

Spatial carbon and price spillovers among EU countries on their pathway toward net-zero electricity supply

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ABSTRACT

This paper introduces a methodology to assess and compare the carbon and price marginal impacts (also known as spillovers) of a country's generation mix on other countries. The methodology is applied for possible decarbonization pathways from 2018 to 2030 and 2040 for EU countries, considering the foreseen expansion of generation and transmission capacities, as well as nuclear and fossil fuel phase-out. Firstly, the optimal hourly dispatch of power plants is computed. Secondly, the impact of each country on the overall European electricity system is analyzed by removing that respective country from the simulation. Thirdly, each country's spillovers on prices and CO₂ emissions are assessed. On the pathway to a net-zero CO₂-emission energy system, the uncoordinated penetration of low-cost renewables among countries enables export opportunities to carbon-intensive electricity generation despite rising prices of EU CO₂ allowances. The spillovers, resulting from those exports, cause in the importing country (i) the substitution of clean electricity with electricity stemming out of carbon-intensive plants and (ii) a market price decrease. While the former lessens CO₂-mitigation strategies, the latter results in a lack of investment in renewable generation due to market prices being insufficient to recover capital costs for new renewables. Redistributing CO₂ revenues among countries could be a way to overcome the drawbacks due to spillovers.

1. Introduction

Greenhouse gas (GHG) emission cuts, as envisaged under the EU climate policy (Commission E, 2021), implicitly require a rapid and extensive integration of new renewable energy generators, such as wind turbines and solar photovoltaics (PV). The transformation and expansion of the electrical generation fleet are necessary to decarbonize the power supply and to match the increasing demand due to electrification (Finger et al., 2013). To achieve this goal, Member States transposed the EU directives into plans (National Energy and Climate Plans or NECPs)

which define their contributions, policies and measures to expand renewable electricity generation in compliance with EU decarbonization targets (Williges et al., 2022).

Significant investments in renewables need to be undertaken in the framework of a set of measures adopted by the EU since 1996 to harmonize and liberalize its electricity and gas markets (Ciucci, 2021). These measures aim to build an integrated EU electricity market based on competition of generation and address market access, regulation, congestion management and security of supply. The desired benefits of this integration have been largely investigated in the literature (Baker

Acronyms: CO₂, Carbon dioxide; CCGT, Combined-Cycle Gas Turbine; CAPEX, Capital expenditures; DSR, Demand Side Response; ENTSO-E, European Network of Transmission System Operators for Electricity; EEG, Erneuerbare-Energien-Gesetz (Renewable Energy Law); EU, European Union; GHG, Greenhouse gases; LOO, Leaving-One-Out procedure; LCOE, Levelized cost of electricity; LOLE, Loss of Load expectation; IEA WEO, International Energy Agency - World Energy Outlook; IHS, Information Handling Services; MWh, Megawatt hour; NECP, National Energy and Climate Plans; NTC, Net Transfer Capacities; OCGT, Open-Cycle Gas Turbine; OPEX, Operational expenditures; PECD, Pan-European Climate Database; PEMMD, Pan European Market Modeling Database; PHS, Pumped-hydro storage; ROR, Run of River; RTE, Réseau de Transport d'Électricité (France TSO); STOR, Reservoir Dams; TSO, Transmission System Operator; TWh, Terawatt hour; TYNDP, Ten-Year Network Development Plan.

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et al., 2018; Böckers et al., 2013). Based on a cap-and-trade principle, the EU-ETS scheme also addresses the harmful effects of production by fossil fuel-fired power plants (Kirat and Ahamada, 2011).

1.1. Introducing the spillover effect

Electricity markets are designed on a supply-demand mechanism, where power generators offer different quantities of electricity from various technologies ranked from the least to the most expensive (Blazquez et al., 2018). For a given hourly demand, the market-clearing price is set at the bid of the last unit needed to satisfy that demand. Suppliers can bid their output at prices equal to or above the marginal cost of their plants (Cramton, 2004). Only suppliers whose bids are below the clearing price supply electricity and earn profits, contributing to their fixed costs. Renewables have zero to very low marginal (Hirth, 2013; Rifkin, 2014) but high capital costs.¹ Such technologies enter first into the market merit-order as once built, their generation is dispatched at no additional costs. As more renewables penetrate the market, market prices will decrease (Blazquez et al., 2018), and the plants with high marginal costs will be forced out of the market. The falling price effect created by renewables is called the merit-order effect and was observed and assessed for different electricity wholesale markets (Sensfuß et al., 2008).

Through such a mechanism, the plants with the highest marginal costs, typically fossil fuel-fired power plants, face a gradual reduction in annual operating hours. Hence, they will likely become unprofitable due to the low operation hours and will eventually be decommissioned. Additionally, as wholesale prices decrease, the overall profit of the power sector is decreased, leaving less money to cover fixed costs or invest in new plants.

The expansion of renewable generation and fossil-fuel decommissioning occurs at different paces since Member States have different fleet mixes and define their own NECP independently. Consequently, the described merit-order effects are heterogeneous across countries.

As markets become integrated, the fossil-fuel plants which face a decrease in their operating hours to supply their domestic market, can still offer their generation output to other countries (Germeshausen and Wölfig, 2020). Such generation export is feasible if (i) transmission capacities are available and (ii) their marginal costs are a comparative advantage in the merit-order of the other markets. By offering this available competitive generation to neighboring countries, cross-border trade minimizes the overall system cost and decreases market prices in neighboring countries.

The price decrease due to the merit-order effect of renewable integration is thus spilled over to neighboring countries. The cross-border impacts of a particular national electricity market on its neighboring countries have been examined empirically, namely on German and French power price volatility linked to renewable growth in Germany, which depresses power prices on average and increases volatility not only domestically but also across borders (Phan and Roques, 2015). The analysis of those price impacts is also carried out among the different bidding zones of Italy (De Siano and Sapio, 2022).

Beyond the previous economic benefits, cross-border exchanges might be accompanied by unforeseen and undesirable effects related to CO₂ emissions. The 'exporting' fossil-fuel plants might be substituting cleaner electricity generations with higher marginal costs in the importing country, causing a negative CO₂ impact across the border.

The CO₂ and price marginal impacts on the neighboring countries resulting from those policies can be referred to as spillover effects (Abrell and Kosch, 2022; De Siano and Sapio, 2022). Spillover effects

might have a positive or unwanted negative impact on the neighbors' efforts toward decarbonizing their electricity system.

1.2. An illustration of the CO₂ spillover

To illustrate such a cross-border effect, German wind electricity (when available) lowers wholesale prices on the German market. If this renewable generation exceeds domestic demand, the surplus can be exported to neighboring countries. Hence, such a surplus of carbon-neutral technologies can substitute the production of fossil-fuel plants abroad, positively impacting the carbon balance of the EU electricity system. Simultaneously, German fossil fuel-fired power plants, utilizing lignite or coal, that would have otherwise remained idle due to lower prices in Germany, could now meet cross-border demand at higher market rates. Consequently, in the importing country, Germany's fossil fuel exports replace domestically generated electricity, which could have been produced using less emissions-intensive technologies but with higher costs, such as gas power or hydroelectric dam plants.

In the framework of the EU-ETS scheme, such a substitution effect should be limited as CO₂ cost is internalized in the marginal cost. However, exporting electricity stemming from fossil-fuel units might still be economically viable if the market price for CO₂ allowances does not position the most emitting technologies as the last technologies in the merit-order of all countries.

1.3. Critical literature and unique contribution

Most studies (Abrell et al., 2019; Cullen, 2013; Gugler et al., 2021; Novan, 2015) have discussed the domestic emission offset due to renewable development. None of them have investigated the impact of spillover effects from one to another country, tied to the changes in their electricity mixes. As an exception, recent research (Abrell and Kosch, 2021) studied these effects for Germany and its neighboring countries. Relying on a rich dataset of hourly technology-level generation, demand and prices for 2015–2020, they calculated the emission effects and distributional impacts due to the large increase of German renewable generation on its neighboring countries. However, a complete investigation of the spillover of all EU Member States on each other regarding their decarbonization strategy toward net-zero has not yet been examined.

This paper aims to identify the impact of the spillover effects on prices and CO₂ emissions generated by the European electricity system on its pathways toward net-zero. The two main research questions are:

- (i) what is the impact of a country on the carbon emissions offset of other countries and, more globally, on the electricity system; and
- (ii) what is the impact of a country's policy on electricity prices and how does the policy affect investments in new generation units?

Contrary to earlier studies (Abrell and Kosch, 2022; De Siano and Sapio, 2022), the assessment is not based on an econometric model fed by historical data. Instead, the novelty in our methodology consists of leaving each examined country out of the whole system calculations to assess its impacts on other countries ("leave-one-out" method). The spatial spillover effects of each country on others can be estimated for the current and future electricity systems along their decarbonization path. Moreover, the methodology considers a set of countries and their interdependency to establish a cross-impact matrix, which specifies the spatial spillovers of a country on its neighbors. Assessing a country's price or carbon impacts on its neighboring countries allows for identifying issues that emerge as a country follows its NCEPs, independently of the effects it may induce on its neighbors. Our approach thus provides new insights for better policymaking for European-wide decarbonization.

1.4. Structure

This paper is structured as follows: Section 2 describes the modeling

¹ Renewables capacity is developed as investors decision is based on the expected difference between the discounted amortization and maintenance costs and the average electricity price they will receive through the life of the project, including any subsidies.

of the European electricity system and details the hourly data used for loads, transmission, and generation capacities. The “leave-one-out” (LOO) methodology is also described in full detail in section 2. Section 3 presents the results of our simulation. We provide generation mixes and energy balances, as they drive our main results on price and CO₂ spill-overs, as computed by the LOO methodology. Section 4 provides a sensitivity analysis of our assumptions relative to past and current market conditions, in relation to the recent geopolitical events and their consequences on the energy markets. Section 5 discusses the findings and discuss a broader perspective on the topic, concerning potential policy and decarbonization implications. Finally, section 6 points out the key conclusions of the study.

2. Methodology & model

2.1. General modeling approach

Our analysis concerns a possible decarbonization pathway of the European electricity system, from 2018 to 2040. In addition to the initial and final year, an intermediate stage by 2030 is also assessed. In the initial year 2018, used as the reference, a simplified EU electricity system is modeled. The system evolves in the next two decades 2030 and 2040, as renewable generation and transmission capacity expansions are integrated, and thermal (nuclear and fossil) power plants are phased out.

The EU electricity system is modeled with the generation dispatch tool Antares (Doquet et al., 2008), version 8.1, a software developed by RTE (the French TSO) to simulate the supply/demand equilibrium at an hourly time resolution. Our modeling approach is carried out in two steps:

- (1) The first step is to determine the optimal dispatch of a predefined set of power plants in each country and the electricity flows between them to balance the overall system's load. To this end, Antares seeks the optimal dispatch of power plants based on the maximization of social surplus.² The optimization, over the annual period, takes into account technical and economic parameters of the generation fleets, such as hydro inflows, plants characteristics, thermal generation marginal cost, wind and solar power intermittency, time-series load profiles, as well as available cross-border (net) transfer capacities (NTC) (see Fig. 1). The market equilibrium between generation and demand is established for each hour. Perfect market and foresight assumptions are assumed within the optimization process. In that case, the system clearing price is set by the operating cost of the most expensive unit online at the given hour. With an inelastic consumer bid curve, which is typical in electricity markets, the cost minimization also provides the maximization of the system's social surplus. The main output of the simulation is a time series of the optimal generation dispatch and wholesale prices, as well as cross-border electricity exchanges. Moreover, supply-demand balances per country are computed.
- (2) The second step assesses the impact of an individual country on the electricity system by leaving that country out (LOO) of the simulation, assuming its demand and generation capacities are zero. Such a LOO procedure is repeated for each country in each stage of the decarbonization pathway. Consequently, by comparing results, we assess a country's (marginal) impact on prices, electricity mixes and CO₂ emissions.

2.2. Inputs and data

The following sections describe the data used as inputs in the Antares

tool for modeling the electricity system at each stage of the decarbonization pathway. A graphical overview is provided in Fig. 1.

2.2.1. Data sources

At the initial stage (2018), different sources (ENTSO-E, JRC-IDEES, ...) of information are collected to represent the current electricity system. Those sources are directly referenced in the description of the inputs.

The modeling of the future systems (2030 and 2040) relies on the information made available by ENTSO-E's Ten-Year Network Development Plan of 2020 (ENTSO-E, 2020). TYNDP 2020 contains three scenarios - National Trends [NT], Global Ambition [GA] and Distributed Energy [DE] - which provide potential future developments of the European electricity sector. Those scenarios are mainly based on TSOs' national long-term planning studies, and their main pathways and distinguish themselves by their decarbonization, centralization or decentralization targets. Decarbonization refers to the decline in total direct CO₂ emissions, while centralization and decentralization deal with the share of large- and small-scale electricity generation units.

Inputs, for the future stages, are taken from the GA scenario. The following reasons justify our choice: (1) While the NT scenario keeps its bottom-up characteristics from TSO's best knowledge in compliance with the NECPs, only the two top-down scenarios GA and DE are in line with COP21 decarbonization targets (ENTSO-E, 2020). Moreover, only those scenarios consider infrastructure investments to achieve net-zero by 2050. (2) The GA scenario features a centralized evolution of the energy system at the European level. To this end, it relies on centralized generation technologies and requires a limited increase in grid infrastructures. Due to the long delay in transmission capacity expansion and the immediate urgency of acting against climate change, we assume that the GA scenario is better suited to address the research questions of this study.

2.2.2. Geographic scope and network

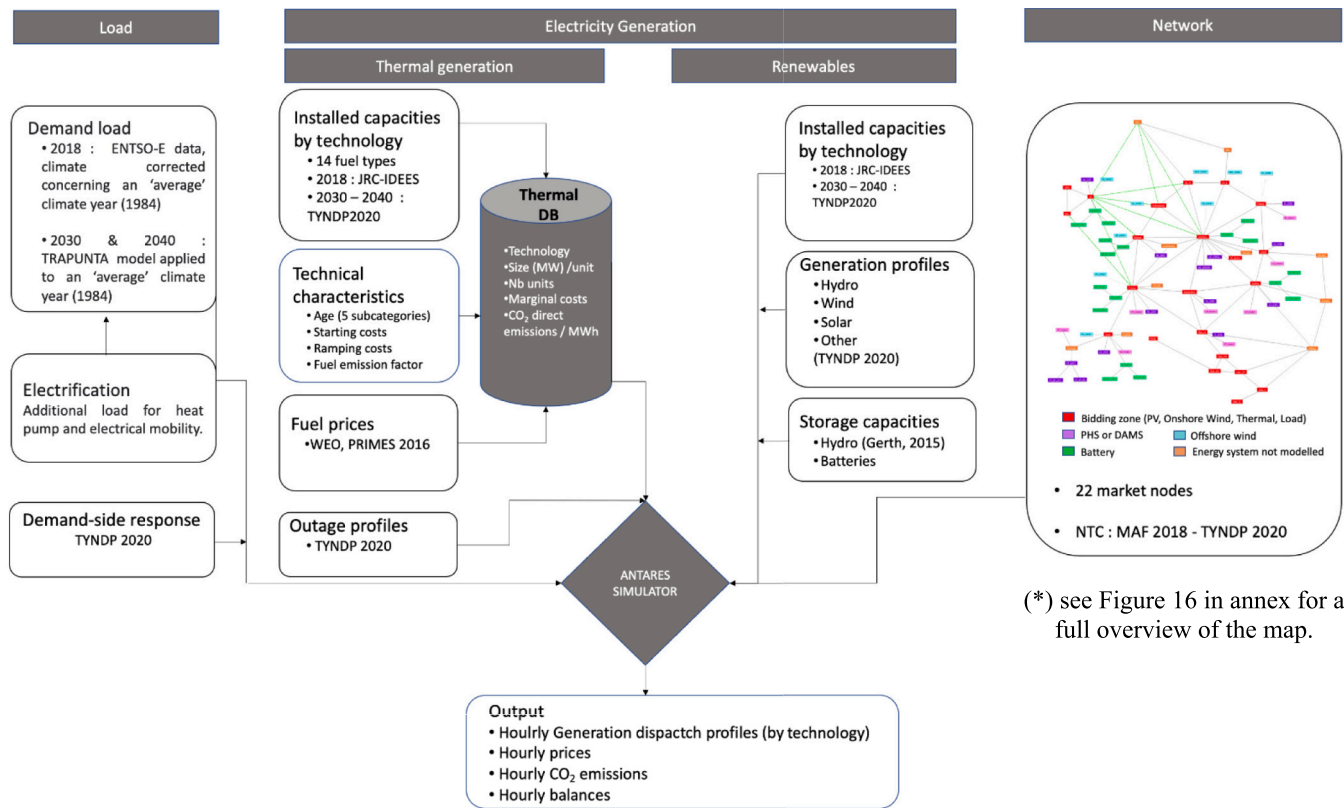
Geographically, the ENTSO-E region covers >35 countries. To focus on the largest economies and their neighbors and to save on computational resources, the number of countries in this study has been restricted to the following 15 countries: Austria (AT), Belgium (BE), Czech Republic (CZ), Denmark (DK), Germany (DE), France (FR), Italy (IT), Ireland (IE), Luxembourg (LU), Netherlands (NL), Poland (PL), Portugal (PT), Spain (ES), Switzerland (CH), United Kingdom (UK). This list is representative of the central regions of the European electricity grid. As some listed countries (i.e. Italy, Denmark, United Kingdom) have two or more market areas, they are modeled with different nodes, accordingly.

A simplified grid is built-in between the mentioned nodes above, where each branch of the grid maps a node to another in accordance to the planned NTC capacities from the TYNDP 2020 GA scenario, for the different years 2018, 2030, and 2040 (see Fig. 2). Besides the cross-border NTC between those market nodes, the NTCs with the following countries are additionally modeled: Norway (NO), Sweden (SE), Hungary (HU) and the Balkans region. Although the energy systems of those countries are not modeled, their interconnection capacities with our considered nodes offers transits capacities, increasing the accuracy of the simulation of the whole European electricity system.

2.2.3. Load and demand-side response

In the reference year, the load profiles of each node are based on 2018 ENTSO-E load data, climate-corrected to consider an ‘average’ climate year (1984) (ENTSO-E, 2019). For 2030 and 2040, the load forecasts (see Fig. 3), as directly provided by TYNDP, are normalized to the same average climate year profile (1984). The load forecasts are based on the TRAPUNTA model (ENTSO-E, 2019), which accounts for additional factors that affect electricity consumption (e.g., penetration of heat pumps, electric vehicles, batteries, population and industrial growth).

