Spatio-temporal assessment of integrating intermittent electricity in the EU and Western Balkans power sector under ambitious CO_2 emission policies

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ABSTRACT

This work investigates a power dispatch system that aims to supply the power demand of the EU and Western Balkans (EUWB) based on low-carbon generation units, enabled by the expansion of biomass, solar, and wind based electricity. A spatially explicit techno-economic optimization tool simulates the EUWB power sector to explore the dispatch of new renewable electricity capacity on a EUWB scale, under ambitious CO_2 emission policies. The results show that utility-scale deployment of renewable electricity is feasible and can contribute about 9–39% of the total generation mix, for a carbon price range of 0–200 €/tCO_2 and with the existing capacities of the cross-border transmission network. Even without any explicit carbon incentive (carbon price of 0 €/tCO_2), more than 35% of the variable power in the most ambitious CO_2 mitigation scenario (carbon price of 200 €/tCO_2) would be economically feasible to deploy. Spatial assessment of bio-electricity potential (based on forest and agriculture feedstock) showed limited presence in the optimal generation mix (0–6%), marginalizing its effect as baseload. Expansion of the existing cross-border transmission capacities helps even out the variability of solar and wind technologies, but may also result in lower installed RE capacity in favor of state-of-the-art natural gas with relatively low sensitivity to increasing carbon taxes. A sensitivity analysis of the investment cost, even under a low-investment scenario and at the high end of the CO_2 price range, showed natural gas remains at around 11% of the total generation, emphasizing how costly it would be to achieve the final percentages toward a 100% renewable system.

Keywords: decarbonization, renewable electricity, intermittency, optimization, geospatial modeling, power transmission.

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1 INTRODUCTION

To boost transformation of the carbon-intensive supply chain of today's energy infrastructure into a low-carbon one, the expansion of Renewable Electricity (RE) deployment must be facilitated. Energy models, based on scenario assumptions that take into account how energy is harnessed, delivered, and used, can help explore such technological transformations as well as their impacts on the existing energy system. Currently, the energy supply (i.e., the power, heat, and transportation sectors) of the European Union (EU) is met to a large extent from fossil fuels and nuclear technologies. Nonetheless, the deployment of intermittent renewables has been increasing steadily over the last two decades. In the EU, the aggregated installed capacity of solar photovoltaics (PV) and onshore wind turbines reached about 111 GW in 2010 and 241 GW in 2016, up from about 13 GW in 2000 [1].

Decarbonization of the energy sector through the integration of intermittent renewables is often discussed as a mitigation measure. Since 2009, the EU has been implementing the so-called EU 20–20–20 climate and energy policy package which mandates: (i) 20% reduction in EU GHG (greenhouse gas) emissions in 2020 compared to 1990 levels, (ii) 20% increase in the share of renewables in final energy use (of which 10% in the transportation sector), and (iii) 20% increase in energy efficiency [2]. To guide a long-term vision, the 2009 package was followed by a new directive in 2014 setting the EU roadmap up to 2030, in which the target for reduction of GHG emissions was raised to 40% (compared to 1990 levels) and the target for the share of renewables to 27% [3].

EU energy and climate policy targets are characterized by high shares of variable renewables (in particular, wind and solar), and this is associated with significant challenges. Several countries in the region are already in the fast lane for the expansion of variable RE, the notable large economies being the United Kingdom (UK) (onshore and offshore wind) and Germany (solar and onshore wind). Both countries, however, have a long way to go to achieve their pledged carbon emission target by 2050, (i.e., 80% lower compared to 1990 levels [4]). In this study, we focus on the expansion of onshore wind power and solar PV supplemented with bioenergy. The coupling of solar and wind plants to thermal generators, and the use of new load management technologies to align the demand for power with the variable supply, offer promising pathways for aggressively reducing the amount of carbon that the power industry disposes in the atmosphere.

