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# The Role of Natural Gas in Electricity Prices in Europe

UCL Institute for Sustainable Resources

Series *Navigating the Energy-Climate Crises*

Working Paper #1

**Behnam Zakeri, Iain Staffell**

with Paul E. Dodds, Michael Grubb, Paul Ekins, Jaakko Jääskeläinen, Samuel Cross, Kristo Helin, Giorgio Castagneto Gissey

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This paper quantifies the role of fossil-fuelled vs. low-carbon electricity generation in shaping wholesale electricity prices across European countries, based on historical data using open, sub/hourly power system data between 2015-2021. We find that, despite a declining share in electricity generation, fossil fuels are still the main power plants "at the margin", and hence setting the wholesale electricity price. With updated analysis, we find that averaged across Europe overall, in 2021 fossil fuels set the price about 58% of the time whilst generating only 34% of electricity per year. This was a slight decline from the values in 2019 (when fossil fuels set the price 66% of the time, with 37% of the generation).

However the trend in the UK was opposite: in 2021, gas set the electricity price 98% of the time, whilst generating just over 40% of electricity; non-fossil sources set the price the other 2% of the time. This was a marked change from the years 2015-2019, when gas set the price 80-90% of the time, with lower-cost imports through interconnectors setting the price for the rest. Overall, in 2021 fossil fuels set the electricity price more than 90% of the time in seven European countries, due to varied factors increasing the role of natural gas prices. As most of Europe (including the UK) imports most of its natural gas from outside Europe, this amplifies exposure of electricity prices to the geopolitical risks of gas supply, as well as the economic risks of currency exchange and natural gas price volatility.

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**Keywords:** energy market coupling, energy policy, energy security, electricity market, renewable energy systems, sustainable energy, energy model.

**Journal of Economic Literature (JEL) Classification Codes:** D4, Q4

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## About this publication

This publication is released as Working Paper 1 in the UCL Institute for Sustainable Resources series Navigating the Energy-Climate Crises. It comprises an underlying research paper from previous research, available as a preprint on SSRN from 23rd July 2022[1], updated by the authors, 13th January 2023.


### Corresponding Author

Dr. Behnam Zakeri, zakeri@iiasa.ac.at, +43 (0) 67683807532, Schlossplatz 1, 2361 Laxenburg, Austria



### Acknowledgements

The underlying research arose within the EU H-2020 RE-INVEST project. Individual authors acknowledge additional support from Ofgem (ACE project, Con-Spec-2018-006), and EPSRC (IDLES programme EP/R045518/1). See Acknowledgements (section 7).

NECC Series produced with support from the Aldersgate Group and Institute for New Economic Thinking.


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Email: m.grubb@ucl.ac.uk. Twitter:@michaelgrubb9 @UCL_ISR


[1] Full citation: Zakeri, Behnam and Staffell, Iain and Dodds, Paul and Grubb, Michael and Ekins, Paul and Jääskeläinen, Jaakko and Cross, Samuel and Helin, Kristo and Castagneto-Gissey, Giorgio, Energy Transitions in Europe – Role of Natural Gas in Electricity Prices (July 23, 2022). Available at SSRN: https://ssrn.com/abstract=4170906 or http://dx.doi.org/10.2139/ssrn.4170906

# 1 Introduction

The unprecedented hike in energy prices in Europe in 2021-22 has raised questions about the impact of European energy transitions [1]. EU energy policy has been centred around increasing the share of renewable energy sources (RES) [2] to enhance energy security and reduce energy prices for consumers in the Union; the two goals that are played down by the current energy crisis. Transitioning from energy systems based on fossil fuel to variable renewable energy (VRE), such as wind and solar photovoltaic (PV), have complex impacts on electricity markets. These can be seen, *inter alia*, through the impact of VRE on price volatility [3]; flexibility, balancing, and storage requirements for integrating VRE [4]; the operation and phase-out of thermal (including nuclear) power plants in the presence of VRE [5]; market design for accommodating high shares of VRE [6]; and policies for promoting distributed VRE generation and storage [7]. The impact of the renewable energy transition in Europe on the formation of electricity prices is another policy question that is difficult to answer, especially as a quantified share of each electricity generation type in setting electricity prices at the European scale. This paper aims to answer this question.

## 1.1 Formation of electricity prices and renewable energy

In energy-only markets, a power plant with a higher merit, i.e., lower marginal cost of electricity generation, is always given a higher priority in dispatch and access to the grid compared to a more expensive one [8]. On the other hand, the electricity price is set by the most expensive supply bid accepted in the market, typically from technologies with a relatively high marginal cost and located "at the margin", i.e., at the far-right side of the marginal-cost driven supply-cost curve [9]. As low-cost RES such as wind and solar PV are growing in the power supply mix, more expensive generation plants such as fossil fuels are being pushed outside the supply mix or further at the margin – a phenomenon known as the "merit order" effect [10].

The impact of the renewable energy transition on the dynamics of electricity prices has been widely studied in the past. The merit order effect of renewables in the Austro-German electricity market is studied in [11]; the role of VRE in electricity price formation is shown in [12]; and the impact of VRE on price volatility in North-West Europe is analysed by [13]. Moreover, the impact of renewables on end-user prices and the affordability of electricity to consumers has been discussed, both from the perspective of feed-in-tariffs [14], dynamic retail pricing [15], and onsite generation [16].

Previous work has considered the concept of plants at the margin (or marginal plants) in different countries. Germeshausen and Wölfing [17] explores the impact of lignite on marginal prices in Germany between 2015-2017. They apply a combination of quantity- and price-based approaches to estimate the time of year a power plant can be at the margin. Staffell [18] measures the progress and implications of decarbonising the British electricity system, considering the marginal generation mix displaced by wind and solar PV without explicitly considering the role of these plants in the electricity price. Blume-Werry et al. [19] analyse price-setting power plants in the power market by modelling a future Dutch system, emphasizing the role of cross-border interconnectors on final electricity prices. Using long-term simulations, Green and Staffell [20] demonstrate that fossil fuel-based generation will remain an important portion of the least-cost generation mix in UK for decades to come, even in high-share RES scenarios with strong carbon pricing. They infer that thermal power plants will play an important role at the margin due to the needs for flexibility and dispatchable generation.

These studies have improved our understanding of the formation of electricity prices and the role of renewable energy transitions. However, the literature on marginal shares has been focused either on one or a few countries, e.g., Portugal [21], Spain [14], Germany [10], and/or derive their conclusions based on simulations of power systems into the future without analysing historical data, e.g., UK 2020-2040 [22], EU 2020 [23] and EU 2030 [24]. Those studies with a focus on historical data are either limited in geographical scope, e.g., to Germany 2007-2012 [25], and Germany-France 2015-2017 [17], or the conclusions may be outdated if at the European scale, e.g., EU-27 1990-2010 [3]. As such, there seems to be a need for a systematic analysis of the energy transitions in Europe based on recent historical data in relation to (i) the role of different electricity generation technologies in the formation of electricity prices, and (ii) the implications of this for energy security and affordability in Europe. We aim to contribute to this gap, which is the ongoing policy debate in Europe.

## 1.2 Contribution of this study

By applying an econometric analysis and looking into the historical power system data of EU27[1] plus United Kingdom (UK) and Norway (hereafter, EU27+) over the past seven years (2015-2021), we analyse the impact of energy transitions in Europe on electricity prices. More specifically, we explore the share of each electricity generation type that has been responsible for setting electricity prices in each country and in Europe, overall. The focus of the literature to date has been primarily on the impact of fossil-fuel and renewable electricity on energy security alone [26], or geopolitical conflicts with regions exporting fossil fuels to Europe [27]. Furthermore, we discuss the question of energy security beyond geopolitical aspects of import dependency by studying the role of fossil fuels on international dependence of electricity prices. This dependency induces risks of currency exchange rate fluctuations that may affect the affordability of electricity to consumers.

The advent of near-zero marginal cost renewables may drive down baseload electricity prices [28], but fuel-based electricity generation is likely to continue to set peak prices, so will

[1] In this paper, EU-27 refers to the EU Member States after Brexit, abbreviated as AT: Austria, BE: Belgium, BG: Bulgaria, CY: Cyprus, CZ: Czech Republic, DE: Germany, DK: Denmark, EE: Estonia, ES: Spain, FI: Finland, FR: France, GR: Greece, HR: Croatia, HU: Hungary, IE: Ireland, IT: Italy, LT: Lithuania, LU: Luxembourg, LV: Latvia, MA: Malta, NL: Netherlands, PL: Poland, PT: Portugal, RO: Romania, SE: Sweden, SI: Slovenia, SK: Slovakia. For hourly data analysis, three countries are excluded due to lack of data or their island situation, namely, LU, CY, and MA.

profoundly affect the wholesale prices, which are the largest component of electricity costs for European consumers [29]. Hence, this paper can be useful in assisting policymakers to design measures aimed to limit the influence of fossil fuel electricity generators on electricity prices. This will become increasingly important, as the share of renewables grows, while carbon-intensive generators such as natural gas still provide the flexibility required to integrate VRE into the grid.

The remainder of this work is structured as follows. Section 2 provides background information about European renewable energy policy and progress in the past decade. Section 3 presents our methodology, its novelty and limitations, and data analysis. Section 4 explores main results, which are discussed in Section 5. Conclusions are presented in Section 6.

