CHAIRE EUROPEAN ELECTRICITY MARKETS/WORKING PAPER #44

RENTS OF ELECTRICTY GENERATORS IN FRANCE AND GERMANY DUE TO CARBON TRADING UNDER DIFFERENT ALLOCATION MECHANISMS

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Mars 2020

Abstract

The European Union Emission Trading Scheme (EU ETS), the key pillar of the EU's climate policy, establishes a Europe-wide carbon price. With over 50% of allocated carbon quotas, electricity generators are heavily affected by carbon pricing. However, its impact on generators' rents and profits varies widely from one technology to another and depends on the price of the quotas as well as their allocation mechanism, i.e. auctioning or grandfathering. Based on detailed models of the electricity systems in France and Germany, the present paper establishes precise estimates of the impact of carbon pricing on the profits of power producers in these two countries. The model is based on hourly 2017 price data from the EPEX Spot day-ahead market and fully accounts for fuel switching between coal- and gas-plants of different efficiencies. The paper also discusses the different impacts of auctioning and grandfathering for consumers, low carbon and fossil fuel-based producers as well as government revenues.

Keywords: European Carbon Market (EU ETS), Electricity Markets, Allocation Mechanisms, Inframarginal Rents.

Acknowledgments: This paper has benefited from the support of the Chaire European Electricity Markets (CEEM) of the Université Paris-Dauphine – PSL, under the aegis of the Foundation Paris-Dauphine, supported by RTE, EDF, EPEX Spot and Total Direct Energie.

Disclaimer: The views and opinions expressed in this paper are those of the authors and do not necessarily reflect those of the partners of the CEEM.

I. INTRODUCTION: CARBON PRICING AND THE PROFITABILITY OF EUROPEAN POWER GENERATORS

During the past fifteen years, prices and profits in the European electricity sector have been on a wild ride. This instability has been closely intertwined with the evolution of the European Emission Trading System (EU ETS). The introduction of the EU ETS with a free allocation of quotas in 2005 and the switch to the auctioning of quotas in 2013 stand out as

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particularly important events in this context. In parallel, the sector has been transformed beyond recognition through forces such as the introduction of large amounts of variable renewables such as wind and solar PV and a number of economic, technological and behavioural changes such as the declining profitability of dispatchable generation, the emergence of markets both more local in nature and closer to real time, electric vehicles, energy efficiency improvements as well as demand response to name just the most important ones. More traditional factors such as a decline in gas prices and stagnating demand have also contributed to keep electricity prices and the profits of generators low.

In this dynamic context it is not always easy to identify and quantify the variables that determine the profits of European power generators. However, the most important of these variables can be determined in a relatively straightforward manner and with considerable confidence: the price of carbon or, more precisely, the price of a European Emission Allowance (EUA) traded in the EU ETS. Of course, the price of a EUA, which corresponds to a quota of one tonne of CO2, results itself from the changing forces of demand and supply in the EU ETS. While the supply of quotas is fixed by a political decision at the level of the EU, demand results from a variety of factors such as electricity demand, the relative costs of coal, gas and non-fossil generation, the technical abatement opportunities in fossil fuel-based power generation or the anticipation of intertemporal arbitrage opportunities weighing current against future demand. The present paper will not try to identify the drivers of the price of carbon as undertaken by Bunn and Fezzi (2009), Keppler and Mansanet-Bataller (2010), Creti et al. (2012) or Chevallier (2013). Instead, it will take the price of carbon as exogenous and concentrate on its impact on the price of electricity and the profits of European electricity producers employing different power generation technologies in the vein of Keppler and Cruciani (2010). *Ceteris paribus* the profits of electricity generators are a function of the changes that the carbon price causes in the infra-marginal rents of different generating technologies.

The EU ETS, which covers slightly less than half of all greenhouse gas emissions in the European Union, is a platform for trading EUAs allocated not only to electricity and heat generation but also to a number of energy-intensive industrial sectors such as refining, steel, aluminium, cement, glass and ceramics, pulp and paper, chemicals as well as intra-European aviation. With over 50% of EUAs, the electricity sector is, however, generally acknowledged as being its most important contributor, which largely determines carbon prices. It is also the only sector, in which quotas must be acquired through national auctions, whereas all other sectors receive a large share of their quotas for free.[1]

Carbon pricing is of special importance to the electricity sector as differences in the carbon intensity between different technologies are huge. Carbon prices thus have a dramatic impact on the choices of operators and investors between coal-fired power generation with roughly 1 000 gCO2 per kWh over gas-fired power generation with 400 gCO2 per kWh to carbon-free generators such hydro, nuclear and renewables. Roughly, every Euro of the price of a EUA increases the variable cost of an MWh of coal-based electricity by the same amount. As electricity remains largely a non-storable good, demand needs to be met by supply second by second. This means that the different variable costs of operators give rise to so-called infra-marginal rents, *i.e.*, differentials between variable costs that allow technologies with lower variable cost to finance their fixed costs. These infra-marginal rents change in

[1] Also in the electricity sector, a special provision allows eight Member States, which have joined the EU since 2004, Bulgaria, Cyprus, Czech Republic, Estonia, Hungary, Lithuania, Poland and Romania, to provide until 2019 a limited amount of free allowances to existing power plants.

function of the price of carbon and the carbon intensity of different power generation technologies.

The impact of the carbon price on infra-marginal rents and profits is straightforward. Since the marginal, price-setting technology with the highest variable costs is usually a carbon emitter such as coal or gas, carbon pricing will improve the profitability of low carbon generators such as renewables, hydro or nuclear. This improvement is independent of the fact whether quotas are allocated to emitters at no cost on the basis of historical emissions ("grandfathering") or have to be acquired through national auctions. Slightly less intuitive, carbon pricing will improve also the infra-marginal rents of fossil fuel-based producers as long as quotas are allocated at no cost through grandfathering. This is due to the fact that the price of an EUA is fully included in the costs of carbon-emitting technologies *regardless of the fact whether the EUA has been received at no cost or paid for at an auction*.

Carbon pricing with auctioning will, of course, tend to negatively impact the profitability of fossil fuel generators. Even in this case, however, one needs to differentiate. While generators based on coal and lignite will unambiguously see revenues and infra-marginal rents decline, the impact on gas-fired power generation depends on relative fuel prices and the precise shape of the merit-order. It is possible that carbon pricing with auctioning *improves* the profitability of gas-fired generators if coal stays in the market as the marginal producer with the highest variable costs.

The precise quantitative estimation of the impact of carbon pricing on the infra-marginal rents of operators remains difficult due to the changes in the merit order that carbon pricing can induce. Based on a highly stylised rendering of the European electricity sector, Keppler and Cruciani (2010) estimated that during Phase I of the EU ETS with a free allocation of allowances the *additional* infra-marginal rents of European generators due to carbon pricing amounted to €20 billion per year with an average price of € 12 per tonne of CO2. The purpose of the present article is provide a far more precise estimate of the carbon rents of French and German power producers on the basis of an hourly model of the EPEX Spot day-ahead electricity market with updated 2018 data coal, gas, carbon and electricity prices. While the hourly day-ahead spot is not the only market for electricity, it remains the market where the prices are set for the forward markets, in which the bulk of electricity is traded. Due to the stark differences of the generating mix in the two countries, the results also allow for instructive comparisons of the profits under carbon pricing of both low carbon and fossil fuel-based generators.

The present paper thus provides a detailed empirical analysis of the impact of carbon pricing on infra-marginal rents. In addition, it contrasts the impacts of the two quota allocation mechanisms, grandfathering or auctioning, on the profits of power generators. As indicated, both grandfathering and auctioning enhance the infra-marginal rents of carbon-free generators but have strongly differing impacts on the infra-marginal rents of fossil fuel-based generators in particular those using coal and lignite. There is a political economy argument here that partly explains the dynamics of European climate and energy policy. Given the fact that the difference in infra-marginal rents between grandfathering and auctioning for German coal and lignite-based power producers amounts to € 4 billion per year, it is unsurprising that Germany, together with other Poland and other countries that rely heavily on coal in their generation mix, has resisted stricter limits on the supply of quotas. While the recent reform of the EU ETS has been an important first step to address the historical overhang of EUAs, leading to a modest increase in carbon prices, there are signs that this improvement is transitory rather than structural (see Matthes (2018) and Trotignon (2018)).

