Redistribution Effects of Energy and Climate Policy

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Abstract-- **While usually designed for a different purpose, energy and climate policies also redistribute wealth between producers, consumers, and the government. This paper compares the redistribution effects of CO_2 pricing and renewable deployment support schemes. An analytical model is developed to show that rents exist and change due to these policies. Qualitative findings are then quantified using a numerical model of the European electricity market. While CO_2 pricing increases the rents of low-carbon conventional generators and decreases those of carbon-intensive producers, wind deployment reduces rents of all generators. Redistribution is often large relative to welfare effects. These findings imply that a society with a preference for avoiding large redistribution might prefer a mix of policies, as opposed to the classical finding that CO_2 pricing alone is the first best climate policy.**

Index Terms-- **Carbon tax, Environmental economics, Power generation economics, Profitability, Rents, Redistribution, Wind power generation, Optimization, Electricity market, Welfare**

I. Introduction

Textbook neoclassical microeconomics implies that in the long-term economic equilibrium, assuming perfect markets, producers do not earn profits (rents). While in the long term the capital stock is an endogenous variable, in the short term investments are sunk and an exogenous parameter. In the short term, producers can earn positive or negative profits and these profits change if economic parameters are shifted e.g. due to changes in policy. For three reasons electricity markets are an interesting application of this observation: First, because electricity is virtually non-storable and demand is variable, the long-term equilibrium features a set of different technologies that differ in their fixed-to-variable-cost ratio and in their dispatch ("peak-load" and "base-load" generators). Second, power plant life-times of 20-60 years and construction periods of up to a decade imply that the short term can be a quite extended period. Finally, during the last decade European electricity markets were subject to two major policy changes that shifted economic parameters significantly. This paper models the effect of these policies on producer profits, consumer rents, and government revenues analytically and provides empirical quantitative estimates.

Several European countries experienced a rapid expansion of renewable electricity generation driven by deployment subsidies. According to governmental targets, the share of renewables in EU electricity consumption is supposed to reach 35% by 2020, up from 17% in 2008.[2] Most of this expansion was and will be driven by wind power. During windy periods residual demand and thus the electricity price is reduced, reducing the income of conventional generators. Consumers, in contrast, benefit from lower electricity prices, while government net income is reduced due to the costs of wind subsidies, if costs are not passed on to consumers.

The second major policy shift was the introduction of CO_2 pricing in the power sector via the EU emission trading scheme in 2005. CO_2 pricing increases the electricity price if the price-setting plant is emitting, which is virtually always the case. Low-carbon plants like nuclear power benefit from higher prices while not being affected by CO_2 costs. Carbon-intensive generators like lignite, in contrast, see their rents reduced because costs increase more than revenues. Consumer surplus is reduced due to higher electricity prices, and government income is increased by CO_2 revenues (if permits are auctioned, which we assume).

This paper provides both a theoretical and an empirical analysis of these redistribution effects. Three actors are distinguished: Conventional generators with sunk investments, consumers, and the government. Generators are distinguished by technology, since the effect of CO_2 pricing on carbon-intensive and low-carbon generators is very different. Disaggregating consumers could yield important insights, but is beyond the scope of this paper. The methodology can be applied 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.

Section II reviews the literature. In section III, an analytical model of two generation technologies (coal and gas) is developed and applied to show that in the long-term equilibrium all producers earn zero profits and that the corresponding capacity mix maximizes welfare. It is shown that if conventional investments are sunk, introducing wind power to the system

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[2] National 2020 targets are set in the as expressed in the National Renewable Energy Action Plans. Reviews are provided by Beurskens & Hekkenberg (2011), ENTSO-E (2011), PointCarbon (2011) and ENDS (2010). 2008 data from Eurostat, www.appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_ind_333a.

strictly reduces profits. In a second application, the effects of CO_2 pricing are modeled. It is shown that increasing the CO_2 price reduces the rent of the carbon-intensive base load technology coal, but increases the profits of gas once a certain CO_2 price is reached. The sum of rents of conventional generators increases or decreases, depending on the CO_2 price and the capacity mix, which itself is determined by investment and fuel costs.

In section IV, we outline a calibrated numerical model of the North-Western European electricity market with more technologies. In section V this model is used to quantify the redistribution effects of different levels of policy intervention. It is estimated that increasing the share of wind power in total consumption from zero to 30% reduces the rents of conventional generators by around € 30bn per year, or 40% of industry turnover. Increasing the CO_2 price from zero to 100 €/t increases their rents by € 20bn per year – even without free allocation of emission allowances. In contrast, wind support increases consumer surplus by € 30bn and carbon pricing decreases it by € 60bn. Wind support increases government expenditures while CO_2 pricing increases government income. Even if the costs of wind support are passed on to electricity consumers, they benefit from wind deployment schemes by extracting producer surplus. Both policies interventions are similarly strong in the sense that they both reduce welfare by about € 20bn.[3] These redistribution effects are large, both compared to total industry turnover and relative to the welfare effect of these policies.