# 2 EU Energy Policy

The objectives of EU Energy policy to date have been dominated by the 2020 targets, implemented in 2009 [30]. These targets comprised a 20% target for carbon emission reduction (against 1990 emissions), a 20% target for improving energy efficiency, and a 20% share of RES in final energy demand. The EU achieved the renewable energy target, having increased its share of RES in final energy demand from 8.5% in 2005 to more than 21% by the end of 2020 [31] and for RES-Electricity from 16% to 34% (figures are for EU-27 without UK) [32]. For the carbon target, the EU is significantly ahead of its objective, having reduced carbon emissions by 24% from 1990 to 2019 [33]. These achievements underline the significant shift in the energy sector in the last decade driven by EU-level policy. However, EU countries import more than 58% of their energy needs from outside the Union, including mainly petroleum products and natural gas [34].

Targets for 2030 were proposed in 2016 as part of the Clean Energy for Europeans package (CEP), and fully implemented into legislation by 2019. The carbon target for 2030 was set at 40%, and the Renewables target for "at least" 32% [35]. However, these targets were superseded as part of the EU Green Deal; the proposal for a new EU Climate Law within this package aims to reach carbon neutrality by 2050, increasing the 2030 carbon reduction objective to 55% [36], RES share up to 39%, and 67% for RES-Electricity [37].

## 2.1 Share of low-carbon electricity in Europe

Figure 1 shows the share of fossil fuel-based and low-carbon electricity generation in EU-27+ in 2021. The values are calculated based on the published hourly data on the ENTSO-E platform, subject to data curation and corrections which will be explained in Section 3.3. The European countries have a very diverse set of electricity generation mixes based on their energy resources and low-carbon transition pathways. While in some countries like France and Norway the power system is largely carbon-free, other countries such as Netherlands and Poland are still largely dependent on fossil fuels. The type of fossil fuel used in the countries varies too, from shale oil in Estonia, to coal mainly in Germany and Poland, and natural gas mostly in Italy, Greece, Netherlands, and UK. The share of fossil fuel generation varies substantially between European countries from 85% in Poland to less than 1% in Norway. Coal generation has reduced in all countries and has been almost eliminated in Spain and the UK. At the EU level, fossil fuels account for 34% of electricity generation, and the rest comes from low-carbon generation.

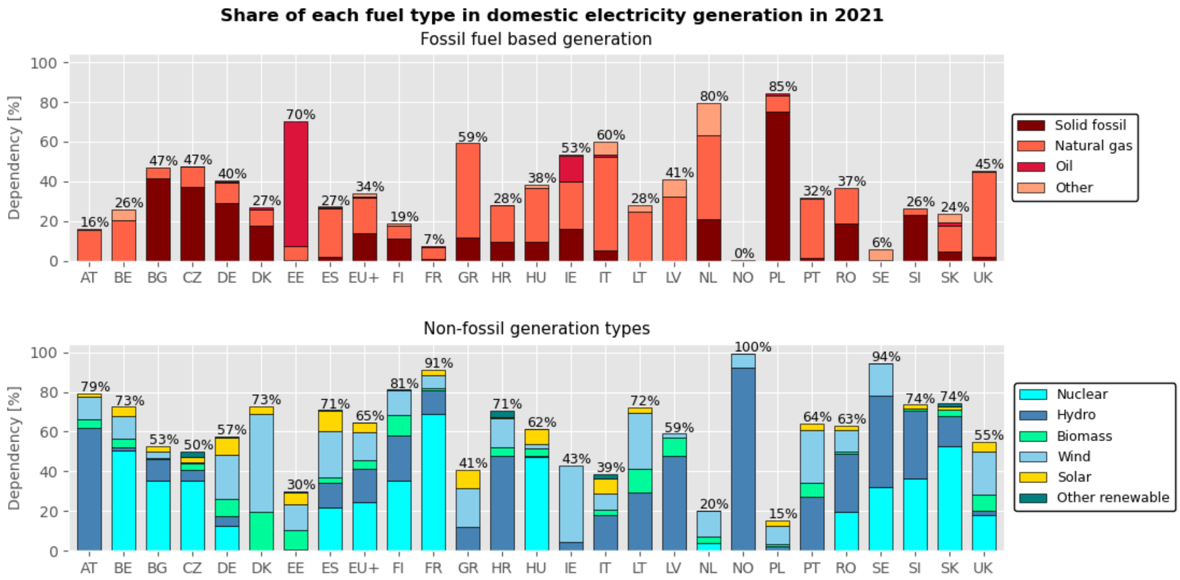


Figure 1 Share of fossil-based, renewable, and nuclear electricity in annual domestic power generation mix of EU-27 + UK and Norway in 2021. The values on top of each stacked bar show the total sum of the percentages of that bar.

## 2.2 Fossil fuels and electricity prices in Europe

The prices of fossil fuels have a substantial role in determining the market price of electricity in Europe. This is because of the market design that incentivizes pricing based on the short-term marginal costs of production, which is traditionally dominated by fuel costs. In Europe, natural gas and coal are the most dominant fossil fuels used for electricity generation (see Figure 1). Aside from market prices of fossil fuels, the relative competitiveness of these fuels is affected by the carbon emission price.

European countries have historically imported most natural gas by pipeline from the North Sea or Russia. Since storing and transporting gas is more expensive than for oil or coal, natural gas markets are less liquid and more volatile [38]. In recent years, especially after the Russian-Ukrainian war a number of import terminals for liquified natural gas (LNG) have been developed across Europe. Yet the EU remains highly dependent on pipeline gas from non-member countries [39].

Coal prices are lower than oil and gas but are also volatile. For example, in 2016, driven by low oil prices, both the price and consumption of coal fell substantially. This was followed by a substantial price rise, which was attributed to the increase in Chinese coal consumption [40]. Since coal has a higher carbon content per unit of energy than natural gas or oil, the coal price is most susceptible to carbon taxes.

Between 2012 and 2017, the EU ETS price remained broadly stable at around €5/t$CO_2$, and this was too low to influence the competitiveness of coal. However, the price of $CO_2$ started to grow significantly in 2018 due to the tightening of the supply of emission allowances through the Market Stability Reserve. The carbon price reached 30 €/t$CO_2$ in 2019, the highest level since 2008, and eventually over 80 €/t$CO_2$ in December 2021. This increase has had a positive impact on the competitiveness of existing gas power plants compared to coal plants in long term. Consequently, carbon emissions from the electricity sector in the EU27 declined by 16% in the year following the introduction of the Market Stability Reserve [41].

# 3 Methods and data

In the day-ahead electricity markets in Europe, demand and supply bids are received one day ahead of delivery, and the electricity price is derived based on market equilibrium rules for each hour of the actual delivery day [42]. In a marginal price-based market design, the system electricity price is equal to the largest accepted supply bid in a specific delivery time, which is the results of crossing many supply bids with the electricity demand curve. The electricity generation plants whose bid determines the system price are called "price setter", or "price maker", or "plants at the margin", while those with bids lower than this price are called "price taker" or "infra-marginal" plants. Figure 2 illustrates how electricity price is typically determined in a specific hour based on crossing electricity demand and supply bids.

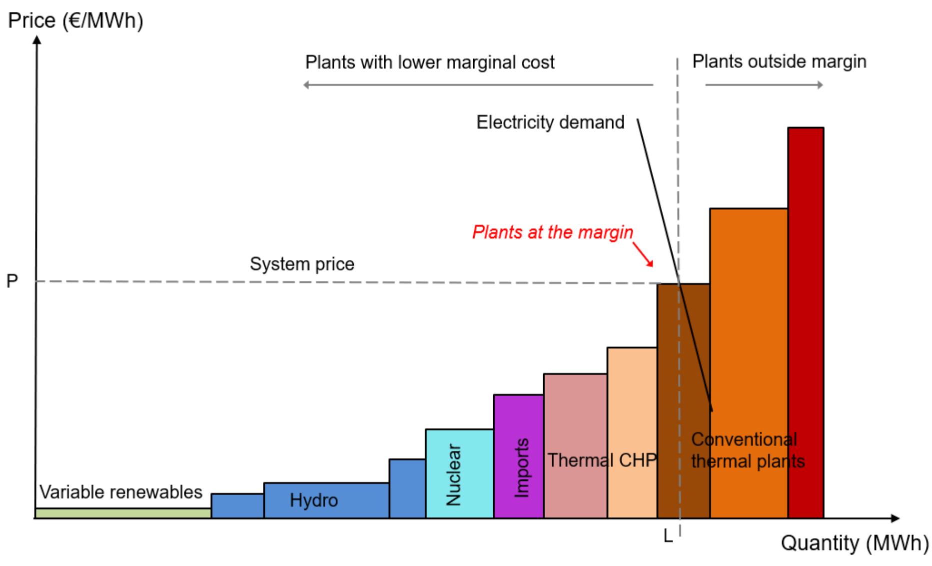


Figure 2 A simplified schematic of electricity supply-cost curve and the position of price setter power plants (plants at the margin) compared to plants with lower bids (inframarginal) at the left and higher bids at the right side. Letters L and P denote load and the system price in this hour.

Understanding the role of each generation mode in the formation of electricity prices, or the marginal share[2] of that generator, is an important topic in power market analyses for

[2] By "marginal share", we refer to the share of an electricity generator at the margin in a certain period. For example, a marginal share of 40% for technology A in a year means that technology has been at the margin (setting electricity prices) 40% of hours a year.

different reasons. Estimating future electricity prices is one of the motivations for determining the marginal share of different power plants, with respect to their age and possible retirement in the coming year [43]. Knowing which thermal generators are at the margin will help analysts to estimate the impact of $CO_2$ prices on the power prices and profitability of different generators [44]. Electricity generators estimate future prices and monitor the outcome of the market to apply different bidding strategies to maximize their profits [45]. The system operator follows prices closely to ensure the market is functioning well with affordable prices for consumers and sending the right signal for prospective investors and suppliers [46]. In the following, we briefly review different methods for estimating marginal shares with respect to their limitations and advantages (Section 3.1), the proposed method in this study (Section 3.2), and the data analysis steps (Section 3.3).

