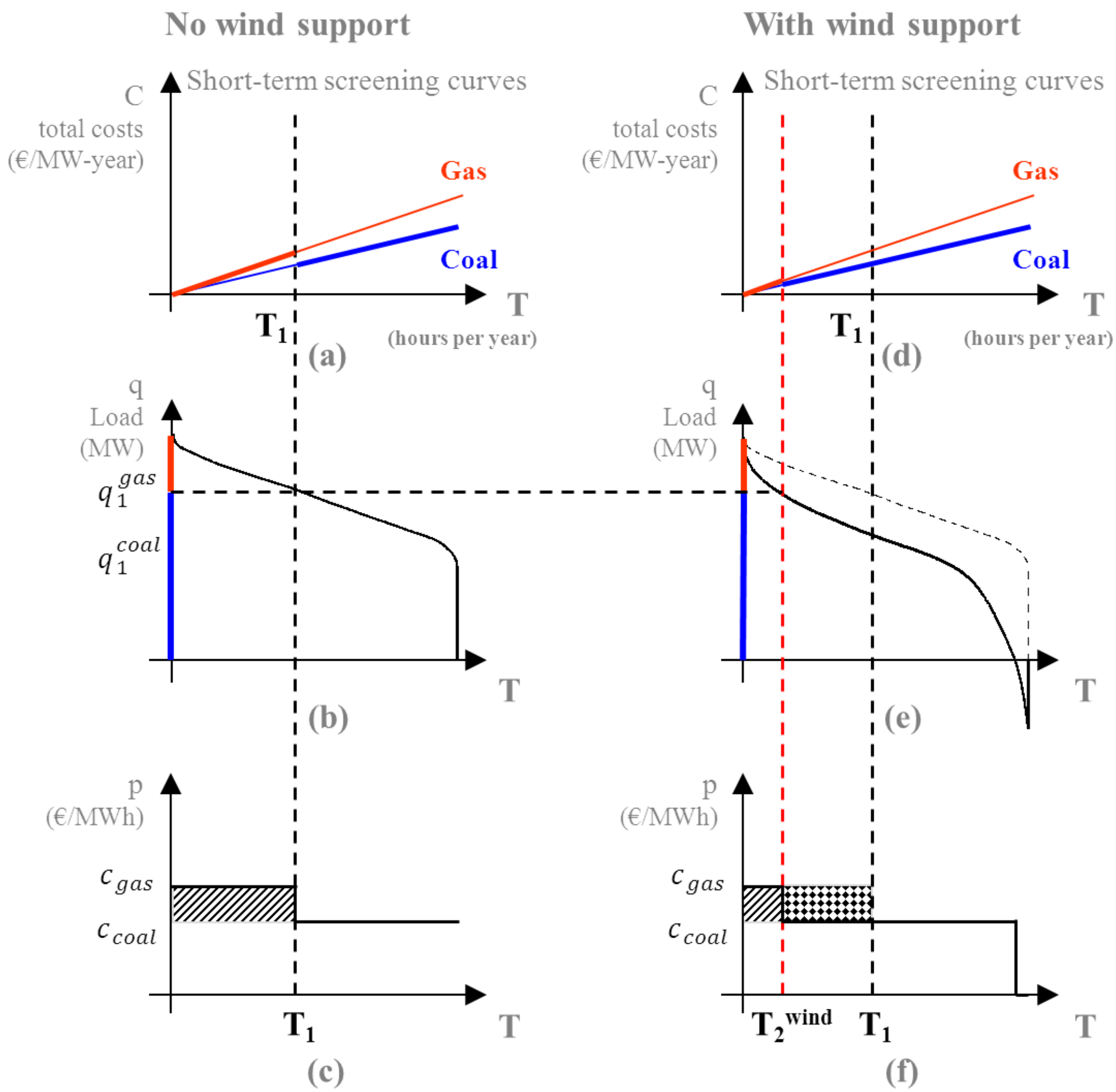

Figure 4: Short-term screening curves, load duration curves, price duration curves without (left) and with wind support (right). Wind changes the residual load duration curve (b, e). Producer rents decrease with wind support (checkered area equals the reduction of specific coal rents).

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, the numerical model introduced in section 3.3 is used to derive additional details and quantifications in three directions. Firstly, redistribution flows are quantified and are 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 zero 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 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 (de Miera et al. 2008, (Sensfuß et al. 2008), O'Mahoney & Denny 2011 and Gil et al. 2012).