II. Literature Review

This paper brings together two branches of literature that have discussed redistribution effects of climate and energy policies from quite different angles. The first branch focuses on the decrease of spot market prices due to renewable electricity generation. This so-called merit-order effect leads to savings for the consumer by reducing generator profits (Sensfuss 2007). For Germany (Sensfuss et al. 2008) and Spain (de Miera et al. 2008) this reduction was estimated to be higher than the costs for renewable support paid by the consumers. For Denmark (Munksgaard & Morthorst 2008) it was calculated that the decrease of electricity prices did not fully compensate consumers for their renewable support expenditures. Under emission trading, renewable support schemes additionally decrease electricity prices through their lowering influence on the CO_2 price (Rathmann 2007).

The second branch of literature deals with the redistribution effect of CO_2 pricing. Depending on different allocation rules for emissions allowances it is analyzed how producer profits change and to what extend 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, e.g. (Bode 2006), (Sijm et al. 2006). In addition some authors find that the aggregated power generation sector might benefit even if allowances are fully auctioned. This is shown for the UK (Martinez & Neuhoff 2005) and for North-West Europe (Y. H. Chen et al. 2008). For the US it was found that 9% of all allowances would need to be grandfathered to preserve total producer profits when introducing CO_2 certificates (Burtraw et al. 2002).

Our work adds to the literature in three ways. First, while many of the existing publications touch upon on a range of topics, we focus on redistribution effects, specifically the evolution of effects at different levels of policy intervention. We comprehensively account for redistribution 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 policies in a consistent framework. Specifically, the long-term equilibrium before the introduction of either one of the two policies is used as a benchmark. 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.

III. Theoretical Model

A two technology model of the power market is used to show that profits are zero in the long-term equilibrium, while in the short run, producers are able to extract rents from their sunk investment. Moreover we analyze the effect of CO_2 pricing and wind support on these short-term rents.

We extend a method from (Green 2005) that uses screening curves (Fig. 1(a)) and a load duration curve (LDC) (Fig. 1(b)) to derive optimal capacities and generation of the long-term equilibrium. A screening curve represents the total costs per kW-year of one generation technology (e.g. gas power plant) 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. Optimal capacities can be derived by projecting the intercepts of the screening curves on the LDC. The LDC can be horizontally divided. Each part of load is then covered by the respective least cost capacity from the screening curves. Hereby the dispatch of plants is also determined and a price duration curve[4] can easily be derived (Fig. 1(c)).

An advantage of this framework is that both policies can be consistently modeled: Wind support reshapes the LDC, while CO_2 pricing pivots the screening curves.

For illustrative reasons the model only uses two generation technologies. Gas power plants tend to operate during mid and peak load periods due to their low fixed-to-variable-cost ratio. Coal power plants with higher capacity costs and lower varia-

[3] Welfare losses are measured as the distortive effects on electricity markets only and ignoring external effects such as the social costs of carbon or knowledge spillovers. This paper does not provide a welfare analysis of policies, but the distortive effects on markets is used as a yardstick to put the size of redistribution flows into perspective.

[4] A price duration curve shows the sorted hourly prices of one year starting with the highest price.

ble costs cover base load. The producers act fully competitive and with perfect foresight. Electricity demand is perfectly price-inelastic and deterministic. Dynamic aspects, like ramping constraints or electricity storage, are neglected as well as international trade and grid constraints. Externalities are assumed to be absent. We model energy only markets with marginal pricing.

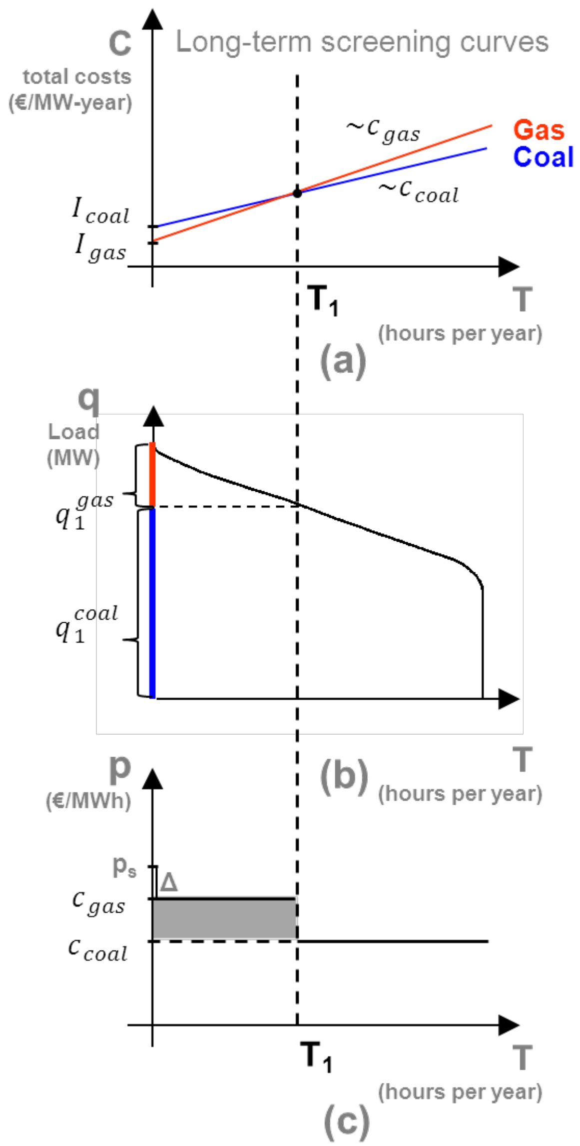

FIG. 1: LONG-TERM SCREENING CURVES (A), LOAD DURATION CURVE (B), PRICE DURATION CURVE (C). THE LONG-TERM OPTIMAL CAPACITY MIX IS DERIVED.