## 3.1 Literature review: Estimating marginal shares

Different modelling methods have been applied to analyse price-maker strategies at the power plant level, including bi-level optimization [47], risk-based two-stage stochastic modelling [48], and mixed integer programming [49]. At the national level, modelling methods based on aggregation of power plants or analysing the past data are needed to study the price impact of each generation mode. Macedo et al. [21] analyse wholesale electricity prices and the merit-order effect of renewable energy sources in Portugal by considering two different samples of wind and solar power using daily data from 2011 until 2019. Ciarreta et al. [14] adopt a GARCH model for investigating the role of renewables in setting prices in Spain. These studies typically focus on the utilization rate of thermal power plants, e.g., increased generation or lower capacity factors due to market transitions and reforms, without specifying the marginal share of such generators. There are two main groups of approaches in estimating/quantifying the marginal share of generators in power markets.

The first approach is based on application of fundamental operation and dispatch power system models. Using models with a high temporal-spatial resolution and representing power plants in a country or a region, one can estimate the marginal share of each generation type ex ante, i.e., by back-casting from the model output. The literature is rich in this area, with many sophisticated models analysing future scenarios mainly relying on optimization algorithms and applying open or black-box computer software packages (e.g., [50–53]). The advantage of such model-based analyses of marginality is the detail, sometimes at the individual plant level, and the flexibility to represent different states of the power system. Some examples of applying models for analysing marginal shares ex ante can be found in [23]. The study calculates marginal shares of different power generation modes, including cross-border power exchange, in many European countries for the modelled year of 2020. In another example, Härtel and Korpås [54] examines the role of cross-sectoral demand bidding and RESs in electricity price formation using a model-based analysis. They quantify the price-setting share of both consumers and producers within a region as opposed to the role of power exchange.

The drawback of using power system models for analysing marginality relates to two aspects. From the process perspective, building a complex model requires adequate modelling skills and a sophisticated tool [55], relies on many assumptions and modelling judgements (e.g., related to future carbon and energy prices) [56]), may be biased by model structure [57], and if not validated remains at the theoretical level [58]. Such modelling tools and underlying data are not always open access [59]. Moreover, concerning the outcome of such models, the calculated marginal shares are ex ante, i.e., they do not reflect what may happen during the market operation in real life, e.g., loss of a large power plant or interconnector, forecast errors in load and variable RES, etc.

The second group of approaches are based on applying econometric and statistical methods to analyse the outcome of a given electricity market for estimating the marginal shares ex post. These approaches are not typically based on plant level data but using time series of the market data, e.g., load, generation, and prices, at the national level or for a pricing area. There exist many examples of this approach for analysing the merit order effect, e.g., on formation of prices [21], generation of certain power plants [60], impact of carbon price on electricity prices [44], role of power exchange in formation of prices [61], and market power [62]. Germeshausen and Wölfing [63] offers a good example for the analysis of marginal shares. They quantify the marginal share of lignite power plants in Germany, by analysing equilibrium prices and quantities. Their method is a combination of two different dimensions based on (i) quantities, e.g., available capacities and demand, and (ii) observed prices resulting from the intersection of supply and demand. The advantage of such statistical approaches lies in their simplicity, better availability of data, reproducibility, and more importantly, the inclusion of past events and actual market clearance information in calculated marginal shares. The limitation of such approaches is the dependence on granular data, which most often requires treating the power market at an aggregate level, e.g., considering all gas generators under one umbrella, which may neglect technological constraints at the plant level.

There are a few studies based on a hybrid approach, e.g., applying econometric analysis to validate the results of a power system model-based analysis or vice versa. For example, Bublitz et al. [64] examine the role of different price drivers in the decline of electricity prices in Europe. They apply an agent-based power system model coupled with a regression analysis to verify model results by comparing both methods. Our approach fits in the second group of reviewed methods and is explained in more detail in the following Section.

## 3.2 A price-generation differential method for estimating marginal shares

We apply a simple but robust regression analysis based on the relationship between marginal electricity generation and prices. This method is useful for calculating the share of hours each year in which different types of generators are at the margin.

The balance between generation and demand for electricity in a power market can be shown by Eq. (1), in which $L_t$ is load in each time slice ($t$) in a year ($Y$); $G_t$ is generation; and $I_t$ $and$ $E_t$ are import and export of electricity at each time.

$$L_t \leq G_t + I_t - E_t \qquad \forall t \in Y \qquad \text{Eq. (1)}$$

In each time slice ($t$), generators whose bid is accepted generate electricity. The electricity generation of these generators can be divided into two main parts: (i) generation from plants with lower marginal cost $G_{l,t}$, or cheaper supply bid, than the market price and (ii) generators at the margin $G_{m,t}$ , whose bid sets the market price (see Eq. (2)).

$$G_t = \sum_{l \in L} G_{l,t} + \sum_{m \in M} G_{m,t} \qquad \forall t \in Y \qquad \text{Eq. (2)}$$

However, as shown in Figure 2, the electricity price ($P$) in each time slice ($t$) is derived based on the bidding price of a generator at the margin ($G_m$). Generators at the margin can set and change the electricity price by their marginal generation. Hence, if changing the electricity generation of a generator between two consecutive time slices will drive the change in the electricity price, it is likely that this generator is at the margin. Let us give an example: if generator type A is generating constantly 1000 MWh/h in 24 hours a day and the prices in these hours vary significantly, this generator is not setting electricity prices nor following the load. But if generator B is changing its generation in each hour, and when it increases its generation prices go higher and vice versa, it can be concluded that (i) this generator is following the load and/or (ii) this generator has an impact on power prices. Generator type B represents a plant at the margin. Eq. (3a) shows this relationship between the change in electricity price in each hour and the marginal generation of a plant at the margin.

$$\Delta P_t = f(\Delta G_{m,t}) \qquad \forall t \in Y \qquad \text{Eq. (3a)}$$

Assuming a linear regression, we derive Eq. (3b) for calculating the marginal share ($m$) for each generation type as the slope of the changes in prices relative to changes in generation ($\propto$ is the intercept):

$$\Delta P_t = m.\Delta G_{m,t} + \propto \qquad \text{Eq. (3b)}$$

$$where: \ \Delta G_{m,t} = G_{m,t2} - G_{m,t1} \ , \ \Delta P_t = P_{t2} - P_{t1} \ , \ \forall t_1, t_2 \in Y \ , \ t_2 = t_1 + 1$$

As generation of different plants depends on their total installed capacity and overall availability, marginal generation of each generator ($g$) needs to be normalized by average generation of the respective generation mode in a year. Eq. (4) shows how normalized generation ($G_{g,n}$) is calculated.

$$G_{g,n} = \frac{\sum_{t=1}^{8760} G_{g,t}}{8760} \qquad \forall g \in G \qquad \text{Eq. (4)}$$

Therefore, the marginal share of a certain generator ($m_g$) can be derived as the linear relationship between change in electricity prices ($\Delta P$) and normalized change in generation of that generator as expressed in Eq. (5).

$$m_g \sim \frac{(P_{t2} - P_{t1})}{(G_{g,t2} - G_{g,t1})/G_{g,n}} \qquad \forall t_1, t_2 \in Y; \ t_2 = t_1 + 1; g \in G \qquad \text{Eq. (5)}$$

Using Eq. (5), the marginal share ($m$) for each type of generator in each year is calculated as the ratio between the difference of a technology's output and the *hourly* difference[3] of electricity prices. In other words, this is the amount that the electricity price can change by varying a technology's output from one hour to the next. Figure 3 shows this Ordinary Least Squares (OLS) regression analysis for UK in Feb 2019. The change in electricity prices is mostly correlated with changes in generation of gas fuelled plants, nuclear with a minor impact while solar generation is found to have negative correlation with prices.

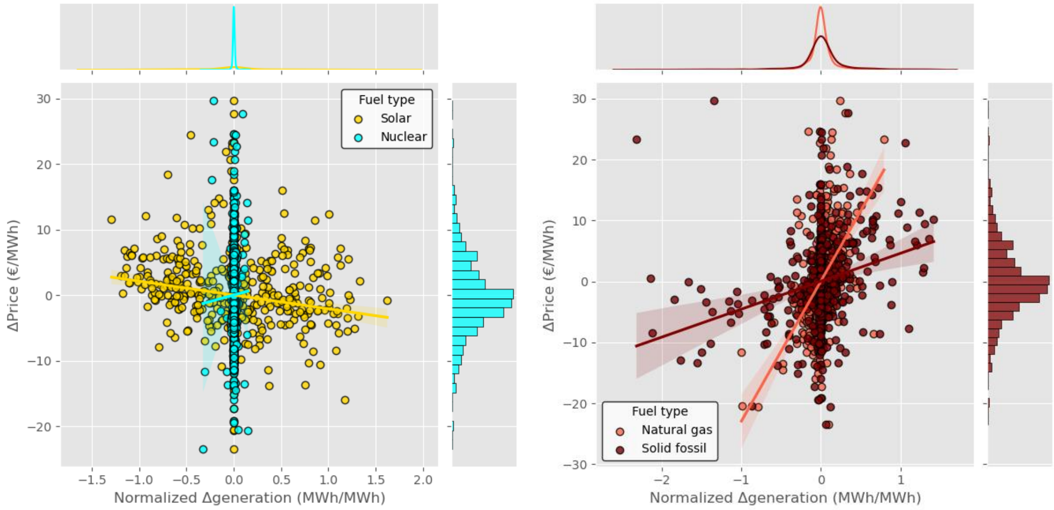


Figure 3 Relationship between changes in hourly electricity prices and (a) changes in generation of non-fossil types (solar and nuclear, left), and (b) changes in generation of fossil fuel modes (gas and coal, right) in Feb 2019 in UK.