Welfare is reduced by 15 €/MWh (Table 1c). This is the net economic cost of wind power. Note that external effects such as the costs of carbon or knowledge spillovers are not accounted for in this model. The welfare effect is merely the distortive effect of policy on the electricity market.

Incumbent Producers (€/MWh)	
Nuclear Rents	- 13
Coal Rents	- 9
Gas Rents	- 1
Producer Surplus	- 22

Consumers (€/MWh)	
Electricity market	+ 28
Heat market	- 2
AS market	- 0.1
Interconnectors	- 0.2
CO_2 taxes	/
Wind subsidies	- 18
Consumer Surplus	+ 7

Welfare (€/MWh)	
Consumers	- 22
Producers	+ 7
Welfare	-15

Table 1a-c: Changes in short-term surplus of producers and consumers, and welfare 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.

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

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

this policy. Short-term profits are 25 €/MWh prior to the policy shock, thus they are reduced by almost 90%. Total long-term costs of electricity are 78 €/MWh, thus the loss in producer surplus is about 28% of total revenues of the industry.

Figure 5 displays the costs of electricity supply and short-term producer rents at wind penetration rates between zero 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% consumer benefit the most. However, decreasing short-term producer rents are not sufficient to cover fixed costs ("missing money"), as indicated by the dotted box. 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.

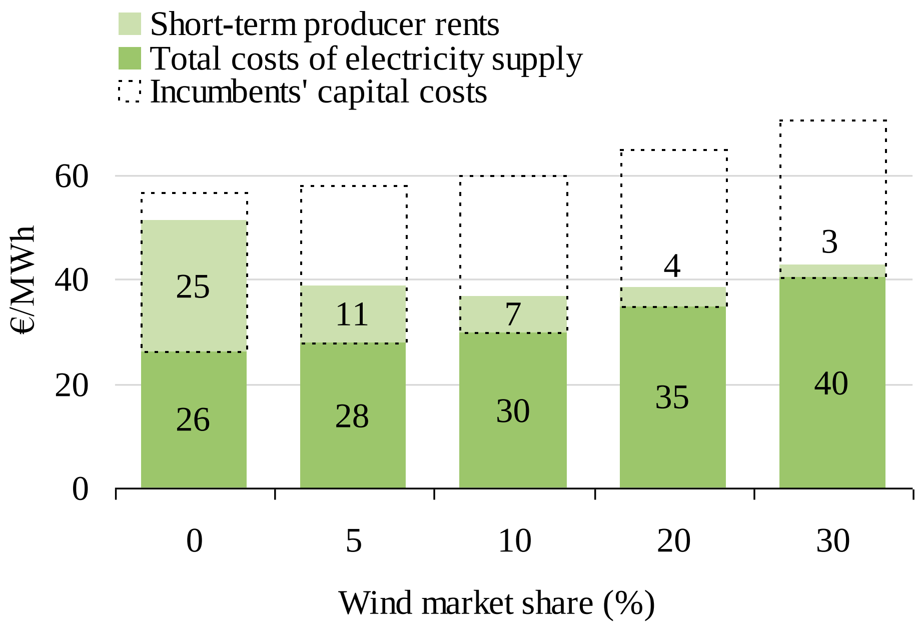

Figure 5: Rents and costs at different wind penetration rates. The sum of the colored bars is consumer expenditure. With increasing wind penetration, producer rents are transferred to consumers. At 10% wind market share, short-term consumer surplus is maximal.

Figure 6 shows how the price-setting technology shifts when adding more wind capacity to the system. This is the mechanism how producer rents are transferred 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.