A. Long-term vs. short-term equilibrium

We now show that all plants generate zero profits within the cost-minimizing capacity mix and that this is the unique long-term equilibrium. At the end of this section we introduce the concept of a short-term equilibrium, in which profits can occur, to analyze the impact of policy instruments.

Operating gas power plants are always price-setting (Fig. 1(c)). They cannot cover their investment costs by setting the price only at their variable costs. Without loss of generality we assume that a gas power plant demands a scarcity price p_s in exactly one hour of the year.

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

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

The markup Δ on variable costs c_{gas} can only be chosen to exactly cover the investment 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 within the optimal capacity mix the scarcity price leads to zero profits also for coal power plants. The screening curves in Fig. 1(a) intersect at T_1:

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

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

With equation (2) it follows:

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

The right hand side of the equation equals the annual income of one unit of coal capacity in the optimal capacity mix as shown in the price duration curve (Fig. 2(c)). Hence, this exactly covers the specific investment costs of coal capacity. We have shown that one scarcity price leads to zero profits for both, gas and coal power plants within the optimal capacity mix. We now argue that this characterizes the unique long-term equilibrium. Let us assume the system's capacities deviate from their optimal values. For instance, substituting gas by coal capacity would imply an increase of the width of the grey area in Fig. 2(c). This means an increase of the annual income of coal power plants and profits would occur. However market entry of coal capacity would be incentivized until profits vanish in the long term. If on the other hand there would be too much coal power then investment costs could not be covered. Coal capacities would be decommissioned in the long-term until optimal capacities are reached and revenues equal costs. 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.

It is assumed that the system is in its long-term equilibrium before policy instruments are introduced. Wind support schemes incentivize wind power that converts the LDC into a residual load duration curve (RLDC[5]). CO_2 pricing leaves the LDC unchanged while the screening curves shift due to increasing variable costs. When introducing a policy instrument the system is displaced from its equilibrium. Before it diffuses into a new long-term equilibrium, producers can earn rents. Within this transition a short-term equilibrium can be calculated. For this purpose it is assumed that investment costs for existing plants are sunk and thus short-term screening curves only contain variable costs[6] (Fig. 2(a)). Price duration curves

[5] The RLDC shows the sorted hourly residual load curve of one year starting with the highest value.

[6] Quasi-fix costs are neglected in the theoretical model.

do not contain scarcity prices anymore. New investments as well as decommissioning of plants are possible.

B. Wind Support

Within this section the impact of wind support on producer rents is derived. Fig. 2 shows the short-term equilibrium of conventional producers without (left side) and with (right side) wind power. With no wind power the full load hours do not change compared to the long-term equilibrium. T_1 still marks the maximum full load hours of gas power plants. These plants are used for peak load and do not earn any rents, since they are always setting the price during their operating hours. Coal power plants, in contrast, generate short-term rents that in the long run would contribute to cover their investments. The grey area in Fig. 2(c) shows the specific rent per MW of coal capacity. It needs to be multiplied by coal capacity q_1^{coal} to calculate the absolute rent R_1^{coal}.

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

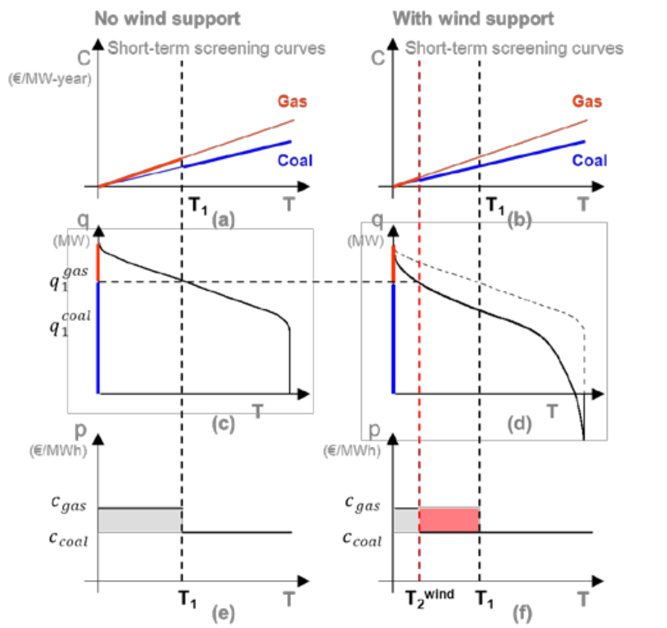

FIG. 2: SCREENING CURVES (A, B), LOAD DURATION CURVES (C, D), PRICE DURATION CURVES (E, F) WITHOUT (LEFT) AND WITH WIND SUPPORT (RIGHT). CONSUMER RENTS DECREASE WITH WIND SUPPORT (RED AREA).

With more wind power the RLDC width decreases and hence the full load hours of all dispatchable plants are reduced. Thus, wind reduces the number of hours where gas is price-setting (Fig. 2(f)). The rent R_2^{coal} decreases proportional to this shift $(T_1 - T_2)$.