The results of the regression analysis, i.e., dependency of electricity prices on the marginal generation of different generators, can be normalized and presented as percentages for the examined time horizon, e.g., a year (8760h). It should be noted that the regression analysis proposed here is not to determine which generation type is at the margin in a specific hour. This method is suitable to approximate the percentage of time in a certain period, e.g., a year (8760 h), that a generation type could have been at the margin. Therefore, the results should be interpreted as aggregated indicators showing the trends and not for predicting the behaviour of a specific generation type or their pricing strategy.

### 3.2.1 Strengths and limitations of the proposed method

The proposed method in this study enhances previous panel data methods reviewed in the literature. For example, Ref. [63] estimates marginal shares by a hybrid indicator based on both demand quantities and prices. However, in addition to supply side-driven factors such as plant availability and technical characteristics such as ramp up/down etc., electricity prices can be a function of electricity demand in many hours. This may skew the regression towards those hours as the two dimensions used for the analysis are interdependent. Moreover, unlike

[3] A first difference is here defined as a change from an hour to the next. Most electricity markets in Europe run on an hourly basis, while the UK market runs every half-hour. For consistency, we therefore focus on hourly changes.

other methods, the approach presented here is based on the relationship between *normalized* changes in power price and generation. This is important as the absolute change of the output of a generation type can be large from one hour to another, implying that this generator is forming the price change, but this generation change may be a small fraction of the total output of that generation type. Putting this into an example, a power plant generation type (A) may change the output by 100 MWh between two consecutive hours corresponding to a certain price change. If the total generation of that plant type in the examined period would be 10,000 MWh, the output is adjusted only by 1% of the total generation. This is different from another power plant type (B) that changes the output by the same 100 MWh, but this amount is 80% of the total output of the plant type. In this example, the generation type B exhibits much more flexibility in load following and it is more likely that this plant would be at the margin, compared to type A.

Estimating marginal shares of different electricity generators using national level data has several limitations. Treating generation modes only by their fuel type in an aggregated way does not capture technical differences that may lead to different pricing strategies by generators. For example, there are different gas-fuelled power plants (namely combined- and open-cycle gas turbines, and steam turbine) with different technical and operational characteristics (efficiencies, ramping rates, minimum load, etc.), which may play different bidding strategies, but all grouped as "natural gas generation" in national statistics and in this study. Normalizing the generation before estimating the marginal share helps capture some technical differences between plant types here, by attributing the price change to a fraction of a generation type, e.g., gas turbines, and not to the total generation, which may include some fewer flexible portions, e.g., steam turbine gas power plants.

However, power plants of the same type may have different sizes, ages, capacity factors, and consequently different (short-term) marginal costs, which would result in a slightly different pricing strategy. Such plant level specificities are overlooked in aggregated methods as introduced here, and that is a limitation. In addition to technical characteristics, there may be some operational differences in power plants with the same generation mode, which is not captured in this study. Some utility companies own a diverse set of power plants, e.g., hydro, gas, coal, etc., and offer electricity or capacity to different marketplaces, e.g., future-forward, day-ahead, intraday, balancing, etc. Hence, the offer of such energy companies to the market is the resultant of a complex internal optimization of their assets, which may be very different from the offer of a single generator participating in one marketplace.

Some of generation types may run combined heat and power (CHP) plants, of which a certain share is must-run CHP[4] with fixed electricity output, i.e., not following electricity demand or price. This is similar to the pricing behaviour of some industry-based power plants, which are used primarily autonomously, but offer their extra available

[4] Must-run combined heat and power (CHP) refers to those CHP plants whose main product is process heat or district heat (DH), with electricity being a by-product. These typically small- to medium-sized plants make the main part of their revenues from heat sales, as such, offering their output power with a relatively low price to the market [103].

electricity/capacity to the market with little flexibility to vary the output [65]. The output of such must-run and inflexible thermal power plants exhibits no or little correlation with variations in power prices, even if these plants would be already at the margin. The above-mentioned thermal power plants are typically grouped together with flexible plants based on their fuel type in national statistics used in this study. Therefore, our analysis may underestimate the marginal share of thermal power plants, as a fraction of such plants fall into must-run and inflexible generation.

The role of infra-marginal power plants should not be neglected in formation of electricity prices. These generators are not at the margin, but some can change their output and push another generator with a higher bid to the margin, hence, setting prices indirectly. A prime example of such behaviour is the role of Norwegian, and to a lesser extent Swedish, hydropower plants in the Nordic region. Benefiting from a large reservoir, these plants vary their production significantly during the day to maximize their revenues based on the concept of water value[5]. Therefore, even though the results of our analysis may show that hydropower plants have been at the margin for most of the time a year, by referring to their generation differential from one hour to another, this may not be completely true. For example, Norwegian hydropower plants shadow-price their offers to the market in off-peak hours based on the price of coal or lignite generation in Germany, pushing these thermal plants at the margin [23]. Therefore, our analysis overestimates the marginal share of hydropower, either run-of-the-river with limited storage size or large reservoirs, especially in hydro-dominant countries like Norway.

Considering the above-mentioned points, i.e., the underestimation of the role of must-run thermal power plants at the margin and the overestimation of the role of flexible inframarginal plants such as hydropower, the results of our analysis for the marginal share of fossil fuel types should be interpreted as conservative values compared to their actual shares.

## 3.3 Data

The provision of open data has contributed to the analysis of energy transitions significantly in recent years [56]. The data used in this paper is the open, hourly data of EU-27 countries (excluding Malta, Cyprus, and Luxembourg) plus Norway and UK in 2015-2021, obtained from the European Network of Transmission System Operator for Electricity (ENTSO-E) Transparency Platform [66]. The following datasets and data curation procedure have been applied to construct time series and conduct regression analysis:

- hourly electricity day-ahead electricity prices for each country in each year are obtained from [66]. In the case of countries with more than one price area the data from the two

[5] “Water value” defines the bidding strategy of hydropower plants in electricity markets, which is based on the opportunity-cost of releasing one unit of water from the reservoir in a certain hour or keeping it for an hour in the future. This strategy shadow-prices water in the reservoir in competition with the bid of a thermal power plant that could be accepted in the market in the same hour [104].

geographically furthest price areas of that country is averaged for each hour to represent the country.

- hourly electricity demand and generation of different fuel types for each country in each year is fetched from [66]. In those cases where the data has big chunk of missing values, these values are possibly corrected based on national and regional electricity market datasets, such as Nord Pool [67], EPEX Spot [68], RTE [69], ESOIS [70], and OMIE [71]. The annual electricity demand, generation and share of each generation mode is checked with national statistics.

- the installed power capacity of each generation type for each country in each year is obtained from [66], and amended and corrected with national statistics if data is missing.

- harmonization of hourly data to a unique time zone (Central Europe) and treatment of winter and summer daylight-saving adjustments.

- data curation and fixing, including filtering out abnormal data, and interpolating the hourly data for missing values.

After these steps, we apply the regression analysis for each country separately to derive marginal shares. For EU-27, we derive the marginal shares by applying a weighted average of marginal shares relative to the generation of each generator type in all countries included.

## 3.4 Analysis of electricity price volatility

We analyse hourly wholesale electricity prices (€/MWh) in the examined countries between 2015 and 2021. In 2021, the average prices show the minimum in Denmark with 88 €/MWh, followed by Germany (97) and France (109) (see Table 1). These countries have a relatively high share of renewable energy and cheap baseload, coal in Germany and nuclear in France. The yearly average electricity prices have been growing in most examined countries since 2015. In some countries like UK, Denmark, Ireland, and Germany, the mean electricity price has been growing at a significant rate of 34%, 24%, 23% and 20% per year, respectively. These countries have the highest share of wind power among the examined countries. The average electricity price is also dependent on the weather condition and overall electricity demand in a year.

Table 1 Average wholesale electricity prices and annual growth rate in mean electricity prices between 2015 and 2021

| Country | DE | DK | ES | FR | GR | IE | IT | PT | UK |
|---|---|---|---|---|---|---|---|---|---|
| Average price 2021 | 97 | 88 | 112 | 109 | 116 | 136 | 125 | 112 | 272 |
| Average price 2015 | 32 | 24 | 50 | 38 | 52 | 39 | 51 | 50 | 46 |
| Cumulative annual growth rate (CAGR) (2015-2021) | 20% | 24% | 14% | 19% | 14% | 23% | 16% | 14% | 34% |

Figure 4 shows the electricity prices for each market in the form of median, standard deviation, and range between 2015 and 2021. The electricity price data were cleaned of outliers, defined as values below 0.5% or above 99.5% of the range. Norway is also added to the comparison, a country with commonly the lowest power prices in Europe. Comparing the results shows that the price volatility and average price soars in 2021, due to the post-pandemic surge in energy prices in Europe. Germany and Denmark have the lowest prices on a year-to-year comparison, followed by France. The median electricity price has been growing in all examined markets between 2015 and 2021. Moreover, the volatility of prices, shown as standard deviation, has been increasing since 2015 in Denmark, Germany, Ireland, and UK, which are the countries with increased share of VRE generation. In some cases, like Spain and Portugal the price volatility has slightly decreased in the examined period. In each year, the largest electricity price volatility occurred in France and Ireland. The high electricity price volatility in France is likely due to the high proportion of inflexible nuclear generation used and the widespread use of electric heating that creates demand spikes in winter, while in Ireland this is mainly due to wind variability.

