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How marginal is lignite? Two simple approaches to determine price-setting technologies in power markets

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ABSTRACT

How much carbon is in the price of power? The answer to this question determines many economic consequences of climate policies, i.e. in terms of costs for downstream industries. It requires, however, to first identify the cost impact of carbon pricing on the price-setting entity on the power market. Economic theory tells us that power prices are determined by the cost of the marginal plant. We propose two simple approaches to conclude on marginal technologies in electricity wholesale from public data. Both approaches are complementary, easy to implement, and based upon assumptions which are commonly used in more complex energy system models. We exemplify their use with a policy example on the compensation for indirect emission costs from the EU Emissions Trading Scheme. We find that the current policy design severely overweighs CO_2 emissions from lignite power plants in the Central Western European power market, which may lead to overcompensation of industrial power users and therefore to a distortion with regard to the policy's stated goal.

1. Introduction

How much carbon is in the price of power? The Paris Agreement requires drastic changes around the world to decarbonise the economy, and, above all, the power sector. In the European Union, carbon dioxide emissions in the power sector are subject to the EU Emission Trading Scheme (EU ETS), which is possibly the most prominent example for an international market based climate policy on the planet. The economic impact of such energy and climate policies depends on how they affect the various market equilibria along the supply chain. For electric power markets, this equilibrium is characterised by the "marginal plant". At a specific point in time, a plant is said to be marginal, if all cheaper technologies are already fully employed and the plant is the least-cost available option to satisfy the remaining demand. The price to get this plant running clears the market. Thus, marginal plants are said to be price-setting. An assessment of energy policies that affect electricity prices therefore crucially relies on identifying marginal plants and their technological characteristics. Specifically, the impact of emissions trading on electricity prices depends on the actual pass-through of emission cost by the marginal plants. Without identifying those plants, the price impact of emissions trading on power markets cannot be credibly assessed.

Price-affecting climate policies bear the potential to worsen the competitiveness of industries that compete on global markets. Compensation schemes are thus designed to ease the competitive burden of these policies. The parametrisation of those schemes and consequently, the overall compensation level, needs to be based on some measure of the policy's market impact, which in turn, is determined by the marginal plant.

This article illustrates two simple approaches to infer marginal technologies from observed market data in a transparent manner and with high timely resolution. We use the concept that lies beneath much more complex fundamental energy system models, and show how this can be applied for a simple but not necessarily less plausible method to determine marginal technologies from observed data. We take a view from two different angles: (1) realised load and its relation to available capacity, (2) realised prices and how they compare to approximated marginal costs. Both approaches are complementary rather than mutually exclusive and can be particularly helpful whenever the parameters for specific policies depend on identifying marginal power plants.

The motivating example for this study is the compensation mechanism for indirect CO_2 costs induced by the emissions trading scheme in the European Union. Indirect CO_2 costs arise from the cost for emission allowances used in power production, driving up the market price for electricity. EU Member States are allowed to implement a compensation scheme to reduce the burden for electricity consuming industries, but the European Commission has issued binding guidelines on a maximum level of the firms' compensation amount (EU Commission, 2012). This

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level depends inter alia on emission factors of power production, which are defined in the guidelines and fixed on a region-specific level. Since the actual indirect CO_2 costs depend on the emission intensities of the marginal plants, choosing an appropriate level is crucial for the scheme to compensate as intended by the regulator. We consider this to be a typical *parametrisation* problem of the regulator, which for energy and climate policies very often depends on the identification of marginal technologies.

According to the European Commission, the currently defined emission factors are based on the weighted average CO_2 intensities of electricity generation from fossil fuels in certain regions. However, when wholesale electricity prices are set by the marginal plant, the average emission intensity of fossil fuel fired power production does not reflect the actual CO_2 cost that is passed-on to the market clearing price. Instead, the impact of CO_2 costs on electricity prices will depend on the emission intensities of the marginal plants (Fabra and Reguant, 2014; Hintermann, 2016). For different hours and load levels, different technologies with varying emission intensities will be marginal. And the proportion in which each of these technologies will be marginal is most likely not the same as the technology's share in total generation from fossil fuels. Consequently, the current compensation scheme, based on emission factors ignoring these aspects, may over- or under-compensate relative to the intended level of compensation for indirect CO_2 costs.

Intended and actual compensation levels will differ most remarkably in systems in which emission intensive technologies have a large share in generation – driving up the average emission factor – but are only marginal in a few hours of the year. A prime candidate of such a technology are lignite power plants. Lignite is a highly emission intensive fuel compared to natural gas or even hard coal. At the same time, lignite plants in Western Europe typically have lower specific fuel costs than natural gas or hard coal plants, which allows lignite plants to hold a high market share. Thus, there is reason to doubt that lignite is indeed price-setting in a relevant number of hours. If this is not the case, including CO_2 emissions from lignite in the calculation of emission factors for CO_2 cost compensation may overstate its actual impact on the power price and consequently, the level of compensation for indirect CO_2 costs.

Central Western Europe (CWE), covering France, Germany, Austria and the Benelux countries, is one region defined by the EU Commission with a common emission factor in the compensation scheme. The bulk of fossil fuel power plants in this region are located in Germany and among all CWE countries, only Germany possesses active lignite power stations. Still, CO_2 emissions from lignite account for about 42 percent of all CO_2 emissions in electricity generation in the CWE region.[1] Thus, the impact of CO_2 emissions from lignite in Germany on the average emission factor in the CWE region is non-negligible. But in Germany, lignite plants are usually considered to be base load capacities, which – by definition – are hardly price-setting. Consequently, we focus our analysis on the German and Austrian electricity wholesale market and the period from July 2015 to July 2017. The reason for choosing this period is that one of our approaches requires technology specific production data, which is not available before July 2015. We choose a sample of two complete years to ensure that no imbalance in the covered seasons could introduce any bias.

Overall, we find that the share of hours, in which lignite was likely price-setting in the German and Austrian wholesale market for electricity, was about 3 to 7 percent and clearly below 15 percent for the period covered in our sample. This finding is in stark contrast to the weight of 39 percent that CO_2 emissions of lignite currently have in the average emission factor. Therefore, including total CO_2 emissions from lignite in the calculation for the current emission factors for indirect CO_2 cost compensation clearly overstates its actual impacts on the indirect CO_2 costs in Central Western Europe.

The remainder of the paper is structured as follows. Section 2 puts our approaches in relation to the literature and details out the scope of our contribution. Section 3 explains the concept of marginality, outlines the empirical approaches to identify marginal plants, and discusses their challenges. Sections 4 and 5 present the methodology and data for either approach and the findings with respect to lignite as a marginal technology. Section 6 concludes and discusses the policy implications of our analysis.