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

The red area in Fig. 2(f) shows the loss of the specific rent of coal capacity. To sum up, the conventional rents continuously decrease with growing share of wind power.

With inelastic demand the reduction of producer rents equals gains in consumer surplus. We assume that the government carries the costs to trigger wind investments, thus its expenditures increase with higher share of wind.

C. CO_2 pricing

The effect of CO_2 pricing on producer rents is more complex. The variable costs of emitting technologies increase and thus the short-term screening curves pivot around their vertical intercepts (Fig. 3). Even in this stylized model six phases can be identified while the CO_2 price gradually increases.

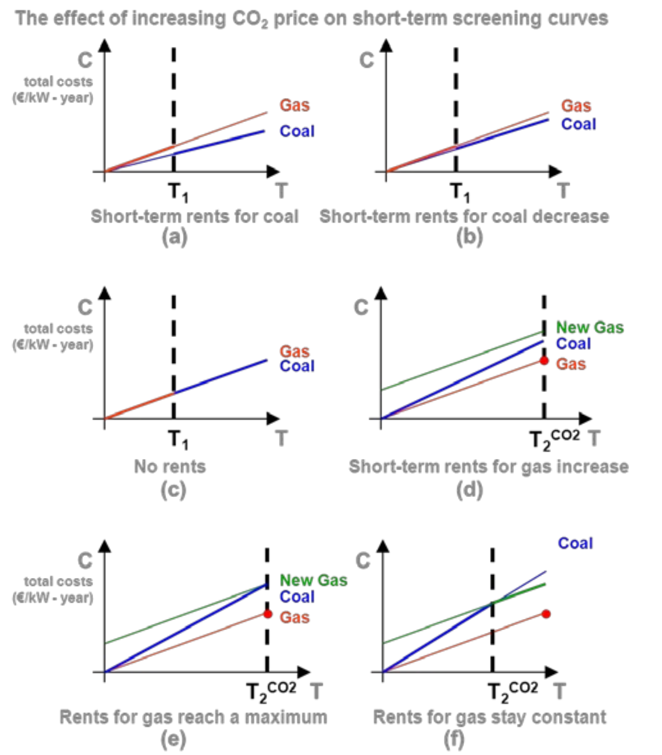

FIG. 3: SHORT-TERM SCREENING CURVES FOR COAL AND GAS POWER PLANTS. THE CO_2 PRICE INCREASES FROM FIG. (A) TO (F).

(a) Without CO_2 pricing rents are generated by coal power plants when gas power plants are price-setting (Fig. 3(a)) as discussed in section III A (Fig. 2(a), (c), (e)).

(b) With increasing CO_2 price the screening curve of coal power pivots faster than the screening curve of gas power (Fig. 3(b)). The difference of variable costs decreases, thus the coal rents decrease. The dispatch remains unchanged.

(c) The two screening curves coincide (Fig. 3(c)) at an increased CO_2 price of about 65€/t CO_2[7]. No rents occur because variable costs of coal and gas power plants are equal.

(d) With further increase the screening curve of coal power rotates above the screening curve of gas power (Fig. 3(d)). Now the dispatch changes: Gas power plants now have least variable costs and cover base load. Coal power plants only cover the remaining base, mid and peak load. They do not generate rents. In contrast gas power plants generate rents when coal power plants are price-setting.

(e) At a threshold of about 80€/t CO_2 the screening curve of coal touches the screening curve of new gas power plants even though the latter also contains investment costs (Fig. 3(e)). The rents of gas power plants reach a maximum.

[7] 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) and investment costs of 100€/kWa (gas).

(f) The right-hand screening curve part of coal pivots above the screening curve of new gas power plants. Up to this point increasing the CO_2 price has only affected electricity prices or the dispatch of existing plants. Now, new investments in gas power plants[8] lead to decommissioning of existing coal capacity. Old gas power plants are the only plants that generate rents. These rents remain at their maximum value. This phase is illustrated in detail in Fig. 4 and is further analyzed within this section.

To conclude, increasing the CO_2 price leads to redistributions of rents between the two producers. The initial rents of coal power plants vanish. Rents for gas power plants occur and increase. First only the dispatch of coal power plants is reduced, then coal capacity is even displaced by new gas power plants.

We now compare the short-term producer rents without CO_2 price (phase (a)) and with high CO_2 price (phase (f)). Investments in new gas power plants are incentivized when the screening curves of new gas power plants and existing coal power plants intersect (Fig. 4(b)).

$$c_{coal}^{CO2} T_2 = c_{gas}^{CO2} T_2 + I_{gas} \quad (8)$$

The threshold CO_2 price (80€/t CO_2) that leads to decommissioning of coal power plants follows from inserting $T_2 = 8760h$ into that condition. The corresponding maximum rent R_2^{gas} of existing gas power plants is:

$$R_2^{gas} = (c_{coal}^{CO2} - c_{gas}^{CO2}) T_2 q_1^{gas}. \quad (9)$$

This corresponds to the product of gas capacity and the specific rent shaded grey in Fig. 4(f). The capacity of old gas power plants remains unchanged $q_1^{gas} = q_2^{gas}$. With equation (8) it follows gas rents depend on their initial capacity:

$$R_2^{gas} = I_{gas} q_1^{gas}. \quad (10)$$

Analogously the short-term profits 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 holds for all new investments.