The only option to raise carbon prices decisively requires a political bargain to return to grandfathering. Only by restoring the pre-2013 arrangement of a cost-free allocation of quotas could the EU countries of Middle and Eastern Europe, including Germany, be convinced to accept dramatically stricter limits on the total quantity of quotas emitted (see Keppler (2016) and OECD (2019)). Higher carbon prices and, in consequence, higher electricity prices, infra-marginal rents and profits would accelerate the transition towards a low carbon electricity supply in Europe. Whether fossil fuel-based producers receive carbon rents or not is ultimately immaterial to the level of total emissions and carbon prices. Other than the technical abatement opportunities, the latter are exclusively a function of the total cap set by member countries.

Such a grand bargain of a stricter carbon emission cap in return for a return to a cost-free allocation of quotas and the ensuing increase in carbon and electricity prices would only modestly increase the retail tariffs paid by European electricity consumers. Retail tariffs are composed of wholesale prices, network charges as well as taxes and levies. The latter include the surcharges to finance the high and rising transfers paid to renewable generators through guaranteed feed-in tariffs. These transfer payments are based on the gap between the agreed upon feed-in tariff and the price that renewable energy has been able to earn in the wholesale electricity market. If wholesale electricity market prices rise, additional transfer payments and surcharges in the electricity bill will fall. The impact on consumer will be second order. The precise outcome will depend on the new levels of carbon and electricity prices as well as the elasticities of demand and supply in the carbon and the electricity markets.

Of course, salvaging the European carbon and electricity markets in this manner would not be entirely costless. Returning to a costless allocation of quotas, the governments of EU member countries would lose the revenues from auctioning. Their magnitude is the price of an EUA times the 1 billion of EUAs required by electricity producers. Returning to free allocation thus constitutes a transfer from taxpayers to electricity producers. While unpalatable for some, such a step would greatly strengthen European electricity markets. Due to the entry of significant amounts of variable renewables with out-of-market financing and zero short-run marginal costs the current wholesale prices in EU electricity markets are far below the costs of production of *any* generation option (for a discussion of price formation in the Franco-German electricity market see Keppler, Le Pen and Phan (2017)). This unhealthy state of affairs requires financing outside energy-only markets for *any* new investments in power generation capacity, be it by way of contracts-for difference, capacity payments or other means. Higher carbon and electricity prices coupled with a return to free allocation, would dramatically improve the ability of European power producers to commit themselves to investing in new low carbon generation based on electricity prices. They would thus decisively contribute to the objective of the European Commission and EU member countries to establish competitive, cost-reflective and healthy markets as the key driving force behind the transition towards a low-carbon electricity sector.

Any policy reform undertaken with a view of putting the sustainability of European carbon and electricity markets on a firmer footing, however, would require reliable estimates of its impacts. This is where the second objective of the present paper comes in. For the two key countries of France and Germany, it provides estimates for all major generation technologies of the added inframarginal rents that electricity generators will earn in function of different allocation mechanisms for carbon quotas.

The paper is organised as follows. Section 2 will briefly review the conceptual framework behind carbon pricing in electricity markets as well as its impact on the merit order inframarginal rents and profits in the long and the short-run. It will also present the major existing contributions to the literature in this area. Section 3 will describe the model of the European electricity market used. Section 4 will present the results of this paper, *i.e.*, the rents of European power generators generated at different levels of carbon prices under both auctioning and grandfathering. Section 5 concludes.

II. THE INTERACTION BETWEEN CARBON PRICES, ELECTRICITY PRICES AND THE PROFITABILITY OF ELECTRICITY GENERATION: THEORY AND LITERATURE REVIEW

The link between carbon pricing and the profitability of electricity producers has been studied in a variety of relevant articles, which will be presented below. However, it has not spawned a broad and systematic endeavour of research in its own right as, for instance, the related question of the "pass-through" of carbon prices into electricity prices. This is surprising as the amounts involved are considerable (see below) and carbon pricing constitutes the most important lever to redress the profitability of generators affected by the entry of significant amounts of wind and solar PV capacity with zero marginal cost.

One reason for this relative lack of attention is the fact that analysing the impact of carbon pricing on generator profits requires integrating two strands of economic literature, environmental economics and the economics of electricity markets. In the years following the introduction of the EU ETS in 2005 with free allocation, a number of contributions also still had to come to terms with notions of opportunity cost and inframarginal rent. On a more technical level, assessing the impact of carbon pricing on operators' profits requires analysing the interaction of two independent sources of rent. Carbon pricing following the introduction of a quantity limit monetises the residual environmental resource rent that comes with the permission to emit a unit of CO2. This is a long-run concept comparable to Ricardian land rent. At the same time, the inframarginal rent of different electricity generation technologies, each one with its own variable costs, which constitutes the profit of generators in the wholesale electricity market, is a short-run concept akin to a Marshallian quasi-rent.

As we will argue below, the two forms of rent can be straightforwardly combined in the analysis of annual impacts on operators profit under the assumption of an unchanged capital stock. This assumption, which is shared by all the contributors to the small literature on carbon pricing and operators' profits, is justified by the fact that carbon quotas in the EU ETS are allocated on an annual basis. A longer-term analysis would, of course, need to take into account also changes in the composition of the capacity mix.

Before coming to the literature directly concerned with the profits of electricity market operators, one need to briefly consider the related literature on pass-through, *i.e.*, the share of the price of an EU quota that is integrated in the wholesale electricity price. At the level of the methodology, most of the literature on pass-through is based on econometric regressions. The question of pass-through is also closely related to the question of "wind-fall profits", *i.e.*, the share of the environmental resource rent captured by operators through grandfathered quotas. An important early contribution was the paper by Sijm *et al.* (2006). While it discusses changes in variable costs and in the merit order, it ultimately relies only on a statistical approach for assessing pass-through rates. This blurs the impact on individual technologies and no longer allows reflecting changes in the merit order. An average pass-through rate of less than 100% is inevitably the result of fuel-switching rather than a failure of individual generators to price in fully the marginal cost of their quotas. Other contributions in this vein were made by Chernyavs'ka and Giullì (2008) as well as by Zachmann and von Hirschhausen (2008).

A recent paper by Verde *et al.* (2018) summarises the econometric work on pass-through rates of the past 15 years. Two results stand out, first results vary widely with the econometric techniques used and second pass-through tends to be higher during peak hours (Verde *et al.* (2018), p. 7). The latter results from the fact there is no fuel switching between coal and gas plants during peak hours, as there is no excess capacity. Each technology will thus always fully price in the marginal cost of quotas. Verde *et al*. (2018) as well as de Bruyn *et al*. (2015) for the European Commission summarise the meanwhile established consensus that a 100% pass-through must be the default assumption independent of the mode of allocation.

This originally lively literature has petered out in recent years as conceptual clarifications and growing familiarity with the principle of opportunity cost has made 100% pass-through at the level of the individual operator the default assumption. Theoretically, it is possible to have less than full pass-through with linear demand curves and monopoly power, an issue explored in particular by Sijm *et al*. (2012) with inconclusive results. Higher than full pass-through instead is possible when competition takes place and the market demand curve is isoelastic (de Bruyn *et al.* (2015) p. 29). However in wholesale electricity markets with low elasticities of demand, in particular in the short-term, and a high degree of competition due to the non-differentiability, difficult storability and low physical transaction costs of electricity, a pass-through of 100% is the appropriate default assumption.

Literature on the impact of carbon pricing on the profitability of electricity generators

Beyond the literature on cost pass-through, much of which was concerned with distributional arrangements and fairness, there exists a small and still evolving literature that models the impact of carbon pricing on the profitability of electricity generators in an explicit manner. The present paper is part of this literature. There also exists a substantive literature on the recycling of revenues from either auctioned quotas or carbon taxes, which is part of an even larger literature on "green tax reform".