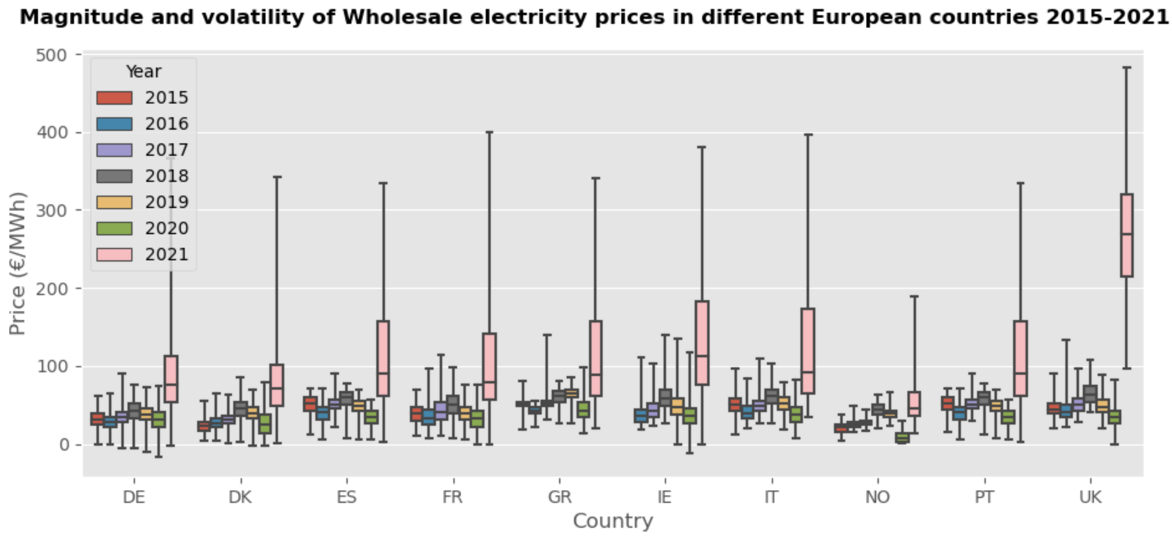


Figure 4 Day-ahead electricity prices of the examined European markets in 2015-2021. Boxes show 25th-75th percentile, whiskers extend from minimum 0.5% to maximum 99.5% of data in each sample. Underlying data from [66].

# 4 Results

We calculate the annual mean shares at the margin for different electricity generation types. These marginal shares, presented as percentages, indicate the fraction of time in a year in which each technology sets the wholesale electricity price in a power system (i.e., percentage of time a technology has been at the margin).

## 4.1 Share of each fuel type in setting electricity prices in Europe

We compare the marginal shares of fossil fuel-based electricity generators with non-fossil and electricity imports in EU-27, UK, and Norway in 2021 (see Figure 5). The results show that in some Nordic countries like Sweden and Norway, hydropower plants set the electricity price nearly all year round. Even though hydropower may be considered a generation mode with near zero marginal costs, but hydropower generation companies typically apply a bidding strategy in the electricity market based on the concept of "water value" [72]. This means these power producers offer their generation with a price tag that reflects the value of water in the dam, which is usually based on the opportunity-cost of supplying hydropower that could be otherwise replaced with the most expensive thermal generator at the margin [73].

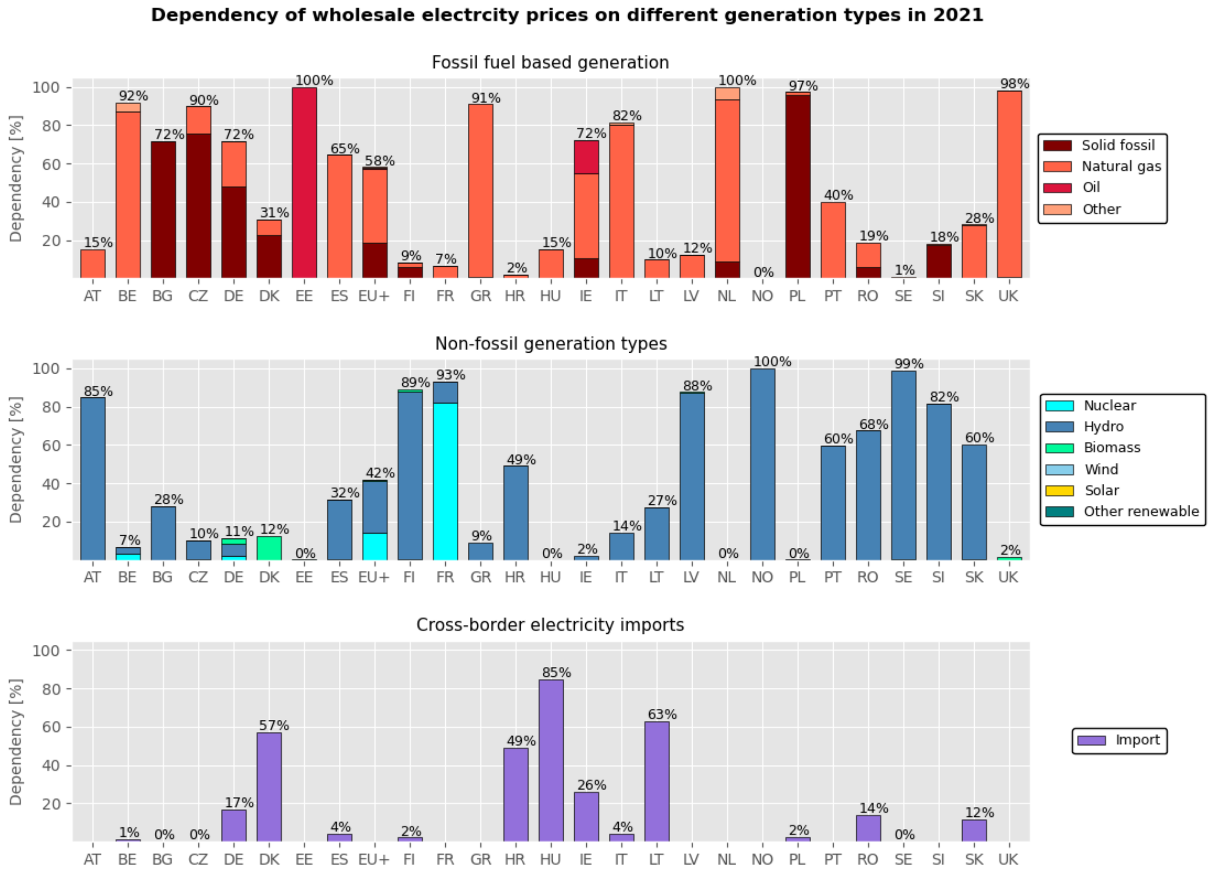


Figure 5 Marginal shares of fossil fuel, non-fossil, and cross-border electricity imports in different European countries in 2021. EU[+] represents EU-27 plus UK and Norway. The marginal shares represent the dependency of electricity prices on each generation type as % of the time in one year. The results for EU[+] are based on the weighted average of the marginal shares of the European countries, i.e., the marginal share of each European country multiplied by electricity generation in that country.

In many European countries, cross-border electricity imports play a strong role in determination of electricity prices. Countries like Hungary, Croatia, and Lithuania with electricity imports more than 50% of their annual demand are among those countries highly dependent on the price of imported electricity. The electricity prices in Denmark are also highly dependent on the prices in the neighbouring countries, namely, Norway, Sweden, and Germany, making Denmark price-dependent on these countries 57% of the time in 2021. Domestic generation in Denmark is largely based on wind and solar PV with near-zero marginal cost, as well as combined heat and power plants mostly running on their heat demand output. Hence, the domestic generation is only 43% at the margin in one year.

Nevertheless, fossil fuels determine electricity prices in many countries for most of the hours in 2021. Coal-based generation shapes electricity prices more than 70% of the time in

Poland, Czech Republic, and Bulgaria, and approximately 48% in Germany. Natural gas plays a big role in formation of electricity prices in Belgium, Spain, Italy, Netherlands, and UK.

Overall, fossil fuels set electricity prices in 58% of hours in 2021 in EU-27+. This means, even though 65% of electricity generation in Europe was from non-fossil power generation in 2021, these plants defined the electricity price in Europe nearly 42% of the time.

### 4.1.1 Fossil vs. non-fossil generators at the margin (2015 vs. 2021)

Table 2 compares the share of fossil fuel, low-carbon generation (nuclear and renewables), and electricity imports in setting electricity prices in 2015 versus 2021 in a few countries. Germany shows the highest share for dependency on fossil fuels in electricity prices among the examined countries in this analysis. In 2015, fossil fuels were responsible for electricity prices 92% of the time in Germany. This share was reduced to 72% in 2021 thanks to renewables. France is the country with least dependency on fossil fuels when it comes to power prices, only 3% in 2015 with a slight growth to 7% in 2021. Portugal, Spain, and Italy had the highest shares of non-fossil-based electricity prices in 2015 after France, with 41%, 36% and 30%, respectively. The marginal share of non-fossil generators in some countries has significantly declined in 2021, e.g., due to the phase-out of nuclear in Spain, and hydropower being at the margin in Italy much less than 2015.