² Social surplus refers to the overall welfare of the system given by the addition of consumer's and supplier's surplus.



(*) see Figure 16 in annex for a full overview of the map.

Fig. 1. Flow chart of data fed into the Antares software as inputs.

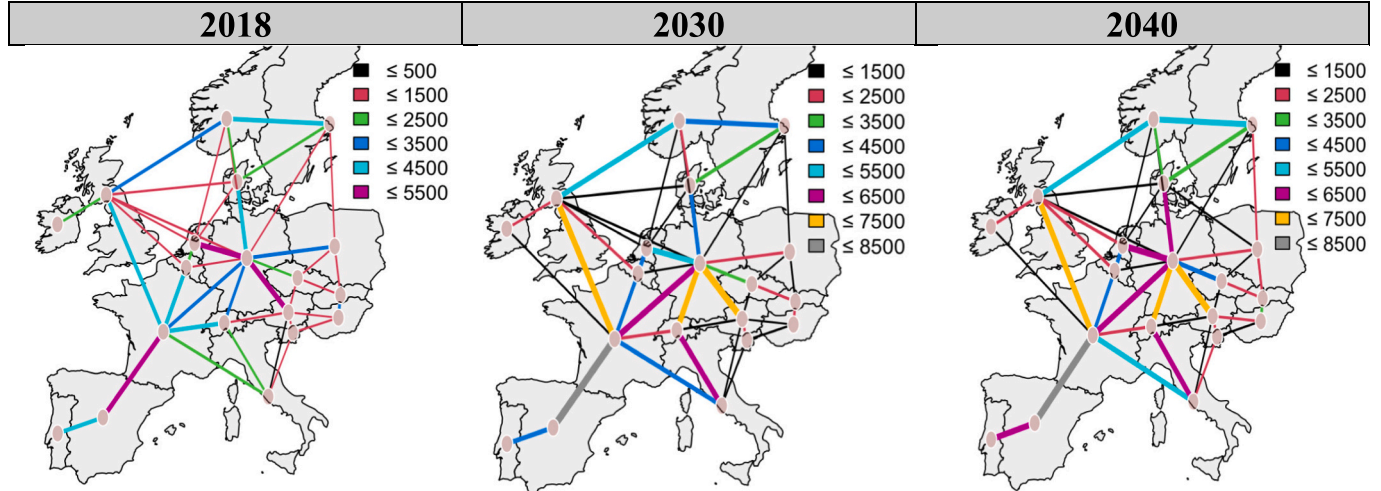


Fig. 2. NTC capacities (in MW) between the different countries over the three stages of the decarbonization pathway.

As large consumers (mainly from industry) tend to soften their country's peak demand by adapting their energy consumption according to electricity prices, demand-side response (DSR) is considered. Such DSR capacities are modeled as demand reduction potential in the case of supply shortage.³ However, they are not modeled as actually shiftable loads. The available capacities for DSR are collected from the TYNDP 2020 GA scenario.

³ Such assumption may result in an annual lower demand when prices exceed the willingness to pay of those large consumers.

2.2.4. Generation portfolio

For the reference stage (2018), the installed capacity in each country is based on the JRC-IDEES database (Mantzou et al., 2017), as it provides a full picture of the existing electricity generation fleet in all EU-28 countries. This database describes 272 different power plant types by their total installed capacity, the number of units, and the average capacity per unit.

For 2030 and 2040, the TYNDP 2020 GA scenario accounts for new investments and plant decommissioning. The capacity development in the scenario results from an investment model that seeks, among a shortlist of generation and transmission candidates, capacities that minimize the long-term average costs of the system. For each

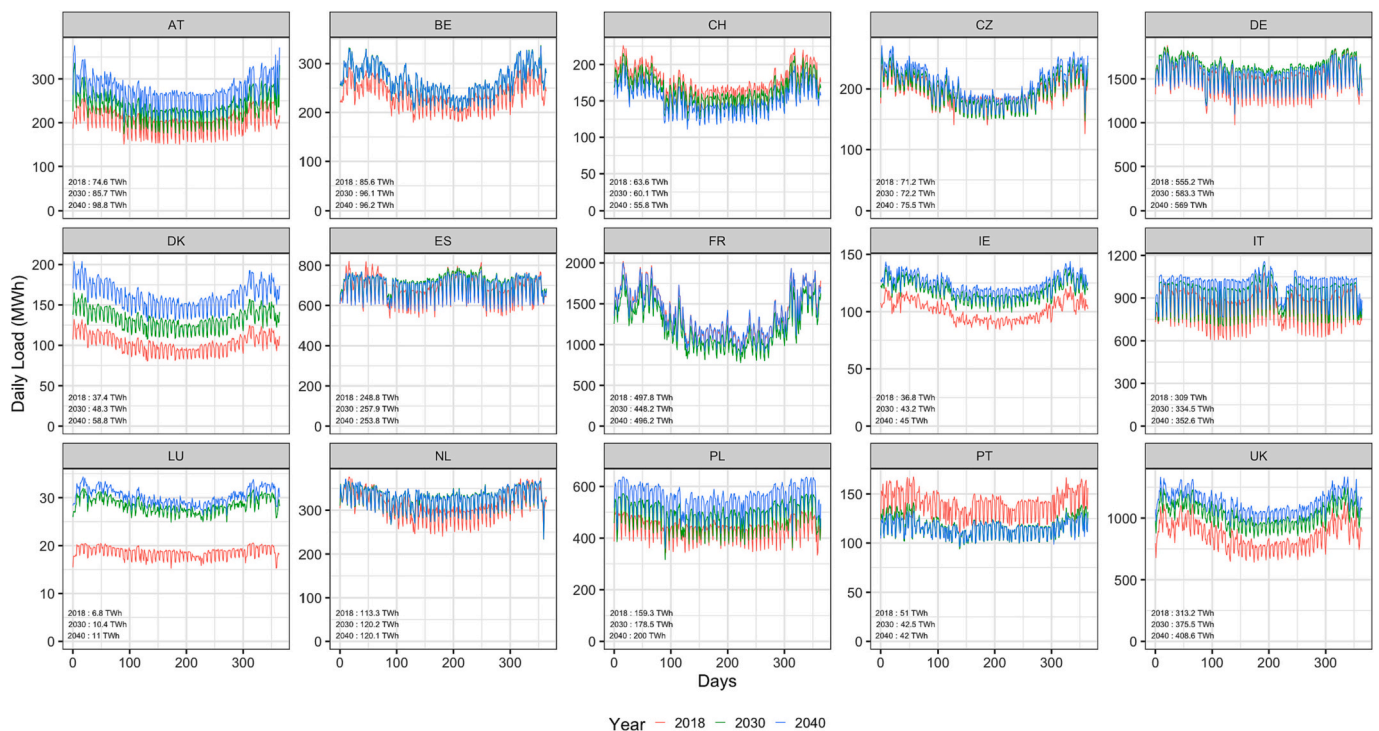


Fig. 3. Daily aggregation of the hourly demand by country over the three stages of the decarbonization pathway.

technology, new capacities are thus added to the generation fleet in 2030 and 2040 if their economic viability is sustained. The investment model also challenges existing thermal generation plants by decommissioning them after finding the optimal level of renewable capacities to fulfill the CO₂ targets. Each technology expansion is also examined regarding its political and social acceptance.

To ensure consistency, the data from the JRC-IDEES database is aggregated and mapped conformably to the fuel types referenced in TYNDP 2020. Those resource types are: wind (differentiated between onshore and offshore), solar PV, hard coal, lignite, gas, nuclear, pumped hydro storage, run-of-river & reservoir hydropower as well as other (thermal) renewable generation from biomass and geothermal. Besides those renewable and conventional fossil technologies, battery capacities are also modeled. The fleet portfolio is classified into categories and subcategories considering their technical characteristics and the age of a facility.

Fig. 4 depicts the installed fleet at the different steps of the transition period from 2018 to 2030 and 2040.

2.2.5. Renewables

2.2.5.1. Installed capacities. With a total installed capacity of 160 GW and 105 GW, wind and solar PV accounted for most of the planned capacity expansion in 2018. An additional 254 GW of solar PV and 280 GW of wind are added to the system by 2040. The largest increase is expected in Germany with an additional 62 GW of each technology. These technologies are complemented with a wide range of other renewable energy sources (e.g., hydro, biomass...) whose capacities are mostly left unchanged along the decarbonization pathway. Among these other renewable energy sources, hydro is the most prominent one with a total capacity of 127 GW, mostly in Alpine countries (CH, AT, FR).

2.2.5.2. Generation

2.2.5.2.1. Wind and solar. Wind and solar generation are modeled as 'must-run' generation. Their hourly generation profiles are taken from the Pan-European Climate Database (PECD) developed by the

Technical University of Denmark (ENTSO-E, 2018; Nuño et al., 2018). The database gathers country-specific profiles for ENTSO-E member states over the 1982–2016 period. The database consists of synthetic hourly time series derived from historical weather data and provides hourly normalized load factors for each market node and each technology: (i) Onshore and (if applicable) offshore wind generation and (ii) solar PV generation.

To be consistent with other climate-dependent input data⁴ (e.g. demand load, hydro inflows, etc.), hourly load factors are specific to the averaged climate year (1984). These profiles are assumed to remain constant throughout the pathway.

Fig. 5 represents the mean hourly profiles for the three renewables: onshore and offshore wind and solar PV. While solar PV is more prominent in southern European countries and during daylight, wind profiles show higher generation in northern countries and at night. Fig. 5 also illustrates how each technology can be complementary to each other in order to achieve a higher tandem capacity factor.

2.2.5.2.2. Hydro profiles. The PECD also includes hydro data. However, hydro profiles differ from wind and solar data in terms of their granularity: Run-of-River (ROR) data is provided as daily inflows, while reservoir storage (STOR) and pumped-hydro storage (PHS) inflows are available on a weekly basis. Contrary to wind or solar PV, where the magnitude of electricity generation is directly linked to wind speeds or irradiation, hydro data provides energetic inflows to water bodies and reservoirs. This potential energy is then turbinized into electricity in the respective power plants. The generation of a hydropower plant is thus a decision variable of the model, which considers hydropower as a dispatchable technology.

Modeling a hydropower system, including (pumped) storage, is challenging due to its complexity and the presence of many stochastic variables, e.g. cascades of reservoirs and unclearly defined marginal costs. For overcoming this complexity, our model includes the following simplifications, which are based on TYNDP practice:

⁴ Our model doesn't account for Monte-Carlo simulations regarding extreme demand and weather dependent generation (hydro, solar, wind).

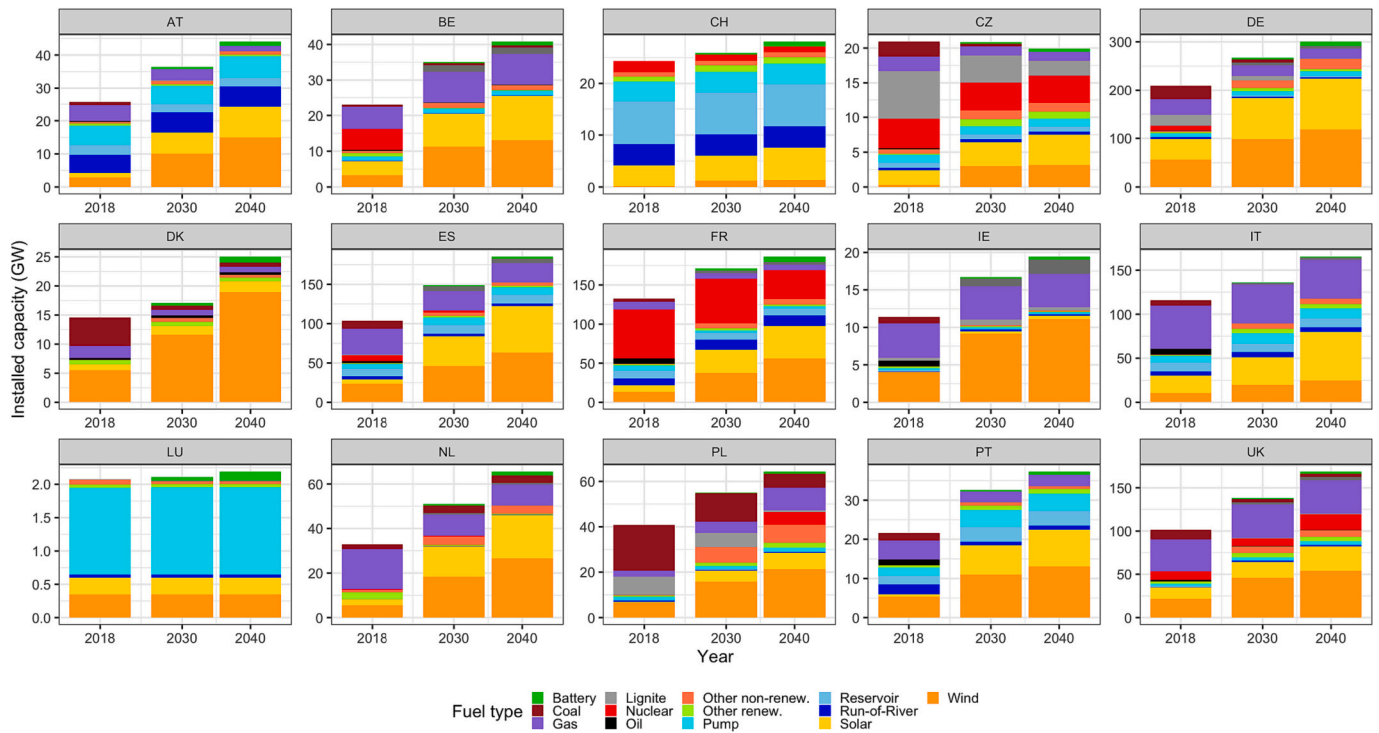


Fig. 4. Installed generation fleet from 2018 to 2040 according to fuel types.

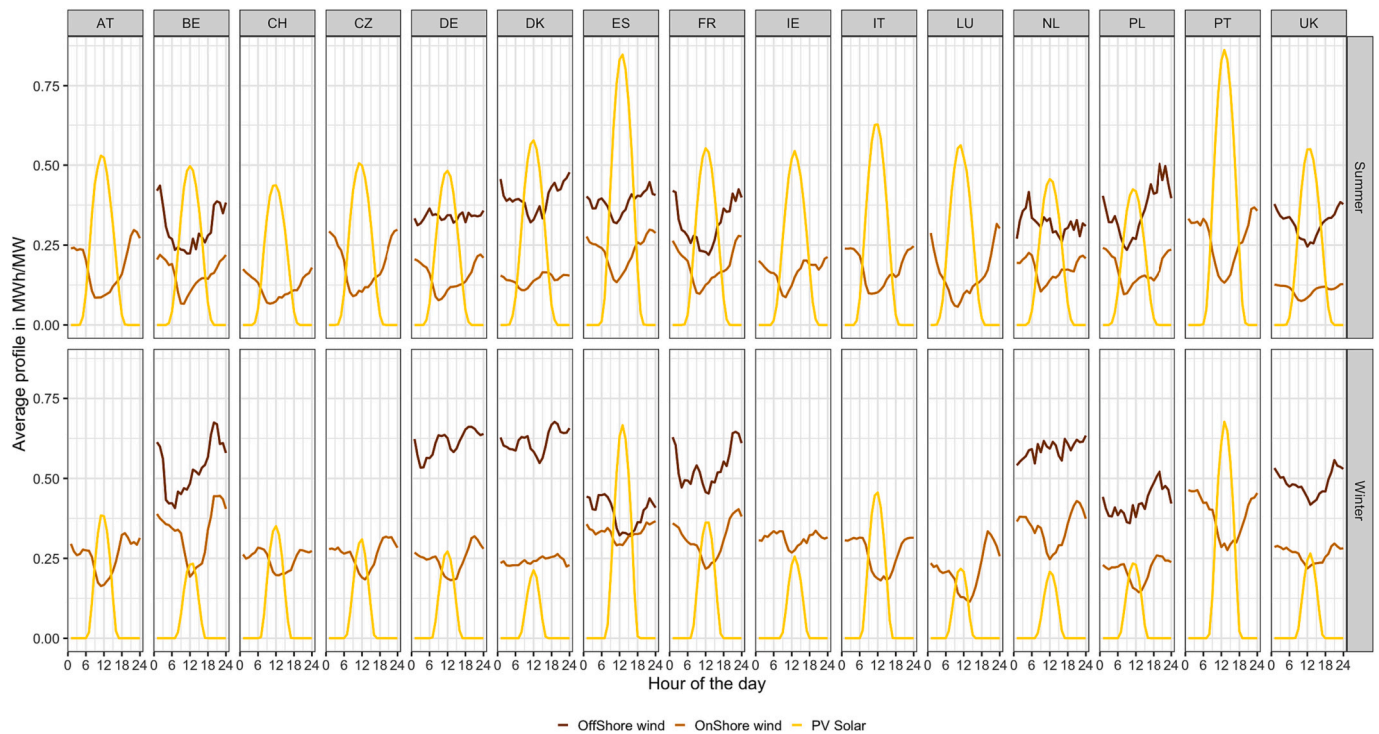


Fig. 5. Average hourly profile of renewable technologies by country (source: PECD).

i) All run-of-river and pondage plants (ROR) of a given market node are modeled as single “must-run” units.

ii) Reservoirs (STOR) of a given market node are modeled according to a storage capacity for the natural inflows but do not have pumping capacity.

iii) Open-loop pumped-hydro storage (PHS) are hydropower plants modeled with a storage capacity and natural inflows as well as a

pumping capacity. The round-trip efficiency of a pumping cycle is assumed at 85% (i.e. the model can retrieve 85% of the energy absorbed by the pumping capacity). (Benitez et al., 2008). The model seeks the best opportunity for pumping (when electricity prices are low) and for generation (when prices are high) to minimize overall system costs.

iv) Closed-loop PHS are hydropower plants with pumping capacity, but no natural inflows. They are subject to similar constraints as open-

loop PHS.

Each hydro category has a set of specific constraints to operate (e.g., maximum turbine and pumping capacity). Due to the absence of official statistics, storage capacities come from TYNDP 2020 for reservoirs and (Geth et al., 2015) for PHS. The previous authors use publicly available information from plant owners, freely accessible databases, scientific articles, reports, brochures and government to define a measure of energy storage capacity, which allows for comparison of PHS plants with other storage technologies (e.g. batteries). The status of storage capacities (PHS and STOR) of the 15 countries are presented in Fig. 6 (logarithmic scale).