This however goes beyond the interest of this paper, which works in a partial equilibrium set-up and looks only on the impact of different CO2 pricing regimes on the annual profits of power generators in France and Germany, without considering wider redistributive effects of energy and climate policies. This allows a transparent representation of the working of the power sector based on hourly data for electricity prices on the European EPEX Spot day-ahead market. Carbon pricing thus translates into hour-by-hour changes in the merit order as well as in the inframarginal rents of operators.

Early papers by Burtraw (2002), Martinez and Neuhoff (2005) and Tsao et al. (2011) first established conceptually that carbon pricing would affect the profits of operators. Burtraw and Karen (2008) also showed that under relatively mild assumptions the electricity sector as a whole would gain from carbon trading even if all or most quotas were auctioned. While coal-based generators may lose in auction-based systems as they become the technology with the highest variable costs and thus no longer earn infra-marginal rents, carbon-free producers such us nuclear, hydroelectricity ad renewables unambiguously independent of the fact whether quotas are auctioned or grandfathered. The impact on gas, which emits about half as much CO2 per MWh as coal, will be neutral under auctioning if it remains the marginal fuel and positive if coal surpasses it in the merit order. Both coal- and gas-fired power generators gain under grandfathering.

Keppler and Cruciani (2010) confirmed this general result for the European electricity sector using a simplified framework without fuel switching to estimate changes in infra-marginal rents due to carbon emissions trading under different allocation rules. Additional annual rents due to carbon pricing with the grandfathering of quotas that prevailed during phases I and II of the EU ETS from 2005 until 2012 thus amounted to EUR 19 billion given an average price of EUAs (EU allowances) of EUR 12 per Tco2. They estimated that auctioning from 2013 onwards would reduce these rents to EUR 10 billion assuming an average price of EUR 20 per Tco2. In particular, coal-based producers would lose more than EUR 4 billion annually compared to a situation without carbon pricing (Keppler and Cruciani (2010), p. 4289). While the orders of magnitude are still relevant, the 2010 paper used a highly stylised model of the European electricity sector without making use of market data. The present paper addresses this issue by establishing a far more precise estimate of the carbon rents of power producers in France and Germany with a model based on hourly data from the EPEX Spot day-ahead market that fully accounts for fuel switching between coal- and gas-plants of different efficiencies.

The orders of magnitude were confirmed in the report of Canfin *et al.* (2016) for the French government, which reports modelling results that establish an increase in costs of EUR 17 billion for a carbon price of EUR 30 per Tco2.

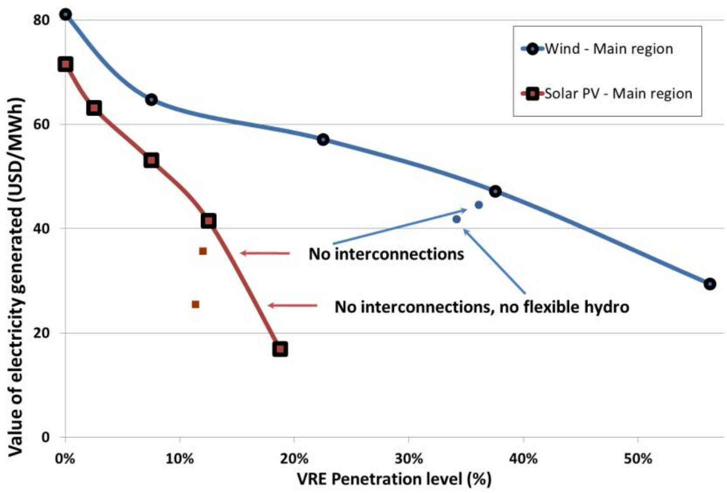
The paper by Hirth and Ueckerdt (2013) on "Redistribution Effects of Energy and Climate Policy" provides modelling results for the combined impact of feed-in tariffs of wind production and carbon pricing on the surpluses of producers and consumer in North-Western Europe. Its key contribution consists not so much in providing new numerical results but in the thorough discussion of distributional issues. They confirm hat CO2 pricing will increase infra-marginal rents under all modes of allocation but that certain types of producers, i.e., if they are coal-based, will lose out under auctioning (p. 934). Most interesting, however, is their discussion of the combined effect of carbon pricing, which raises electricity prices, and renewables support, which lower electricity prices. In a roundabout, order-of-magnitude way the two effects offset each other as far as conventional, unsubsidised power producers are concerned:

> "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 (Hirth and Ueckerdt (2013), p. 946)."

Such interactions between the evolution of carbon prices under the EU ETS and other energy policy measures such as the German phase-out of coal-powered power generation are also highlighted on the basis of extensive statistical documentation by Matthes (2018). Hirth and Ueckert also justify the assumption of a fixed capital stock, *i.e.*, the absence of new entry, in assessing changes in infra-marginal rents due to inertia and time lags in reacting to newly introduced policies (*ibid.,* p. 935). This is correct. One might even add that the long lifetimes of assets and the lack of long-term visibility and credibility of carbon policies further justify disregarding the impact of carbon pricing on the capital-stock for current modelling of the current impact of carbon pricing on the profits of electricity market generators under the EU ETS.

Technology by technology the impacts are straightforward: carbon-free generators will always gain, coal-based generators will lose under auctioning and gas-based generators will gain under auctioning to the extent that the variable costs of coal exceed those of gas. For utilities holding a differentiated mix of assets, Möst *et al.* (2016) report results from a European-wide model that overall most utilities gain from carbon pricing even under auctioning (Möst *et al.* (2016), p. 56). Cometto and Keppler (2019) consider the impact of inframarginal rents on the relative shares of carbon-free and fossil-fuel based generators in three different scenarios, (1) the absence of carbon pricing, (2) a carbon tax or full auctioning of CO2 emission quotas and (3) the costless allocation of emission quotas (grandfathering) under a more stringent carbon emissions cap. They consider, in particular, the fact that the free allocation of quotas can work as a capital cost subsidy which might be able to function as a substitute for other forms of capacity remuneration mechanisms (CRMs). Cometto and Keppler also point out that with a free allocation of quotas EU Member countries with large shares of fossil fuel-based production might agree to more ambitious carbon targets. Letting the letter benefit from carbon pricing through a costless allocation of quotas would open the way for overall tighter carbon caps and higher carbon prices. Higher electricity prices due to higher carbon prices would also help renewable generators such as wind and solar PV. Moving towards market-based remunerations, the latter are faced with declining revenues as their shares increase due to autocorrelation (OECD (2019). P. 192-3, see Figure 1 below).

Figure 1
Remuneration of Wind and Solar PV Generation as a Function of their Market Share



Source: OECD (2019), p. 132.

Overall, there is recognition that the creation of the EU ETS and the different modes under which carbon emission quotas can be allocated to generators has an important impact on the inframarginal rents of generators. Considering the existing literature, it is also increasingly evident that explicit modelling based on hourly dispatch rather than econometric estimation is the appropriate form of inquiry for getting meaningful results differentiated by technology. Employing econometrics, in particular, masks the effects of coal-gas fuel switching in the merit order. Nevertheless, the number of in-depth studies that have modelled the impact of carbon trading on the rents and profits of generators remains small, compared to the size of its impact. The present paper is part of the effort to address the lack of knowledge in this area and to contribute to a better understanding of the interaction of carbon and electricity markets.