When the CO_2 price is zero coal power plants earn their maximum rent R_1, that can be calculated by inserting (4) into (6).

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

To compare the change of short-term rents we assume $I_{coal} = 2 I_{gas}$. The shift of rents only depends on the initial long-term capacity mix:

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

[8] It is assumed that new gas power plants have the same cost structure as old ones.

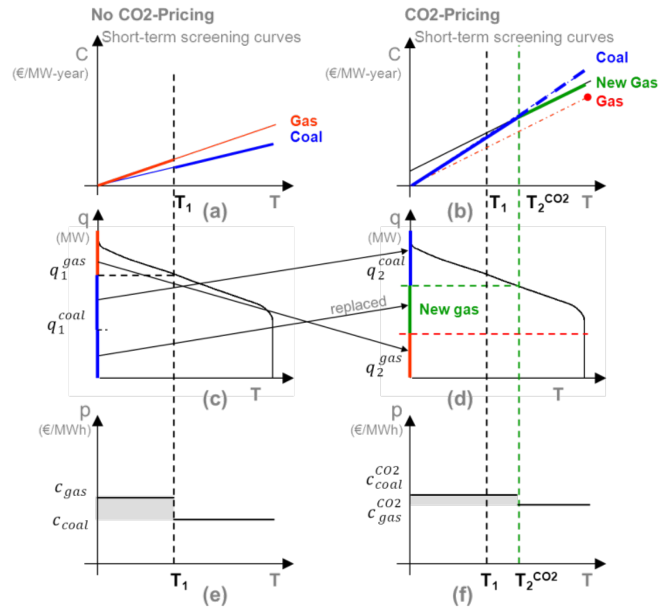

FIG. 4: SCREENING CURVES (A, B), LOAD DURATION CURVES (C, D), PRICE DURATION CURVES (E, F) WITHOUT (LEFT) AND WITH CO_2 PRICING (RIGHT). WITH CO_2 PRICING PROFITS OF COAL POWER PLANTS VANISH WHILE GAS POWER PLANTS GENERATE RENTS (F).

If there is more low-carbon gas than carbon-intensive coal capacity in the initial mix the total producer rents will increase with high CO2 prices. If we add a low-carbon base load technology like nuclear the total rents would be more likely to increase already at low CO2 prices. This effect is empirically shown in section V.C.

IV. EMPIRICAL MODEL

While the analytical two-technology model from section III. provides crucial insights in the mechanics of policy-induced redistribution, it is too stylized to provide quantifications. To derive quantitative estimates of rents and redistribution effects of energy policy a stylized numerical model of the European electricity market was developed. The model minimizes total costs with respect to investment, production and trade decisions under a large set of technical constraints and thus can be used to model the long-term equilibrium as well as the short term. It is linear, deterministic, and solved at hourly resolution for a full year. Assuming perfect competition, cost minimization is equivalent to profit-maximization of decentralized agents. The following paragraphs discussion crucial model features. Further details and a formal representation can be found in (Hirth 2011).

Generation is modeled as seven discrete technologies with continuous capacity: a fluctuating renewable source with zero marginal costs (wind), five thermal technologies with economic dispatch (nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT)), and pump hydro storage. Wind output is determined by exogenous generation profiles. Dispatchable plants produce when the price is above variable costs. Storage is optimized endogenously under turbine, pumping, and storage volume constraints. An energy-only market is modeled. The electricity price is the shadow price of demand, which is the marginal cost of increasing demand. This guarantees that the prices in the long-run are consistent with the zero-profit condition for generators. Curtailment is possible at zero costs, which implies that the electricity price does not become negative. Unlike in section III, quasi-fixed costs such as personal is taken into account.

Demand is given exogenous by hour and thus assumed to be perfectly price inelastic. Hourly demand as well as wind and solar generation factors are derived from real data of the same year. This ensures that crucial correlations across space, over time, and between parameters are captured. For this paper, 2010 data are used.

Combined heat and power (CHP) generation is modeled as must-run generation by fuel. That means that a certain share of the heat-providers lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of that technology is freely available for optimization. The heat profile is based on ambient temperature.

There is no physical representation of the grid and no load flow modeling. Bidding areas are assumed as today and are modeled as copperplates. Cross-border trade is endogenous and limited by net transfer capacities (NTCs). Endogenous investment in interconnector capacity is possible and done if capacity and generation cost reductions exceed annualized investment costs for interconnectors.

The model is linear and does not feature any explicit integer constraints such as start-up cost, minimum load or minimum downtime conditions. Thus, it is not a unit commitment model. However, start-up costs are parameterized as run-through discounts to achieve a more realistic bidding behavior. Ancillary services such as regulating power are not explicitly modeled. However, it is attempted to proxy their effects on dispatch and investment: there is a spinning reserve requirement such that during every hour conventional capacity equivalent to 20% of the yearly peak demand has to be online. The shadow prices for the spinning reserve constraint and the CHP constraints allow to report not only spot market prices, but prices for these markets as well.

The model is calibrated to North-Western Europe and covers Germany, Belgium, Poland, The Netherlands, and France with a total consumption of 1,400 TWh annually. It is written in GAMS and solved by Cplex. With one million equations and four million non-zeros, solving time is about half an hour per run with endogenous investment and a few minutes without investment. The model has been back-tested with historical data and has proven to be able both to replicate the existing capacity mix as well as dispatch decisions and prices in a satisfactory manner.