2.2.5.2.3. Other renewable profiles. Installed capacities of other renewable generation (e.g. biomass, marine, or geothermal) complement the renewable capacities in our model. Even though those technologies' capacities remain marginal at the system level, they are integrated into the model with a constant (baseload) generation profile at their nominal power.

2.2.5.3. Environmental aspects. Although all renewable technologies have a small amount of embodied CO₂ associated with their output due to the emissions from manufacturing and installing them, this study only looks at the direct emissions caused during operation. Therefore, the renewable generators have no CO₂ release in the model.

2.2.6. Thermal plants

2.2.6.1. Installed capacities. The total thermal capacity amounts to 463 GW in 2018. By 2040, 203 GW will be decommissioned. Fossil fuel withdrawal occurs mostly in Germany (−72 GW) and Poland (−21 GW). A −36 GW (out of 102 GW in 2018) of nuclear capacity is also progressively phased-out. Other non-renewable capacities based on gas will increase (+57 GW) and will be still in operation at the end of 2040. Those units, mainly CHP plants throughout Europe, are expected to play a role in decarbonization. They are expected to replace oil, coal and lignite units with gas, which is a less CO₂ emitting fossil fuel, especially when admixed with renewable gas. In agreement with national policy plans, the decommissioning of nuclear and coal generation capacities in Germany is considered by 2022 and 2038, respectively, and the nuclear phase-out in Belgium by 2025.

2.2.6.2. Generation. Thermal plants are dispatched according to their marginal costs, which rely on commodities and CO₂ emission prices. In the TYNDP 2020 (ENTSO-E, 2020), which compared several sources of price forecasts (e.g. PRIMES, IEA WEO, Bloomberg, IHS), the PRIMES data was used as a reference for oil, gas and coal. For nuclear and lignite, forecasts are similar to the World Energy Outlook (WEO, 2016), which provides future commodity price trends between 2018 and 2040. Table 1⁵ summarizes assumptions for each fuel type and CO₂ allowance price.

Marginal costs of a thermal plant also depend on a set of technical constraints: Those parameters are sourced from the Pan European Market Modeling Database (PEMMDB) of ENTSOE (ENTSO-E, 2018), which provides information by technology for the maximum power, efficiency, operation & maintenance (O&M) as well as ramping costs

⁵ Forecasts on commodity prices are complex exercises which can be impacted by geopolitical events. As the Ukrainian war affected the supply of the European natural gas market, Fossil-fuel prices and CO₂ prices in Table 1 might appear to be relatively low in comparison to the actual market conditions. Section 4 discusses the sensitivity of our results to changes on CO₂ allowances and fossil-fuel prices.

and CO₂ emissions. This information is available for different technologies, fuel types and age of power plants.⁶

By combining the previous information on technical constraints and commodity prices with the thermal generation fleet data, we define the marginal costs of the different thermal plants. The ascending ranking of the generation fleet's marginal cost provides the merit-order of our model (Fig. 7). It reveals the progressive shift of lignite and coal units to the right-hand side of the merit-order over the analyzed time horizons, which is due to an increase of prices for CO₂ certificates and commodities. While the marginal costs of highly emitting fossil-fuel units (lignite and coal) are among the lowest in 2018, they will overtake the marginal cost of gas-fueled units by 2040.

A share of other non-renewable (other non-RES) capacities, in line with TYNDP2020 assumptions, are considered as “must-run” units. Price signals do not drive their operations, but other factors such as heat demands in the residential and industrial sectors. Those units are installed in France, Denmark, Germany, and the UK.

2.2.6.3. Maintenance profiles. Thermal generation is subject to periods of planned maintenance, which is necessary for reliable operation. Each thermal unit is given a rate of unavailability (forced outage and maintenance rate as well as duration) based on the unit type. This information also comes from historically observed outages in the PEMMD. This information includes the number of days per year of maintenance, the ratio of maintenance between winter and summer periods as well as the maximum number of units in maintenance simultaneously to avoid lumped risks.

2.2.6.4. Environmental aspects. Only direct CO₂ emissions from thermal generation are considered, as embodied greenhouse gas emissions comprised <2% of the CO₂-equivalent emissions in the power sector (Brown et al., 2019). Based on the dispatch of the thermal generators, CO₂ emissions are assessed by thermal technology using the emissions factor of the specific fuel and the efficiency of the generators. At each time step, total CO₂ emissions are calculated as the sum of all CO₂ emissions per country's generation technology.

2.2.7. Batteries

According to the TYNDP, decreasing the cost of batteries and the evolution of their benefits from other services could also increase their competitiveness for congestion management and other network services. In our model, batteries are considered as storage facilities with a round-trip efficiency below 80%. In line with TYNDP 2020 data, the capacity of batteries in our model increases from 1.3 GW in 2018 to 24.9 GW in 2040. The largest facilities of batteries are installed in Germany, France and Spain. Battery storage capacities are modeled as weekly storage, with a maximum of 64 h allocated for charging and discharging over a week. We recognize the limitations of this approach and intend to address this issue in the near future, with a more precise determination of storage capacity, shifting to a daily storage capacity model, which will necessitate a reframing of the storage optimization problem in the use software ANTARES.

3. Results

3.1. Electricity generation mixes

European-wide electricity generation increases from 2'780 to 3'070 TWh between 2018 and 2040, ca. +10% (Fig. 8),⁷ as it faces additional

⁶ In ENTO-E TYNDP studies, five subcategories (new, present 1 and 2, old 1 and 2) differentiate the thermal power plants according to their building period. Each subcategory corresponds to a certain technical efficiency range of the power plant.

⁷ In appendix, Figure 17 depicts the generation mix in relative values.

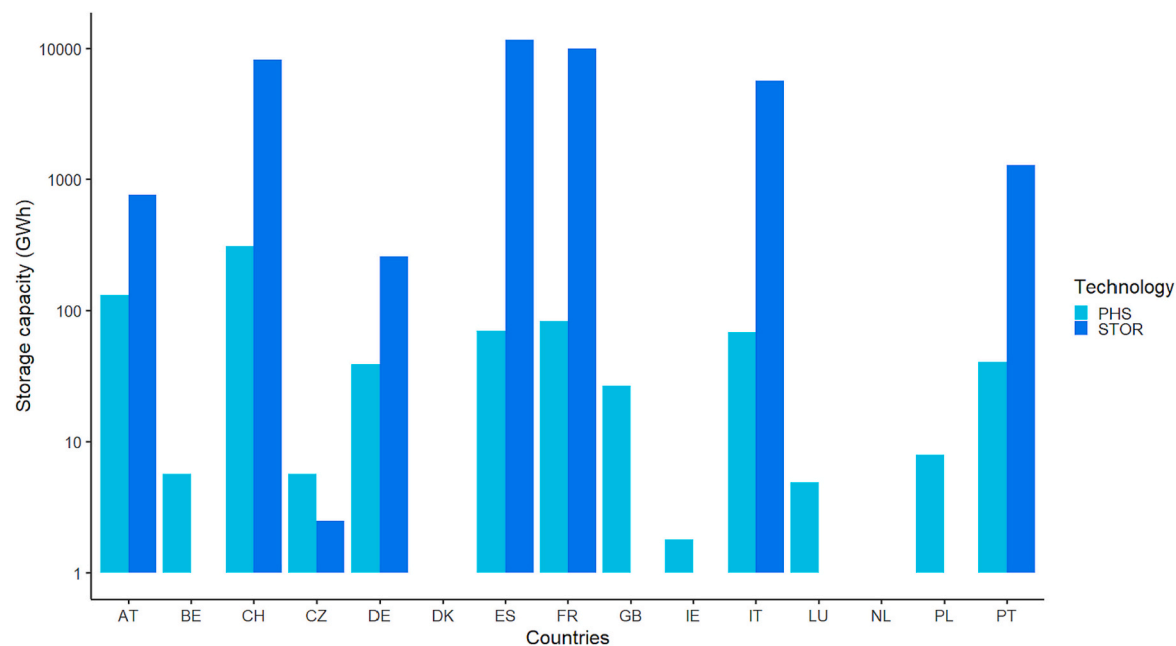


Fig. 6. Storage capacities (PHS and STOR) in the system countries (logarithmic scale) – Year 2018

Table 1
Commodity prices per fuel type and CO₂ emission price.

	Nuclear €/MWh	Lignite €/MWh	Hard Coal €/MWh	Gas €/MWh	Light Oil €/MWh	Heavy Oil €/MWh	Oil shale €/MWh	CO ₂ €/t
2018	1.55	3.63	9.90	18.48	42.57	38.16	8.28	19.7
2030	1.55	3.63	14.19	22.80	67.65	52.56	8.28	35
2040	1.55	3.63	22.80	24.12	73.26	61.92	8.28	80

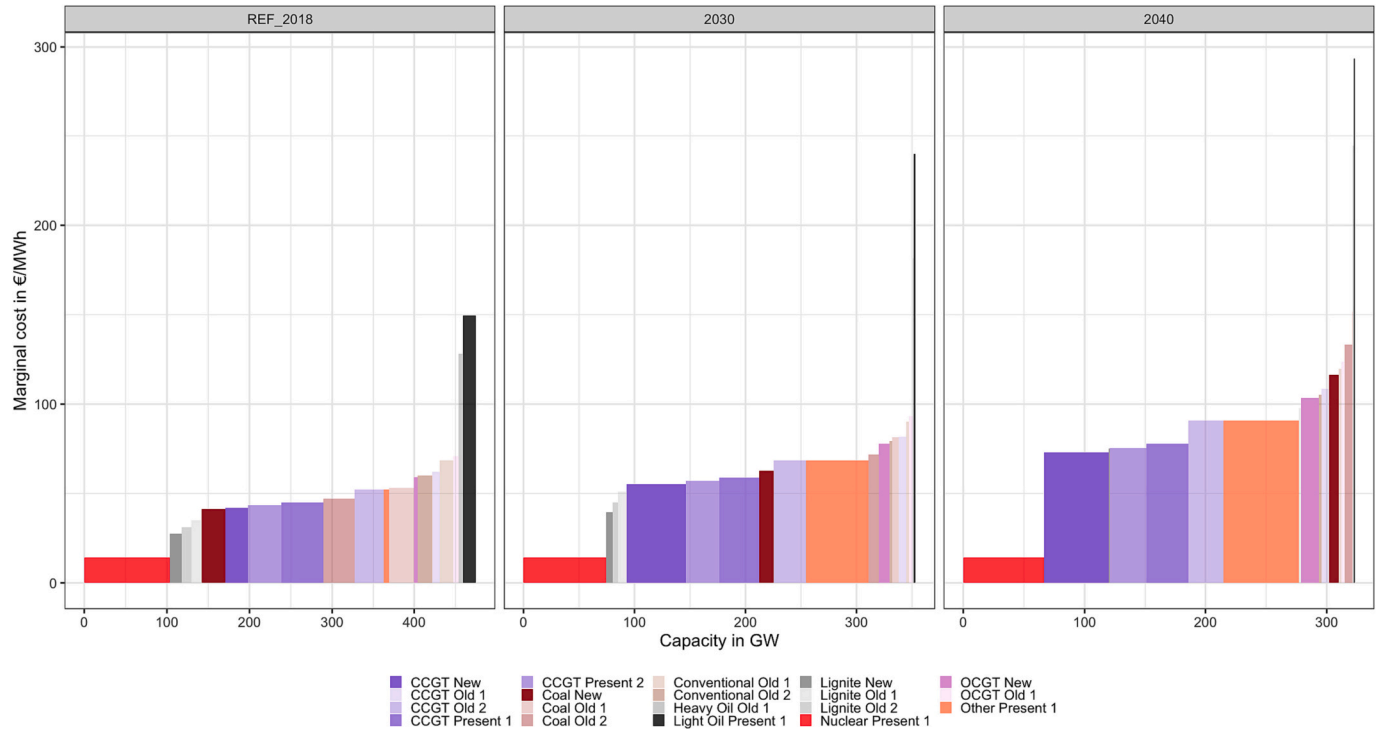


Fig. 7. Marginal cost and capacities of the thermal units in the system (including CO₂ allowances price).

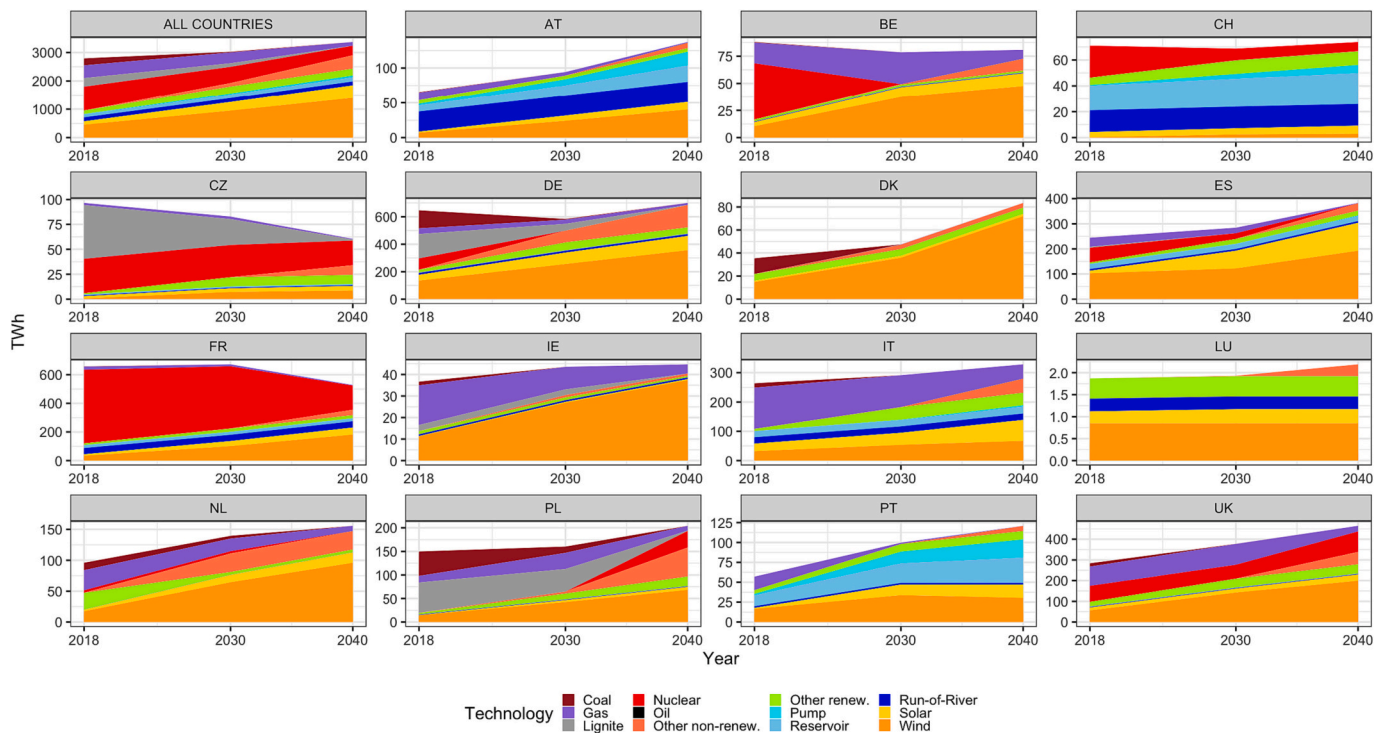


Fig. 8. Electricity mixes by fuel type over the decarbonization pathway (2018-2040) - Absolute values.

demand due to electrification. Higher generation volumes are observed in all countries, apart from France, Czech Republic and Belgium. In those countries, the decrease is mainly explained by the phasing out of thermal generators. They progressively need to rely on imports to satisfy their demand for electricity (see section 3.2) by 2040. While electricity from nuclear power plants decreases in France (down by 169 TWh over the period) - similarly in Czech Republic and the United Kingdom - the generation stemming from other non-renewable “must-run” units (e.g.,

CHP units) increases in Germany and the Netherlands. A larger overview of the aggregated outcomes (generation mix, batteries storage, prices, CO₂ emissions,) was moved to the appendix, as they are not the focus of this research, but are only used to validate our model.

3.2. Energy balances

A country’s electricity balance depends on its generation mix and the

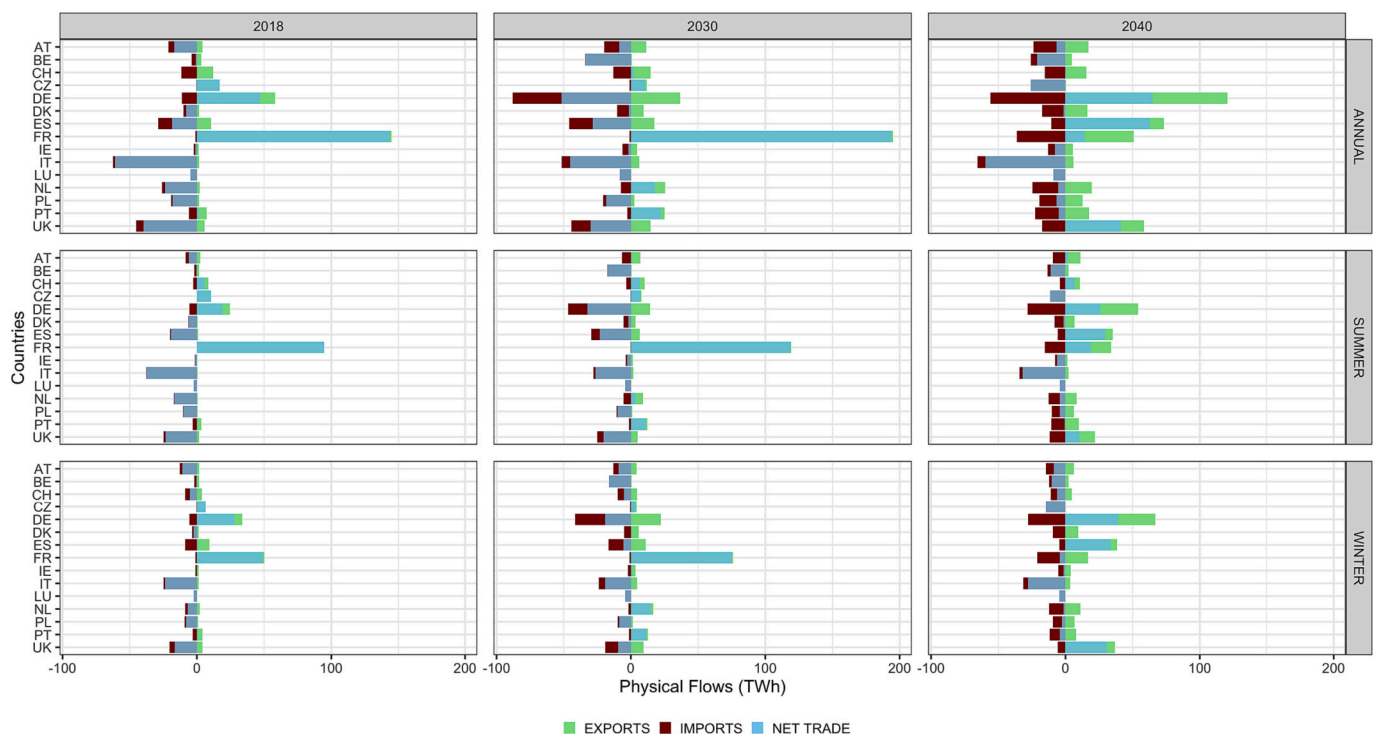


Fig. 9. Hourly Physical balances – sum of hourly exports and imports and net balance by each country.

available NTC with the neighboring countries. Fig. 9 depicts, at annual and seasonal (winter and summer) levels, the sum of hourly exports, imports and net balances for each country. In 2018, the two largest net exporters, Germany (47 TWh) and France (143 TWh), exported 190 TWh to their neighbors, which exhibit a net importing balance: Italy (−64 TWh), UK (−39 TWh), Spain (−18 TWh), the Netherlands (−24 TWh), Poland (−18 TWh), and Austria (−17 TWh). Such trade results from the price differences between the countries, characterized by distinct generation mixes.⁸

Switzerland shows a seasonality in its electricity trade. The country's net balance shows a surplus in summer (exporter) and a deficit (importer) in winter. Over time, winter imports increase from 2 to 6 TWh per year, while summer exports remain stable between 2030 and 2040 (7 TWh). This is notably explained by a lack of seasonal storage capacities (Rüdisüli et al., 2022).