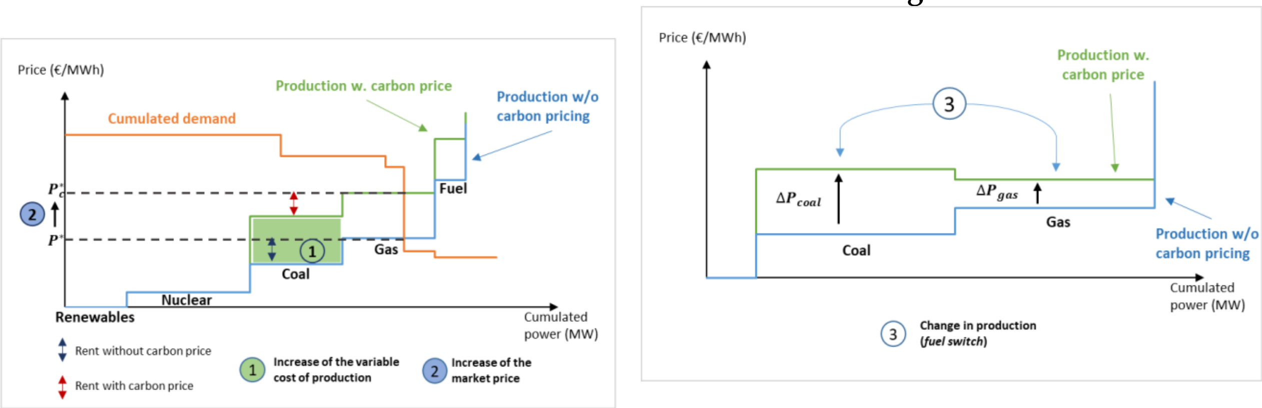
III. ESTIMATING THE RENTS OF ELECTRICITY GENERATORS IN FRANCE AND GERMANY DUE TO CARBON TRADING UNDER GRANDFATHERING AND AUCTIONING

Following the liberalization of the energy sector initiated by the EU in 1996, electricity is traded on exchanges through standardized products with various maturities. Day-ahead auctions for hourly prices in France and Germany clear on the EPEX Spot market. The resulting spot price is commonly used by economists as a proxy of the hourly price of electricity. It is defined as the intersection of a highly competitive supply curve sorted in an ascending order with an equally competitive demand curve sorted in descending order. Electricity producers bid at their marginal cost, i.e., their short-run variable costs of production measured in EUR/MWh. The latter are zero for variable renewables such as wind and solar. Variable costs are equal to the sum of fuel costs and the opportunity costs of carbon quotas and variable costs for operators relying on nuclear, hydro or fossil fuels such as coal and gas. A fully complete calculation the variable costs of operations and maintenance (O&M) and technical constraints for start-up, shut down and ramping.

Prices are equal to the variable cost of the marginal technology, *i.e.*, the technology with the highest marginal costs still retained in the merit order. Only during rare moments of involuntary supply interruption, prices will rise to the very high levels of the value of lost load (VOLL). To allow smooth market function, the VOLL is subjected to an administrative cap, which, for instance, is set at EUR 3000/MWh in the European EPEX Spot market. VOLL hours, which on average are counted in the single digits per year may not arise at all during a given year. The price of carbon quotas is always directly reflected in the bids of power producers and impacts their infra-marginal rents according through three channels:

1. **Costs:** the cost of production of carbon-emitting technologies increases with the intensity of their emissions and their rents decrease accordingly.
2. **Prices:** the market price, which is equal to the variable costs of the marginal producer, which is usually coal or gas, will tend to increase in function of the carbon price. This will result in an increase of the inframarginal rents of all producers except the price setting one.
3. **Fuel switching:** since the carbon emission factors vary between technologies, the rank order of their variable costs might change in function of the carbon price, a phenomenon known as "fuel switching". It usually plays itself out between coal- and gas-fired power plants. Switching impacts the capacity utilisation of both technologies and increases the rents of the now lower-cost technology and decreases it for the now more expensive technology.

Figures 2a and 2b
The Merit Order with and without Carbon Pricing



As mentioned, two different allocation mechanisms were used during the various phases of the EU ETS. During Phases I and II, quotas in the electricity sector were given out for free based on past emissions thus allowing carbon-emitting producers to preserve or increase their inframarginal rents. In Phase III since 2013, electricity producers need to buy quotas from governments through an auctioning process. Only a small number of Eastern European countries are allowed to cede a share of quotas at no cost. In all cases, the carbon market allows participants to trade quotas in order to meet their effective emissions, which sets an effective price to the quotas reflecting their relative scarcity. This incentivises power producers to integrate the cost of a carbon quota in their bids in the electricity market, even if they received it for free. This counter-intuitive phenomenon is due to the principle of opportunity cost, i.e., a valuable resource will be accounted for at its value when employed in the highest-value alternative use. The latter in this case would be a sale of the quota in the carbon market. The value of quotas thus depends *exclusively* on their relative scarcity in the market and is always fully integrated in the variable cost of production, independent of the allocation mechanism.

In the following, we study the impact of carbon pricing under different allocation mechanisms in France and in Germany. France and Germany are not only the largest electricity producers in Europe, they also have very different electricity systems, which allows for an instructive comparison. France's electricity sector with its large shares of nuclear power and hydroelectricity has very low per unit carbon emissions of 70 gCO2/kWh and emits about 33 million tCO2 per year. This compares to Germany's electricity sector, which due to its large share of coal-fired power production has per unit emissions above 325 gCO2/kWh and emits over 210 million tCO2 per year.

Carbon Rents in Function of Different Allocation Mechanisms with Fuel Switching and Resulting Changes in Electricity Market Prices

The model used in this paper recalculates the merit curve hour by hour on the basis of the changed variable costs due to the carbon price and the carbon intensity of each technology. In particular, it accounts for *fuel switching* which has a strong impact on rents at carbon prices above 25 EUR/tCO2. In this context, the following assumptions are made:

- Electricity demand inelastic in prices. This hypothesis is reasonable in the short term and widely used. In this context, the most important consequence is that total demand remains unaffected by the price of the carbon quotas.

- Power plants are available at any time of the year. This is a strong assumption, as power plant need to undergo regular maintenance and can experience unscheduled outages.
- In the same spirit, also inter-temporal constraints of operations of power plants are not taken into account. Power plants can be brought online and switched off within an hour.

While a large-scale model by a TSO might want to include such technical constraints, integrating them into the present effort would have massively complexified the model without significantly affecting key results. The model thus allows a technology-based formalisation of the electricity markets in France and Germany in order to account for the three impacts of carbon pricing on the rents of power producers mentioned above.

Technology modelling

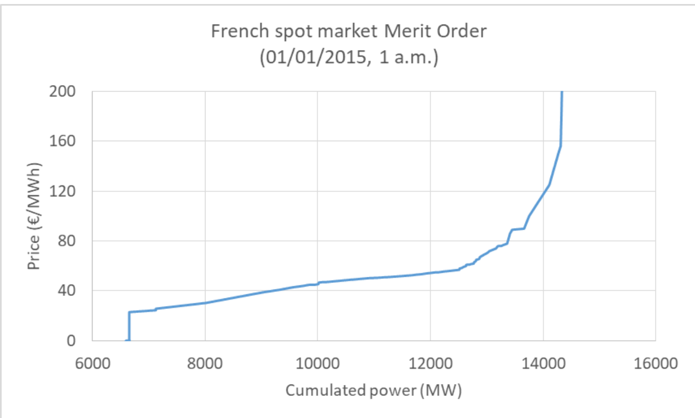
The technology-based economic model of dispatch used here is calibrated using the actual price and production time series in France and Germany. Modifying the parameters of the model taking into account the carbon price allows computing the rents of power producers in both countries. Price time series are again provided by the EPEX Spot database. Production data is based on the open data of RTE in France and SMARD (*Strommarktdaten*) in Germany. Available technologies are the following (the sets of technologies are not identical due to different statistical conventions):

- France : nuclear, coal, combined-cycle gas turbine (CCGT), gas-fired combustion turbine, cogeneration gas turbine (cogeneration), oil-fired combustion turbines, other oil, run-of-the-river hydroelectric, reservoir hydropower plant, pumped storage power stations (PSPS), wind onshore, solar PV and biomass.
- Germany: nuclear, coal, lignite, gas, other conventional producers, pumped storage power stations (PSPS), other hydroelectricity, biomass, wind offshore, wind onshore, solar PV and other renewables.

An important feature of the model is that it allows for differentiated variable costs inside each technology category. These costs are based on the detailed analysis of hourly prices. The usually adopted description with a unique variable cost of production for the whole of a single technology is too simplistic as it does not reflect the diversity of different power plants in terms of variable costs. The analysis of the merit curves available on EPEX Spot's database shows clear evidence of this (see Figure 3).