V. Empirical Results

The numerical model is now used to estimate redistribution effects of wind targets and CO_2 pricing. As in section III, first the long-term equilibrium is derived and then policies are evaluated in a short-term framework. While long-term equilibrium have been estimated in calibrated models (*(Lamont 2008)*, *(Bushnell 2010)*, *(Green & Vasilakos 2011)*), using the resulting capacity mix to evaluate policies is to our knowledge a novel approach.

A. Long-term vs. short-term equilibrium

Assuming that the electricity market was in long-term equilibrium before introduction of those policies, a long-term equilibrium capacity mix is estimated. As shown in III.B for two fuels, all generators just earn their capital costs back and rents are absent also in the case of more technologies. Costs and technical parameters are consistent with empirical data, and were chosen such that today's capacity mix is roughly replicated (Fig. 5).

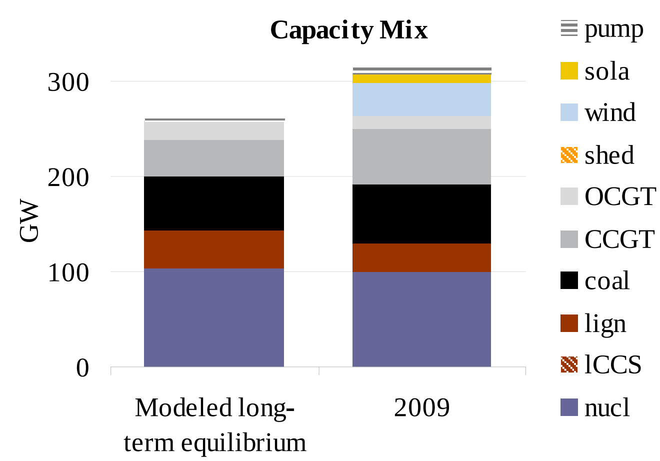

Fig 5. Model long-term equilibrium capacity mix vs. historical capacity mix in 2009. The reality is replicated fairly well.

Then the short-term impact of policies was modeled by taking the long-term capacity as given while changing policy parameters. The short term can be interpreted as the transition period after a change of policy parameters, but before capacity have adjusted and the new long-term equilibrium is reached. Additional investments as well as decommissioning of plants are possible, but capital costs for existing plants are sunk. Nuclear investments are not possible due to their long implementation time. As in section III, the effects of wind deployment (B) and CO_2 pricing (C) are shown. Furthermore, interaction effects are reported when both policies are introduced simultaneously. All results are presented as € per MWh of consumed electricity.

B. Wind Support

In four steps the market share of wind power is exogenously increased from zero to 30%. During windy hours wind power reduces the electricity price by reducing residual load, leading to a price drop. This reduces revenues for conventional generators, whose short-term rents fall dramatically: From 25 €/MWh without wind to almost zero at large wind penetration (Fig. 6). For the five countries modeled this drop is equivalent to € 30bn per year in absolute terms. Note that producers use short-term rents to pay for investment costs. Reducing those rents increases the amount of "missing money" for investors. Thus wind support policies can be seen as a mechanism to transfer rents from producers to consumers, which is possible if and only if investments are sunk. It is assumed that wind generators receive a subsidy that is just covers their costs, so they do not earn profits. Due to the shift in the generation mix the specific costs of electricity (dark green) increase somewhat. The sum of producer rents, generation costs and CO_2 costs equals the total revenue of the industry from the spot market or total spot market costs of consumers. Interestingly, by pushing in intermediate volumes expensive wind generation, total revenues are *reduced*, since rents are reduced much more than costs increase. In other words, at moderate penetration rates the merit-order effect is larger than the cost increase due to wind subsidies, which is consistent with the findings in (de Miera et al. 2008) and (Sensfuss et al. 2008). A policy maker that aims at minimizing electricity costs will find a wind penetration rate of 10% optimal. While producer rents and CO_2 revenues are transfers that do not change welfare, generation costs are true economic costs. They increase by 15 €/MWh as wind penetration grows from zero to 30%, meaning that welfare is reduced by this amount. Supporting solar PV instead of wind has similar effects, but lower running hours and higher investment costs lead to smaller redistribution and larger welfare effects (results are available upon request).

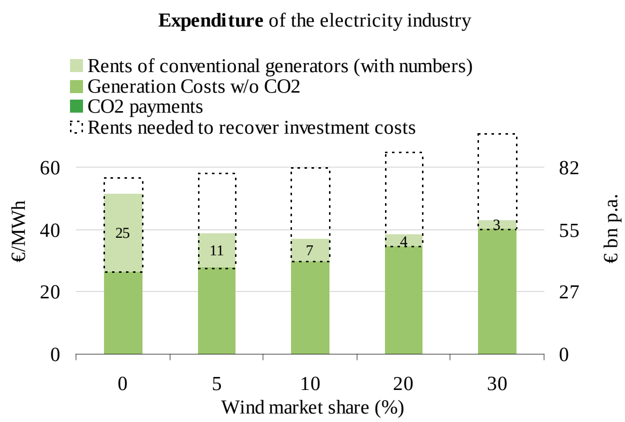

FIG 6. RENTS AND COSTS AT DIFFERENT SHARES OF WIND POWER. CO_2 REVENUES ARE ABSENT DUE TO A CARBON PRICE OF ZERO. THE DOTTED BOX REPRESENTS THE AMOUNT OF RENTS NEEDED TO RECOVER CAPITAL COSTS.