In 2030, a further rise in exports could be expected due to increasing renewable generation, notably in Germany. Although, Germany still exports during some hours in winter and summer, at this stage the country becomes a net-importer, with net trade rising to −51 TWh, as nuclear and coal power plants are phased out. In turn, France still plays a major role as the main European electricity exporter, with an annual exporting balance reaching 194 TWh. Besides France, other countries also export a significant share of their generation, such as Portugal (22 TWh), the Netherlands (18 TWh) and the Czech Republic (10 TWh), although this latter is decreasing its generation output. In 2040, Spain, Germany and the UK become net exporting countries on an annual basis. While exports from France drop to 15 TWh, the country even becomes a net importer in winter (4 TWh), due to decommissioning of some nuclear power plants. Furthermore, the net annual electricity exchanges among countries in the entire system decrease from 216 to 187 TWh over the years, although their hourly volumes increase. Nevertheless, exchanges increase in winter and decrease in summer, as countries become more self-sufficient during the hot season due to solar PV.

3.3. Spillovers

3.3.1. Price spillovers

In this section, we apply the LOO methodology for assessing the price impact of one country on the others. This methodology calculates the price impact on each market node due to removing a specific node (i.e., country) from the system. Results are shown in Table 2, where each value indicates the price variation (increase = positive sign, decrease = negative sign) on the country at the bottom of the matrix by leaving out the country on the right-hand side of the matrix. This spillover table illustrates how, due to the interdependency of the market, a country contributes to the price signal of another country. From an economic perspective, those price spillovers can be interpreted as the benefit or drawback (depending on the sign) of producer or consumer participation in the integrated EU electricity market.

As a notable example (red horizontal rectangle in the matrix of Table 2), in 2018 the withdrawal of France (w/o FR), led to a price increase in all other countries. This is due to France mainly exporting electricity from a low marginal cost technology (nuclear), which substitutes more expensive marginal cost power plants abroad. Without those exports, some countries would have to rely on more expensive domestic or foreign generation to satisfy their demand, which would increase the price above 1 €/MWh. On the other hand (blue vertical rectangle in Table 2), by leaving one of its EU partners out, price fluctuations in France would vary according to the country grouping.

⁸ In appendix, Figure 18 illustrates the real 2018 net balance (EUROSTAT, 2023) alongside the net balance outcomes derived from our model. The disparity is notable in the case of France, attributed to a discrepancy in the availability generation factor of French Nuclear Power plants in our model compared to the actual observations.

Without the main importers' group (ES, IT, UK, NL), French prices drop between −2.37 and −0.35 €/MWh. Although the French generation mix is less requested, it still supplies the demand of the other countries with its low marginal cost nuclear generation. Without the main exporters group (DE, CZ), the French generation supplies additional demand to other countries with more expensive generation plants. Without the last group (BE, AT, DK), prices in France evolves positively. Although those countries are net importers, part of their low-cost generation is exported requesting more expensive to be dispatched when they are left out of the system.

To a smaller extent, Germany also has a depressing effect on other countries' market prices. Without it, the annual average price in all countries increases, yet only by <1 €/MWh. Although these values represent overall annual values and do not depict short-term (i.e. hourly) impacts (which may occur for periods when climatic conditions are favorable for renewable generation) it indeed depicts the merit-order effect of the German renewable generation on the rest of the continent. On the other hand, without an importer country such as Italy, the prices drop in the neighboring countries (CH, AT, FR), by 1.06 €/MWh in France to 4.62 €/MWh in Switzerland, revealing an excess of supply in those countries without their potential exports toward Italy.

The exclusion of a country might have divergent price spillovers. Spain and Portugal experience opposite price movements when Belgium is withdrawn in 2030. Spain witnesses, on an annual basis, a reduction (−0.21 €/MWh), primarily attributed to increased imports of low-cost electricity, notably from the French market on its northern border, as more nuclear surpluses are available after Belgium withdrawal. Conversely, Portugal prices increases (+0.31 €/MWh). This is explained by some hours in July, when Belgium is an exporter. Portugal and France trigger additional generation to offset for the absence of Belgium. Portugal activates power plants, less costly than imports from France. This occurs at a discontinuity point on Portugal's supply curve, resulting in a significant price increase over those hours. The observed price increase during the underlying week of those hours, amounting to +16 €/MWh, spreads across the entire year, contributing to an annual average increase of 0.31 €/MWh. This price fluctuation underscores the intricate interplay of the various market equilibria over the grid and the challenges to examine spillovers effect at the hourly granularity. It also pinpoints on how the spillover effect can be made of increasing and decreasing impacts at seasonal and hourly granularity.

For 2030 and 2040, Table 2 depicts the increasing dependence of the EU electricity markets on specific countries, namely Italy and France. Italy, which highly depends on imports, causes higher prices in the other countries: if left out, the market prices of the other countries would drop substantially (up to −9 €/MWh in 2040). In contrast, France contributes substantially to lower EU prices: if left out, the market price in some countries would increase substantially (up to 10 €/MWh in 2040).

Globally, with a higher penetration of renewables, we observe an increase in the volatilities of spillovers over the 2030 to 2040 period. This confirms previous observations of an increase in price volatilities (Phan and Roques, 2015). When leaving out countries with net exports from low-cost generation (e.g. France, UK), more expensive plants are required to ensure the demand/supply equilibrium, leading to a price increase in the other. When leaving out countries with net imports (e.g. Italy, Germany, Belgium), prices in other countries drop, as fewer plants with higher marginal costs are needed in the system. The more a country remains dependent on electricity imports from fossil fuel power plants, the larger its LOO impact on price decrease in other countries.

3.3.2. Price spillovers and economic viability of new investments

As a complement to the above analysis of the price spillovers, we investigate their impact on the economic viability of the new additional capacities during the transition pathway. As long as the revenues collected by the additional capacities recover their fixed and variable costs over the lifetime of the investment, their economic viability is guaranteed.

Table 2
Mutual price spillovers from 2018 to 2040 in €/MWh.

2018															2030															2040															
NA	-0.30	-0.59	-0.40	-0.34	-0.33	0.21	0.62	0.00	-0.07	-0.34	-0.33	-0.14	0.17	-0.22	NA	-0.58	-2.69	-1.65	-0.88	-0.68	0.46	0.43	0.14	-0.54	-0.88	-0.09	0.28	-0.43	NA	1.35	0.24	0.19	1.64	1.70	0.66	0.27	0.14	-0.72	1.64	1.61	1.55	-0.15	0.94		
-0.16	NA	-0.23	-0.16	-0.15	-0.15	-0.15	0.07	0.08	0.01	-0.15	-0.14	-0.04	-0.23	-0.09	-1.75	NA	-1.55	-1.32	-1.81	-2.04	-0.21	-0.61	-0.38	-0.40	-1.81	-2.54	-0.24	0.31	-1.61	-3.14	NA	-2.86	-3.36	-2.98	-2.89	-1.37	-1.92	-1.09	-0.95	-2.98	-2.91	-2.39	-0.17	-2.15	
0.02	0.02	NA	0.02	0.03	0.03	0.00	0.00	0.01	-0.01	0.03	0.03	-0.04	-0.02	0.02	0.06	-0.54	NA	-0.52	-0.57	-0.50	-0.35	-0.29	-0.08	-0.21	-0.57	-0.50	-0.18	-0.12	-0.47	0.88	0.47	NA	0.76	0.80	0.78	-0.41	-0.33	0.37	-0.10	0.80	0.73	0.70	-0.15	0.32	
0.11	0.07	-0.01	NA	0.08	0.08	-0.14	0.31	0.10	0.07	0.08	0.08	0.02	-0.17	0.07	0.06	0.11	NA	0.14	0.12	0.65	0.98	0.15	-0.09	0.14	0.13	0.00	0.86	0.03	-2.73	-1.28	-1.89	NA	-1.78	-1.76	-0.26	-0.72	-0.41	-1.00	-1.78	-1.56	-2.23	0.10	-0.81		
0.45	0.68	0.45	0.49	NA	0.77	0.19	0.54	0.21	0.41	0.77	0.77	0.33	0.20	0.58	-1.89	-0.79	-1.62	-1.53	NA	-0.61	0.43	0.35	-0.56	-0.24	-1.13	-0.60	-0.37	1.38	-0.63	-3.52	-2.29	-2.42	-3.99	NA	-2.95	-0.41	0.14	-0.81	-0.50	-2.12	-2.59	-2.51	0.04	-1.16	
-0.23	-0.19	-0.27	-0.22	NA	-0.15	0.23	0.05	0.04	-0.22	-0.21	-0.09	-0.18	-0.14	WIO DK	0.04	0.03	0.31	0.01	0.19	NA	0.70	0.95	0.15	-0.09	0.19	0.20	-0.09	0.84	0.04	-1.31	-0.49	-1.03	-1.36	-0.80	NA	0.15	0.08	-0.30	-0.53	-0.80	-0.48	-0.43	-0.15	0.01	
-0.09	-0.07	-0.19	-0.09	-0.07	-0.07	NA	-2.37	0.01	-0.01	-0.07	-0.07	-0.03	-0.03	-0.06	-0.64	-0.77	-0.56	-0.35	-0.88	-0.83	NA	-6.14	-0.87	-0.08	-0.68	-0.77	-0.10	-6.08	-0.90	0.25	0.40	0.42	0.12	0.28	0.29	NA	1.35	0.55	0.21	0.28	0.30	0.19	0.52	WIO ES	
1.23	1.66	1.33	1.17	1.37	1.38	2.73	NA	0.34	0.12	1.37	1.39	0.47	2.48	1.15	5.00	7.16	5.76	4.47	6.14	6.46	NA	4.32	1.57	6.14	6.67	1.23	7.16	6.37	0.71	0.76	0.47	0.52	0.37	3.08	NA	3.98	2.29	0.57	0.75	7.04	0.31	1.91	WIO FR		
-0.16	-0.11	-0.21	-0.15	-0.12	-0.12	-0.14	-0.29	NA	0.04	-0.12	-0.12	-0.07	-0.17	-0.50	-0.28	-0.21	-0.17	-0.15	-0.21	-0.23	0.98	1.13	NA	-0.11	-0.21	-0.20	-0.06	0.83	0.26	-0.40	-0.47	-0.35	-0.66	-0.40	-0.37	-0.04	-0.15	NA	-0.35	-0.40	-0.39	-0.30	0.13	-3.01	
-1.27	-0.91	-4.62	-1.55	-0.96	-0.97	0.01	1.06	0.44	NA	-0.98	-0.97	-0.62	0.01	-0.75	-6.65	-2.70	-6.50	-6.22	-3.12	-2.78	-0.98	-2.58	-0.78	NA	-3.12	-2.74	-0.57	-0.35	-2.18	-5.88	-3.59	-6.21	-3.97	-3.86	-2.29	-3.04	-1.13	NA	-3.97	-3.66	-6.01	-0.84	-2.48	WIO IT	
-0.16	-0.13	-0.21	-0.16	-0.15	-0.15	0.05	0.00	0.03	-0.03	NA	-0.14	-0.04	0.02	-0.11	-0.50	-0.52	-0.42	-0.41	-0.62	-0.56	0.08	0.01	-0.13	-0.18	NA	-0.55	-0.09	-0.04	-0.48	-1.62	-1.18	-1.44	-1.48	-1.51	-1.45	-0.20	-0.64	-0.09	-0.44	NA	-1.32	-1.04	0.09	-0.70	WIO LU
-0.32	-0.35	-0.37	-0.32	-0.38	-0.38	-0.03	0.15	0.07	-0.02	-0.38	NA	-0.07	-0.04	-0.28	0.64	1.57	0.77	0.50	1.32	1.52	0.59	0.84	0.46	0.19	1.32	NA	0.12	0.20	0.95	-1.45	-0.59	-1.18	-1.46	-0.83	-0.85	0.18	0.06	0.20	-0.32	-0.83	NA	-0.57	0.15	-0.24	WIO NL
-0.35	-0.29	-0.40	-0.42	-0.32	-0.32	0.07	-0.05	0.07	-0.09	-0.32	-0.31	NA	0.05	-0.25	-1.41	-0.78	-1.18	-2.31	-0.89	-0.82	-0.14	-0.48	-0.15	-0.65	-0.89	-0.80	NA	-0.01	-0.62	-1.64	-1.08	-1.38	-3.83	-1.48	-1.51	-0.10	-0.34	-0.05	-0.83	-1.48	-1.25	NA	0.11	-0.61	
-0.09	-0.07	-0.16	-0.08	-0.08	-0.08	-1.17	-0.37	0.03	-0.02	-0.08	-0.07	-0.03	NA	-0.07	0.08	0.08	0.10	0.04	0.06	0.08	4.70	2.08	0.42	0.02	0.06	0.09	0.01	NA	0.11	0.69	0.88	0.96	0.44	0.79	0.77	4.91	1.36	0.68	0.19	0.79	0.77	0.53	NA	0.82	WIO PT
-0.88	-0.81	-0.74	-0.91	-0.90	-0.90	-0.90	-0.35	1.33	-0.09	-0.90	-0.90	-0.15	-0.10	NA	-2.35	-3.15	-2.20	-1.91	-2.78	-3.11	-0.64	-0.85	-1.93	-0.54	-2.78	-2.95	-0.20	-0.83	NA	3.28	3.78	3.67	2.30	3.19	3.44	0.93	3.85	-0.88	0.95	3.19	3.68	2.52	-0.48	NA	WIO UK
AT	BE	CH	CZ	DE	DK	ES	FR	IE	IT	LU	NL	PL	PT	UK	AT	BE	CH	CZ	DE	DK	ES	FR	IE	IT	LU	NL	PL	PT	UK	AT	BE	CH	CZ	DE	DK	ES	FR	IE	IT	LU	NL	PL	PT	UK	

Fig. 10 compares the average revenue per MWh received by new units of different technologies and their associated levelized cost of energy (LCOE). The former is computed on the revenues during hours when the technology is dispatched, which is equal to the product of the market price (€/MWh) and its generation (MWh). The latter is calculated based on all variable and fixed costs (i.e. marginal costs, annual OPEX and CAPEX) as given by Table 6 in the annex.

In 2030, market conditions provide the necessary economic incentives for new capacity for onshore wind in most countries, as the technology's income exceeds its LCOE. Such conditions are also met for solar PV in Austria, Italy and Spain, where generation valued at market prices brings sufficient revenues for investors to be profitable. Apart

from Poland, offshore wind revenues are lower than their LCOE (between 36% in France and 8% in Denmark). In all other countries, additional renewable capacities would not be economically viable without additional subsidies or additional market perspectives (e.g. power-to-X). In 2040, the addition of renewables with lower investment costs but similar generation profiles, due to similar continental climatic conditions, leads to a decrease in both revenue and average total cost. Onshore wind in some countries (eg. IT, AT, CZ) remains the only economically viable technology.

A similar finding is observed for new thermal capacities, especially for new OCGT power plants, whose limited number of running hours induce a high LCOE, which is even above the boundaries of the graph (7

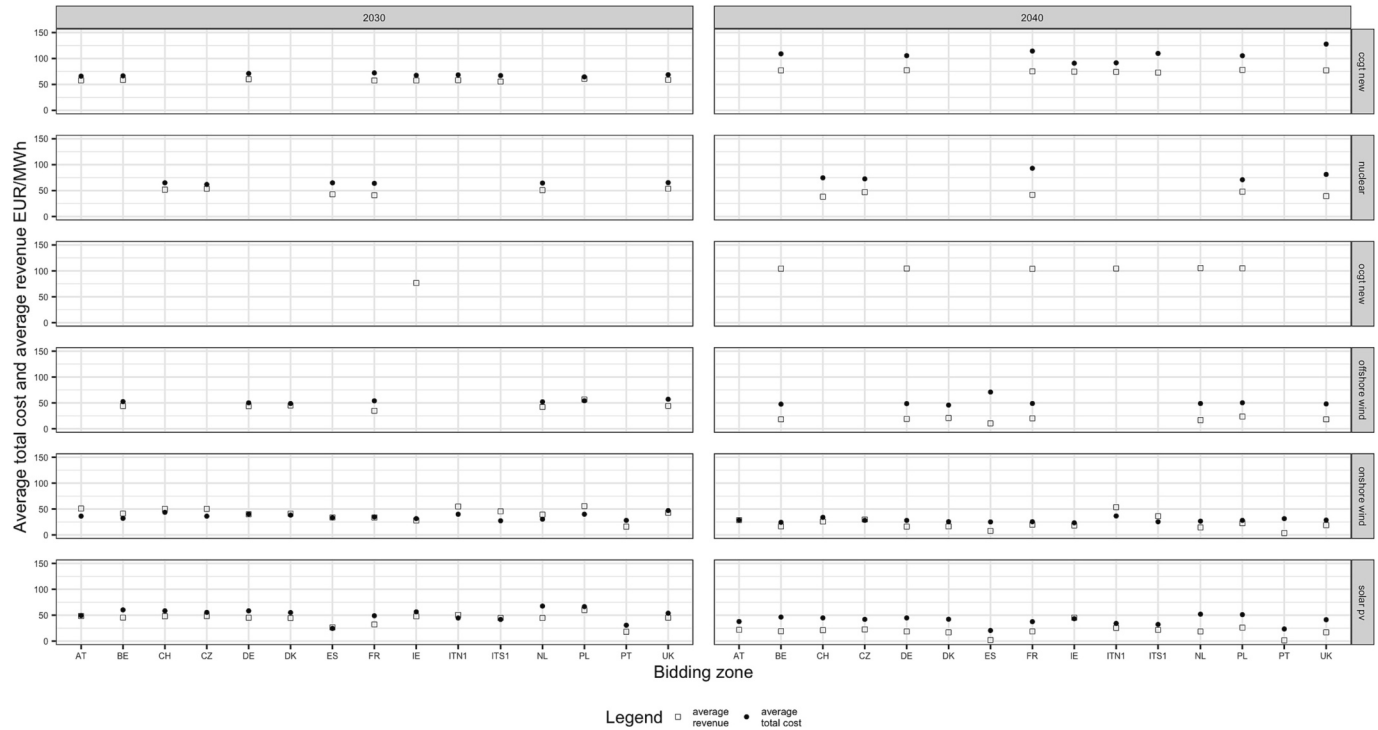


Fig. 10. Annual income per MWh vs LCOE for different technologies candidates in 2030 and 2040. OCGT and CCGT are acronyms for Open cycle gas turbines and Combined Cycle gas turbines, which are two generator technologies to produce electricity usually from gas.

to 30 times higher depending on the country).