To provide sufficient insight to address these issues, a system-level approach with adequate representation of both the spatial and temporal features of renewable energy sources is essential. In prior studies, various modeling and evaluation approaches were applied to analyze the complexity of a European high–share variable RE system. Gils et al. [5] used an optimization model with multiple spatial nodes, each representing a region in the EU, and hourly temporal resolution, to investigate an integrated European electricity market with high shares of variable RE supply, with focus on balancing strategies. Using a dynamic linear electricity system model, Jägemann et al. [6] studied the economic implications of decarbonizing the EU power sector by 2050. The impact of the EU 2030 energy target on the electricity sector was assessed by Knopf et al. [7] using a linear electricity model of the European electricity system, with each country being represented by a spatial node. The current state of renewable energy performance in the EU was assessed at the country level by D'Adamo and Rosa [8] for the period 2015–2020, based on averaged values of the period 2008–2014, in order to suggest a new reference RE trajectory. Bussar et al. [9] performed a sensitivity study on the storage demand of a European power system with high shares of RE in 2050 using a power system model of Europe, the Middle East, and North Africa (EUMENA) represented by 21 regions. Buttler et al. [10] assessed the variability of wind and solar power in the EU based on the installed capacities of 2014. Several other studies have assessed country-level strategies, for example, focusing on integrating RE in Germany [11–13]; these analyzed and discussed long-term scenarios and strategies [11], the importance of transmission grid capacity expansion [12], and in the context of long-term energy-economy models using residual load duration curves [13]. The management and engineering aspects of large-scale integration of variable RE have become essential subjects to compensate for intermittency of wind and solar power, for example, using a market-based principle [14], and using energy storage systems coupled to stochastic modeling of wind energy [15].

The approach used in our assessment combines a high spatial (0.4°) and temporal resolution (representing a period of one year), which allows us to analyze regional differences as well as temporal effects. This approach can capture reasonably high-resolution load-matching, which is often overlooked by country or regional-level aggregated dynamic linear models used for planning long-term consequences, e.g. [5–7]. The objective this work is to assess the potential for reducing CO_2 emissions from the EU and Western Balkans (EUWB) electricity sector. We explicitly target the high CO_2-emitting technologies in the existing generation fleet and evaluate how they compare against a spatio-temporally explicit RE portfolio supplemented by a state-of-the-art natural gas combined or open cycle (NGCC or NGOC) depending on the nature of the load. This paper also aims to identify the optimal spatial distribution of new RE plant installations, as well as the most beneficial, from a cost as well as CO_2 emission mitigation perspective, power generation mix, given grid specific biomass resource availability, insolation, wind speed, and the locations of major power transmission hubs connecting new RE installations to the demand sites.

The spatially explicit dimension of our approach enables the simultaneous optimization of the capacity of, and the investments in, new RE plant installations at the grid level. This is particularly important for balancing the space for intermittent plant installations and other ecosystems services, such as designated protected areas, which in this text is considered based on harmonized International Union for Conservation of Nature (IUCN) categories I through VI [16]. In the absence of adequate energy storage, power systems with high-share of intermittent RE rely on flexible baseload to maintain stability. Our analysis also highlights not only the importance of a low-carbon baseload, such as biomass, nuclear, and hydropower, complemented with battery storage units, but also the potential benefits of cross-border transmission capacity expansion.

Brief descriptions of the optimization model and the input data processing are presented in Section 2. The main results are presented in Section 3, where a sensitivity analysis of the optimal generation mix toward expansion of existing transmission capacities between EUWB nations is also performed and presented. The main findings are further discussed in Section 4, where a sensitivity analysis regarding the impact of the investment cost on the salient features of a highly renewable EUWB power system is also introduced and discussed. Section 5 summarizes the main conclusions drawn.

2 METHODOLOGY AND INPUT DATA

In this study the BeWhere model [17] is used to simulate a highly renewable power dispatch system at the European level. The BeWhere model is a geographically explicit mixed-integer linear programming (MILP) model which was originally developed for optimizing the capacity and localization of bioenergy facilities. The model is written in GAMS and uses CPLEX as solver. The adaptability of the model to different applications has been demonstrated in previous studies, for example, on bioenergy and intermittent RE coupled with carbon capture and utilization (CCU) [18], bioenergy with carbon capture and storage (BECCS) [19], algae cultivation from captured CO_2 [20], and, recently, decarbonization of steel production in Europe [21]. BeWhere has been used for national [22–24] and regional [18,25] studies, as well as for studies at the European scale [26].