Figure 3

A Merit Order Curve with Intra-Technology Variations in Variable Costs



The true variable cost of production of a given technology was thus approximated by estimating the linear relationship between its variable cost and its capacity utilisation rate at each hour:

$$Variable\ cost_{techno} = a_{techno} + b_{techno} * Capacity\ utilisation_{techno}$$

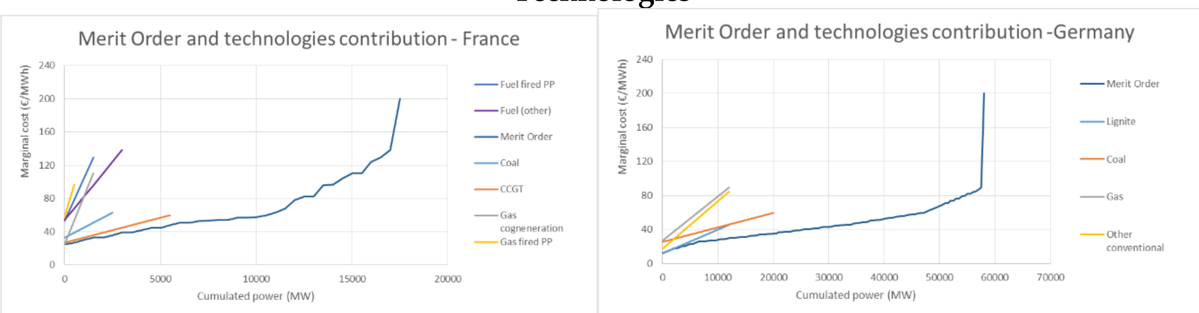
Both coefficients $a_{filière}$ and $b_{filière}$ are determined by linear regression of the actual price and production data of each technology (see Annex 1). To run the regression, only those hours were used during which the technology in question was considered to be the price setting one.

The hourly merit order curve and the resulting dispatch decisions are recalculated using these assumptions. Each technology is split into intervals of 100 MW and sorted in ascending order. The model thus endogenously generates an hourly merit order for any given demand in function of the variable costs of each technology, which includes, where appropriate, the carbon price. The variable costs are in themselves a function of the total capacity deployed of each technology according to the econometric relationship that was previously estimated as indicated above.

Figure 4 below shows for both France and Germany, the results of the relationship between capacity and variable costs for each technology as estimated, as well as the combined re-estimated and calibrated merit order curve. It is important to understand that the methodology employed does not assume that prices for certain large intervals of demand are set by the same technology. While this assumption is frequently employed, it provides a very abstract and partly misleading picture of the electricity market, in particular when dealing with fuel switching between different technologies due to carbon pricing. The present model develops a far more realistic setting in which for different 100 MW slices of demand, different technologies set prices in function of their marginal costs. These marginal costs, however, increase to the extent that the capacity of that particular technology is employed. Annex 1 provides further information on the underlying information that was used in the technology-specific econometric estimations.

Figures 4a and 4b

Estimated Merit Order Curves in France and Germany for Fossil Fuel-based Technologies



The dispatch model was limited to those technologies whose level of production depends on the market price. The level of production of low carbon technologies with low variable costs in the model remains unaffected by the carbon price. Their rents are thus exclusively determined by the carbon price as they do not participate in fuel switching. This includes, of course, variable renewables with zero short-run marginal costs, hydroelectric plants dependent on natural stocks and nuclear power plants assumed to be following pre-established cycles for maximum security and maintenance.[2]

Subsequently, the inframarginal rents of all power generators, carbon emitters as well as low carbon generators, were computed as follows:

1. ***Rents without carbon price***
   a. Hourly calculation of the production of each technology using the actual price time series (*Merit Order* in the indirect way, price → production)
   b. Computation of revenues, costs and rents of each technology

2. ***Rents with carbon price***
   a. Calculation of total hourly load (⇔ total production of the technologies) using the actual price time series (*Merit Order* in the indirect way, price → production)
   b. Computation of the new *Merit Order* taking into account the carbon price
   c. Calculation of the price and production (by technology) time series (*Merit Order* in the direct way, production → price)
   d. Calculation of the revenues, costs and rents of each technology depending on the allocation method of carbon quotas.

IV. RESULTS

The results of the model which allows for fuel switching provide for an instructive picture of the impacts of a carbon price of 30 EUR/tCO2 on the inframarginal rents of power producers in France and in Germany. The total increase in the annual inframarginal rents of power producers due to carbon trading in France and Germany amounts to EUR 22.5 billion with free allocation and of EUR 17.1 billion under auctioning, These gains are somewhat higher than the simple estimates presented in Keppler and Cruciani (2010) that did not take into account fuel switching.

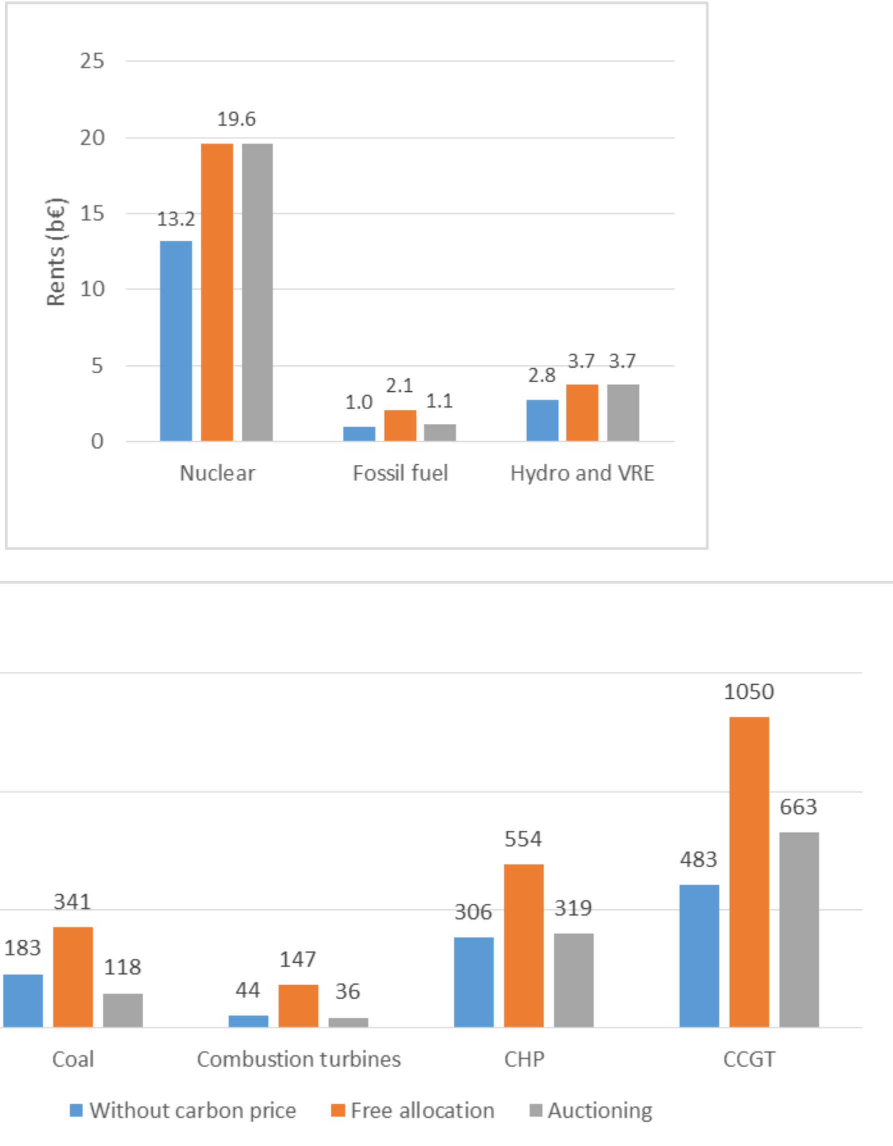
In France, the major story is the extent to which nuclear energy, which provides 75% of French electricity, as a carbon-free baseload technology benefits from carbon pricing, independently of whether one assumes that quotas are allocated at no cost (grandfathering) or sold at government auctions. Due to the ability to pass through costs to consumers, even fossil-fuel based technologies, taken together, gain both under grandfathering and auctioning when compared to a situation without carbon pricing. Only coal-based power producers would experience losses of roughly EUR 100 million under auctioning. Overall, French electricity producers would gain an additional EUR 8.4 billion from carbon pricing under grandfathering and EUR 7.4 billion under auctioning (see Figures 5a and 5b below). Of these amounts, nuclear power plants would gain EUR 6.4 billion under both modes of allocation. Hydropower and variable renewables (VRE) such as wind and solar PV would gain an additional EUR 0.9 billion in both modes. In short, the results of the model on the basis of market data from EPEX Spot confirm the intuition that low carbon electricity production in France strongly gains from carbon pricing. This holds *identically* for

[2] In reality, hydroelectric resources and nuclear energy do vary their level of production. However, these variations take place according to the complex interactions of several parameters, of which price is only one. They thus do not participate in fuel switching according to the carbon price in the manner of fossil fuel-based plants. Their output level is thus independent of the carbon price.

grandfathering as much as for auctioning. An additional result is that French fossil fuel producers would overall also marginally gain from carbon pricing even under auctioning, as CCGTs would gain due to the price increases induced by coal and by oil and gas combustion turbines during peak hours.