3.3.3. CO₂ spillovers

Fig. 11 illustrates the calculated direct CO₂ emissions due to electricity generation of each country. In 2018, total CO₂ emissions in our model amounted to 611 million tons (Mt).⁹ Four countries in Fig. 11 are the largest emitters: Germany (261 Mt.; 42%), Poland (109 Mt.; 18%), Italy (62 Mt.; 10%) and Czechia (55 Mt.; 9%). Over time, as fossil fuel plants are decommissioned, CO₂ emissions relative to their 2018 basis decrease to 320 Mt. (−48%) in 2030 and to 246 Mt. (−60%) in 2040. The largest reduction is observed in Germany, with an abatement of −186 Mt. (−70%) between 2018 and 2040.

Table 3 illustrates the mutual CO₂ impact of the EU countries, as given by the LOO methodology. The table can be read like Table 2: each value indicates the change in CO₂ emissions (negative sign = decrease; positive sign = increase) of the country located at the bottom of the matrix, by leaving out the country on the right-hand side of the matrix. For example, without Switzerland (w/o CH), in 2018 Germany would increase its CO₂ emissions by 1.70 Mt.

In 2018, by removing the main importer countries, such as the UK or Italy, the main CO₂ emission spillovers are observed in Germany (−14.68 or −13.99 Mt). Similar observations are noted when leaving out Poland and the Netherlands, in which case German emissions would be reduced by 5.60 and 5.20 Mt. From such observations, it can be inferred that imports into the UK, Italy, Poland and the Netherlands are partly or mainly due to German fossil-fuel power plants.¹⁰

In the absence of Germany, a major net exporter, Italy experiences an increase in electricity imports from France, contributing to a reduction in its territorial CO₂ emissions (−1.13 Mt). However, the withdrawal of Germany prompts the need for the UK, Poland, and the Netherlands to ramp up their generation, resulting in increased emissions (UK +5.66 Mt., Poland +2.90 Mt., the Netherlands +2.35 Mt). The rise in emissions in these countries, stemming from Germany's withdrawal, is less than the offset caused by their own removal.

Dutch imports, sourced from German low-cost thermal units (as mentioned previously), are thus likely crowding-out domestic cleaner units, like gas plants, characterized by higher marginal costs. Thus, had Germany exported less, the country would have generated less electricity from lignite or coal power plants, potentially avoiding some systemic CO₂. This insight suggests that, from an environmental policy standpoint, the 2018 carbon price of 19.7 €/t CO₂ fails to deter the importation of electricity with higher carbon intensity, even when less emitting but more expensive domestic generation is available.

By removing France, the other main exporter, the major CO₂ spillovers of the French exports are in the UK (+16.44 Mt), Germany (+12.20 Mt), the Netherlands (+8.02 Mt) and Italy (+5.06 Mt). In total (sum over all countries w/o FR), French CO₂ offsets accounts for +59.3 Mt. The French impact is due to its large share of low-carbon nuclear power generation, which is mainly exported,¹¹ and crowds out fossil fuel power plants abroad.

In 2030, as France remains the main exporter, the main beneficiaries

⁹ Calculation based on EEA emission factor and Eurostat data estimates the CO₂ emissions stemming out of the electricity sector within the same geographic perimeter to 811 Mt. in 2018. Figure 22 in Annex shows the difference between effective and stimulated emissions by countries.

¹⁰ If an exporter country is withdrawn, other countries need to make up for the generation of the withdrawn country. On the contrary, if an importer country is withdrawn, generation in exporting countries can (i) decrease, and/or (ii) be made available for exports toward other countries.

¹¹ Such role of the French nuclear power plants has been verified recently. By the end of 2022, when their availability was constrained due to technical issues (ACER, 2023. Wholesale Electricity Market Monitoring 2022, Key Developments.), fossil-fuel plants were dispatched to compensate for the gap between supply and demand at the European level, leading to an increase of CO₂ emissions.

from France's exports are Italy (+15.64 Mt. w/o FR), the UK (+12.99 Mt), Germany (+13.15 Mt) and Spain (+9.37 Mt), which would have seen their emissions increase otherwise. On the contrary, over the same period, Germany becomes an importer, as the marginal cost from lignite power plants becomes higher than the ones of gas power plants, making imports more profitable than domestic generation. The country's net importer role increases contribution from the UK (+8.90 Mt) Netherlands (+4.64 Mt) and Italy (+3.79 Mt).¹² By 2040, as gradually increasing electricity generation comes from renewables, we observe that the mutual CO₂ spillovers are fading.

Fig. 12 summarizes the systemic CO₂ emissions of a particular country, including its spillovers as estimated by the LOO methodology. These CO₂ emissions can be interpreted as the actual contribution of a country to the overall CO₂ emissions in the total EU electricity system, including the sum of positive or negative CO₂ spillovers caused by its imports and exports. A country's contribution can be either higher or lower than its CO₂ emissions due to its generation mix alone (Fig. 11). If the spillovers offset a country's impact due to its own emission, a country can even contribute with "negative CO₂ emissions" to the overall system. As the differences in CO₂ emissions between Fig. 11 and Fig. 12 are equal to the sum of a country's spillover at the systemic level (sum of the row's value in Table 3), the LOO method aims at redistributing CO₂ among countries considering their spillovers.

For example, France's CO₂ contributions in 2018 account for -50 Mt., and German's contributions rise to 244 Mt. With its zero-carbon generation replacing some fossil fuel plants abroad, the French electricity system contributes to an overall CO₂ offset in the whole European electricity system. For Germany, the characterization of its contribution is less straightforward, as Germany still causes a positive contribution to systemic CO₂ emissions. The CO₂ abatements, due to German exports made of renewables or fossils, which substitute higher emitting generation (e.g. oil or old hard coal units) in neighboring countries (i.e. Poland), do not counterbalance the CO₂ impact of the generation needed for German domestic consumption.

For 2030 and beyond, Germany's systemic contributions increase (summer: +14 Mt.; winter: +12 Mt), due to imports from UK and the Netherlands stemming from gas-fired plants. In 2040, although Germany becomes a net exporter again, its contribution to the systemic CO₂ emissions increases, as German imports, which account for 55 TWh of its net trade, are still embedded with CO₂ from fossils fuels plants.

Fig. 13 examines CO₂ spillovers as a function of each country's net exports. Negative CO₂ spillovers occur due to the carbon-intensive nature of the country's electricity imports, thereby elevating overall systemic CO₂ levels. Conversely, positive spillovers in the context of exports denote that the electricity system derives benefits from the presence of a specific country. In simpler terms, a country exports replaces more emissions-heavy technologies that would have been dispatched if that country were excluded from the system. In a broader perspective, exports play a significant role in mitigating CO₂ emissions.

3.3.4. Hourly profile of CO₂ spillovers

Fig. 14 depicts the hourly marginal CO₂ contribution to the system for a selection of countries, as given by the LOO methodology. We refer to those hourly marginal CO₂ contributions as a country impact factors. They are computed as the ratio between the hourly contribution and the hourly demand. The profiles in Fig. 14 can be read as follows: Positive values indicate that the country's impact increases the CO₂ of the system. In turn, negative values state that the country contributes to offset the CO₂ of the system ("negative emissions") at these hours.

While profiles may vary between countries, certain seasonal patterns are discernible, particularly in France and Switzerland, where these

¹² Without Germany, the CO₂ emissions of the three countries decrease (negative sign in Table 3), which means that they contribute positively to German imports when the country is within the system.

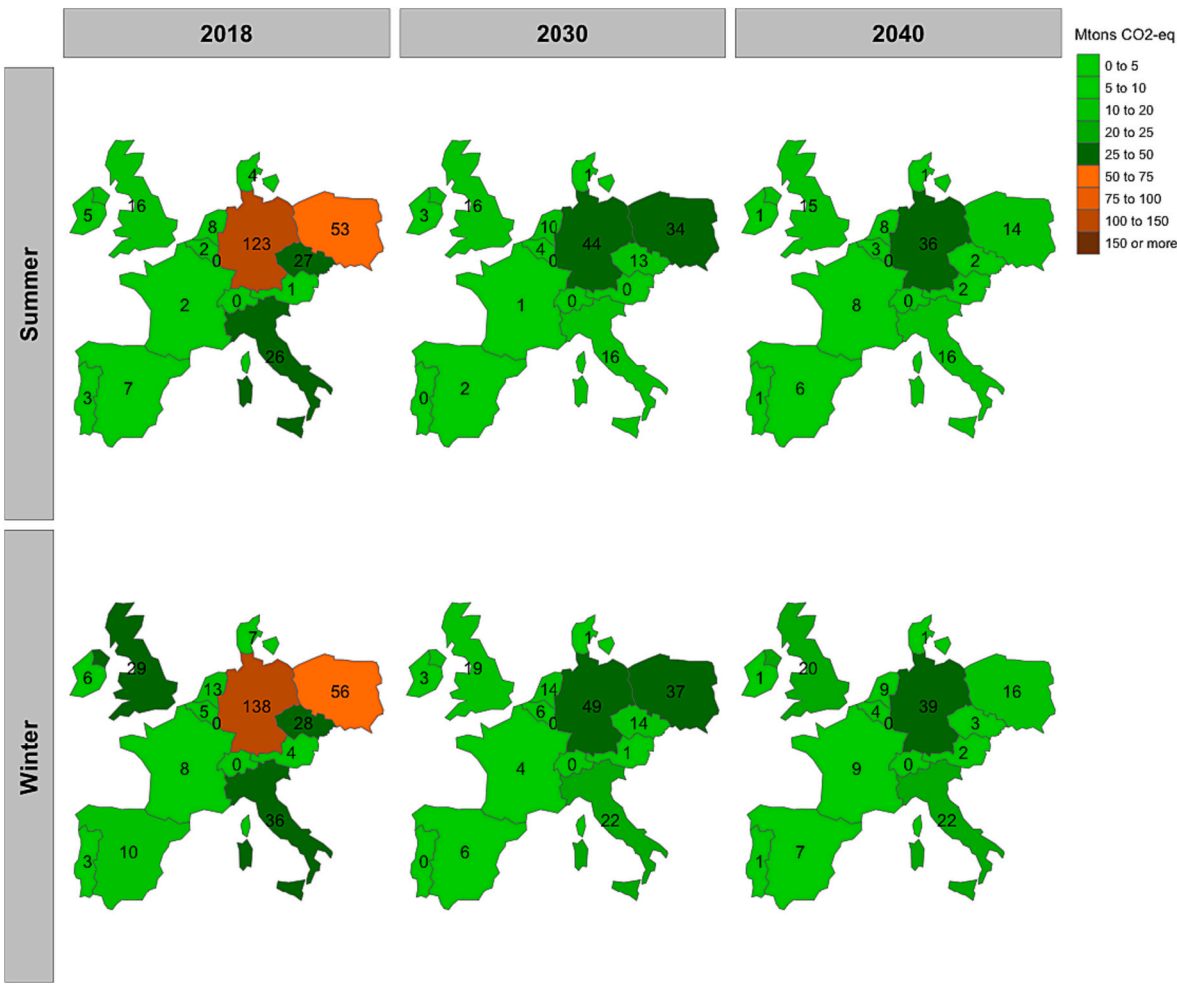


Fig. 11. Direct CO₂ emissions from generation, by country (Mt/year).

Table 3
Mutual CO₂ spillovers from 2018 to 2040 in Mt CO₂.

2018																
NA	-1.20	0.03	-0.84	-6.40	0.37	-0.33	0.45	0.38	-0.97	-0.00	1.43	1.40	-0.05	-5.75	W/O AT	15
-0.60	NA	-0.00	0.11	-1.40	-0.02	0.69	-1.26	0.32	-1.64	-0.00	2.41	1.00	0.31	-2.90	W/O BE	10
-0.02	0.04	NA	0.00	1.70	-0.02	-0.07	0.04	-0.31	0.46	0.00	0.27	-0.10	-0.03	-2.29	W/O CH	5
0.25	0.17	0.03	NA	0.10	0.93	-0.14	1.34	0.49	-0.27	-0.00	2.55	2.30	0.04	-3.90	W/O CZ	0
0.39	1.53	0.02	0.36	NA	1.24	0.96	2.25	0.23	-1.22	0.00	2.35	2.90	0.33	5.66	W/O DE	-5
-0.34	-0.23	0.02	-0.14	-4.50	NA	-0.38	0.86	0.39	-1.37	-0.00	1.31	1.80	-0.00	-5.33	W/O DK	-10
-0.12	-0.34	-0.01	-0.01	-1.10	0.15	NA	-0.39	0.07	-0.85	-0.00	-0.45	-0.10	-3.23	-0.30	W/O ES	
1.52	2.53	0.01	0.52	12.20	2.63	4.78	NA	0.45	5.06	-0.00	8.02	2.30	2.76		W/O FR	
-0.31	-0.61	-0.01	-0.12	-5.90	1.75	0.22	2.15	NA	-1.44	-0.00	2.56	2.00	0.02	-4.98	W/O IE	
-1.88	-1.88	0.01	-2.41	-1.00	-1.30	-0.55	-2.59	-0.39	NA	-0.00	-1.89	-2.60	-0.13	-4.94	W/O IT	
-0.61	-0.26	0.00	-0.27	0.05	-0.03	-1.84	0.26	0.08	-0.73	NA	0.17	0.10	1.63	-5.68	W/O LU	
-0.55	-0.87	-0.01	-0.36	-5.20	-0.73	0.72	-1.10	0.02	-1.46	-0.00	NA	0.40	0.28	-6.35	W/O NL	
0.01	-0.51	-0.00	-0.59	-5.60	-0.92	-1.14	-0.80	0.03	-2.80	-0.00	-1.25	NA	1.54	-1.84	W/O PL	
0.01	-0.15	0.01	-0.08	-1.70	0.14	1.29	-0.12	0.09	-0.42	-0.00	-0.14	-0.10	NA	-2.19	W/O PT	
-0.66	-1.05	-0.01	-0.85	-1.92	-0.52	-0.78	-1.91	-1.50	-0.00	-2.61	-0.90	-0.06	NA		W/O UK	
AT	BE	CH	CZ	DE	DK	ES	FR	IE	IT	LU	NL	PL	PT	UK		

2030																
NA	-1.54	-0.04	-0.22	1.66	-0.02	-0.77	-0.33	-0.55	-1.72	0.00	1.09	1.07	0.01	-0.08	W/O AT	15
-0.25	NA	-0.03	-1.11	-0.77	-0.11	-1.09	-1.10	-0.36	-3.07	-0.00	-1.57	-0.32	-0.06	-2.77	W/O BE	10
0.05	-0.87	NA	0.08	-0.59	0.00	-0.02	0.17	-0.24	0.69	0.00	0.25	-0.06	-0.01	2.04	W/O CH	5
0.07	0.31	0.02	NA	-0.13	-0.03	-0.18	-0.03	-0.55	2.55	0.00	0.56	0.95	0.03	0.07	W/O CZ	0
-0.94	-2.48	-0.05	-0.51	NA	-0.13	-1.42	-1.74	-0.42	-3.79	-0.00	-4.64	-2.13	0.02	-8.98	W/O DE	-5
-0.16	-0.15	0.01	0.05	-1.24	NA	-0.30	-0.23	-0.62	1.56	0.00	-0.51	0.44	0.01	-1.11	W/O DK	-10
-0.26	-1.83	0.02	-0.37	-0.95	-0.03	NA	-1.16	-0.18	-1.55	-0.00	-0.22	-0.37	-0.37	1.26	W/O ES	
1.92	4.84	0.21	3.40	13.15	0.20	9.37	NA	1.26	0.01	7.73	4.31	0.66	12.88		W/O FR	
-0.10	-0.13	0.01	-0.14	-1.23	0.04	-0.35	-0.21	NA	1.55	0.00	-0.05	0.55	0.01	-1.48	W/O IE	
-0.36	-2.41	0.11	-4.14	-4.60	0.01	-0.17	-0.20	-0.19	NA	-0.00	-0.63	-1.71	-0.05	-2.15	W/O IT	
-0.21	-1.42	-0.01	-0.37	-1.14	-0.02	-0.10	-0.49	-0.04	-1.71	NA	-0.54	0.30	-0.02	1.20	W/O LU	
0.05	-0.16	-0.00	0.19	1.43	0.02	0.49	0.20	-0.01	0.15	-0.00	NA	0.51	-0.02	1.89	W/O NL	
-0.27	-0.41	-0.00	-1.50	-1.99	-0.01	-0.38	-0.34	-0.35	-1.47	-0.00	-1.07	NA	-0.01	0.00	W/O PL	
-0.06	-0.93	0.00	0.10	0.28	0.00	4.89	0.38	-0.19	-0.34	0.00	0.10	0.04	NA	2.49	W/O PT	
-0.15	-0.83	-0.00	-1.47	-4.90	-0.03	0.27	0.38	-0.48	-1.13	-0.00	-0.81	-1.17	0.01	NA	W/O UK	
AT	BE	CH	CZ	DE	DK	ES	FR	IE	IT	LU	NL	PL	PT	UK		