Table 2 The marginal share of fossil-fuelled and non-fossil electricity generation in the examined European electricity markets in 2015 and 2021.

| Year | 2015 | | | 2021 | | |
|---|---|---|---|---|---|---|
| **Country** | **Fossil fuel** | **Non-fossil** | **Imports** | **Fossil fuel** | **Non-fossil** | **Imports** |
| **Germany (DE)** | 92% | 8% | 0% | 72% | 11% | 17% |
| **Denmark (DK)** | 76% | 0% | 23% | 31% | 12% | 57% |
| **Spain (ES)** | 62% | 36% | 2% | 65% | 32% | 4% |
| **France (FR)** | 3% | 97% | 0% | 7% | 93% | 0% |
| **Ireland (IE)**[a] | 87% | 2% | 11% | 72% | 2% | 26% |
| **Italy (IT)** | 59% | 30% | 10% | 82% | 14% | 4% |
| **Greece (GR)** | 42% | 0% | 58% | 91% | 9% | 0% |
| **Portugal (PT)** | 59% | 41% | 0% | 40% | 60% | 0% |
| **United Kingdom (UK)** | 88% | 1% | 12% | 98% | 2% | 0% |

[a] Values for Ireland are from 2016 instead of 2015.

The share of electricity imports in setting domestic electricity prices has increased between 2015 and 2021 for most of the examined markets. This shows the success of European electricity market integration. The electricity price in some countries like Denmark is shown to be dependent on imports from neighbouring countries almost 57% of the time in 2021, which is higher than any other country in this Table. Ireland is another country with a successful wind integration between 2015 and 2021, and with an increased dependency of electricity prices on cross-border electricity imports, rising from 11% in 2015 to 26% in 2021.

## 4.2 Trends in marginal generators

Variations in the generator at the margin between 2015 and 2021 are shown in Figure 6 for nine selected countries over the past five years. In France, nuclear power generation dominated the marginal price throughout the period. The flexibility of French nuclear power depends on the fuel cycle and hence there might be some flexibility between 70–100% of the nominal capacity early in the fuel cycle [74]. Coal and gas dominated in the other countries in 2015. In almost all the examined countries, the share of coal power plants in setting electricity prices has declined between 2015 and 2021. The marginal share of coal in UK decreased from 23% in 2012 to 11% in 2017, and almost to zero since 2019. Germany's electricity sector is very much coal-intensive, which makes coal power generators the main price setters in the country (75% of the time in 2019 and 48% in 2021).

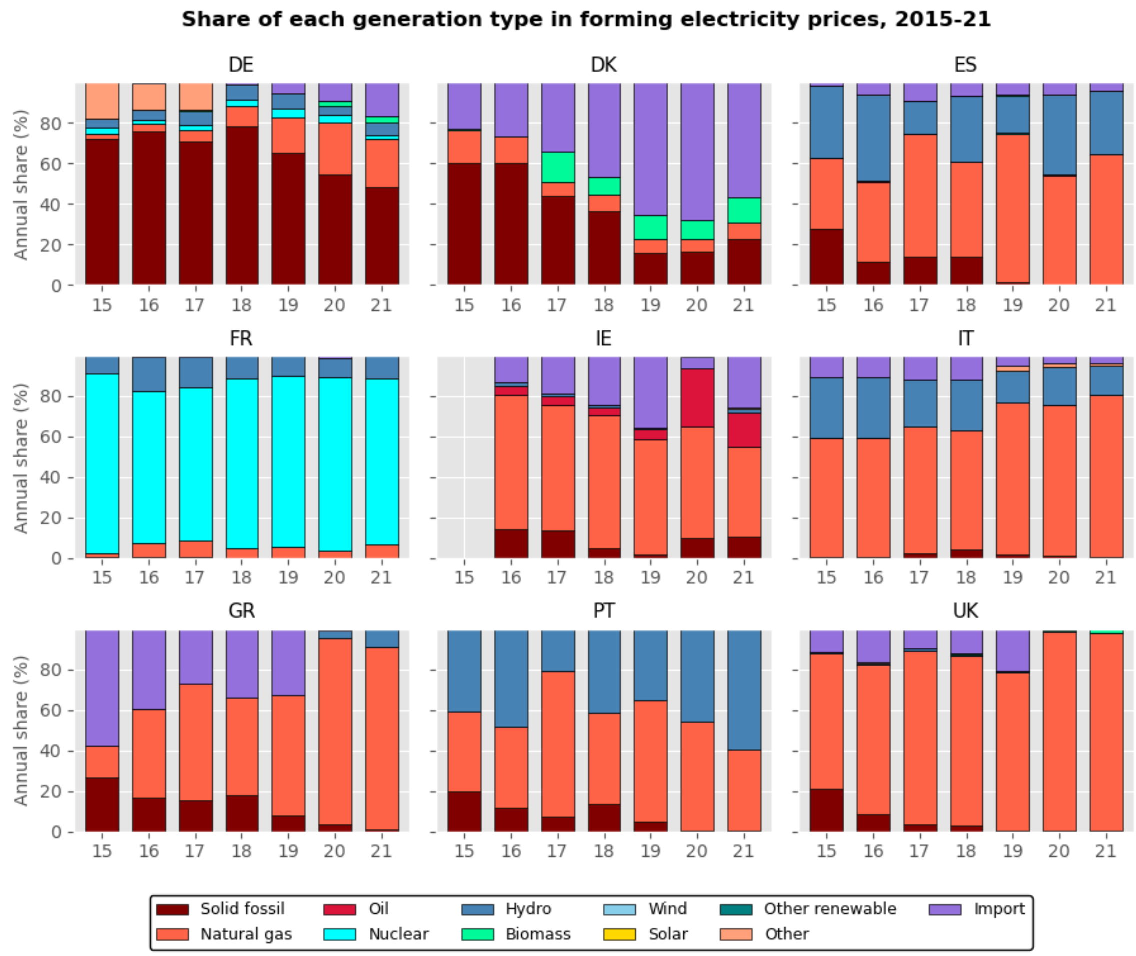


Figure 6 Share of each electricity generation type in determining electricity prices in each year in selected European countries in 2015-2021 (for Ireland the data are available from 2016).

In Denmark, the role of coal-based electricity generators in forming electricity prices has declined dramatically, from near 60% in 2015 to less than 20% in 2019. In Portugal and Greece, the share of coal has steadily declined, but depending on electricity imports (in Greece) and hydropower availability (in Portugal), coal plays a role in setting electricity prices.

Moreover, in most of the examined countries the marginal share of natural gas has increased in the examined period, with Greece, Italy, Spain, and UK being the countries with the highest dependency of electricity prices on natural gas. Denmark is one of the few countries where natural gas has lost its importance in setting electricity prices over the examined period. This role of gas in setting prices in Denmark has been displaced partly by biomass-based combined heat and power plants, and to a larger extent by electricity imports from other countries. This situation has been observed in Ireland too, where the role of natural gas in the formation of electricity prices has not increased significantly but imported electricity has replaced coal-based marginal shares.

## 4.3 Natural gas as a generator at the margin in Europe

The marginal share of natural gas has increased in most of the examined countries. UK, Greece, Belgium, Netherland, and Italy have the highest dependency, with gas being the marginal fuel for more than 80% of the time in 2021 (Figure 7).

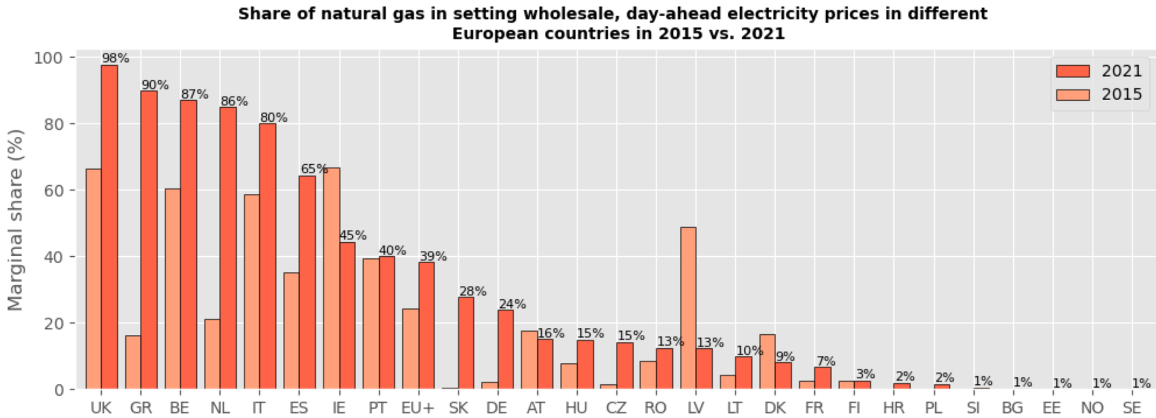


Figure 7 Share of natural gas electricity generation in determining wholesale day-head electricity prices in different countries in Europe in 2015 and 2021, sorted from highest to lowest values in 2021. The percentage on each bar shows the marginal share of gas in 2021. The dashed line shows the marginal share of gas for EU+ (EU-27 plus the UK) in 2021, which is the average of the marginal share of gas in all examined countries weighted relative to the electricity generation in each country.

From countries with a major increase in VRE between 2015 and 2021, the gas share has only decreased in Denmark and Ireland, which have both become more dependent on imports for price setting. Latvia is the only other European country with a major reduced share of gas between 2015 and 2021. A few countries showed significantly increased dependency on gas as the marginal generator, e.g., Greece from 17% to 90% and Netherlands from 22% to 86%, between 2015 and 2021. Gas has become the key determinant of the European electricity wholesale price and in 2021 was on the margin almost 39% of the time across Europe overall (the weighted average of the marginal share of gas in all examined countries relative to total electricity generation in each country). This share has been increasing since 2015, as gas has risen to the greatest share of the generation mix, and especially the greatest share of flexible, dispatchable capacity. This development was largely due to the decline in the price of natural gas globally and in Europe until 2021, when price of natural gas soared after the pandemic, as well as the sharp increase in $CO_2$ price, which strongly favored gas over coal.