2.1 Model Setup

To investigate the techno-economic potential of transitioning the EUWB power system, the model is reconfigured to assess expansion of RE units. The version used here has a spatial coverage of the EU28 and Western Balkans (Bosnia and Herzegovina, Montenegro and Republic of Serbia), herein referred to as EUWB. Input data for RE resources is considered at grid level, formulated based on ~40 km x 40 km spatial resolution. The electricity demand data are considered at the country level. The model is run for a period of one year with a temporal resolution of 192 hours, corresponding to the peak and median demand days of each month at a 3-hourly step.

The objective function is to minimize the total cost of an energy supply chain in order to meet a known demand while providing information on the optimal localization of new plant installations. The model considers a wide range of techno-economic parameters related to the performance of the technologies in the existing generation fleet and also the deployment of RE capacities. The output from the model is a set of existing and new power production installations as well as the resulting annual power production from operating the installations, a set of existing and new options for cross-border transmissions, and the costs and CO_2 emissions related to the integrated electricity system. The details of the techno-economic and emission parameters used are presented in **Appendix A-C**.

The model simulates expansion of the three RE generation technologies bioenergy, solar PV, and onshore wind. The model also considers deployment of generic battery storage units to augment solar and wind intermittency. Historical data are used to simulate RE generation potentials with a time resolution consistent with the meteorological dataset of choice over a one year period. A brief description of the data processing of each category is presented in subsequent sections.

To establish a business-as-usual (BAU) scenario, the model reproduces the existing dispatch system of the EUWB power sector, using the 2010 demand profile and the 2016 generation mix installed capacity as base (see Section 2.6.1). The 2010 power demand profile is chosen to maintain consistency with the wind and insolation dataset used for the derivation of the intermittent power potential (see section 2.5). The generation mix of 2016 is used to avoid underestimation of the installed capacity of solar PV and wind technologies, which more than doubled in aggregate compared to 2010.

2.2 Power Demand

The hourly power demand for each country is derived from the European Network of Transmission System Operators for Electricity (ENTSO-E) [27], which reports historical demand and indicative net transfer capacities (NTC) at the country level. As described above, the year 2010 is chosen for consistency with the meteorological data. When demand data are unavailable for a specific hour, the data from the previous hour are used, or from the same hour in the previous day, depending on data availability. The resulting aggregate demand profile is shown in **Fig. 1**.

The power demand is sampled every three hours from the peak and median day in each month. This reduces the computational complexity by compensating for the high spatial resolution and is consistent with sampling methods from previous high-resolution electricity sector planning models [28]. To represent the entire year, the sampled days are weighted to represent multiple days by fixing peak days to represent one day of the month, and median days to represent the remaining days in the month (i.e., all days in a month minus one) [28]. This ensures that peak conditions are included in the power constraint, while the economic assessment is dominated by the typical demand profile, as peak demand occurrences are rare. Accordingly, all samples (i.e. eight samples per selected day) represent three hours each, peak days represent a day of the corresponding month, and median days represent the remaining days in the month. This procedure is included in the model by means of a time-indexed weighting parameter.