2. Relation to the literature and scope of the contribution

The most common approach to analyse the power system and its technological and economic interdependencies are fundamental energy system models. The existing literature on energy modelling is very broad and an extensive review is beyond the scope of this article (see e.g. Hirth (2018) or Beran et al. (2019) for an overview on different modelling approaches). However, some widely shared features of fundamental energy system models can be summarised as follows: They are mainly numerically solvable optimisation models which use technological information and market data to represent the system-wide provision of energy which meets market demand and obeys the technological and economic constraints. For the provision of electric power, these constraints include fuel costs, capacity, and availability of power generation. A well-calibrated power market model therefore allows to determine marginal plants by back-casting actual market outcomes. Beran et al. (2019), Kallabis et al. (2016), Hirth (2018), Bublitz et al. (2017), Everts et al. (2016) and Weigt and von Hirschhausen (2008) as well as Müsgens (2006) can serve as examples for such an approach, comparing realised prices in the past with model results for marginal cost. Recently, Blume-Werry et al. (2018) investigate price-setting technologies on European markets ex-ante for the year 2020 against the background of a proposed minimum carbon price in the Netherlands.

A strength of fundamental energy system models is their capability to produce forecasts and scenario analyses, see e.g. Weron (2014) for an overview. A point of critique frequently brought forward, however, highlights that the models' complexity makes them akin to a 'black box' to the uninitiated. Thus, a common worry is that the models' results are mainly driven by their underlying assumptions and that their validity is hard to assess. Nahmmacher et al. (2016), for example, investigate the sensitivity of model outcomes with respect to the choice of representative days and propose an approach for their selection as input data in energy system models. On the transparency side, there is an important stream of research working on opening 'the black box' by publishing the energy system models' code and data sources for public scrutiny and collaborative work. Pfenninger et al. (2017, 2018) provide an authoritative account of these efforts. Open energy system modelling is a great leap forward for transparency in policy consulting and policy design. However, the usage and scrutiny of these models will always be restricted to a group of experts with corresponding training.

The aim of our work is therefore not to rival with fully fledged energy system models, but to provide an easily accessible alternative for the ex-post determination of marginal technologies. Our method is meant to be transparent and easy to use to inform policy makers in their assessment of CO_2 cost pass-through and price impacts. It could even serve for a dynamic and purely data driven updating of policy parameters based on some general assumptions made by the regulator. Our approaches are based on simple computations, which we implemented in the open source statistical software *R*. It is straightforward, however, to perform similar computations with a broad range of widely used software – in particular, spreadsheet programs – which should make our approach particularly appealing to a larger, non-expert audience.

[1] Period from 2005 to 2015, own calculation based on data from Eurostat and IPCC default emission factors for fossil fuels. Note that lignite in Germany typically exhibits a higher emission intensity than the IPCC factors, see Juhrich (2016).

Our identification of marginal plants evidently requires a number of assumptions, but not substantially more (or more critical ones) than those required for most energy system models. Moreover, our two approaches rely on differing assumptions. Thus, comparing results across methods will help to check their plausibility. Finally, the approaches do not require any explicit optimisation algorithm. Indeed, all we do is to summarise and interpret a number of descriptive statistics against the backdrop of a set of transparently stated assumptions about the market mechanism. Thus, our approach should be easily reproducible without a specific modelling software. Another contribution of this paper is to exemplify how such a simple calculation can be used to check the parametrisation of a policy for consistency with the declared aim of being a compensation for incurred CO_2 costs. In this paper, we apply our method for illustrative purpose to a specific technology – lignite based power generation – in a specific market – the German and Austrian wholesale electricity market – but comparable approaches are straightforward to implement for similar questions in different circumstances.

Besides our contribution on methodology, we also contribute to the existing literature by analysing a particular new policy, namely compensation for indirect emission costs. For example, Kallabis et al. (2016), Bublitz et al. (2017), Everts et al. (2016) and Hirth (2018) as well as Beran et al. (2019) examine different drivers of the evolution of electricity prices in Germany and Europe. Furthermore, Müsgens (2006) and Weigt and von Hirschhausen (2008) investigate issues of market power in electricity markets. However, to the best of our knowledge, we are the first to study marginality and its implications for the emission factors set in the EU Guidelines for the compensation of indirect emission cost. This is in stark contrast to the currently high interest of policy makers in the issue. Current Guidelines will expire on 31 December 2020. They therefore have to be revised for the next trading period starting on 1 January 2021. The current redesign of the compensation mechanism by the European Commission is correspondingly high on the agenda of national regulators and industry associations alike, as witnessed by the public and targeted consultations.[2]

3. Concept of marginality and empirical approaches

3.1. Motivation to study marginality of lignite power plants

Emissions from lignite fired power plants have a high weight in the emission factor that is used to compensate industries for indirect CO_2 costs. However, for the German market, lignite plants are generally considered to serve base load, running most of the time due to their low marginal costs. This means that the electricity price level is no crucial determinant of the decision to produce power from lignite once the investment costs are sunk. In return, one can assume that the marginal costs of lignite plants, including marginal emission costs, are no crucial driver of the electricity price level. Such reasoning would obviously fail (a) due to enormous increases in their marginal costs, e.g. when greenhouse gas emissions are priced heavily, or (b) when lignite plants are priced out of the market due to cheaper rival technologies. The former scenario (a) does not prevail in any jurisdiction around the world yet, but has gained in relevance with the price increase for European Emission Allowances in 2018. The latter scenario (b), however, could be relevant in energy systems with large renewable or nuclear capacities in the market or in connected neighbouring markets. Both of the latter conditions apply to Germany. Thus, we study marginality of lignite specifically for the German–Austrian market.

[2] See https://ec.europa.eu/competition/state_aid/legislation/ets_en.html.

3.2. The concept of marginality and the merit order

'Merit-order pricing' is a stylised model of price formation in electricity markets: when power plants are ordered according to their marginal costs, the last plant that is necessary to satisfy demand sets the price. But what price does the plant set? One possible assumption would be that all plants are pricing at their own marginal costs. An economically more plausible assumption is that the plant owner is pricing just a tiny amount below the marginal cost of the closest competitor, keeping the next plant out of the market, but still raising the own margin. Without more detailed plant level information, but knowing that no generation technology is completely monopolised within the German-Austrian market, we can assume that all plants of the same technology compete with each other, and thus, it is the marginal cost of the marginal technology which is setting the price. Indeed, most of the well-established energy system models used in industry and for policy consulting are based on some variant of such a merit-order model (see e.g. Hirth, 2018; Weigt and von Hirschhausen, 2008; Müsgens, 2006). Fig. 1 illustrates the concept.