Panel 1 reports changes to rents and its sub-components: Producer rents decrease due to lower prices, net government revenues decrease due to wind subsidies needed to trigger investment, but consumer surplus increases strongly due to reduced electricity prices. Costs for district heating, ancillary services, and interconnections increase somewhat, but do not overcompensate the reduced wholesale electricity price. Rents of producers are reduced roughly proportionally to their generation. If the government passes the costs of subsidies on consumers, consumer surplus is increased less, but it still increases. Thus wind deployment subsidies can be understood as a mechanism to extract producer rents. The sum of the three surpluses, economic welfare, is reduced. Note that external effects such as the costs of carbon or knowledge spillovers are not accounted for. The welfare effect is merely the distortive effect of policy on the electricity market. Importantly, the amounts redistributed between consumers, producers and the government are large relative to the welfare effects.

PANEL 1: REDISTRIBUTION (€/MWH) WHEN INCREASING THE WIND SHARE FROM ZERO TO 30 %.

Conv Producers		**Effect on Government Budget**	
Nuclear Rents	- 13	CO_2	/
Coal Rents	- 9	Wind	- 18
Gas Rents	- 1		
Producer Surplus	- 22	Gov't Budget	- 18
Consumer Surplus		**Welfare**	
Electricity market	+ 28	Consumers	+ 25
Heat market	- 2	Producers	- 22
AS market	- 0	Government	- 18
Interconnectors	- 0		
Cons Surplus	+ 25	Welfare	- 15

Fig. 6 shows how producers generate income. The amount of subsidies that are needed to trigger wind investments increases (light blue). But spot market revenues decrease even more (dark blue). The sum of revenues from the spot market, from support schemes, and secondary markets such as heat and ancillary services is equivalent to the sum of expenditures, thus the bars in Fig. 6 and 7 are of the same height.

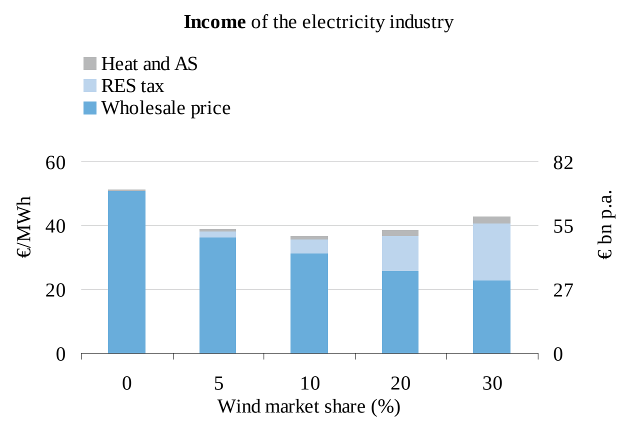

FIG 7. SPOT MARKET REVENUES, WIND SUBSIDIES, AND OTHER INCOME AT DIFFERENT WIND MARKET SHARES.

C. CO_2 pricing

To evaluate the impact of carbon pricing, the CO_2 price was varied between zero and 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. No free allocation was assumed, thus in the present model approach there is no difference between an emission tax and a cap and trade scheme. A higher CO_2 price increases the electricity price if the price-setting technology is emitting. Low-carbon technologies such as nuclear power gain due to higher prices and unchanged costs, and carbon-intensive technologies such as lignite loose since costs increase more than revenues. Importantly, total rents increase from 25 €/MWh to close to 40 €/MWh as the CO_2 price increases from zero to 100 €/t. Recall that the effect of CO_2 pricing on total producer rents was found to be dependent on the initial capacity mix in III.C. 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. At the same time, CO_2 expenditure increase due to the higher CO_2 price and other generation costs increase due to the induced shift in the generation mix with more intense use of high-cost fuels (Fig. 8).

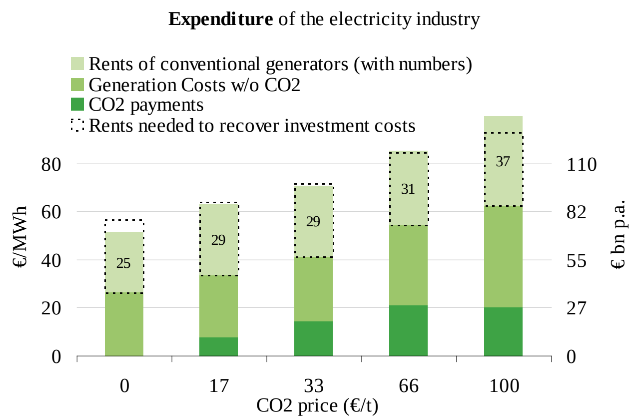

FIG. 8: RENTS AND COSTS AT DIFFERENT CO_2 PRICES. RENTS INCREASE SINCE NUCLEAR PLANTS BENEFIT FROM HIGHER PRICES. RENTS INCREASE OVER AND ABOVE THE LEVEL THAT IS NEEDED TO RECOVER CAPITAL COSTS, WHICH MIGHT BE LABELLED "WINDFALL PROFITS".