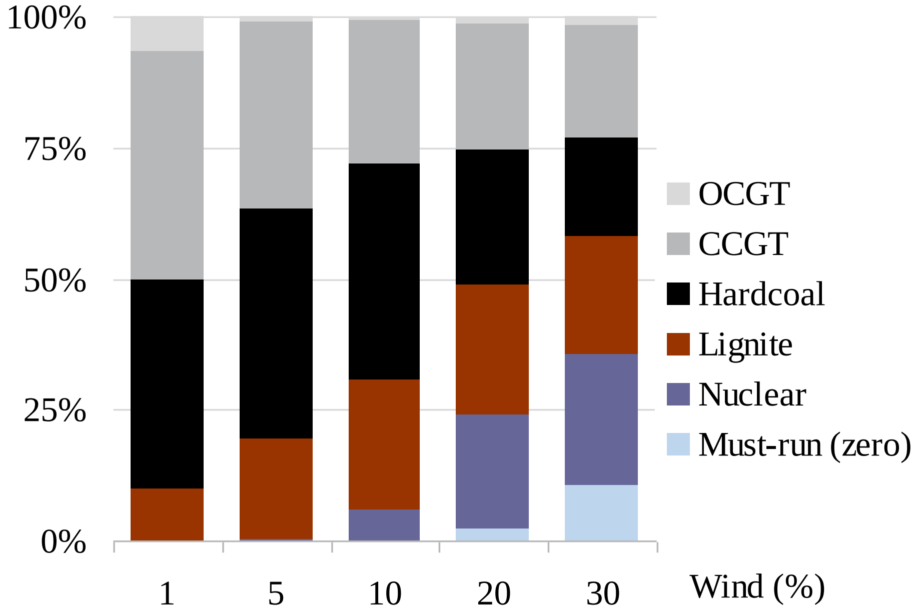

Figure 6: Share of hours in which different technologies are price setting. With higher wind penetration, the share of base load technologies increases. At 20% wind and above, prices drop to zero, when must-run constraints become binding.

4.3. Findings

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 welfare 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 potentially the costs of subsidies are larger than redistributed producer rents.

5. CO_2 Pricing

This section presents analytical and numerical model results of the redistribution effects of carbon pricing. The price of CO_2 could be implemented via a price or a quantity instrument, both classes of policies are equivalent in the present models. It is assumed that neither emission rights are allocated freely to emitters nor there is any other direct transfer to generators.

5.1. Analytical Results

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. With inelastic demand the increase of producer rents equals losses in consumer surplus, and vice versa. In addition, 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 and depends mainly on the generation mix prior to the policy shock and the size of the shock.

Figure 7 shows short-term screening curves for different CO_2 prices. Figure 7a displays a price of zero and is identical to Figure 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 (a-f).