3.3. Approaches to evaluate if a technology is price setting

Building on a simplified merit-order model and without detailed plant level data, we consider two different approaches. Both approaches are based on the fundamental principle that the intersection of supply and demand determines prices and quantities in wholesale electricity markets (Stoft, 2002). Observing equilibrium prices and quantities, the marginality of lignite power plants is inferred from two different angles (basically along each axis in Fig. 1). While the first approach focusses on quantities, specifically available capacities, and demand (the abscissa in Fig. 1), the second one exploits that observed prices (plotted on the ordinate in Fig. 1) result from the intersection of supply and demand and therefore, can refer to the marginal technology:

(1) **Quantity approach: marginality according to residual load**. We identify hours in which total electricity demand is such that it fulfils the following two criteria: (a) load is so high that it cannot be covered alone by production from technologies that rank before lignite in the merit order; (b) load is so low that no technology which is more expensive than lignite is needed to satisfy total demand. In this approach, we identify residual load for lignite after production from cheaper technologies is subtracted and evaluate whether it falls within the range of available capacity for lignite rather than exceeding it. Due to the varying nature of electricity demand, this approach is most reasonably executed at the highest available frequency, i.e. hourly.

(2) **Price-cost approach: marginality according to marginal costs**. We identify time periods in which electricity prices are above the marginal costs of the most efficient lignite power plants, such that lignite plants are in the market, but below the marginal costs of the closest more expensive competitor, which, in our case, is the most efficient hard coal fired power plant. Both technologies are subject to start-up and ramping costs which render them inflexible to a certain degree with respect to high frequency price changes. This is captured in our approach comparing marginal costs to daily average prices, assuming that plants are sufficiently flexible to react to price drops that extend over at least 24 h. Moreover, note that the day-ahead auction takes place at noon the day before delivery. A plant that would have to shut down or to start-up for the period of 24 h would still have 12 h to adjust before the beginning of the delivery period. Taking daily average prices may thus help to overcome the potential bias introduced by those inflexibilities.

Taking the two approaches in parallel and comparing the results helps us to control for the drawbacks of either one.

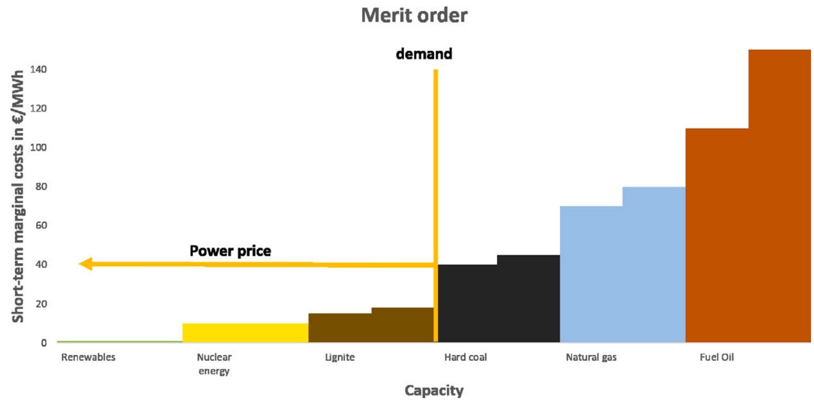

Fig. 1. The merit order (stylised) as a concept for price formation in electricity markets.

3.4. Challenges of identification of the marginal technology

3.4.1. Deviations from the strict merit-order model

The following paragraphs address potential issues concerning the concept of marginality and pricing behaviour of power plants, specifically deviations from the merit order due to inflexibilities and forward contracting. On the one hand, these aspects can be dealt with by using additional market specific information. On the other hand, we believe that taking two different perspectives – one on prices, one on quantities – with possibly differing frequency of observation allows to account for deviations in plant scheduling.

The merit-order model is economically and technologically intuitive, but a bit too simplistic to fully capture the reality of production and pricing decisions in power markets. Plants might stay on the grid during hours where the price appears to be below their (short run) marginal costs, or plants that could possibly produce profitably for certain hours might stay out of the market for some unobserved reasons. The former plants are often referred to as "must-run capacities", while the exact reason for why they "must-run" is not evident. Possibilities are e.g. combined heat-power (CHP) plants that base their production decisions on two separate streams of revenues. An optimised CHP-production schedule can then look like a "must-run" production with regard to the power output. Start-up and ramping costs are another possibility which could convince a plant owner to stay online for certain hours at a loss to be able to produce during other subsequent hours with a profit. Evidently, such frictions blur the picture that one can obtain based on simple merit-order reasoning. We discuss some of these issues in the next subsection.

Aside of these technological and economic aspects, which are hard to quantify , the merit-order model relies on the assumption that firms base their decisions on marginal costs alone, disregarding possibilities to exert market power and total cost recovery. Nevertheless, merit-order pricing still is the dominating assumption underlying most energy system models and in the competitive market setting, that we currently observe in the CWE region, marginal cost based pricing appears to be a reasonable assumption.

3.4.2. Start-up costs, block bids, and economic must-run

Many power plants are characterised by inflexibilities. In economic terms, these inflexibilities take the form of start-up and ramping costs. The high costs to heat especially large thermal power plants, such as lignite or nuclear plants, render a fast adjustment of production to short lived price changes unattractive. To account for these inflexibilities, power can be traded forward in blocks of several hours, days or weeks. One could therefore suppose that a producer who is completely hedged might not react to short time price changes. This latter form of inflexibility is sometimes referred to as 'economic must-run'. However, any participant on the wholesale market has the possibility to continuously trade and adjust positions, i.e. buying back power for single hours that had been sold as part of a block before. Forward contracted power producers therefore continuously face "make-or-buy" decisions, which induce the incentive to adjust production to short-term price fluctuations. Based on this reasoning, "economic must-run" does not appear to be relevant beyond the physical constraints induced by the different production technologies. "Economic" must-run might, however, occur for smaller producers, which cannot afford to maintain a trading unit for short-term adjustments that actually realise the opportunity profits from short-term markets.

An exact separation of 'economic' or 'technological' must-run is not possible. In the end, every production decision is based on an economic decision subject to technologically determined constraints and costs. The German Transmission System Operators (TSOs) commissioned a study on the dimension of the capacity which can be expected to "must run" (Consentec, 2016). The results give a first impression on the scale of the phenomenon. Further details on this study are given in Section 4.2.5.

4. Analysis of marginality according to residual load

4.1. Approach based on residual load calculation

In our first approach, we evaluate the relevance of lignite as a price setting technology through the lens of market data on load, generation, and available capacity. The approach builds on market quantities rather than prices. Identification is based on the merit-order model: assuming a set of technologies with typically lower marginal cost than lignite (e.g. hydro, nuclear, also called 'inframarginal technologies' in the following), we conclude that lignite is not price setting whenever the observed output from these technologies alone suffices to serve overall demand. Lignite would then be 'out-of-the-market'. On the contrary, when total demand exceeds the production from cheaper technologies, we know that the residual load for lignite power plants is just the difference of total demand and the production from these cheaper technologies. We can then compare this residual demand to the available capacity of lignite. If lignite capacities do not suffice to meet residual demand, we know that more expensive technologies must kick-in and lignite will thus again not be price setting. Classifying all observed time periods according to these possibilities allows us to deduce the periods in which lignite is neither out-of-the-market nor insufficient to meet its residual demand. For these periods, lignite power plants qualify to be at the margin, and thus price-setting.