Figure 8 shows the development of the marginal shares of different electricity generation types in EU-27+ between 2015 and 2021. The results indicate that while the share of fossil fuels in the generation mix is declining overall, these carbon-intensive generators are still the most influential determinants of electricity prices. More specifically, the share of natural gas power plants in setting electricity prices in Europe has increased from 25% in 2015 to 39% of the time in 2021, which is more than any other technology. This happens while the share of gas in electricity generation was only 18% in 2021.

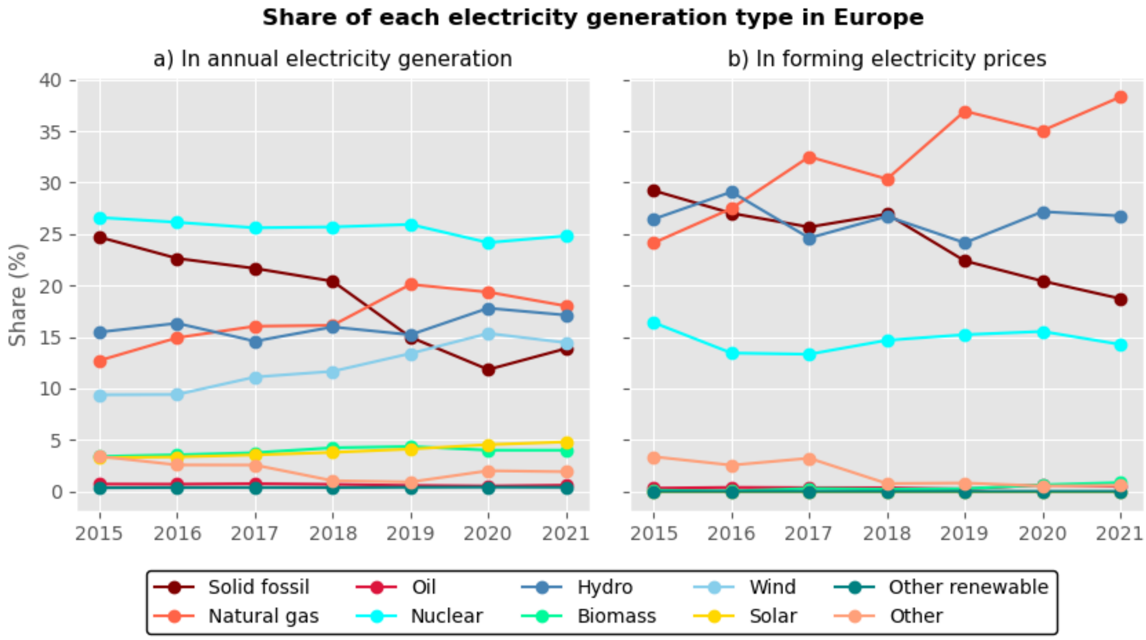


Figure 8 Share of each generation type in (a) annual electricity generation and (b) in formation of electricity prices in Europe 2015-2021. The share in generation is directly calculated by dividing generation of each plant by total generation. The marginal shares are the weighted average of marginal shares in European countries relative to generation in each country.

# 5 Discussion

## 5.1 European energy transitions and displacing coal with gas

We find that the EU electricity wholesale price level is most strongly influenced by fossil fuel-based generators, and mainly natural gas. The share of gas in determining prices has been increasing since 2015, as gas has risen to both a higher share in the generation mix, and, especially, the greatest share of flexible, dispatchable capacity complementing electricity from VRE. This development was also due to the decline in the price of gas before post-pandemic price hikes in 2021, and the sharp increase in $CO_2$ prices, which strongly favors gas over coal.

In contrast, the role of coal in setting electricity prices is declining in most of the examined countries. This is partly due to higher carbon prices in the European ETS starting in 2017. Also, the EU Large Combustion Plants Directive[6] has forced some older coal plants to close since 2015. Fossil fuel plants continue to operate at the margin in many countries, and therefore, set electricity prices for much of the year, a finding that bears out that in other studies [75] [18]. We have found that the proportion of time that gas plants are the marginal generators has increased replacing coal power plants in many countries. The very low marginal share of coal reflects its diminishing role in the fuel mix, and the relative higher flexibility of gas plants and lower carbon emissions may explain why natural gas prevails as the major price-setter in European markets. The aging coal fleet in many countries is inflexible, which further reduces operational hours in a market with increasing demand for flexibility. We have found that coal has continued to dominate marginal costs in a small number of European countries, especially Germany and Poland, which is confirmed by other studies [76], but its role has transitioned from baseload generation to providing peak capacity at times of high demand. However, lignite has persisted as baseload in Germany, at least until 2022.

Since natural gas markets are more localized than global coal markets, this potentially increases energy security concerns for European electricity systems [77]. The extensive influence of gas generators on the electricity price therefore makes consumers heavily exposed to several risk factors. A second difference between natural gas and coal is that gas is used for heating in many homes in Europe. If supply were constrained in Europe in winter, since it is unlikely that the supply for heating would be rationed, it would be necessary to either ration gas or electricity to non-residential customers, or to keep non-gas generation capacity in reserve so the electricity system industry could switch to alternative fuels, but at a cost. Similarly, if gas prices rise, as happened in the second half of 2021 in Europe, consumers must pay more for both heating and electricity if gas is the marginal fuel for electricity generation. This could reduce energy affordability and access for European citizens.

## 5.2 Geopolitical risk of natural gas lock-in

As most EU countries import their gas from outside Europe, by pipeline, security of supply is affected by regional geopolitics. Geopolitical conflicts between countries that are the import corridors of natural gas to Europe, such as those between Ukraine and Russia, have affected the availability and price of natural gas to EU countries a few times [27]. More recently, the sanctions and disruptions in import of gas from Russia in the aftermath of the war in Ukraine have created significant concerns over the impact on prices in the short run [78,79]. In the long run, as similar energy trends are happening in many countries, demand for natural gas and LNG may rise globally, which will impact the gas price as a global energy commodity [80].

The risk of dependency on natural gas imports in Europe has been the subject of much debate within the EU. To reduce the current dependency on a small number of gas suppliers, the EU is seeking to find new gas supply routes and to diversify supplies. This has made the

[6] The EU's Large Combustion Plant Directive (LCPD) required all coal-fired and oil-fired plants whose owners were not willing to fit sulphur-scrubbing equipment to close by the end of 2015.

Union become more active in political and economic cooperation with gas exporting regions, e.g., in North Africa and the Middle East [81], which requires changed foreign policy in establishing long-term relations and forming new coalitions [82]. Therefore, natural gas interconnectors and LNG infrastructure has become a lever in the policy debate, which makes the construction, completion, and commissioning of such multi-billion-euro projects dependent on the prevailing political environment between the EU and other countries. Nord Stream 2, a sub-sea gas interconnector between the Russia and Germany is a good example of this geopolitical risk, when in 2019, the US pressed companies involved in the construction of the pipeline to stop working on the project by threatening sanctions. Later in the European natural gas price crisis in 2021, it was argued that Russia has reduced gas supply to Europe through other lines as leverage to push the final approval of Nord Stream 2 by the European Commission. Ultimately, the commissioning of the line was withdrawn by the German side as a consequence of the Russia-Ukraine war in 2022 [83].

Reducing dependency on fossil fuel imports was one motivation of the EU energy transition, which aims to enhance energy security by increasing the role of renewable energy [27]. However, since the European energy transition has replaced coal in large part with natural gas in the power system, this has led to a natural gas lock-in in major power systems in the Union, such as Germany [84], increasing the vulnerability of the European electricity system.

## 5.3 Risk of volatility in fossil fuel prices and exchange rates

Importing natural gas from overseas exposes electricity generation prices to two major risk factors: changes in prices of imported gas and currency exchange rate variations. According to the Office of Gas and Electricity Markets (Ofgem), the volatility in peak electricity prices in the UK is 54% correlated with the variations in the market price of natural gas [85]. As natural gas prices are cleared based on cross-continental supply-demand imbalances, and partly indexed to the global prices of crude oil, any fluctuation in crude oil prices or transitions in exporting regions influences the natural gas price in European markets as well [86].

Fluctuations in the currency exchange rate create another risk factor related to the dependency on fossil fuel imports. The volatility of currency exchange rates can influence the electricity price of fossil fuel generators in Europe [87]. For example, it has been shown that the Spanish electricity spot prices are dependent on both the USD/EUR exchange rate and fossil fuel prices in the global markets [88].

The impact of Brexit on electricity prices in the UK is another example. Mean day-ahead power prices were nearly 18% higher in the UK in the year after the EU referendum compared to the previous year. As shown in [75], the dominant influence was through the exchange rate impact on the cost of inputs to generation linked to the drop in the GBP/EUR and GBP/USD exchange rates, which fell by 15% in the year after the vote. With wholesale costs accounting for over a third of the final electricity bills in the UK, the impact of the referendum on exchange rates thereby appears to correspond almost exactly to the increase of 5.7% in retail electricity prices from 2016 to 2017 [89], adding about two billion pounds to energy bills in a single year [90]. This clearly depicts the risk of exchange rate fluctuations for countries whose electricity prices widely depend on the exchange rate.