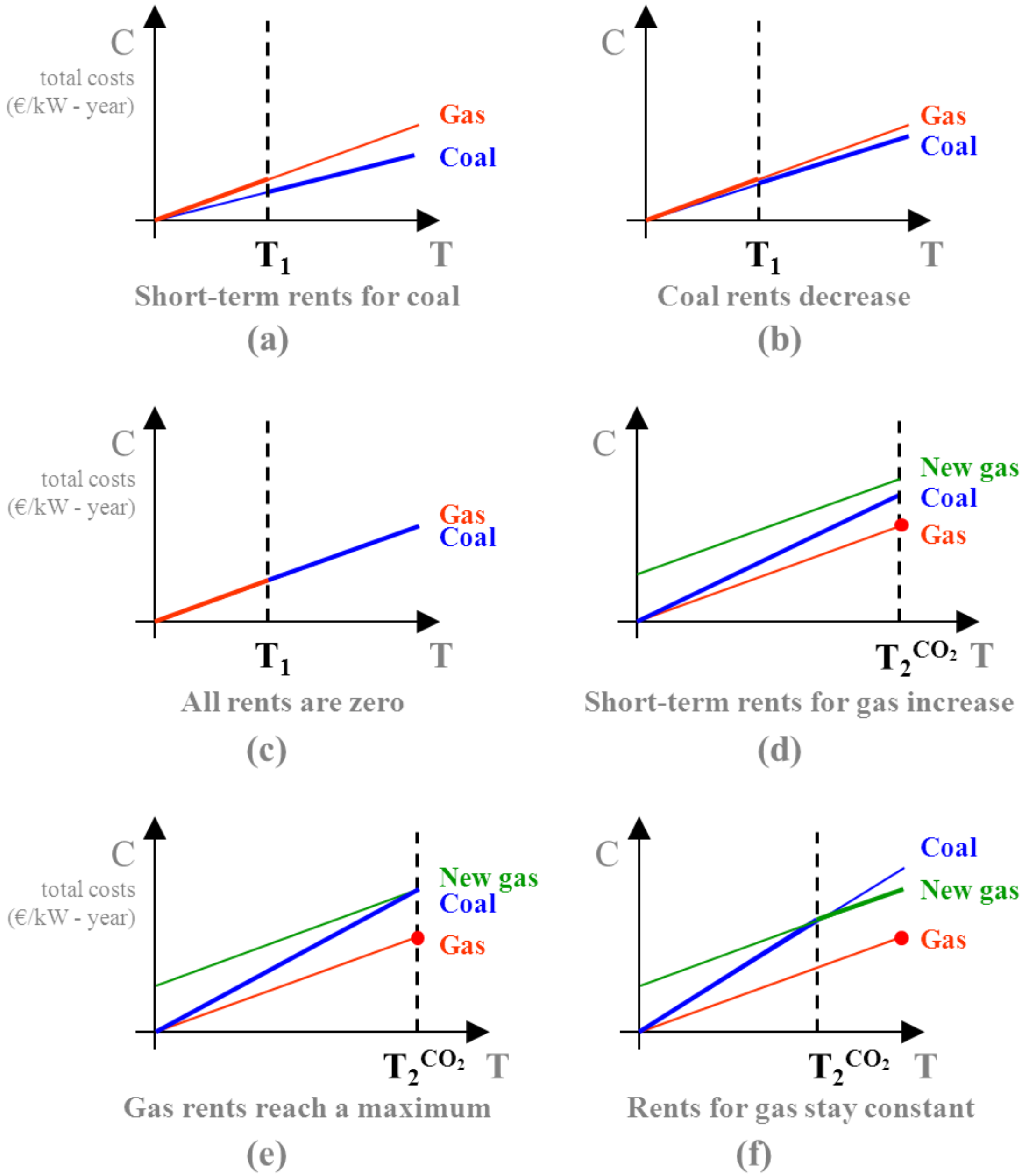

Figure 7: Short-term screening curves for coal and gas power plants. The CO_2 price increases from Figure a to f, and thus the short-term screening curves pivot further around their vertical intercepts. Six qualitatively different CO_2 price levels can be identified.

(a) Without CO_2 pricing costs and rents are $(c_{gas} - c_{coal})T_1 q_1^{coal}$ 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 Figure 9.

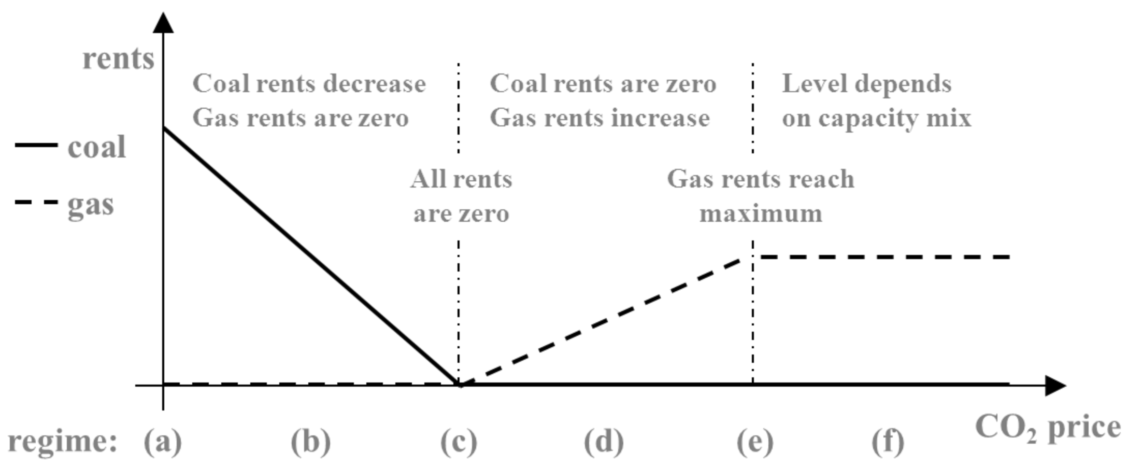

Figure 8: Rents of gas and coal power plants change with increasing CO_2 price. Six regimes (a-f) can be distinguished. Coal rents decrease to zero, while gas rents increase to a maximum level. The gas rents in regime (e) and (f) could be above or below the coal rents in (a), depending on the initial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

Figure 8 summarizes the development of short-term rents 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 show later this section.