4.2. Data sources on production, consumption, and capacities

4.2.1. Data on generation

We obtain hourly, day-ahead planned generation for the German-Austrian bidding zone from the EEX transparency platform for all available technologies, comprising the following: *biomass, coal, gas,* *pumped-storage, run-of-the-river, seasonal-store, coal-derived-gas, garbage, lignite, oil, other, uranium, wind-offshore, wind-onshore*. Technology specific data for generation is available from 29 July 2015 onwards. The last day in our sample is 28 July 2017, giving us exactly two years for the analysis. So all seasons enter with equal frequency.

The implausibly low reported quantities on generation from wind and biomass in this data set, and the missing information on solar require the use of additional data from other sources. For wind and solar power, we refer to the hourly data on day-ahead predicted inflows from the EEX transparency platform.

As there is no corresponding data on power production from biomass, we follow Agora Energiewende in their approach to impute biomass production,[3] which is assumed to enter uniformly and at a stable rate. The production levels are imputed such that they conform to the yearly reported overall production as well as to the intra-yearly increases in installed capacity.

4.2.2. Data on cross-border flows

We obtain scheduled cross-border flows for all interconnectors to/from the German–Austrian bidding zone in hourly frequency from the ENTSO-E transparency platform. We aggregate flows into net-flows such that negative flows indicate net imports. Several interconnectors, especially smaller ones, lack data for significant time windows. Corresponding flows are counted as zero when calculating total net exports from the German-Austrian bidding zone to neighbouring countries. The corresponding interconnectors are minor in terms of capacity and excluding all observations due to missing data on some interconnectors would imply a large loss of information for other interconnectors and from other data sources.

Following this definition, we observe net cross-border flows from 29 July 2015 to 28 July 2017.

4.2.3. Data on demand

We obtain data on the total system load for the German-Austrian bidding zone from the ENTSO-E transparency platform at hourly frequency. It is known from Hirth and Schumacher (2015) that these load levels do not represent actual total electricity consumption in precise quality due to several reporting problems, especially with respect to self-consumption. However, these are the only available data with sufficiently high frequency. Moreover, the ENTSO-E data is consistent with the other data we use. We therefore rely on the ENTSO-E data, which also represents the industry standard.

A total of 96 hours in our sample has missing values for predicted load. We replace the corresponding missing entries with the realised load levels whenever the latter are available.

4.2.4. Data on available capacity

We obtain information on available capacity from the EEX transparency platform and screen all documented capacity reports for the last available date before actual production. Thus, we typically capture the day-ahead reported availabilities.

Due to shortcomings of the EEX transparency platform when updating their server in 2016, available capacity reports from the first semester of 2016 are completely missing. Discarding the whole semester for the analysis would significantly reduce our sample. As a means of interpolation, we alternatively use the median reported available capacity within the time frame from 29 July 2015 and 28 July 2017 which amounts to 17.686 GW. In other words, half of the daily reported values are above this number, while the other half is below. Note that the distribution of records of available capacity for lignite is left-skewed such that our median capacity is much closer to the maximum observed available capacity of 20.044 GW rather than to the minimum observed capacity (see Fig. 2). Details and validity checks are reported later in conjunction with the empirical analysis.

[3] See http://www.agora-energiewende.de/agorameter.

Table 1
Must-run capacities based on Consentec (2016).

Fuel type	Capacity in MW
Lignite	8526.3
Uranium	6981.7
Coal	2587.3
Gas	1901.3
Oil	62.0
Garbage	148.3
Run-of-the-river	118.3
Pumped-storage	70.3
Seasonal store	18.3
Other	869.0

4.2.5. Data on 'must-run' capacities

As explained before, the definition of must-run capacities is vague, and a clear cut quantification is missing. The crucial characteristic of must-run capacities for this analysis is that they are by definition not responding to electricity price level. Technologies that are more expensive could thus alter the residual load for lignite. Moreover, some parts of the lignite plants might also be 'must-run' capacities and therefore would not bid according to marginal costs. We use the results of Consentec (2016) as a measure of must-run capacities, which are considered to be generating independently of the price level. Averaging over the three different scenarios in Consentec (2016) yields quantities for must-run capacities as given in Table 1.

4.3. Results on marginality according to residual load

4.3.1. Marginality based on simple residual load

Taking all information together, we obtain our data set with the variables for the residual load calculation as described in Table 2.

In total, we have 17,532 complete hourly observations, except for the available capacity of lignite. Residual load for lignite power plants is calculated as system load minus the generation from technologies that are considered to run at lower marginal costs (thus being inframarginal compared to lignite). We consider the following technologies to fulfil this condition: uranium, run-of-the-river, garbage, wind, solar, biomass.

To illustrate our approach consider Fig. 3. It shows (from top to bottom) day-ahead predicted load plus net export (black line), planned production from technologies that are considered to be inframarginal (shaded area in light blue), and the reported available capacity of lignite (dark brown shaded area) over the course of our sample period. Residual demand for lignite is therefore given by the lower border of the light blue shaded area. The occurrences where residual demand dips into the range of available capacity of lignite are those which can be considered to be hours where lignite would be marginal (not yet accounting for must-run technologies). The first half of 2016 shows the large gap in the time series of available capacities. For not completely discarding this period, one has to assume some form of interpolation for the available capacity of lignite. In our case, we chose the median value of those values that we do observe, depicted by the dashed, red line below.

Evaluating our sample for the marginality of lignite, using the median available capacity of lignite for interpolation, we obtain 541 hours out of 17,532 fulfilling the marginality condition. This corresponds to 3.1 percent of all hours in our sample.

4.3.2. Sensitivity with respect to interpolation

The graphical presentation in Fig. 3 indicates that the actual reported available capacities do not vary much around the median and drop more prominently below, rather than above. This suggests that the median could serve as a good proxy for the missing data. To get a better understanding of how well the median proxies actual available capacities in relation to residual load, we compare both methods on

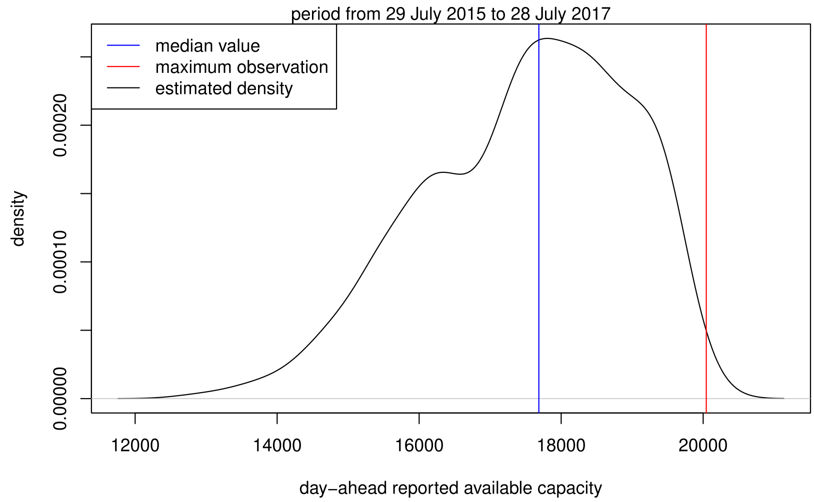

Fig. 2. Available capacity reporting for lignite.