Figures 5a and 5b

Inframarginal Rents of Electricity Producers in France



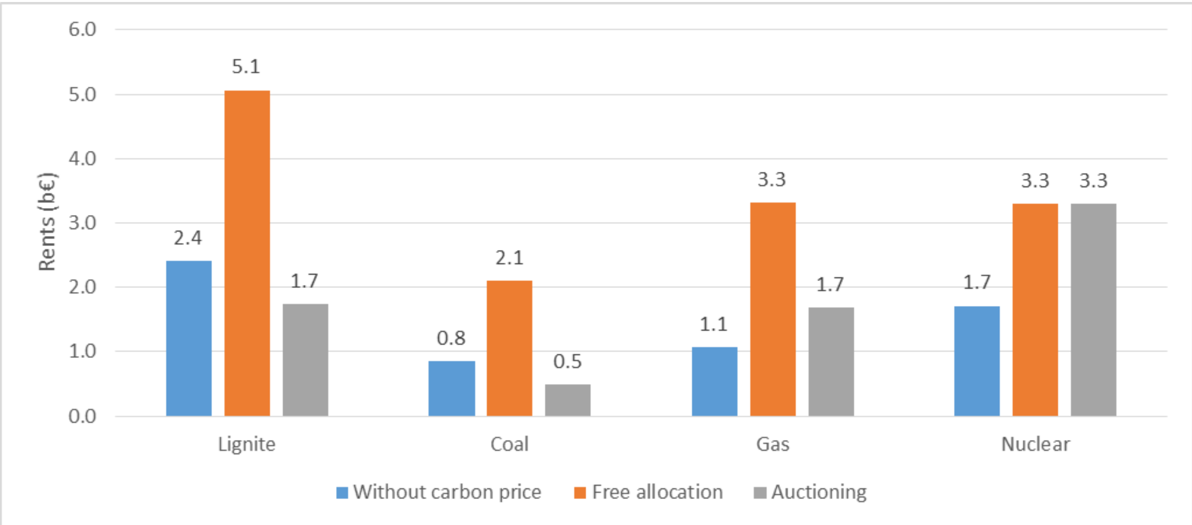
Also, in Germany power producers benefit considerably from carbon pricing. The key point here is that the high share of fossil fuel-based power production (lignite, coal and gas) now introduces a strong difference between free allocation and auctioning. Under free allocation, the gains of German power producers from a carbon price of 30 EUR/tCO2 would thus amount to EUR 12.8 billion. Of these EUR 2.7 billion would accrue to lignite, EUR 1.3 billion to coal, EUR 2.2 billion to gas, EUR 1.6 billion to nuclear and EUR 5.0 billion

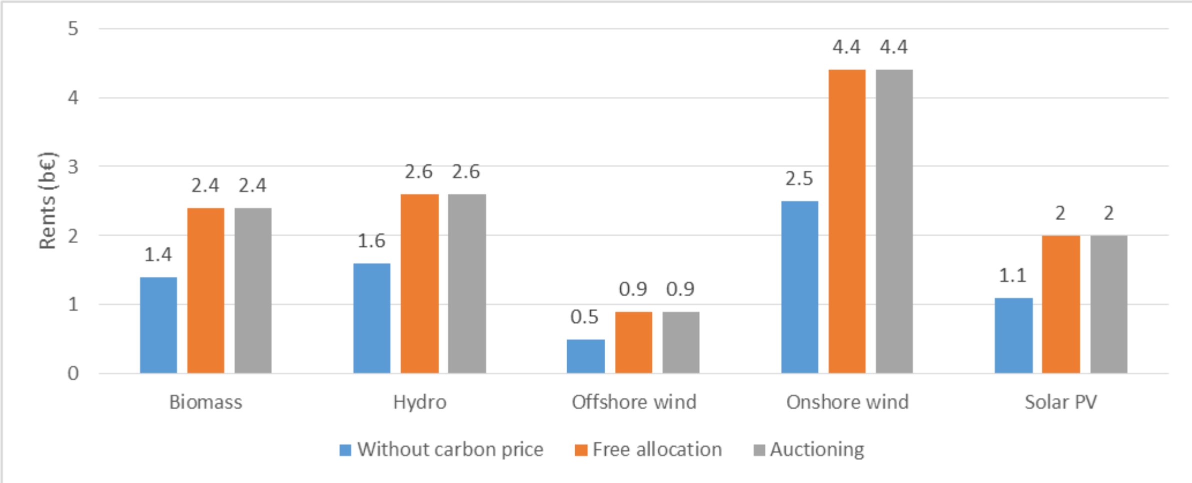
(!) to renewable energies (biomass, hydro, on-shore ad off-shore wind and solar PV). Onshore wind alone would gain EUR 1.9 billion.

The story is very different if the chosen mode of allocation is auctioning. While carbon-free technologies would experience an identical increase in inframarginal rents, this is obviously not the case for fossil-fuel based producers. Lignite-based producers would experience a loss of EUR 0.7 billion when switching from a system without carbon pricing to a system with auctioning, while coal would lose EUR 0.3 billion. Gas-fired power producers due to fuel switching would instead still gain EUR 0.6 billion. Total gains in inframarginal rents due to carbon pricing at EUR 30 per tCO2 would thus amount in Germany to just EUR 9.5 billion. Producers based on lignite and coal would be absolutely worse off by EUR 1 billion with a EUR 30/tCO2 price in a carbon trading system with auctioning.

The crucial point is the difference in terms of inframarginal rents between free allocation (grandfathering) and auctioning, which for fossil fuel-based power generation amounts to EUR 6.6 billion. This goes a long way in explaining the structural difficulty of the German electricity sector as well as its policy-making instances to move more vigorously towards faster decarbonisation of power generation through higher carbon prices. The laborious compromise reached in the context of the recently decided *Kohleausstieg* that postpones the phase-out of coal and lignite-based power production until 2038 is a case in point. However, it is also evident that returning from the present mode allocation to the free allocation, which was practised in the electricity sector until 2012, would be highly profitable for fossil fuel-based producers in Germany. Political economy considerations at the European level should take this account. In order to move towards a more rapid decarbonisation of the European power sector, the German electricity industry would quickly become part of a coalition in favour of higher carbon prices if a full or partial return to free allocation of carbon quotas was part of the policy mix. Needless to say, such a move would also assist in generating the necessary funds for financing the transition of moving towards an increasingly decarbonised power mix.