In detail we discuss regime (f) because it includes a multitude of relevant policy-induced effects. Figure 9 compares the short-term equilibrium of the electricity market prior (left)

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[8] The short-term screening curves coincide at a carbon price of 65 €/t CO_2, assuming variable 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.

and after (right) the introduction of a carbon price. The short-term screening curves in Figure 9 (a, d) change according to the development illustrated in Figure 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 (Figure 9e). Coal rents vanish, while incumbent gas plants generate profits when coal is price-setting (Figure 9f).

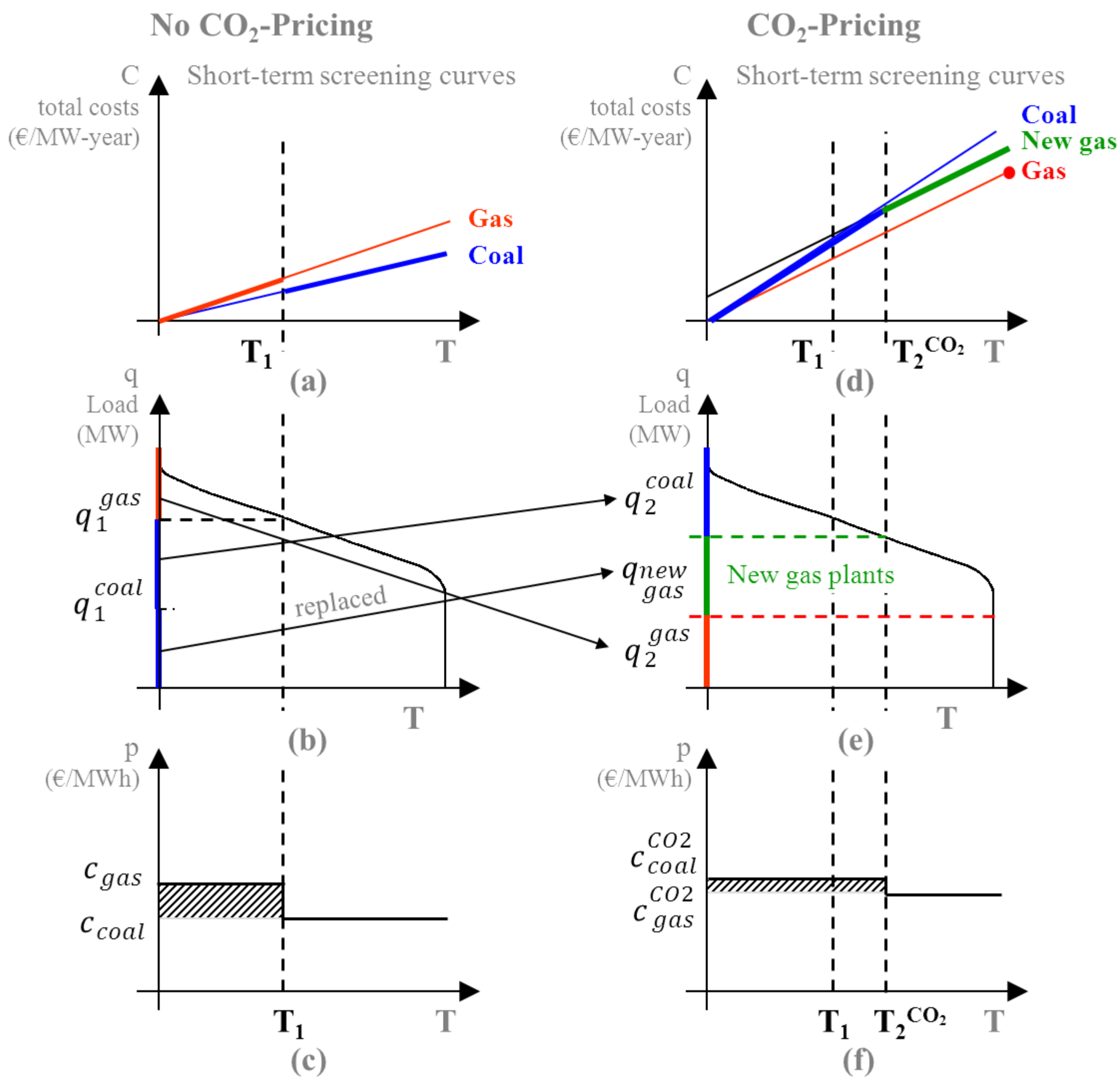

Figure 9: Short-term screening curves, load duration curves, price duration curves without (left) and with CO_2 pricing (right). Coal rents disappear, while gas rents appear. New gas power plants are built.