Table 2
Descriptive statistics for data on quantities.

Variable	Min	Median	Max	Observations	Missing
Predicted load	38 131	62 359	85 600	17 540	4
Planned generation nuclear	2 852	8 174	9 926	17 542	2
Planned generation garbage	8	136	222	17 542	2
Planned generation run-of-the-river	221	1 690	4 302	17 542	2
Predicted wind and solar	5 891	17 969	58 090	17 533	11
Net exports	−7 065	4 675	13 744	17 542	2
Available lignite capacity	12 852	17 686	20 044	13 369	4175
Inframarg	13 284	27 968	69 423	17 533	11

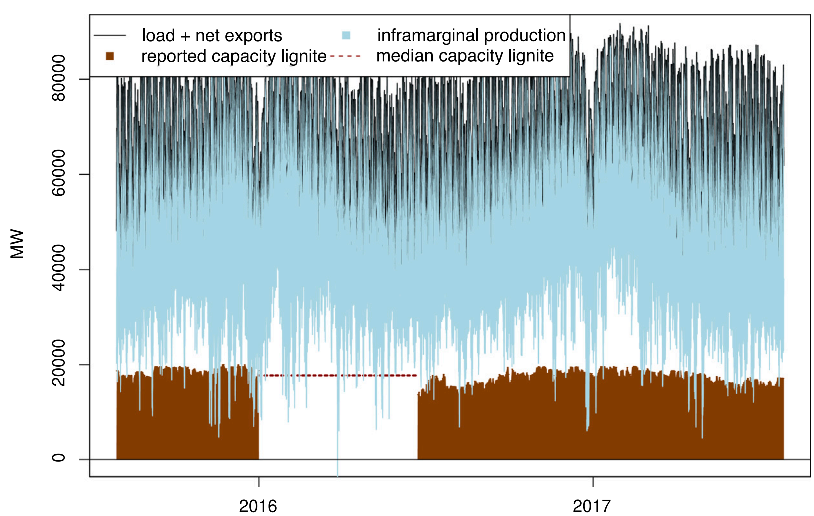

Fig. 3. Residual load and available capacity. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

the same reduced sample. Precisely, we calculate the ratio of marginal hours for lignite solely based on the sample where we have actual reports and compare this ratio with the ratio that one obtains, using only the median capacity on the same sample. We find 2.8 percent of hours in which lignite is likely marginal using the actual reports, compared to 3.2 when using the median of the available capacity as a proxy. This suggests that our approach using the median rather overestimates the number of hours where lignite is marginal compared to the actual reports. This is not surprising in light of the skewed distribution of available capacity, showing that the median is closer to the maximum rather than the minimum. Overall, both numbers are still very close, which makes us confident that the interpolation we used before is a good approximation.

4.3.3. Accounting for must-run capacities

The previous numbers do not take into account that several capacities might be must-run. This applies e.g. to hard coal or gas fired plants, which would then be placed in the merit order before lignite plants. But it would also apply to parts of the lignite plants. Plants that must run are by definition not reacting to price signals and are therefore not price setting in the sense of marginal-cost-based pricing. As discussed above, information on capacities that ‘must run’ and to what degree this ‘must’ applies is sparse. As an approximation, we are using the information from Consentec (2016) to account for must-run capacities by technology. In the following, we add must-run capacities for technologies which had not yet been declared to be inframarginal (e.g. hard coal, gas, oil,…) to the block of inframarginal production.

On the other hand, we consider only those available capacities of lignite power plants to be potentially price setting, which exceed the capacities that are declared to 'must run'.

Fig. 4 depicts again predicted load plus net exports in black. But now, we subtract the must-run capacities of more expensive technologies (coal, gas, etc. in pink). Again, we subtract the production from cheaper, inframarginal technologies (nuclear, renewables in light blue) to obtain residual demand for lignite (lower border of the light blue shaded area). Reported available capacities of lignite are depicted in dark brown as before. We moreover account for the must-run capacities of lignite, which cannot be price setting. They are marked below in light grey.

For this modified setting, we find 1344 hours fulfilling the marginality criterion based on the interpolation of missing availability data with the median. This corresponds to 7.7 percent of hours in our sample. When using only those hours for which we have full capacity reports, we find 7 percent of hours fulfilling the marginality criterion, while when we use the median as a proxy for available capacity over the full sample, we find 8.3 percent. Again, this points out that our interpolation using the median is overstating rather than understating the importance of lignite as a price setting technology.

4.3.4. Robustness check: maximum available capacity

Our analysis takes different approaches to determine residual demand for lignite plants and compares it to reported available capacities where possible. We moreover use an interpolation for periods where availably capacity reports are missing, and check the sensitivity of this approximation. The chosen method (taking the median) is found to exaggerate rather than underestimate the relevance of lignite as a marginal technology. As another robustness check for this interpolation, we repeat the analysis using the clearly exaggerating assumption that available capacity in the time where reports are missing had been at the maximum value we observe in our sample. Under this maximum assumption, we find 3.7 percent of our sample to fulfil the marginality condition, not taking potential must-run capacities into account, and 9 percent when accounting for must-run capacities as detailed above. Note that these values are still clearly below 10 percent, even though these values are exaggerated due to the maximum assumption on available capacity.

5. Analysis of marginality according to marginal costs

5.1. The approach based on marginal cost calculation

In the first approach, we have drawn conclusions on the relevance of lignite as a price setting technology from demand, production, and available capacity. Such a quantity-based analysis evidently depends on a number of assumptions concerning the merit order and the price responsiveness of power plants. The second approach takes a different perspective on the same question, drawing conclusions from realised prices and production costs. Lignite power plants are considered to be price setting when market conditions are such that lignite plants can recover their marginal costs (meaning they are "in the money"), but more expensive competitors cannot (putting the latter "out of the money"). We are thus interested in the price range that spans between the marginal costs of lignite power plants and the closest marginal competitor, usually hard coal fired plants. We then identify how often the observed prices fall within this price range, suggesting that lignite plants have been price-setting during the corresponding periods.