## 5.4 Carbon prices and marginal generation

Carbon emission prices have increased in Europe since 2017. This has increased the marginal cost of carbon-intensive generators, particularly by reducing the competitiveness of coal power plants in recent years, even in countries like Germany where the price of hard coal and lignite are typically low [91]. The subsequent reduction in coal generation across Europe has caused the carbon intensity of electricity generation to reduce substantially between 2017 and 2019. While this trend has contributed to achieving emission and renewable energy targets, the combination of higher zero-marginal-cost VRE in the power system and higher carbon prices has increased the dependency of electricity prices on the cost of carbon emissions from flexible, fossil-based power plants. This is expected to continue as EU carbon prices are predicted to increase to between 80 and 200€/t by 2030 [92]. Carbon-intensive generation is likely to continue its dominance as a price setter in Europe in the future [93], even with increased carbon prices, as they remain the major dispatchable and flexible generators.

The carbon emissions from the electricity sector in the EU27 declined by 16% in 2019 compared to 2018 [41]. The impact of higher carbon prices on wholesale electricity prices was partially moderated by declining fossil fuel prices, reduced electricity demand and the rising share of renewable generation. However, in countries with greater reliance on fossil fuels, electricity prices grew. More notably, the cost of coal-based generation increased in 2019-2020, which together with plummeting gas prices before 2021 resulted in gas prices falling below coal-to-gas (and even lignite-to-gas) switch price levels in North West Europe in 2020 [91]. This resulted in an unprecedented displacement of coal and lignite with natural gas in Germany.

As natural gas is historically considered a "bridge fuel" in energy transitions to phase-out coal and provide flexibility for integration of VRE. However, the natural gas lock-in in Europe, with significant investments in gas fueled electricity generation, gas network, and LNG infrastructure taking place in different countries across the continent, poses a risk in achieving EU climate goals such as carbon neutrality by 2050 [94]. While the level of carbon emissions from natural gas combustion is relatively low compared to coal and oil, the climate impact of methane leakage from the natural gas supply chain may counter-balance the benefits of gas if not controlled adequately [95]. This has raised a debate over the taxonomy in the European Commission's decision for labelling natural gas together with nuclear as "green" investments under some conditions [96]. Alternatives to natural gas for balancing variable renewable energy

## 5.5 Flexibility requirements of renewable energy transitions

As the share of generation from VRE has increased, price volatility in many European markets has also increased. For example, the number of hours with negative electricity spot prices in Germany broke all records in 2020, whereas UK witnessed price peaks of almost £1,500/MWh in early 2021. If VRE generation increases to high levels then these technologies alone will provide generation needs throughout much of the year instead of natural gas, at very low marginal cost. While historical trends would suggest a need for more rather than less flexible generation, there are other ways to balance supply and demand.

One apparent source of flexibility is strengthening the European internal energy market via cross-border transmission lines, which is also one of the core targets of EU energy security strategy [97]. Despite a temporal correlation in wind or solar conditions within Europe, the intermittency is less pronounced across a larger spatial area and an interconnected grid [98]. Consequently, cross-border transmission capacity is estimated to grow significantly within the next decades [99]. Figure 9 shows that those countries with a high level of interconnectivity (e.g., Denmark) or notable hydropower capacity have been able to integrate higher shares of VRE with low reliance on natural gas. But others like Italy, UK, Ireland, Spain have kept gas as a flexible generation source.

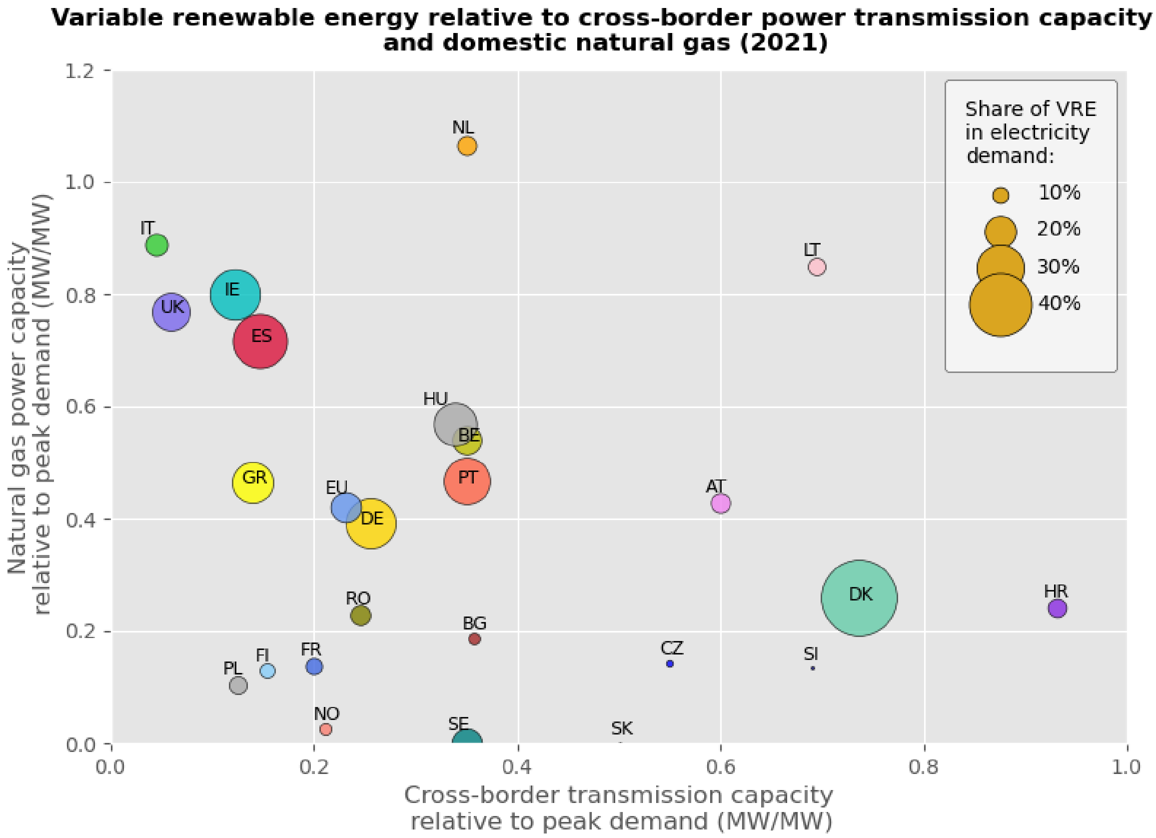


Figure 9 Relationship between the share of variable renewable energy (VRE), mainly wind and solar, in European countries and the cross-border power transmission and domestic natural gas capacity. The size of circle shows the share of VRE from annual electricity demand in 2021, while the two axes show the capacity of gas (vertical) and cross-border interconnector (horizontal), both normalized by peak electricity demand in each country. The colour of the circles is only for visual distinction between countries.

However, if the imported electricity is originated from fossil fuels, the interconnectivity may increase overall carbon emissions, such as the import of coal baseload electricity from Germany to Denmark [100] or the UK-Europe interconnections with different carbon prices [101]. Energy storage systems are other sources of flexibility. The competitiveness and role of batteries in providing flexibility has received much attention in the literature, but large-scale batteries are only just starting to be deployed in global electricity markets [102].

# 6 Conclusions

Given substantial efforts to decarbonize European electricity systems, the post-Covid hikes in electricity prices seen across Europe, followed by the natural gas price shocks after the war between Russia and Ukraine in 2022, have raised the question of whether fossil fueled generation is still dominating in setting power prices. We have analyzed hourly electricity generation data by fuel type, electricity prices, and the generation mix in the EU-27, UK, and Norway. Using econometric techniques, we estimated the shares of fossil-fueled and fossil-free generation in determining European electricity wholesale prices.

We find that the share of carbon-free electricity from renewables has grown during 2015–2021 in most European countries, while fossil fueled electricity generation has fallen to 34%. However, carbon-intensive plants were responsible for setting electricity prices 58% of the time in 2021. The increased shares of wind and solar PV have reduced the share of coal at the margin, and the role of natural gas as a more flexible and cleaner form of generation has increased. The competitiveness of coal has further been reduced due to increasing carbon prices and variable renewable electricity generation with lower marginal costs that have downsized the baseload market. As a result, coal generation has been partially phased out in many countries and replaced by more natural gas. This trend has led to higher dependency on electricity imports in Ireland and Denmark, leading to an increased price dependence on interconnected electricity markets.

The share of natural gas in power generation has increased from 13% in 2015 to 18% in 2021 in Europe. The share of natural gas in determining electricity prices is, however, much higher than its role in electricity generation. Gas-fueled power plants were at the margin for 39% of the time in 2021 across European electricity markets. Electricity prices in Europe have never been so often set by gas prices during the last decade as they are now. As most natural gas is imported to Europe, this increasing reliance on natural gas makes European electricity prices subject to geopolitical risks, international natural gas price volatility, and currency exchange rate fluctuations. While increased generation from renewables and natural gas have replaced coal and reduced European carbon emissions, mean electricity prices and volatility have increased during 2015–2021 due to the rising cost of gas.

# 7 Acknowledgements

B.Z. acknowledges the support from International Institute for Applied Systems Analysis (IIASA), and the RE-INVEST project, Aalborg University, Denmark for his contribution.

G.C.G. acknowledges the financial support from Ofgem for the ACE project (Con-Spec-2018-006). I.S. acknowledges support from the Engineering and Physical Sciences Research Council for the IDLES programme (EP/R045518/1).

We express special gratitude to Prof. Derek Bunn (London Business School), Prof. Donald Lawrence and Jakub Radomski (UCL), Prof. Richard Green (Imperial College), Prof. David Newbery (University of Cambridge), Prof. Sanna Syri (Aalto University, Finland) for useful advice.

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