Moreover investments in new gas power plants are profitable because screening curves of new gas power plants and existing coal power plants intersect (Figure 9d). All coal power plants that would otherwise 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 indicated by the shaded area (Figure 9f): $(c_{coal}^{CO2} - c_{gas}^{CO2})T_2$. The absolute rents of old gas are derived by multiplying with the old gas capacity:

$$R_2^{gas} = (c_{coal}^{CO2} - c_{gas}^{CO2})T_2 q_1^{gas} \tag{8}$$

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

$$c_{coal}^{CO2} T_2 = c_{gas}^{CO2} T_2 + I_{gas} \tag{9}$$

Thus T_2 is the "break-even point" in term of FLH. For utilization higher than T_2 it is profitable to build new gas capacity. Because the zero-profit condition needs to hold for new investments, this can be substituted into equation 8 and it follows:

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

One MW of existing gas capacity receives short term rents that are exactly equal to the costs of constructing new capacity. Thus the sunk nature of capital can be understood as entrance barrier that allows investors to generate profits. Total gas rents R_2^{gas} depend only on the fixed costs of gas investments and on their initial capacity. With higher CO_2 prices the cost gap $(c_{coal}^{CO2} - c_{gas}^{CO2})$ increases in proportion to the decrease of T_2, since (9) has always to hold. Analogously the short-term income of new gas power plants are $R_{\substack{new\\gas}} = I_{gas} q_{\substack{new\\gas}}$ and hence exactly cover their investment costs so that they earn zero profits. That condition needs to holds for all new investments.

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 equation 4 into equation 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 equations 10 and 11 it can be followed that the change in producer rents depends only on the initial capacity mix:

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

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 high 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 maximum level. 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 very high CO_2 prices and more initial gas capacity 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. A CO_2 price of 100 €/t has a similar welfare 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. 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 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 & 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 transfer of 20 €/MWh of revenues from the carbon market. Overall, consumer surplus is reduced by 29 €/MWh. Summing up consumer and producer surplus gives a distortive welfare-reducing effect of 17 €/MWh on the electricity market. Again, this calculation ignores efficiency gains from internalizing carbon externalities.

Incumbent Producers (€/MWh)	
Nuclear Rents	+ 21
Coal Rents	- 10
Gas Rents	+ 0
Producer Surplus	+ 12

Consumers (€/MWh)	
Electricity market	- 43
Heat market	- 6
AS market	- 0
Interconnectors	- 0
CO_2 taxes	+20
Wind subsidies	/
Consumer Surplus	- 29

Welfare (€/MWh)	
Consumers	- 29
Producers	+ 12
Welfare	-17

Table 2a-c: Changes in short-term surplus of producers and consumers, and welfare changes when increasing the CO2 price from zero to 100 €/t (€/MWh). Producers gain and consumers lose.

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 25 €/MWh prior to the policy shock, thus they are increased by about 50%. 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 in spot prices are of the same order of magnitude as the rents generated from entirely free allocation, while having received much less attention in the public and academic debate.

Figure 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. Carbon-intensive coal power plants continuously lose surplus. 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.