This approach does not depend on observed quantities or assumptions about must-run capacities. Recall that start-up or ramping costs can render adjustments to short term price changes too expensive for large scale power plants. The day-ahead market for electric power at EPEXSpot accounts for such kind of frictions by allowing "block-bids". The standard traded unit in the day-ahead market is the delivery of electric power during a specific hour of the following day. Block-bids allow tying together several hour-contracts to larger blocks of hours. Common blocks are "base load" or "peak load" blocks, which capture all 24 hours, or all hours from 8 a.m. to 8 p.m., respectively. A selling bid, for example, is executed when the average price for all covered hours is above the price limit of the seller. The seller has then sold power for all hours of the block, although the price for power in some of these hours might be below the variable production cost of the producing plant. For an outsider, observing a plant producing at prices below its marginal costs appears to be a "must-run" capacity, although this plant might go offline when low prices prevail for a longer period.

It is simple to account for such block-bidding in our price-based approach. In the following, we consider day-ahead prices for the full block of 24 hours. These blocks are traded one day ahead at noon, leaving 12 hours before delivery begins. A conventional coal or lignite plant with limited flexibility can sell such a block and still has half a day to ramp up without the need to adjust production during the day. The plant could thus be marginal for the whole day on average, although in the shorter run, we see price variations between different hours. Thus, we consider this approach to be more robust with respect to ramping and the specification of must-run technologies. On the other hand, we have to rely on estimates for the marginal costs of lignite and hard coal plants, based on the data we describe in the following.

5.2. Data on prices and cost

5.2.1. Data on prices for electricity and emission allowances

We obtain hourly day ahead auction prices for the German-Austrian bidding zone from EEX for the time period from 29 July 2015 to 28 July 2017. The hourly prices are averaged on a daily basis which is equivalent to the *Physical Electricity Index* Phelix. EU emission allowances prices are obtained from the EUA spot market at EEX.

5.2.2. Data on the cost of power production from lignite

Lignite is hardly traded and usually produced close to the actual plant it fires. The most recent study on the production cost of lignite in Germany is from Öko-Institut (2017). They distinguish production costs of older and newer plants. As a lower bound for our relevant price range, we are interested in the lowest marginal costs of lignite, which correspond to newer and more efficient plants. For newer lignite plants, Öko-Institut (2017) estimates marginal fuel costs of 3.6 Euro per Megawatt hour (MWh) electric output and additional variable costs of 2 Euro per MWh electric output. The study moreover reports specific CO_2 emissions of 963 kilogramme (kg) per MWh electric output. Together with the EUA prices, we can approximate daily marginal costs for the production of electric power from lignite by summing up variable cost, fuel cost, and emission cost per MWh electric output.

5.2.3. Data on the cost of power production from hard coal

For the price of hard coal, we refer to the weekly McCloskey MCIS Marker coal price index for North-West Europe. It is normalised to the price of hard coal with a calorific value of 6000 kilocalories (kcal) per kg for delivery in the Amsterdam–Rotterdam–Antwerp (ARA) region harbours. We translate the price into Euro values, using the European Central Banks (ECB) official USD/EUR daily exchange rate. We moreover adjust the price per ton to represent the inner German 2015 average heat rate for hard coal of 6448 kcal/kg (Arbeitsgemeinschaft Energiebilanzen, 2017). To account for shipping costs from ARA to Germany, we add costs of 1.53 Euro per ton as suggested by BAFA (2016). Finally, we attribute the weekly published price index to each following day after its publication until a new price observation is available.

As we are interested in the closest competitor to lignite, we look for the lowest marginal costs of a hard coal plant. We observe efficiency rates of 0.465 for the most efficient German hard coal plant based on the data gathered by *Open-Power-System-Data.org*. With respect to the CO_2 content of the fuel, we refer to Juhrich (2016), reporting 93.6

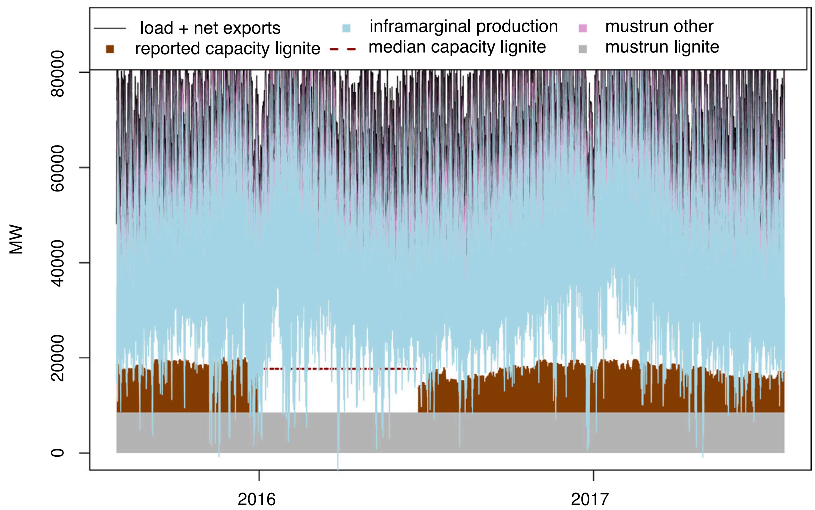

Fig. 4. Residual load, available capacity, and must-run capacities. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

ton CO_2 per Terajoule (TJ) thermal input for hard coal. From these numbers, we can calculate fuel cost per MWh electric output for the most efficient hard coal plant. Together with the CO_2 price data, we can moreover calculate the emissions cost per MWh electric output. Finally, we are lacking precise estimates on further marginal cost components such as wear-and-tear. As a proxy, we use the same amount of 2 Euro per MWh electric output as for the lignite plants.

5.3. Results on marginality according to marginal costs

5.3.1. Marginality according to marginal costs

Fig. 5 depicts the evolution of marginal costs for hard coal and lignite plants that we calculate based on the efficiency levels, CO_2 contents, input prices, and further variable costs as detailed above.

The range between the marginal costs of these two types of fuels (here shaded in light brown) can be expected to be the price range in which lignite power plants are price setting. The following graph (Fig. 6) puts on a larger scale the daily average power prices (physical electricity index, "Phelix") in comparison to the marginal costs.

It is evident that over the course of this period, power prices are typically above the marginal costs of hard coal fired power plants and just occasionally fall into the cost range that spans between lignite and hard coal. This suggests that usually more expensive technologies than lignite are price setting in the day-ahead market.

However, we also observe power prices dipping below the marginal costs of lignite, thus implying that coal and lignite plants would have been out of the market altogether. Precisely, we find that power prices are in between the marginal costs of lignite and hard coal for 90 days of our sample, which covers 731 days in total. In relative terms, the days where lignite would be potentially marginal correspond to 12.3 percent of the total number of days within our observed time period.

5.3.2. Robustness checks: fuel switch

Throughout this study, we have largely considered the merit order to be stable across generation technologies. In other words: while we did allow costs to fluctuate for different fuels, we did not consider the case where marginal costs of different technologies switch their order.