Figures 6a and 6b
Inframarginal Rents of Electricity Producers in Germany

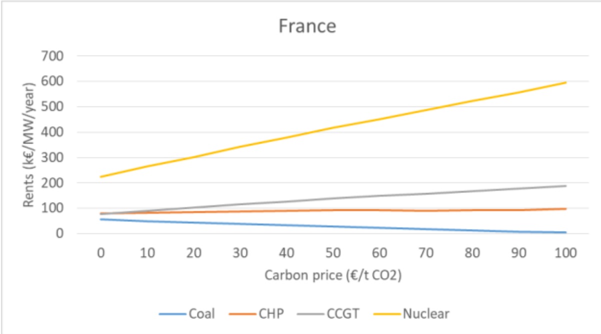


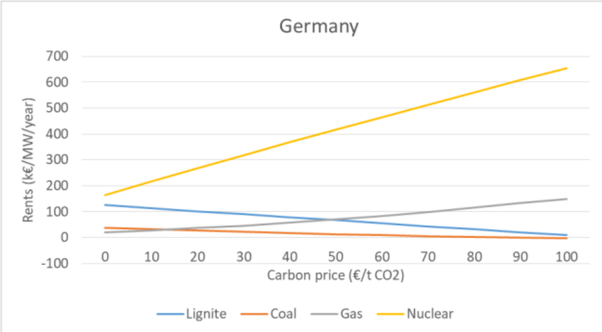


The detailed results above are provided for a carbon prices of EUR 30/tCO2. It is instructive to consider how the inframarginal rents change in function of this carbon price. This is particularly relevant for policy discussions at the European level whether current prices for carbon quotas that are currently trading between EUR 20/tCO2 and 30/tCO2 are appropriate. Sweden, for instance, has a generalised EUR 100/tCO2 carbon tax (which in distributional terms corresponds to a trading system with auctioning), the United Kingdom is aiming for a carbon price floor in 2040 of £ 52/tCO2 which corresponds roughly to EUR 60/tCO2. Figures 7a and 7b below indicate the evolution of the inframarginal rents of dispatchable producers in function of the carbon price in France and Germany. For easier comparison, the amounts have been normalized in terms of kEuro/MW/year. The results are particularly relevant for coal plants in France and for coal and lignite plants in Germany. Rents decline almost linearly with the carbon price to essentially disappear when it approaches EUR 100/tCO2.

Considering that annualised investment costs for a new coal plant are above € 150/kW (Matthes *et al*. (2012), p. 19), new investment is unprofitable under any carbon price scenario. More interesting is to look at the fixed annual O&M costs, which determine whether an existing plant stay open given the amount of rent that it earns in the electricity market is sufficient. Fixed annual O&M costs for a coal plant will not be below € 50/kW (*ibid*., p. 22). This means that coal plants would be forced to leave the market in both France and Germany already at relatively modest carbon price starting at € 10/tCO2. Lignite plants would fare better due to their exceptionally low fuel costs. Carbon prices of € 60/tCO2 or above would thus be required to drive German lignite plants fully out of the market.

Figures 7a and 7b
The Impact on Inframarginal Rents of Variations in the Carbon Price





The final elements of the results of the modelling undertaken in this paper pertain to the question who will pay the increase in inframarginal rents of power producers under carbon pricing, be it with free allocation or auctioning of quotas. Ultimately, all increases in inframarginal rent are due to the fact that that carbon pricing will raise electricity prices. In other words, consumer surplus will be transferred from electricity consumers to power producers in the form of higher inframarginal rents. However, the share that power producers actually receive from this increase in electricity prices depends on the mode of allocation. Quotas are tradable financial assets, receiving them for free means that producers can capture the full transfer of wealth from consumers. However, if they have to be paid for through government-sponsored auctions, the monetised value of those assets accrues to the governments.

It is instructive to compare in Figure 8a and 8b the relative sizes of the shares that depend on the mode of allocation (allocation effect) and the remaining share of the increase in electricity prices that accrues to producers independently of the mode of allocation (price effect) in both France and in Germany. Electricity production in France is largely decarbonised, emitting only 20 million tCO_2 in 2018. Thus only few quotas are actually issued. Giving them away for free or auctioning them off does only make a minor impact to the inframarginal rents of the electricity sector. Only EUR 2 billion of the overall EUR 14 billion that would be generated by a carbon price of EUR 30/tCO_2 depend on the allocation mode. Consequently, the French electricity industry remains largely indifferent to the choice of the allocation mechanism.

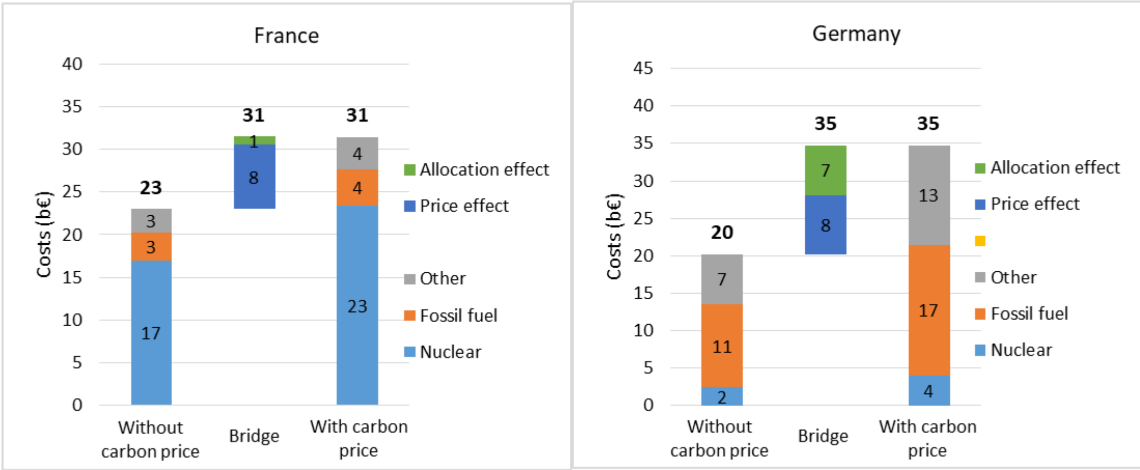
This is quite different from the situation in Germany, where the power sector emitted 273 million tCO_2 in 2018. Switching from auctioning to free allocation would more than double the additional inframarginal rents of power producers to a total of EUR 21 billion. The price effect would contribute EUR 10 billion. This is slightly less than in France due to the fact that variable costs of German power producers are, on average, higher than those in France, whereas prices, while not completely identical, would have a tendency to converge due to the cross-border trading of electricity. The allocation effect would instead contribute an additional EUR 11 billion and would be wholly supported by the government in terms of auction revenues forgone.

The question "who pays for the price effect?" is, for both France and Germany, is more difficult to answer. Of course, higher prices will be paid for by buyers in the wholesale EPEX Spot electricity market. Assuming that markets are efficient, this would imply that competitive distributors would pass on those higher prices to consumers. However, to which extent translate higher wholesale prices into higher retail prices and net reductions in consumer surplus for industrial, commercial and residential consumers? While no quantitative estimates could be prepared in the present context, the answer must be "only partly". This is due to the fact that most of consumers contribute through retail tariffs to the financing of the gap between the feed-in tariffs for wind and solar PV and the revenues that these energies can obtain in the wholesale market through the *CSPE* in France or the *EEG-Umlage* in Germany. If that gap declines due to higher wholesale prices, additional support payments will also decline. Final tariffs for end-users will thus result from the outcome of a complex interplay of partly off-setting forces. Only those consumers currently exempted from financing of the energy transition would be subjected to the full increase in wholesale prices.

Which conclusions should policy-makers draw from these results? The answer depends on distributional considerations and policy priorities. Economic efficiency is achieved as long as they set the appropriate carbon price, or the corresponding amount of carbon quotas, independent of the mode of allocation. However, the question whether to leave a large "allocation rent" to fossil fuel-based producers is not an easy one. Leaving it to producers would strengthen the pan-European coalition for robust carbon pricing and provide utilities with additional funds for a costly restructuring during a particularly challenging period. Using receipts from coal and lignite-base power production for the future *Kohleausstieg* would be one example for this. However, collecting those receipts for the government would be attractive from a budgetary point of view and provide added funds for public expenditure. Ultimately, choosing between free allocation and auctioning comes down to the question which mode allows for the most sustainable manner of financing the energy transitions in France and Germany.