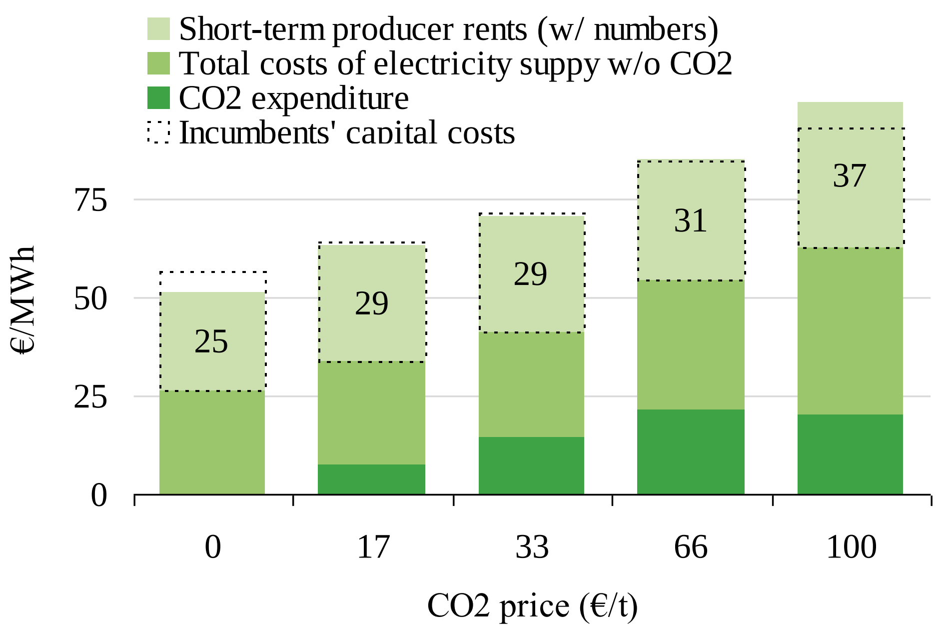

Figure 10: Rents and costs at different CO_2 prices. The sum of the colored bars is consumer expenditure, but CO_2 expenditure of fossil plants (dark green) is recycled to consumers via lump-sum payments. Short-term rents increase with higher carbon prices ("windfall profits"). Rents increase over and above the level that is needed to recover capital costs.

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.

Figure 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 Figure 9f, the carbon price is high enough to incentivize new investments, in this case lignite CCS, CCGTs, and wind power.

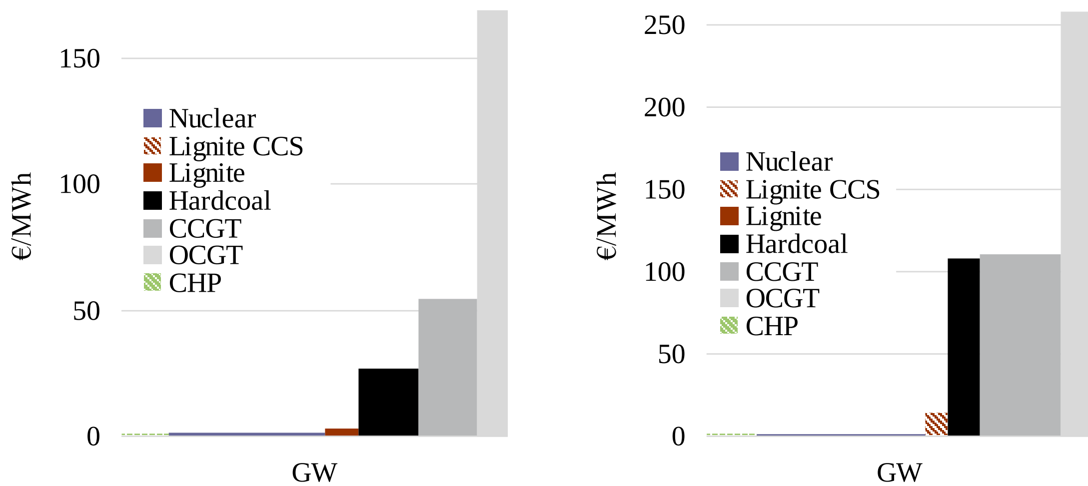

Figure 11a-b: The merit-order curve without carbon pricing (left) and at 100 €/t CO_2. The y-axis shows bidding price that takes into account start-up costs. Only dispatchable plants are shown and capacity is weighted with average availability.

5.3. Findings

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, surplus of electricity producers can increase. If that is the case 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. If the infra-marginal capacity is mainly carbon intensive, producers lose and consumers 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. 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 striking difference. While the welfare 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 producers lose.

It is plausible to assume that policy makers try to avoid transferring surplus to conventional generators.[11] On the other hand, reducing generators' short-term rents too much might leave them in a situation where they can't 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 of both instruments allows mitigating CO_2 emissions without changing conventional generators' rents too much. For example, introducing a CO_2 price of 100 €/t *and* a wind target of 30% simultaneously leaves conventional rents virtually unchanged (Figure 12, Figure 13).