2040																
NA	0.00	0.03	0.19	0.61	0.04	-0.00	0.11	0.28	0.63	-0.00	0.44	0.15	-0.02	-0.48	W/O AT	15
-0.11	NA	-0.04	-0.15	-0.76	0.01	0.08	-0.42	0.31	-0.95	0.00	0.12	-0.22	-0.02	-0.73	W/O BE	10
0.10	-0.10	NA	0.16	0.46	0.02	0.02	0.10	0.03	0.53	0.00	0.09	-0.12	-0.00	1.78	W/O CH	5
-0.07	-0.49	-0.03	NA	-0.29	0.01	0.06	-0.27	0.38	-0.58	-0.00	-0.03	-0.93	-0.03	0.52	W/O CZ	0
-0.12	-0.45	-0.06	-0.62	NA	-0.04	-0.18	-0.31	-0.11	-1.28	-0.00	-0.66	-0.93	-0.03	-2.39	W/O DE	-5
-0.03	0.16	-0.04	-0.21	-1.00	NA	-0.02	-0.21	0.35	0.62	-0.00	-0.06	-0.45	-0.02	-1.01	W/O DK	-10
0.09	-0.14	-0.01	0.11	0.05	0.01	NA	0.10	0.04	-0.05	0.00	0.09	-0.28	0.08	1.55	W/O ES	
0.15	0.46	-0.02	0.20	2.21	0.01	0.13	NA	0.18	2.06	-0.00	0.51	-0.10	-0.03	6.12	W/O FR	
-0.07	-0.29	-0.03	0.00	-0.31	0.00	0.09	-0.33	NA	-0.40	0.00	0.35	0.08	-0.02	-0.56	W/O IE	
-0.05	-0.44	0.03	-0.11	-0.61	0.03	0.05	0.02	0.04	NA	0.00	0.04	-0.47	-0.01	-1.05	W/O IT	
-0.02	-0.63	0.02	-0.14	-0.37	-0.00	0.03	-0.15	0.04	-0.60	NA	0.24	-0.38	-0.03	0.78	W/O LU	
-0.02	-0.47	-0.02	-0.11	-0.37	-0.00	0.00	-0.09	0.03	-0.30	0.00	NA	-0.87	0.01	1.10	W/O NL	
-0.02	-0.02	-0.03	-0.12	-0.30	-0.01	-0.03	0.02	0.06	0.01	0.00	-0.01	NA	0.07	0.32	W/O PL	
0.08	-0.07	-0.02	0.13	0.17	0.01	0.45	0.13	0.03	0.16	0.00	0.07	-0.23	NA	1.57	W/O PT	
0.28	1.20	0.09	0.68	1.28	0.07	0.16	1.18	0.29	2.18	0.00	0.88	0.82	0.01	NA	W/O UK	
AT	BE	CH	CZ	DE	DK	ES	FR	IE	IT	LU	NL	PL	PT	UK		

nations function as net exporters of electricity with a low CO₂ footprint. This trend is notably prominent in both countries, primarily during the summer months when they generate a substantial portion of their electricity from hydropower sources.

The hourly variations of the impact factor are considerably more pronounced in smaller countries in comparison to larger ones. This underscores the greater dependence of smaller nations on electricity exchanges, whether sourced from fossil fuels (resulting in a positive

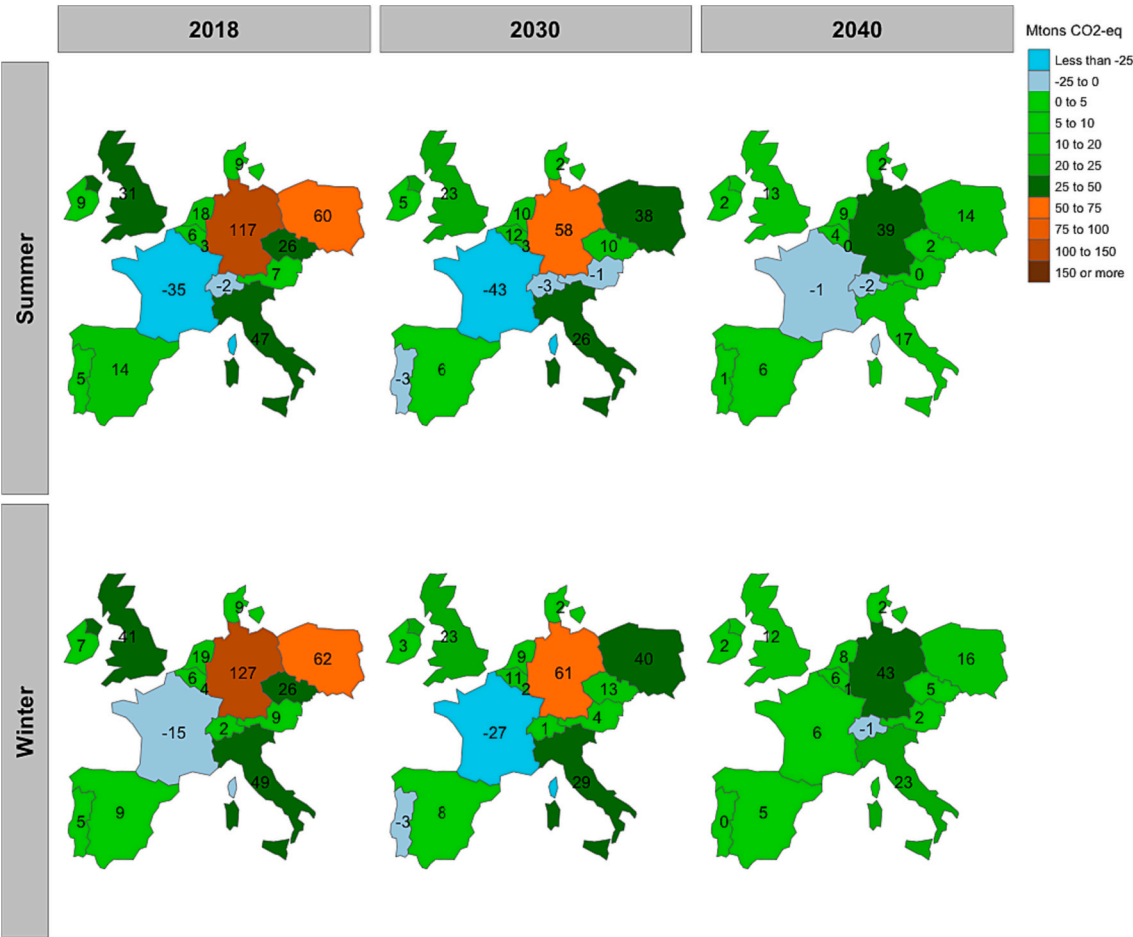


Fig. 12. Contribution to system CO₂ emissions, by country (Mt/year).

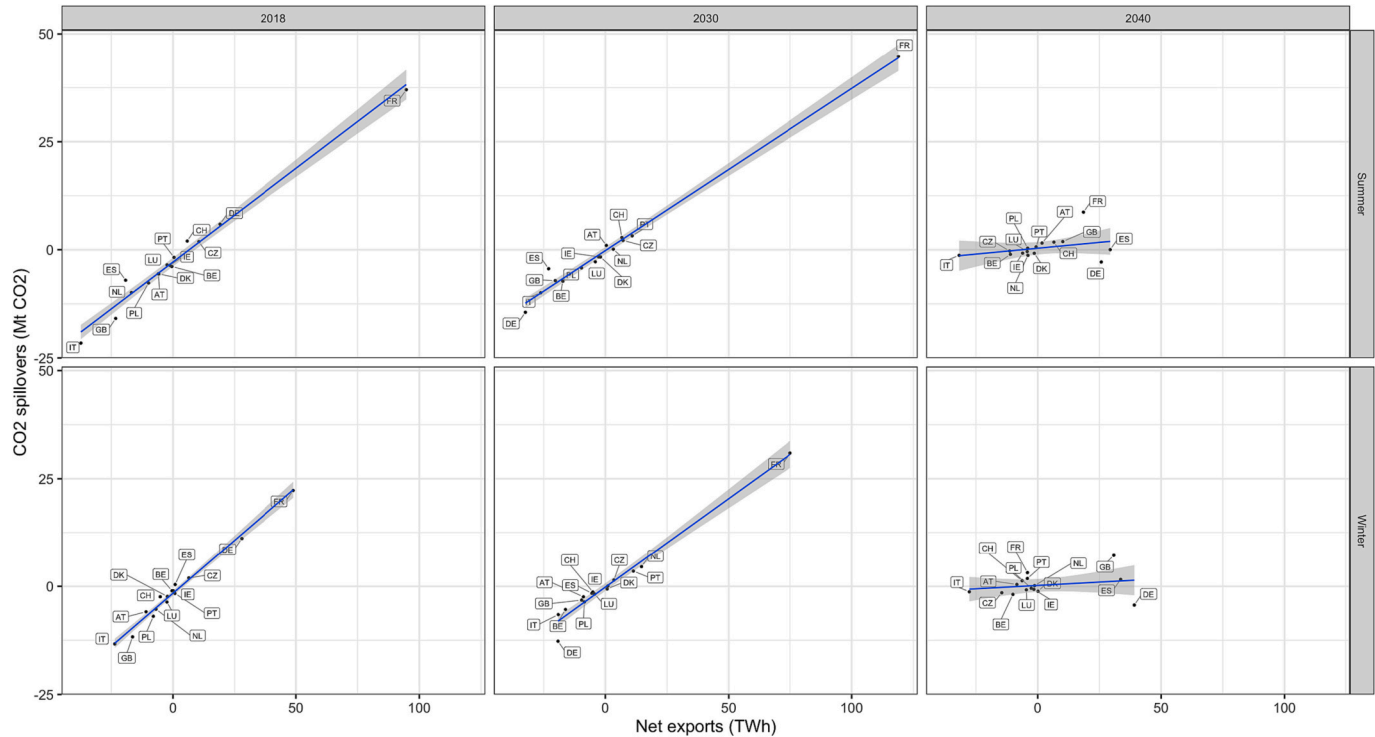


Fig. 13. Countries' CO₂ spillovers with respect to exports.

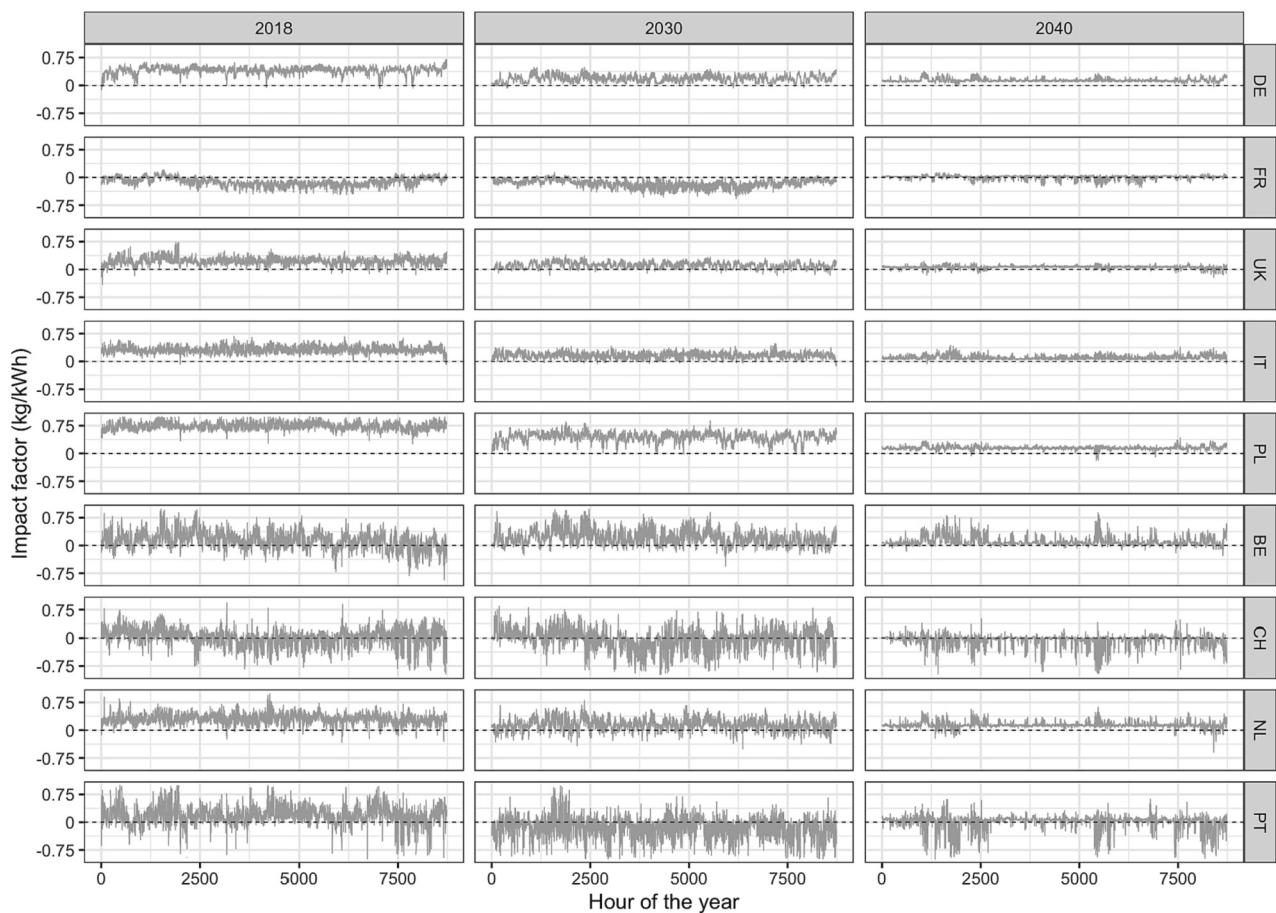


Fig. 14. Hourly profile of a country contribution on the systemic CO₂ by country.

impact) or renewables (resulting in a negative impact). As the global effort to attain net-zero emissions gains momentum, there may still be occurrences where the hourly CO₂ impact factor surges, reaching levels as high as 0.858 kg CO₂ per kilowatt-hour (kWh_{el}), as exemplified by Belgium.

4. Sensitivity analysis

The previous CO₂ and price spillovers are mostly driven by the marginal costs and the CO₂ emissions of the fossil-fuel generation units across countries. Although our assumption on fuel and CO₂ prices is directly taken from the TYNDP 2020 GA scenario, market conditions have drastically changed since the scenario setup. They have become much more volatile due to the current context of the war in Ukraine. Under this current context, one may wonder how our results are impacted by the current conditions and how they can be related to previous assumptions and spillover results.

For such analysis, three scenarios on CO₂ and gas prices are assumed (Table 4). Two of them reflect strained supply conditions on either CO₂ allowances (Strained CO₂) or natural gas (Strained Natural Gas). A third one considers a midway level of prices for both commodities

Table 4

Initial and alternative assumptions on natural gas and CO₂ prices in the sensitivity analysis.

	Initial 2018	Strained Natural gas	Intermediate	Strained CO ₂
Natural gas (€/MWh)	18.48	57.6	50.4	43.9
CO ₂ (€/tCO ₂)	19.7	80	120	180

(Intermediate).

The three scenarios are used to compute new sets of marginal costs of the fossil fuel fleet, one for each scenario (Fig. 15). Each set of marginal costs resulting from this computation is then compared to the original sets of marginal costs as computed with the TYNDP 2020 assumptions. To assess the degree of similarity between the different sets, a rank correlation (Spearman correlation) is applied.

The correlation table (Table 5) brings some insights in comparing the current market conditions to the fuel and CO₂ prices as assumed in our model. Given the correlation coefficient, the merit-order resulting in the reference year (2018) can be closely related to an intermediate scenario or one in which natural gas is strained. To the contrary, our 2040 assumptions are more closely related to the scenario with a strained CO₂ market.

As the CO₂ spillovers are only dependent on the technologies ranking on the merit-order, the spillover which appear under a strained natural gas market, should be very similar to the one we have in our model for 2018 and 2030. This is explained as the arbitrage between natural gas and coal-lignite is typical under the current context of high gas prices.

The price spillovers related to the current market condition require a more sophisticated analysis and cannot be examined under the scope of this study. Meanwhile, the current context of high market prices at the European level lowers the need for subsidies to support the development of new generation capacities. Nevertheless, the computation of the price spillovers can still be carried out to pinpoint the countries where market signals do not provide sufficient economic incentives to invest in renewable generation.

5. Discussion and outlook

This paper introduces an innovative and straightforward

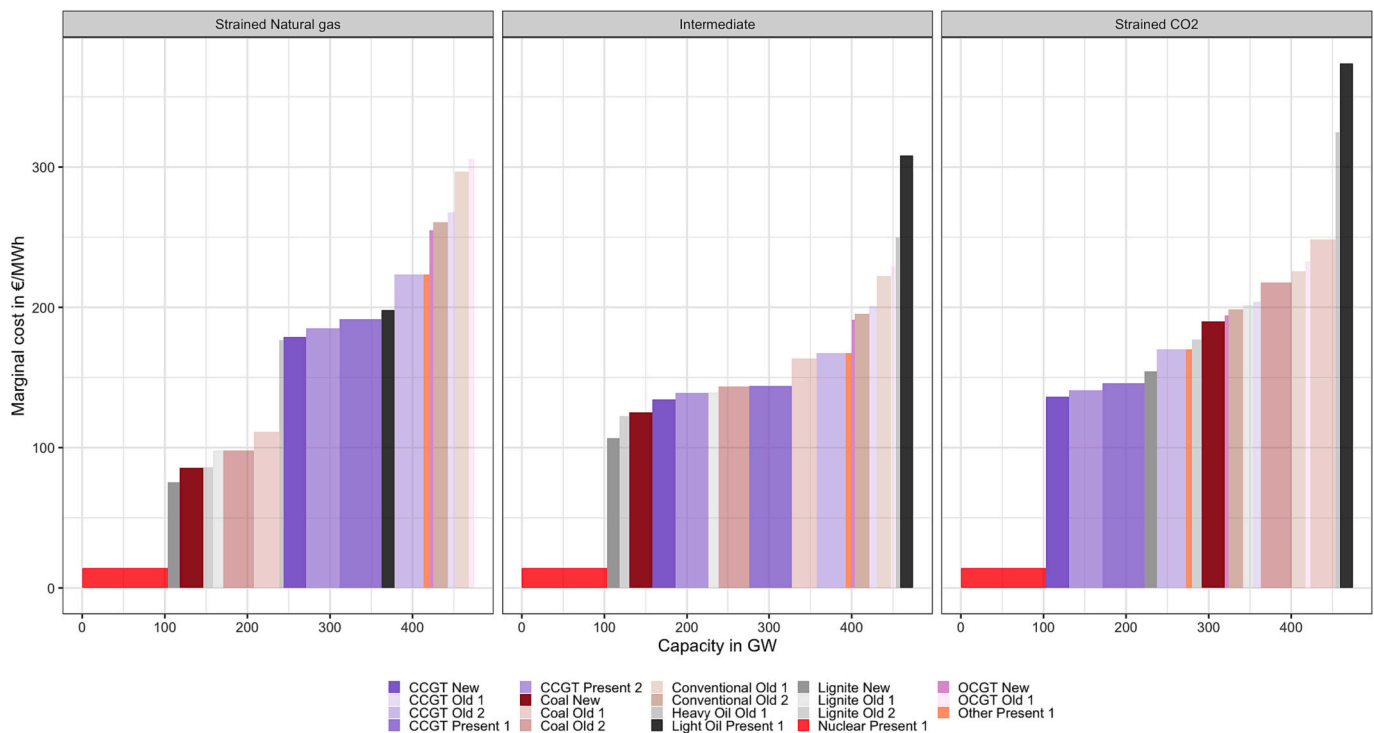


Fig. 15. Merit-order of the different technologies under alternative fuel and CO₂ price assumptions.