Figures 8a and 8b

Decomposing the Inframarginal Rents Due to Carbon Pricing into Allocation and Price Effects



V. CONCLUSIONS

The present paper analyses the increase in inframarginal rents of power producers in France and Germany due to carbon pricing. An electricity market model calibrated on hourly 2017 price data of the EPEX Spot day-ahead market shows that with a carbon price of EUR 30/tCO2 the additional rents accruing to power producers in France amount to EUR 12 billion per year and to EUR 10 billion per year in Germany under the current system of auctioning off carbon quotas. These amounts rise to EUR 14 billion per year and EUR 21 billion per year if quotas are allocated freely based on emissions of the previous year (grandfathering). The difference in inframarginal rents concerns only fossil fuel-based producers. Quite intuitively, carbon-free producers based on nuclear, hydro or renewables remain unaffected by changes in the mode of allocation.

At a methodological level, the model used in this paper has the advantage to allow for full fuel switching due to carbon pricing based on a differentiated representation of the variable costs of power producers. This representation takes into account not only differences in variable costs between different technologies, but also between different segments of the productive capacity of one given technology. The analysis of electricity market data shows that in particular gas and coal-fired capacity is dispatched at very different levels of prices. Not all differences in prices that trigger the dispatch of different segments of capacity of a given technology are due to differences in variable costs, factors such as portfolio effects or ramping constraints will also play a role. Differences in variable costs, however, are the most important factor. The present paper thus takes a first step forward with respect to models working with uniform variable costs per technology. Needless to say, an even more detailed representation of the sector, plant by plant, would allow further refinements.

While the current policy discussions about the impact of carbon pricing in the electricity sector are lively and lobbying efforts, unsurprisingly given the amounts involved, intense, much of the debate is based on a mix of intuition and rather limited modelling of the working of the electricity sector. Most efforts are concentrated on explaining the carbon price itself. It is rare that analysis addresses the decisive policy-relevant metrics of what carbon pricing does to the inframarginal rents of power producers, the revenues of governments and the surplus of consumers. By addressing this gap in the literature, the current paper aims at contributing to a more complete and systematic debate on these issues that are decisive for the functioning as well as the economic and financial sustainability of the electricity sector in France and Germany.

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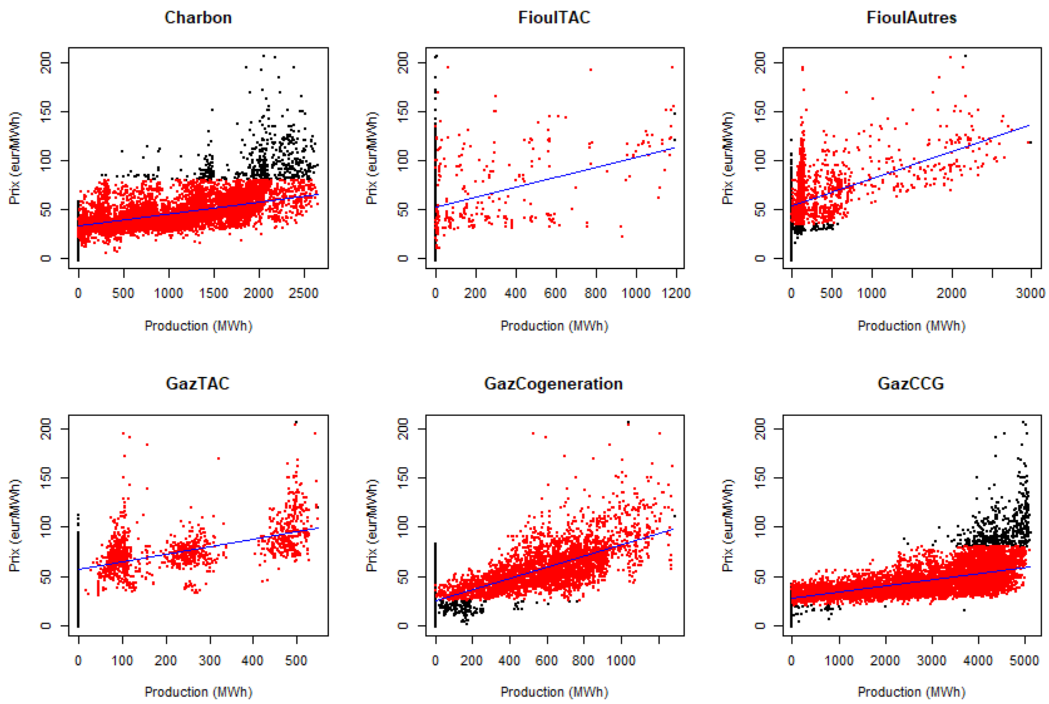
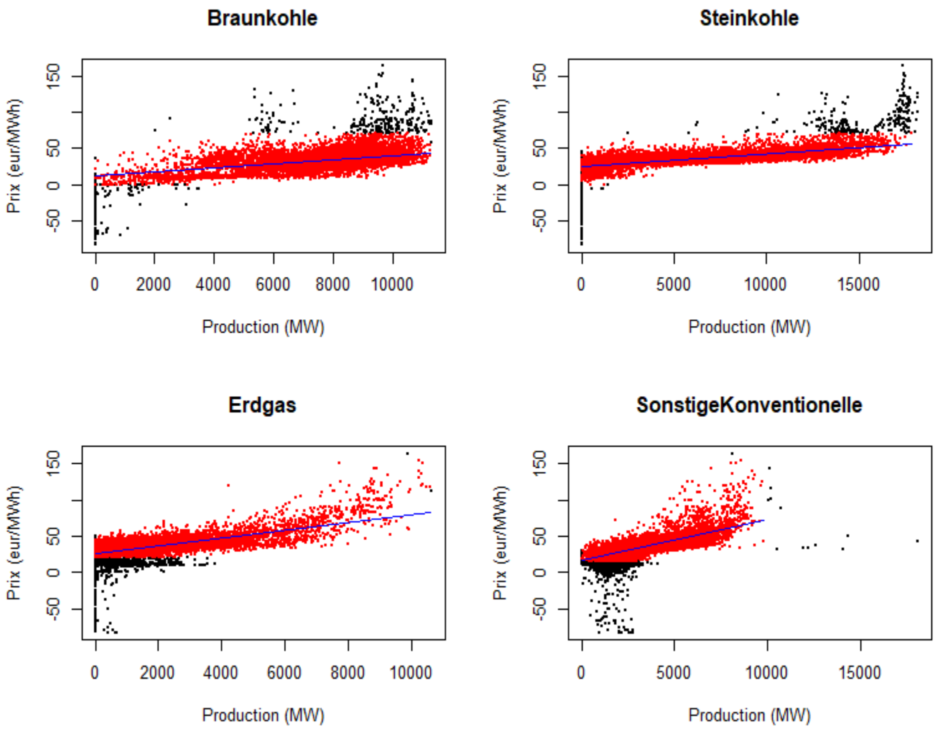
ANNEX: PLOTS AND KEY PARAMETERS FOR ESTIMATING THE VARIABLE COSTS IN THE FUEL-SWITCHING MODEL

France 2017



Germany 2017



France 2017

	Coal	Oil Turbines	Gas Turbines	CHP	CCGT
Installed capacity (MW)[1]	2 650	4 200	550	1 300	5 100
Carbon intensity (tCO2/MWh)	0,96	0,8	0,6	0,6	0,45
$a_{filière}$**(€/MWh)**	33	53	58	25	27
$b_{filière}$ **(€/MWh/MW)**	0.012	0.05	0.077	0.057	0.006

1 Installed capacity refers to the maximum level of capacity that was reached during the year 2018 and was thus relevant for the calculation of carbon rents. Total available capacity, in particular of open cycle gas turbines ("Gas Turbines") is considerably higher.

Germany 2017

	Lignite	Coal	Gas	CHP and Other Conventional
Installed capacity (MW)[2]	12 000	20 000	12 000	12 000
Carbon intensity (tCO2/MWh)	0,96	0,96	0,45	0,6
$a_{filière}$ **(€/MW)**	11,9	25,5	27,0	17,4
$b_{filière}$ **(€/MWh/MW)**	0,0028	0,0017	0,0052	0,0056

2 Installed capacity refers to the maximum level of capacity that was reached during the year 2018 and was thus relevant for the calculation of carbon rents. Total available capacity, in particular for gas-fired power generation us somewhat higher.