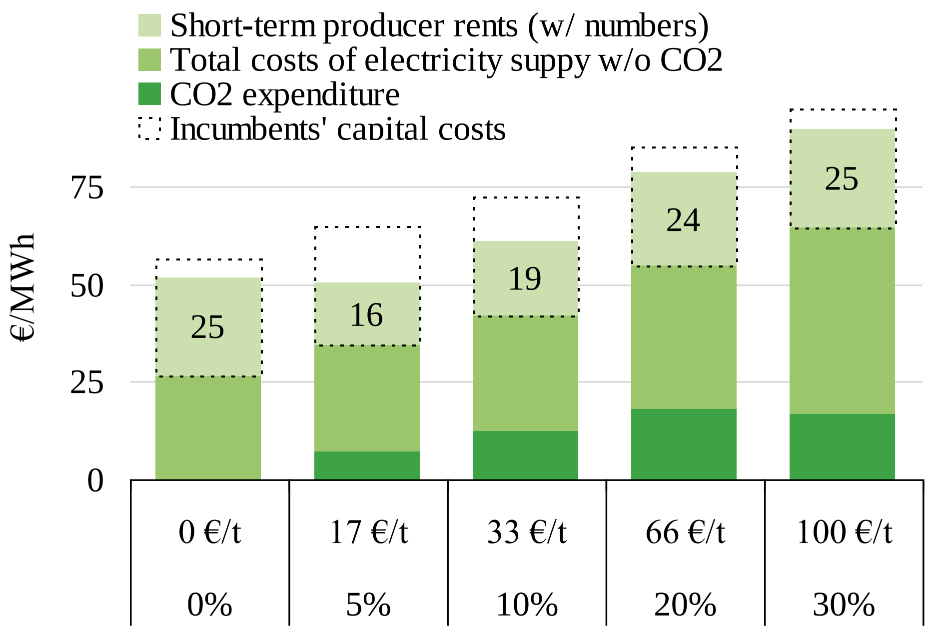

Figure 12: Rents and costs with a mix of policies. The policy mix represents a path which leaves rents roughly unchanged.

[11] 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 European countries.

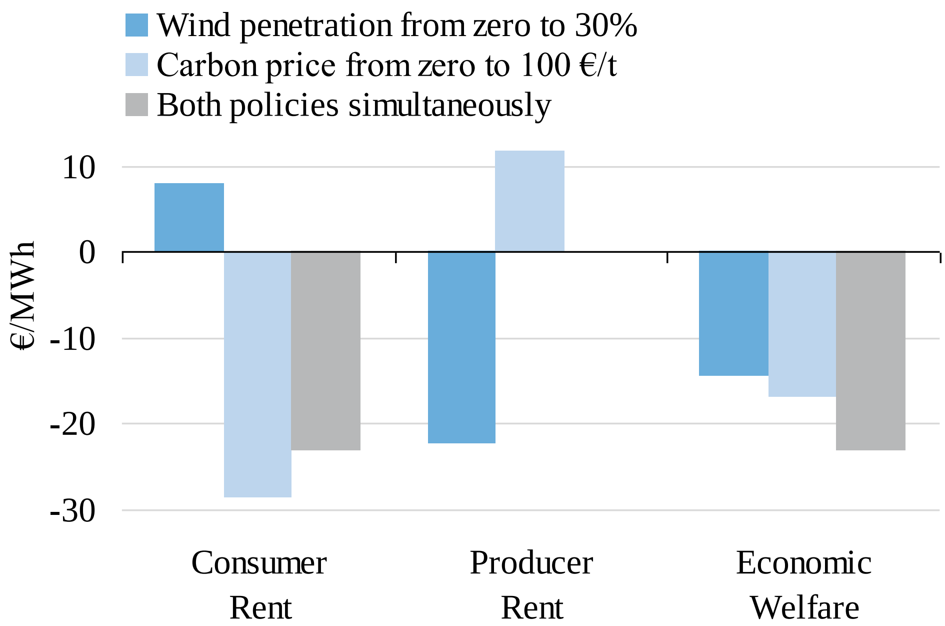

Figure 13: Change in consumer rent, producer rent, and welfare due to wind support (30%), carbon pricing (100 €/t) and a combination of the two policies. A policy mix reduced the impact on profits virtually to zero.

7. Conclusion

This paper discusses redistribution effects of carbon pricing and renewable support on short-term producer and consumer rents in the electricity market. Results have been derived from an analytical model and a numerical model that are applied in a framework that allows isolating the redistributive effects of policies.

We find that redistribution flows are large relative to the welfare 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 the costs of subsidies. Suppliers as a group benefit from carbon pricing, even if they pay the costs of 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.

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