Table 5

Spearman correlation coefficient between merit-order sets.

	Strained Natural gas	Intermediate	Strained CO ₂
2018	0.92**	0.96**	0.85**
2030	0.84**	0.96**	0.92**
2040	0.52**	0.85**	0.96**

** statistically significant with a p -value ≤ 0.01 .

methodology to evaluate the unique spillover effects of one country on the CO₂ emissions and electricity prices of other nations within the broader European electricity system. This ‘leave-one-out’ (LOO) methodology consists of two successive simulation runs and comparing the results with and without the specific country, thus allowing the assessment of the marginal impact of the country on the whole electricity system.

Applied to the TYNDP 2020 GA scenario, the LOO methodology identifies the countries with the largest imports or exports, respectively, having the largest impacts on the overall EU CO₂ emissions and prices. For the leading exporters (Germany and France), the methodology pinpoints their impact on the rest of the system. We express concerns that Germany could hinder decarbonization efforts because some of its fossil fuel electricity generation is exported to other countries due to economic incentives. Hence, Germany may substitute cleaner domestic power generation in other countries (e.g. combined cycle gas turbine (CCGT) power plant in Italy, the Netherlands or the UK). This occurs when the exported power generated with fossil fuel technologies has a price advantage on the merit-order due to low carbon prices or subsidies on fossil fuels. Such arbitrage is even more typical under the current context of high gas prices. Although, these arbitrages mostly occur when the carbon price is low, they decline as the carbon price increases.

Although cross-border trade improves system costs, it can deteriorate the systemic CO₂, as cleaner generation units could have been run in the importing countries. Therefore, there is a clear trade-off between the economic (cost of electricity) and the environmental (mitigation of CO₂) objectives of the energy policy. By identifying the impact of switch from domestic gas to cross-border coal power plants, our analysis allows

policymakers to adjust for such effects.

Although, these effects are limited through the CO₂ price of allowances, they remain. To limit the switch, a CO₂ market price should rank renewable and fossil fuel technologies in the merit-order according to their environmental impact. The CO₂ market should thus be tightened, and CO₂ allowances rights should be adjusted in consequence. To offset the adverse price spillover, there should be a consideration of redistributing CO₂ auctioning revenues. Specifically, funds from countries where electricity exports are generated using inexpensive fossil fuel power plants should be redirected to support cleaner generation technologies in neighboring countries. Further studies need to be carried out on such a redistribution mechanism.

Moreover, the model points out France’s leading role as the main exporter of low-carbon (i.e. nuclear) electricity in the EU electricity system until 2030. Although other countries also export a significant share of their generation (e.g. Portugal, the Netherlands, Czech Republic), the major future exports from France imply the reliance of the EU electricity system on France, especially in the winter season. Such reliance may raise concerns regarding the security of supply, especially with France’s aging nuclear fleet. Those concerns are even strengthened in the context of the Ukrainian invasion, when the risk of gas shortages became a reality due to Europe’s dependency on Russian gas in winter. Therefore, seasonal storage solutions should be further exploited to prevent winter deficits from offsetting carbon-intensive generation. Sector coupling (power-to-X) can reduce high-carbon electricity generation in winter in combination with seasonal storage. However, the technological and economic assessment of such new technologies should be further investigated in future research.

Another finding of this paper is that countries (e.g. France) can have significant importance on the price settlement of their neighboring importing countries. When inexpensive electricity is exported, this induces a price drop due to the merit-order effect being spilled over to neighboring countries. Although the cross-border impacts benefit the consumers in the short-term, they may create insufficient incentives to invest in renewable technologies to the extent needed to achieve the long-term objective of net-zero emissions in electricity supply in the importing country.

As the advantage of power generation at low marginal cost (e.g. nuclear or onshore wind) could not be replicated in the importing countries due to limited social/political acceptance, the imported power generated at low-marginal cost may create inadequate overall revenues for the more readily socially-accepted technologies (e.g. solar PV) in the importing countries. Such a market condition hinders investors from recovering their investments in renewable energy technologies, which are urgently needed to decarbonize the energy system. As a result, renewable energy technologies will still need to be heavily subsidized.

Our study shows that some technologies (such as solar PV or offshore wind) might already obtain insufficient revenues by 2030 in some countries. This same problem is also observed in 2040, but at that stage, for all countries and all technologies, requiring even higher subsidies. The way-out of this unattractive investment environment is the pursuit of financial incentives to ensure the economic viability of investments in renewable technologies (e.g. renewable auctions mechanisms) or additional capacity markets in which the installed capacity will be economically rewarded.

Given the cross-border spatial price spillovers, the financing source for renewable technology subsidies should also be revised. So far, in most countries, as electricity wholesale market prices have failed to reflect the renewables' costs, the additional costs have been heavily burdening consumers' power bills through renewable surcharge fees (e.g. German EEG surcharge, [Cludius et al., 2014](#)). However, such surcharge fees can deter the move toward electrification. Therefore, without a reform of the current market mechanism, new renewable generation financing sources need to be considered, notably through countries' energy and climate funds, partly funded by revenues from the allocation of emission allowances. Especially with increasing CO₂ allowances revenues, funds to finance efforts toward decarbonization need to be distributed according to the herein computed spillover effects of individual countries. Such redistribution mechanism is essential to succeed with the decarbonization of Europe's power generation at the fastest pace possible and thus limit the identified concerns due to cross-border impacts, such as insufficient revenues for renewables or mitigation of CO₂ efforts. As those funds differ among countries due to heterogeneous dependencies on fossil fuels for electricity generation, further research should be undertaken regarding the distribution.

Findings may also provide useful insights for policymakers on off-setting carbon emissions at the continental level through better coordination of investment policies among countries. This calls for a higher level of coordination of policymakers in Europe (bottom-up) or, alternatively, for a regulatory approach by the EU (top-down).

In this regard, the spillover effects are highly related to the ranking of the different technologies in the merit-order. Due to the recent market evolution of fossil fuel and carbon prices linked to recent geopolitical changes, we show that the amplitude of the price spillovers requires an update of the study. Meanwhile, the approach of the proposed model still remains valid and the trade-off between economic cost and CO₂ emission mitigation stands, as shown in the sensitivity analysis.

Further research is required to investigate the implementation of the LOO methodology on key indicators used to measure the system adequacy, such as the Loss of Load Expectation (LOLE in hours/year). Such an application will examine how a country contributes to the security of supply of its partners in the network. Such a study requires many potential demand and generation availability scenarios, which reflects the expectation of load curtailment in a year computed over a whole "potential years" search space (different weather conditions, different yearly PECDs etc.), which needs to be integrated.

6. Conclusions

The presented leave-one-out energy systems modeling method offers a straightforward way to assess an individual country's impacts (spillover) on prices and CO₂ emissions in the whole EU electricity system. The mutual spillovers can be assessed among countries.

Considering its specific CO₂ spillovers, a country can cause negative or positive contributions to the carbon content of the electricity consumed within the EU. By quantifying spillover effects induced by cross-border trade, the methodology reveals a trade-off between CO₂ mitigation and cost-minimization objectives among countries. This trade-off is observed when electricity generated by high-emitting power plants is imported, instead of being domestically produced with low-emitting but more costly power plants. Consequently, it identifies countries where investments in renewable technologies should be prioritized to minimize overall CO₂ emissions of the whole system.

The main conclusions and findings can be summarized as follows:

- In a general way, country exports contribute to offset systemic CO₂ as exported generation crowds out high-emitting generation units.
- However, decarbonization efforts (i.e. the most CO₂ efficient technologies are not always dispatched first) could be hindered in times when more carbon-intensive fossil-fuel generated electricity is exported, and crowds out less-emitting technologies due to cost advantages. Our methodology offers reasonable suspicions regarding the presence of such impacts; however a more in-depth investigation is needed to accurately gauge the magnitude of this crowd-out effect between countries.
- In that context, electricity from gas-fired plants could reduce the systemic CO₂ emissions if their generation substitutes for electricity imported from more CO₂-intensive power plants, such as coal or lignite. Gas power plants can even further decrease systemic CO₂ if an admixture of biogenic or synthetic gas reduces the CO₂ content of natural gas.
- If the CO₂ market price is too low, countries with lignite and coal-fired plants will still substitute cleaner generation due to cost advantages. To align the socio-economic policy, which aims at minimizing electricity generation costs, and the environmental policy, which requires CO₂ mitigations, power plants need to be dispatched not only according to their marginal costs but also based on their overall environmental impacts. To prioritize environmental policy objectives, the CO₂ market needs to be tightened and CO₂ allowances rights should be adjusted to ensure an appropriate price signal, which ranks the generation units according to their environmental impacts. However, this is done at the expense of the system costs. The proposed methodology should allow policymakers to examine the adjustment of CO₂ allowances to weaken the carbon spillovers.
- A redistribution of CO₂ auctioning revenues from countries exporting electricity generated with inexpensive fossil-fuel power plants but high CO₂ emissions should be thought in favor of the countries, where market prices prevent additional investment in renewables. The redistribution of those revenues should be considered according to countries' spillover impacts.
- Finally, with the increasing penetration of renewables, prices are expected to dwindle. As a consequence, the inadequate revenues may become more acute for new investments in renewable generation. Without a market design reform, the economic viability of new capacities cannot be guaranteed, and additional incentives, such as subsidies, remain.

CRedit authorship contribution statement

E. Romano: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Software, Visualization, Writing – original draft, Writing – review & editing. **R. Mutschler:** Writing – original draft. **P. Hollmüller:** Funding acquisition, Writing – original draft, Writing – review & editing. **M. Sulzer:** Conceptualization, Writing – review & editing. **K. Orehounig:** Funding acquisition, Writing – review & editing. **M. Rüdisüli:** Conceptualization, Project administration, Supervision, Writing – review & editing.

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Appendix A

A.1. Methodological appendix

A total of 22 bidding zones are considered. Offshore wind, and hydro-storage power plants (PHS DAMS) are modeled as independent nodes, connected to the main bidding zone with unlimited transmission capacities. To facilitate the readability of results, multiple zones in a country are aggregated.

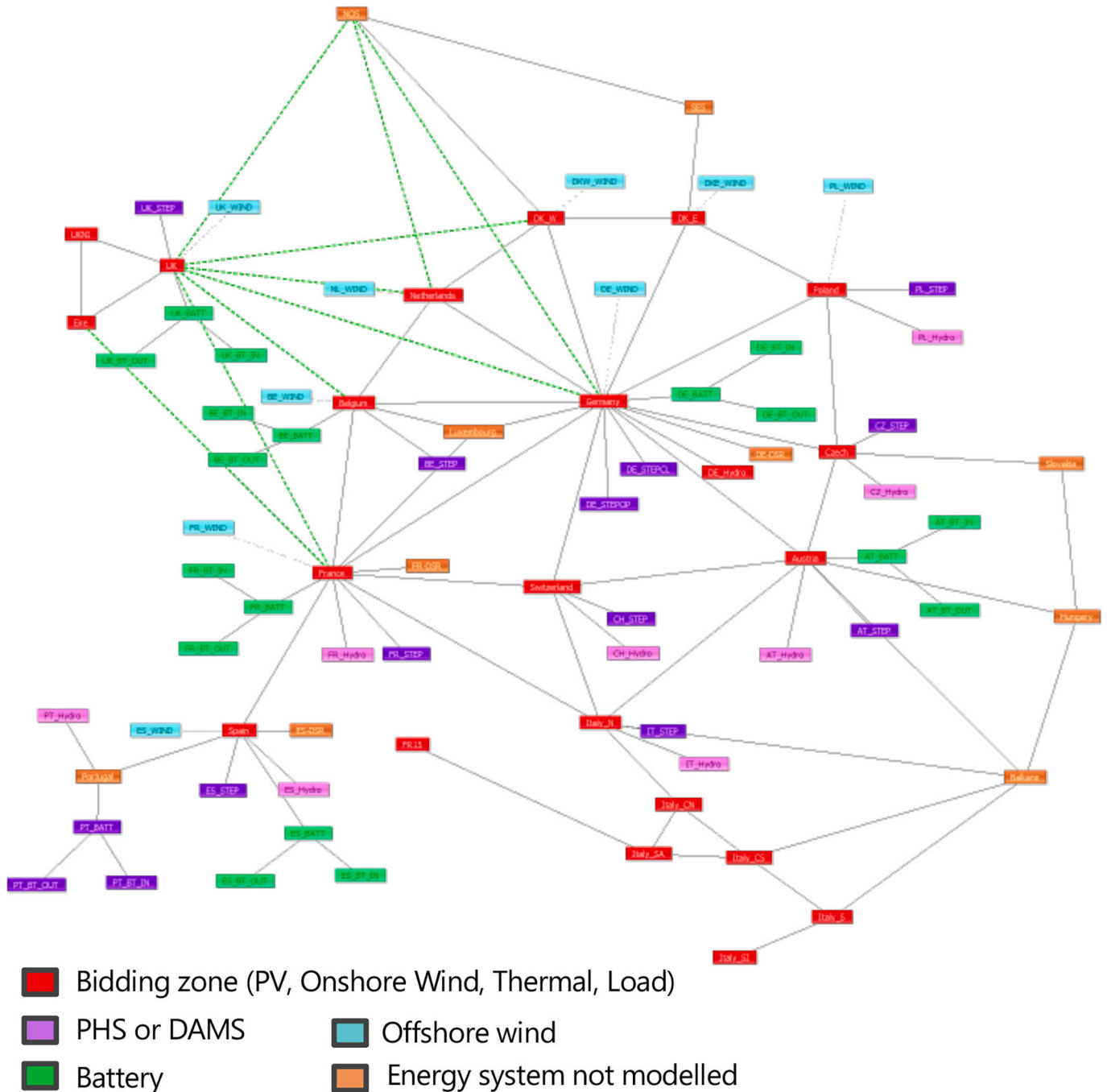


Fig. 16. Representation of nodes and branches in Antares.

Regarding CAPEX and OPEX information for the investments, the draws data from (De Vita et al., 2018) as shown in Table 6.

Table 6
Power generation capital (CAPEX) and operational (OPEX) expenditures.

	CAPEX		OPEX	
	EUR/kW/year		EUR/kW/year	
	2030	2040	2030	2040
Wind onshore	70	60	18	17
Wind offshore	174	163	37	35
Solar PV	44	32	13.5	12.1
PHS and STOR	158	158	25.5	25.5
Run-of-River	131	129	8	8
Other renew.(Bio-mass)	234	211	22.9	22.9
CCGT new	50	49	15	15
OCGT new	43	43	13	13
Nuclear	267	251	115	108
Battery	107	108	15	13

A.2. Results appendix

The results in this section are mostly an evaluation of TYNDP's GA scenario. They were used to validate our model.

A.2.1. Electricity generation mixes and balances

The share of renewables (Fig. 17), which cover 32% in 2018, will increase to 59% and 73% of electricity generation in 2030 and 2040, respectively. Most renewable electricity is contributed by wind (42%) and solar PV (13%). The share of fossil and nuclear power plants, covering 68% of the current European electricity demand, drops to 27% by 2040. As expected, in the selected decarbonization path oil, coal and lignite are phased out by 2040, but a share of non-renewables remains in the generation mix. Besides nuclear, other non-renewable capacities based on gas (18%) are still in operation.

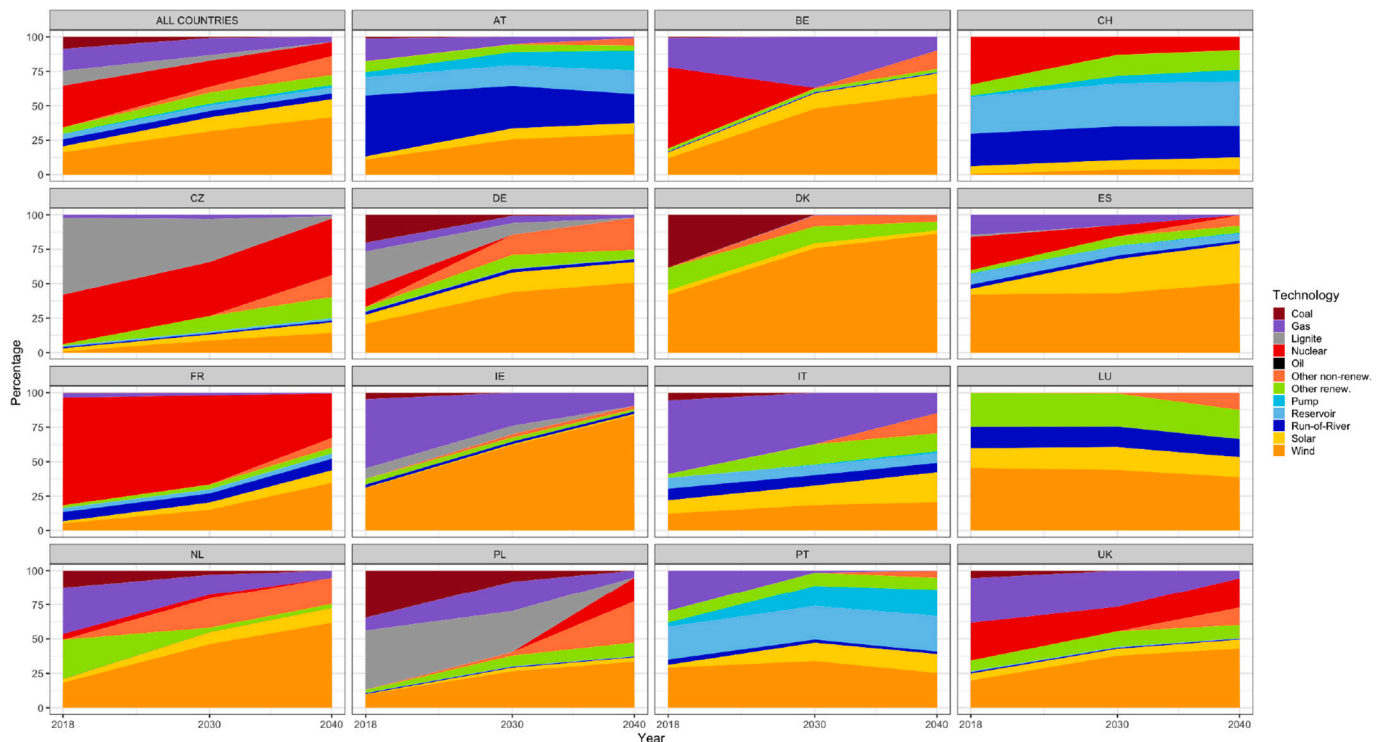


Fig. 17. Electricity mixes by fuel type over the decarbonization pathway (2018-2040) - Relative values.