For the case of hard coal and lignite, we can see from Figs. 5 and 6 that, within our sample period, such a switch is clearly out of reach. Lignite fuel is produced at very low cost on-site. All the dynamics we see in marginal costs for electricity production from lignite are due to varying CO_2 prices. Hard coal, on the other hand, is imported at world market prices. Freight costs and emission costs apply on top. While lignite is slightly more emission intensive than hard coal, higher CO_2 prices still drive marginal costs for both technologies. The relative difference in emission intensity is not as large as it is between hard coal and gas. Thus, the leverage of CO_2 prices is moderate when comparing hard coal with lignite. For a fuel switch to occur, one would need to see a drastic drop in prices for hard coal and/or a drastic increase in prices for emission allowances to compensate for the fuel price advantage that lignite currently enjoys. Let us consider what the implications would be if any other fuels switched order:

Let us first consider the case of a fuel switch between lignite and cheaper technologies. Possible candidates are wind, solar, biomass, hydro, and nuclear. The marginal costs of renewables can reasonably be considered to be zero. While this is not entirely true for biomass, biomass capacities in Germany are remunerated through a specific feed-in tariff, which puts them for the merit order into the same category as wind or solar. As lignite has evidently non-zero marginal costs, a fuel switch of lignite and one of the renewable technology appears to be out of reach.

Nuclear, in contrast, has positive, but small and rather stable fuel costs. A switch with lignite appears to be unlikely. But even if such a switch occurred, what would be the consequence? Consider Figs. 5 and 6 depicting the range of costs between lignite and hard coal: In case some cheaper technology took the position of lignite, this new fuel would become the new closest competitor. Thus, the cost range in which lignite can be considered to be marginal would shrink.

Consider now the case of a fuel switch at the other end of the merit order, e.g. between hard coal and natural gas. Such a change of relative position is not impossible and has been witnessed in several markets before (e.g. in the USA in conjunction with decreasing natural gas prices). Again, in Figs. 5 and 6, if we had a fuel switch at the upper end, there would be a new closest competitor upwards, e.g. natural gas instead of hard coal, and the relevant cost range would become smaller. Thus, considering fuel switching would drive our results even further down, pointing to less importance of lignite as a price setting technology.

In summary, the possibility of a fuel switch would rather decrease the likelihood of lignite being marginal. As we solely considered hard coal as a closest competitor here, we are rather over-estimating the relevance of lignite as a marginal technology, which could also explain our larger findings here compared to the quantity-based approach.

5.3.3. Robustness check: peak and off peak prices

The analysis of costs and prices has yet focused on daily average prices. This allows overcoming the implausible assumption that lignite plants can adjust quickly to hourly price changes. In contrast, by

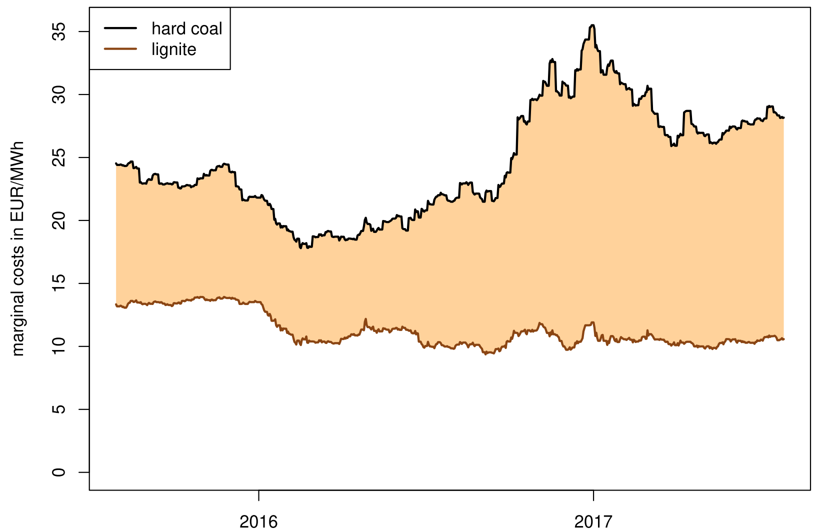

Fig. 5. Marginal cost range between lignite and hard coal.

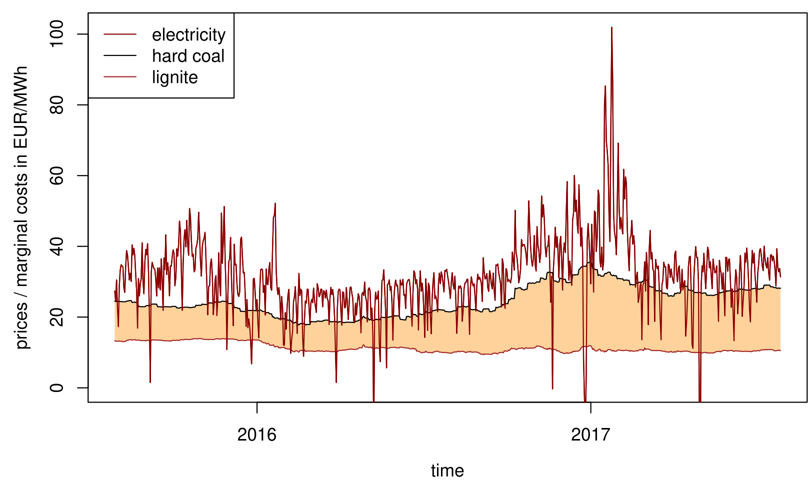

Fig. 6. Power prices and marginal cost range between lignite and hard coal.

bidding for complete days, the marginal cost of lignite plants might have an important effect on the equilibrium price for electricity. These daily averages obviously wash down price variation, e.g. between night and day hours. One might thus wonder if evaluating complete days could mask the marginality of lignite plants specifically during the off-peak hours. Therefore, we split our hourly prices into blocks between 8 a.m. and 8 p.m., capturing prices during the day and between 8 p.m. and 8 a.m. for the night. For not splitting two consecutive nights in half, we have shifted the last four hours of each day to the next day. Thus, we calculate an average price per night, capturing 12 consecutive hours. Doing so, and comparing the corresponding prices with our marginal cost range, gives us 87 day-time averages as well as 130 nights where prices are in that range. In total, this amounts to 14.8 percent of all days or nights.

As an extreme case, one could assume lignite plants to be completely flexible and to adjust production to every price change in the day-ahead-market. Disaggregating our measure down to the hourly level, we observe that 2574 out of 17 544 h in our sample (14.7 percent) fulfil this criterion.

Note, however, that for this to be appropriate, we would need to assume that lignite plants are capable of ramping up and down sufficiently quickly to adjust to shorter price changes on a 12 h or even the hourly level. Thus, again, these numbers are likely to exaggerate the relevance of lignite plants as price-setting technologies.

6. Conclusion and policy implications

We have presented two different approaches to evaluate the relevance of specific power production technologies to be price setting. One approach solely focuses on quantity data and takes a merit order of technologies as given. Comparing the derived residual demand with available capacity provides an indicator for the technology in question to be price-setting. Neither price nor cost data is needed. The other approach is independent of any quantity data by simply calculating minimal marginal costs for competing technologies. Comparing the range between those costs with realised wholesale electricity prices provides an alternative measure for the price-setting generation technology. Both approaches are computationally simple and lightweight and use data which is usually available for most power markets. Moreover, the approaches are based on a number of assumptions that are frequently made in the study of power markets. But as both approaches vary in the assumptions they require and in the data they use, comparing the obtained indicators from either approach can be informative.