Panel 2 displays all redistribution flows. Total conventional rents increase with higher CO_2 prices, but there is a large shift of rents from emitting plants, mainly lignite and hard coal, to the low-carbon base load technology nuclear. If large-scale new nuclear investments would be possible in the short run, these gains would be strongly limited by new investments. Government revenues go up, and consumer surplus decreases. Welfare decreases.

PANEL 2: REDISTRIBUTION (€/MWH) WHEN INCREASING THE CO_2 PRICE FROM ZERO TO 100 €/T

Conv Producers		**Government**	
Nuclear Rents	+ 21	CO_2	+ 20
Coal Rents	- 10	Wind	/
Gas Rents	+ 0		
Prod Surplus	+ 12	Gov't Budget	+ 20
Consumer Surplus		**Welfare**	
Electricity market	- 43	Consumers	- 49
Heat market	- 6	Producers	+ 12
AS market	- 0	Government	+ 20
Interconnectors	- 0		
Cons Surplus	- 49	Welfare	- 17

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 an increase in spot prices are of the same order of magnitude as the rents generated from full free allocation, while having received much less attention in the public and academic debate. The role of the sunk capacity mix is also reflected in the distribution of rents across countries: while producer rents in France double when increasing the CO_2 price from zero to 100 €/t, they remain roughly stable in Germany. This is due to the availability of lignite resources in Germany and the resulting significant sunk lignite capacity whose rents are reduced.

Comparing the two policy instruments with respect to their redistribution effect reveals strikingly different patterns, which is maybe the most important empirical finding of this work. While the welfare effect is comparable in size, wind support and CO_2 pricing redistribute surplus very differently: CO_2 pricing benefits established generators and increases government revenues, but it harms consumers via higher electricity prices. Subsidizing low-variable cost generation technologies such as wind power has the opposite effects.

It is plausible to assume that policy makers try to avoid transferring surplus to conventional generators.[9] 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 conventional producer rents and wind subsidies reduce them, a combination of both measures allows pursuing climate policy without changing conventional generators' rents drastically. For example, introducing a CO_2 price of 100 €/t and a wind target of 30% simultaneously leaves conventional rents virtually unchanged (Fig. 9,10).

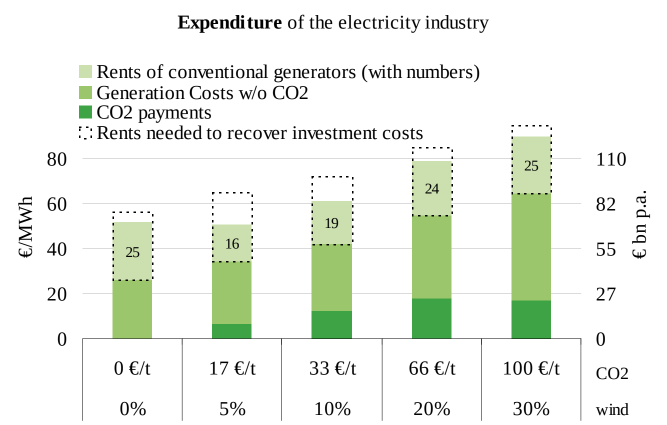

FIG. 9: RENTS AND COSTS WITH A MIX OF POLICIES. THE POLICY MIX REPRESENTS A PATH WHICH LEAVES RENTS ROUGHLY UNCHANGED.

[9] 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 scheme in several European countries.

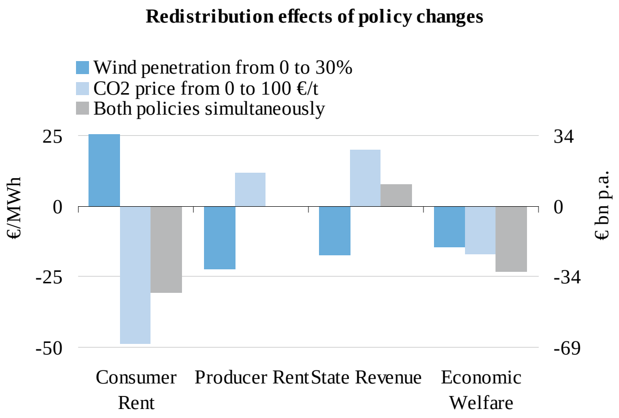

FIG. 10: SPOT MARKET REVENUES, WIND SUBSIDIES, AND OTHER INCOME AT DIFFERENT WIND MARKET SHARES.

VI. CONCLUSION

Redistribution effects of carbon pricing and wind support have been analyzed with an analytical and a numerical model. A crucial finding is that different policies induce diametrically opposed redistribution flows: CO_2 pricing shifts welfare from consumers to producers and the government, while wind support transfers welfare from producers and the government to consumers. Even if the government passes on expenditures and income to consumers, CO_2 pricing redistributes welfare from consumers to producers and wind support has the opposite effect. Redistribution is large relative to the welfare effect of policies and industry turnover.

Our results might help to explain the diverging attitude of actors towards certain policies. Often the academic literature explains the co-existence of carbon pricing and wind support with knowledge spillovers and other externalities. The finding that deployment subsidies redistribute rents from conventional producers to consumers offers a complementary explanation for the attractiveness of renewables support to policy makers.

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