At the national level, the generation mix depends on local resources, the installed technologies, and their political/social acceptance. While the share of wind increases above 60% in some northern European countries (e.g. Denmark (DK), Ireland (IE), Belgium (BE) and the Netherlands (NL)), solar PV is rather dominant in southern European countries such as Spain and Italy (up to 29%), confirming results by previous researchers (Victoria et al., 2020). In the Alpine region (Austria (AT) and Switzerland (CH)) as well as in Portugal (PT), Fig. 17 depicts their high share of hydropower (up to 40%). Regarding non-renewables, France still relies on a significant share of electricity from nuclear power (33%). Germany (DE) and Poland (PL) keep a significant share of fossil fuel (mainly gas) generation (up to 35%).

Fig. 18 illustrates the net trades for the validation of the model. The depiction in the figure highlights the proximity of the “2018” results, with the exception of France (FR), to the actual values as extracted from Eurostat electricity balance database. The deviation of the French exports can be explained by the availability factor of the French nuclear power plant fleet in our model, which exceeded the actual value for that specific year. Despite this discrepancy, it is noteworthy that the net trades results exhibit consistent signs with the actual values for every country in our network.

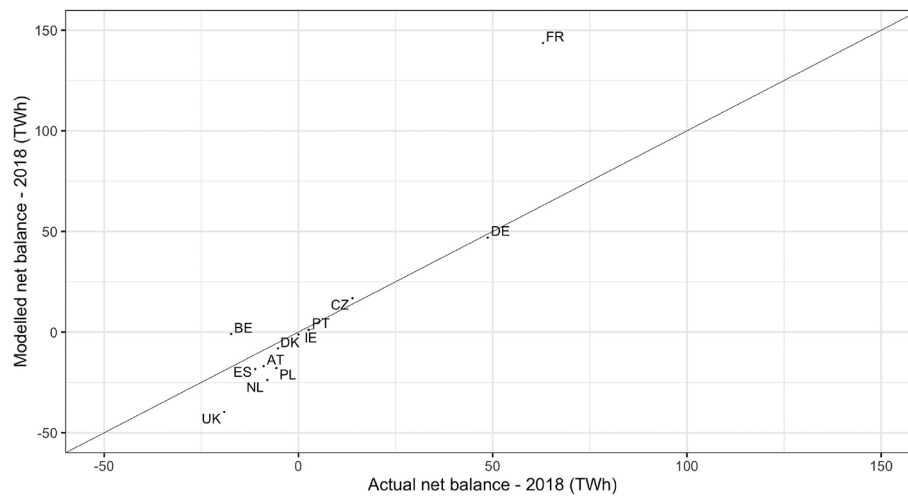


Fig. 18. Actual and modeled net balances - (+) Exports (–) Imports.

Table 7

depicts results of the batteries optimization. It provides the installed batteries capacities in each country, the weekly average storage, and the estimated load factor.

	2018			2030			2040		
	Capacity (MW)	Storage (MWh)	Load factor (hours)	Capacity (MW)	Storage (MWh)	Load factor (hours)	Capacity (MW)	Storage (MWh)	Load factor (hours)
AT	NA	NA	NA	534	753	1	1234	3536	3
BE	410	208	1	300	488	2	950	31994	34
DE	NA	NA	NA	3990	4791	1	8114	16549	2
ES	500	15	0	1618	2548	2	2593	36761	14
FR	NA	NA	NA	3084	4677	2	7122	23972	3
NL	NA	NA	NA	NA	NA	NA	1737	35831	21
PL	NA	NA	NA	NA	NA	NA	1000	3983	4
UK	410	37	0	701	1184	2	2130	21259	10

Table 7: Installed capacities, average weekly storage, and average load factor of batteries.

A.2.2. Electricity prices

Hourly electricity prices for each market node are modeled over the period 2018 to 2040. They are based on assuming a perfectly competitive “energy-only-market” (EOM), in which generation units are paid by the price of the marginal costs of the last unit dispatched. Average prices are shown in Fig. 19 for each year. In the reference year, prices slightly differ between countries. Annual averages range from 36 €/MWh in France to 45 €/MWh in Poland and Italy. Apart from France, a weak price seasonality is depicted between winter and summer in other countries. Prices reach their peak values in 2030 for two reasons: (i) an increase in the marginal cost of fossil fuels and (ii) an increase in volume due to electrification, as shown in Fig. 19. Those two previous effects dominate the merit-order effect related to the expansion of low marginal cost capacities, such as solar PV and wind. On average, a significant disparity of prices is observed, from 20 €/MWh in Portugal in summer to 60 €/MWh during winter on the Polish market. In 2040, as renewable capacities are further implemented, prices decrease in all markets due to the low marginal cost of those technologies (predominant merit-order effect). Annual averages range from 7 €/MWh in Portugal to 54 €/MWh in Italy.

As transmission capacities allow for cross-border trade, the merit-order effect stimulates net-exports to neighboring countries. If exceeding renewable surpluses are available, those surpluses can be exported due to their low marginal cost. Otherwise, as wind and solar PV replace more and more fossil fuels, this replaced expensive generation is available for exports to bidding zones with higher price opportunities. Consequently, renewables also offer additional opportunities for a country to export generation from more expensive plants if they have a price advantage against the importing countries' generation mix.

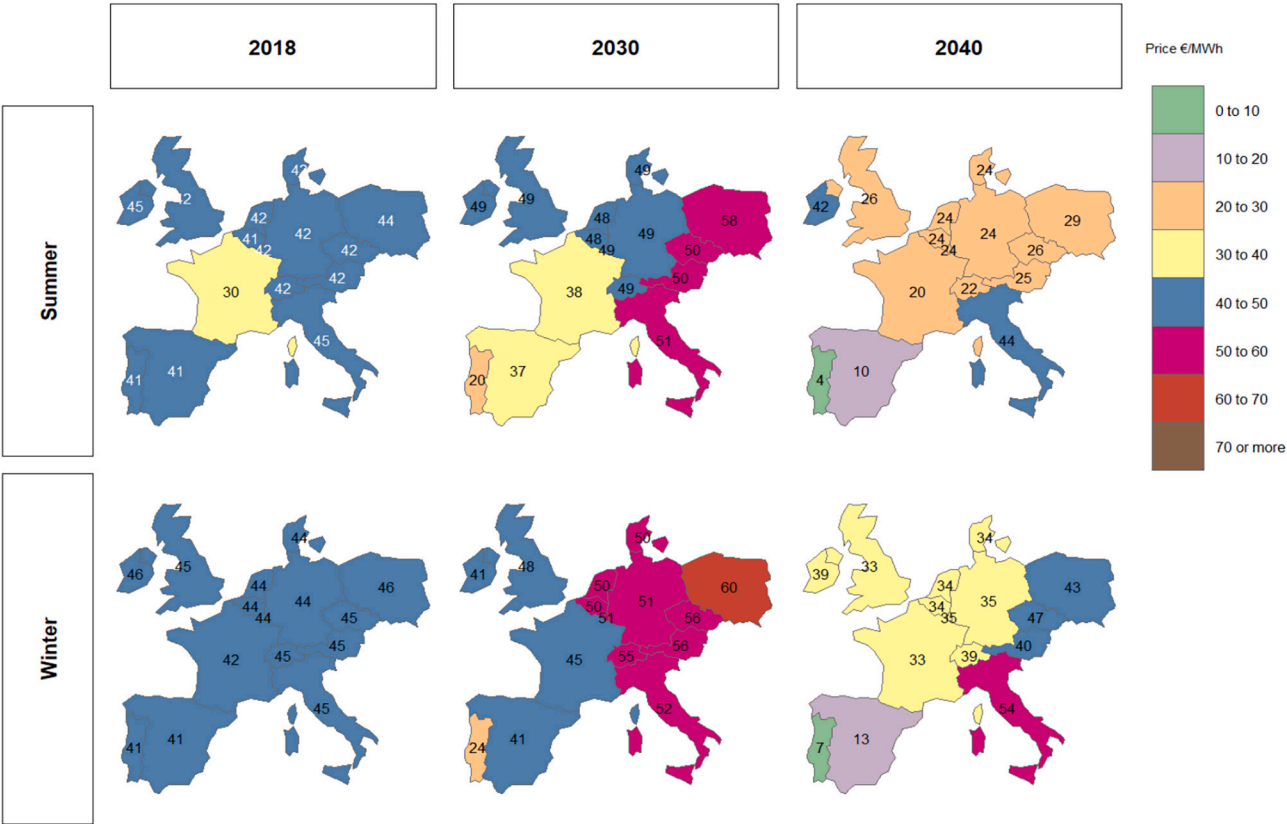


Fig. 19. Seasonal average of hourly electricity prices by country.

For benchmarking purposes, Fig. 20 also shows a comparison between the annual average of the simulated hourly prices in the reference year 2018 of our model and the observed annual averages of hourly market prices for the years 2016–2020. Fig. 21 shows a comparison of the estimated market clearing between our simulations and the ENTSO-E TYNDP 2022 study for 2030 and 2040.

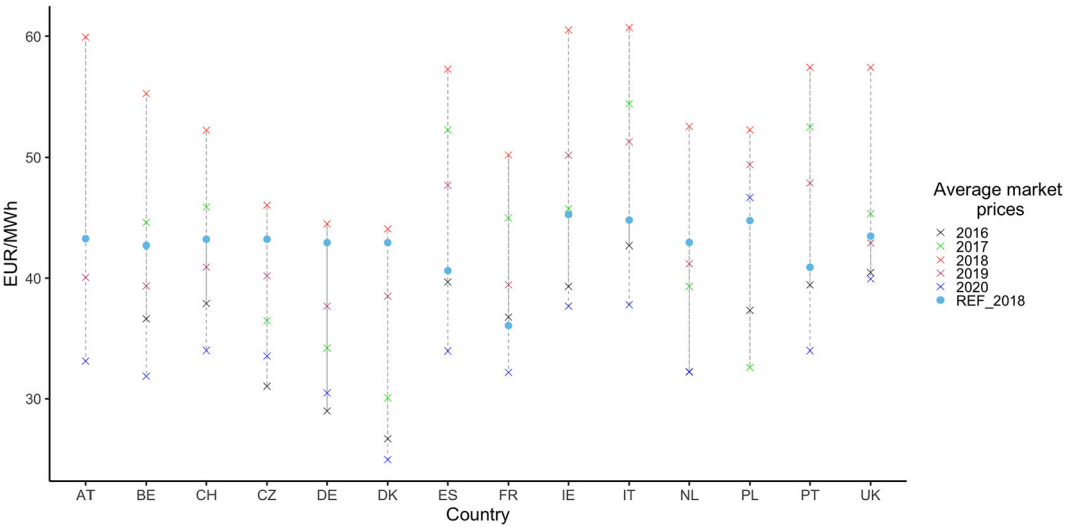


Fig. 20. Annual mean of hourly simulated prices (REF_2018) vs. mean of hourly prices for years 2016 to 2020

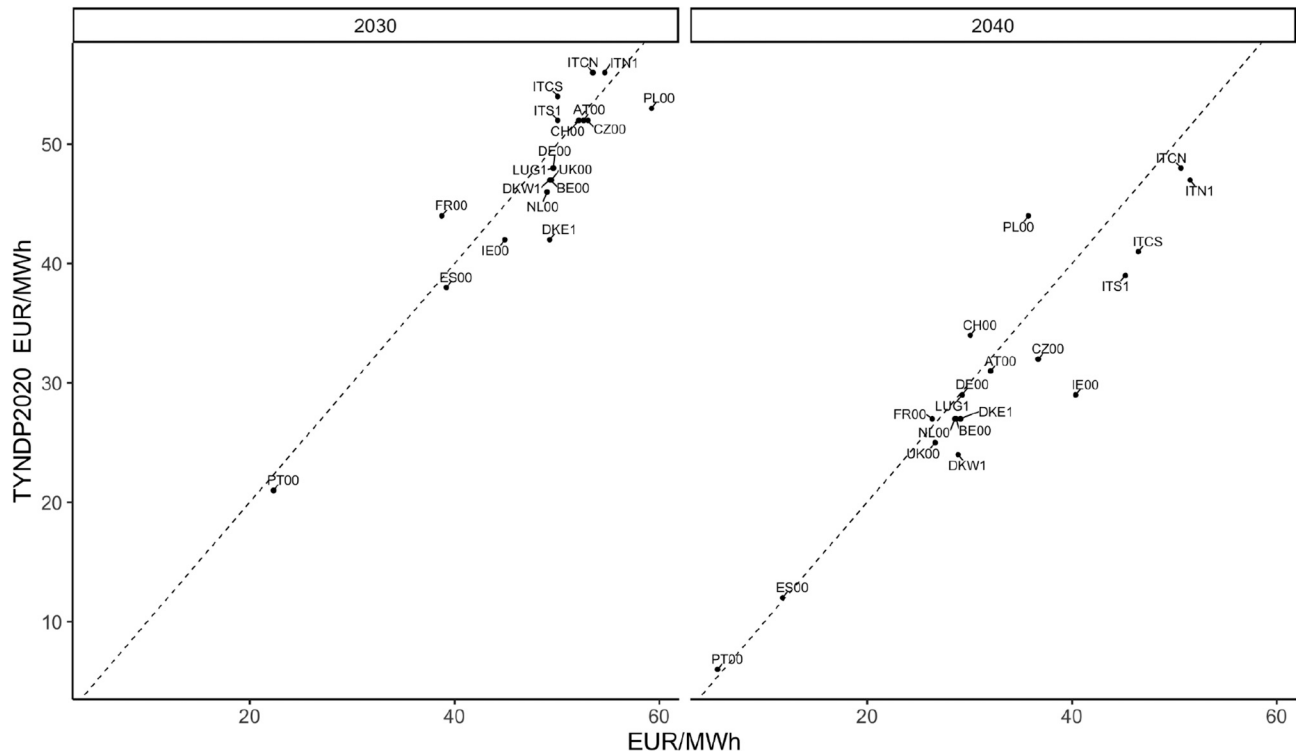


Fig. 21. Difference between stimulated market clearing prices (x-axis) and TYNDP 2020 estimates (y-axis) by bidding zones in 2030 and 2040.

A.2.3. Direct CO₂ emissions

In 2018, direct CO₂ emissions from generation amounted to 611 Mt. Four countries are the largest emitters: Germany (258 Mt.; 42%), Poland (108 Mt.; 18%), Italy (60 Mt.; 10%) and Czech Republic (55 Mt.; 9%). Over time, as fossil fuel plant are decommissioned, CO₂ emissions decrease to 320 Mt. by (−48%) in 2030 and to 246 Mt. (−60%) in 2040 relative to their 2018 levels. The largest reduction is observed in Germany, with an abatement of 183 Mt. (−70%) between 2018 and 2040.

Fig. 22 also provides a comparison between the annual CO₂ direct emissions of our model and the effective CO₂ emissions in 2018 as reported by European Environment Agency (2018).

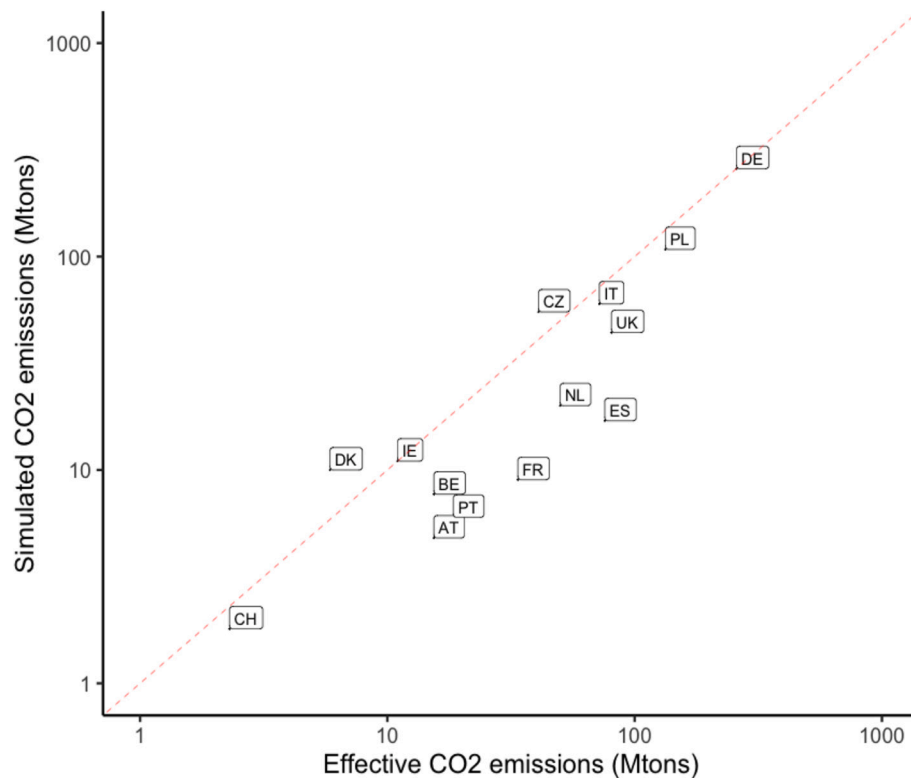


Fig. 22. Difference between effective and stimulated emissions by countries in 2018 in Mt Logarithmic scale.

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