We apply both approaches to assess to which extent lignite power plants are price-setting in the Austrian–German power market. The main contribution of this application is to show that a range of differently obtained numbers all provide the same message: most of the times, lignite is not setting the price. Thereby, the two approaches complement each other as they differ by their advantages and underlying assumptions. For example, a major advantage of the cost-based approach is the capability to accommodate short-run inflexibilities in electricity generation by using daily average prices. Thus, there are days for which lignite is determined to be marginal based on the price-cost comparison. But, based on the residual load approach, one might find that the individual hours of these days do not indicate that lignite plants are marginal because they are either inframarginal or out of the market in the majority of hours, when assuming that all plants flexibly adjust their production. This example illustrates that both approaches are complementary and their joint application offers additional insights. By applying both approaches, we can assess the sensitivity of results that originate from the different assumptions and investigate the importance of these assumptions in the particular setting.

In different cases, the assumptions of one or the other approach may be more or less plausible. For example, the cost based approach might be preferred if prices and costs are transparent and inflexibilities are considered to be important (as for hard coal or in our example of lignite power in the German-Austrian market). On the contrary, when we want to assess the marginality of more flexible technologies, such as gas or hydro power, the residual load based approach may be preferable. Overall, we recommend to apply both approaches to investigate whether qualitatively similar conclusions can be drawn. If this is not the case, one might give more weight to one or the other approach based on data quality and the characteristics of the system. For our case of lignite power in the German-Austrian market, overall results from both approaches are comparable. For example, the frequency of hours for which lignite is marginal in the residual load approach is around six times higher on days where lignite is marginal based on the cost based approach compared to days where this criterion is not fulfilled.

Our analyses suggest that lignite plants are price setting for more than 3 to 7 percent, but evidently less than 15 percent of all observed periods in our sample, spanning from 29 July 2015 to 28 July 2017. This result contrasts with the average contribution of lignite power in the German-Austrian bidding zone, in which lignite plants had an average share of 39 percent in fossil fuel power production over the years 2005 to 2015. Evidently, the share in production and the relevance as a price setting technology of lignite clearly diverge. While this insight might be trivial for experts, it is of relevance for policies that are implemented in a couple of EU member states. The European Commission allows to compensate electricity intensive sectors for incurred indirect CO_2 costs that are passed-on by power producers through the electricity price. A key ingredient for the calculation of the compensation payments are emission intensities of power production defined by the European Commission that are based on the average contribution of specific fuels to the mix of fossil fuel fired power production. Here, lignite is the most emission intensive technology, but is found to be inframarginal for most of the time.

Consequently, our analysis illustrates the potential fallacies that occur if policies ignore the relevance of marginality in power generation. In the example of the EU compensation scheme for indirect CO_2 costs, our results suggest that the weight of lignite in the specified regional emission factor is likely too high. A possible alternative approach would be to ban lignite completely from the calculation of the average emission intensity. In this case, the calculated emission factor in the period from 2005 to 2015 would drop from around 0.733 to around 0.608 ton CO_2 per MWh, representing a decrease of about 17 percent. Since the emission factor enters the formula for the compensation payments in a multiplicative way, reducing the emission factor by 17 percent leads to lower compensation payments by the same order.

Doing so, however, would assume that lignite is not marginal in any hours (like it is currently assumed for nuclear or renewable capacities as well). A more accurate approach would capture lignite's and the other fuels' relevance as price-setting technologies. Focusing only on lignite, our analysis suggests that just 3 to less than 15 percent of the emissions and electricity generated by lignite power plants should enter the calculation of the emission factor. Assuming that the other fossil fuels' emission intensities still enter according to their average contribution would then yield an emission factor of about 0.622 or 0.668 ton CO_2 per MWh, respectively. Note, however, that not only the proportion of natural gas and hard coal being marginal might differ as well from their average share in total production, but also that we have found emission free technologies, such as nuclear or renewable power to be price-setting during several hours of our sample period.

To translate these factors into monetary terms, consider the total compensation payments in Germany in 2017 of about 202 million Euros (UBA, 2019). Since compensation payments scale linearly with the emission factor, reducing the emission factor by about 15 (with 3 percent lignite being marginal) and 9 percent (with 15 percent lignite marginal) lowers total compensation payments to about 172 and 184 million Euros, respectively. While the absolute reductions of about 18 to 30 million Euros in 2017 may seem not substantial, those compensation payments reflect rather low EU ETS prices at that time with compensation in 2017 being based on a price of 5.40 Euro per ton of CO_2. Using the current prices of around 25 Euros per ton CO_2, total compensation payments would increase to around 935 million Euros, with potential reductions to about 794 and 853 million Euros, respectively, through the adjustment of lignite in the emission factor. Ultimately, a comprehensive analysis on appropriate emission factors and targeted compensation level would have to study the extent of marginality for all different technologies, and their emission intensities. However, such an analysis is out of the scope of this paper.

We propose the two approaches in this paper with the intention to provide a useful tool for policy analysis beyond the specific example addressed here. This relates in particular to the evaluation of energy policy impacts that work through electricity prices, which is a common issue in many economic impact evaluations of national and international energy policies. Evidence on price-setting technologies in electricity generation is much needed for other technologies, countries and time periods, which is again, unfortunately, out of the scope of this paper.

When applying our approaches to other generation technologies and/or other geographic areas, focussing on a single country/price-zone within the increasingly connected European electricity market may become an issue. For example, Blume-Werry et al. (2018) found that the price-setting (marginal) plant in a country does not have to be located within the same country. While this issue is potentially less important in our analysis given the amount of relatively low cost generation available in Germany (compared to neighbouring countries) and the inclusion of imports and exports of electricity, it may be an important shortcoming of this approach applied to a small market setting.[4]

Another avenue for application of the proposed methods would be a rule based and dynamic adjustment of energy policy parameters. Our study suggests that alternative procedures for the parametrisation of compensation policies are available and that these approaches can be implemented in a transparent and computationally non-demanding manner. Based on a predefined set of assumptions and data sources, our approaches could be used for a dynamic updating of compensation levels as the crucial policy parameters, depending on power prices and their constituents.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

[4] We are grateful to an anonymous referee pointing out this aspect.

CRediT authorship contribution statement

Robert Germeshausen: Conceptualization, Formal analysis, Methodology, Software, Data curation, Writing - original draft, Visualization, Validation, Writing - review & editing. **Nikolas Wölfing:** Conceptualization, Formal analysis, Methodology, Software, Data curation, Writing - original draft, Visualization, Validation, Writing - review & editing.

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