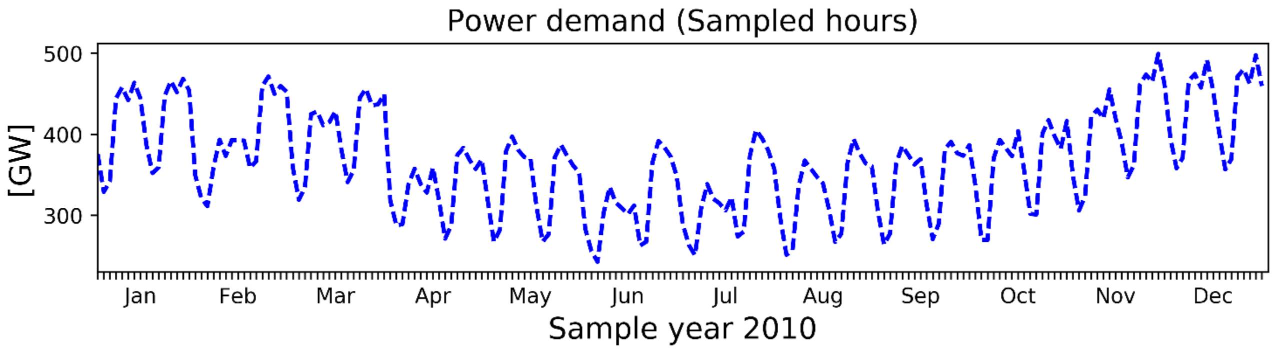

Fig. 1. EUWB aggregate power demand profile for the sampled hours in 2010

2.3 Power Transmission

Particular attention is given to the role of cross-border transmissions to stabilize intermittency. The optimization procedure considers the network of transmissions to be a direct power flow balance. There is no attempt to mimic the voltage phase shift, which is highly nonlinear. However, the power flow balance approximation is a reasonable representation of a high-voltage direct-current (HVDC) transmissions network [29]. An HVDC transmission is used, as opposed to a high-voltage alternating-current (HVAC), because of the nonlinear nature of HVAC, which significantly complicates the optimization. However, the HVDC transmission can be thought of as an approximation of HVAC in terms of power flow because it includes electrical losses and describes transmissions at a high level.

The existing network of transmissions between countries are derived, similar to the power demand, from the historical indicative values of NTC reported by ENTSO-E [27]. Moreover, the construction of transmission lines connecting new RE installations to an existing power transmission hub (station, substation or junction) with capacities greater than 100 kV is endogenously formulated in the model. This is done by applying costs for connecting to a hub and for the construction of new transmission lines from the installation site to the nearest hub. A grid connection cost of 300 €/kW and a connecting transmission line cost of 1 €/ km-kW are used, both assuming an economic life time of 40 years. The distance from the potential sites to the nearest hub, which is calculated by overlapping the map of the existing hubs and the spatial grid used in this study, is parameterized in the model for cost estimation. The spatial map of existing transmission hubs is presented in **Fig. B1**, Appendix B.

2.4 Biomass based electricity

Bioenergy is of particular interest in terms of the role of baseload on multiple counts —carbon neutrality, predictability of available resources and, eventually, the potential to contribute to negative CO_2 emissions when coupled with carbon capture and storage (CCS) technologies. Despite a fast growth in bioenergy use over the past two decades, its immediate contribution to the reduction of CO_2 emissions is low when short-term targets (up to 2030) are considered. This is because biomass has a similar elemental composition to fossil fuels, although in different proportions, and emits CO_2 upon conversion to heat and electricity. From a strictly operational CO_2 emissions view point, the power sector can thus transform faster to a low-carbon system by introducing high shares of intermittent renewables, than by using high shares of bioenergy without CCS. In addition, the integration of solar PV and wind technologies is becoming increasingly attractive as their cost per unit capacity drops and as policies against greenhouse gas emissions tighten. The diversity of biomass cannot be refuted; biomass is believed to be a key platform resource for transforming the petrochemical-based transportation system and the coal-intensive industrial sectors (such as iron and steel- and cement-production facilities) into low-carbon systems, and has the potential to significantly contribute to achieving short-, mid-, and long-term (2030, 2050 and beyond) CO_2 emission targets.

As the focus of this study is the power sector, the use of the available biomass resources is paired to conversion technologies that prioritize power generation. All the bioelectricity technologies considered produce heat as byproduct, which in the model is set to displace fossil use in the heating sector. Country-specific heat demands are given in **Table C2**, Appendix C.

Table 1 summarizes the different biomass conversion technologies considered, including their respective plant capacities and efficiencies. The capacity refers to the biomass input on lower heating value (LHV) basis, and the efficiency of the energy conversion to heat or power from biomass. The cost parameters of these conversion technologies are documented in **Table A1**, Appendix A**.** For bioenergy power production, the availability factors are derived from the annual operational hours of the biomass conversion technologies, which are also reported in **Table A1**.

Table 1. Biomass conversion technology parameters [30]

Type	Description	*Capacity [MW]*	*Output*	*Efficiency*
Gasification technologies	Circulating fluidized bed for CHP	29	Power Heat	0.35 0.5
	Circulating fluidized bed for IGCC	200	Power Heat	0.4 0.45
	Bubbling fluidized bed for CHP	17	Power Heat	0.3 0.52
Solid combustion	Circulating fluidized bed for CHP	180	Power Heat	0.35 0.5
	Fixed bed combustion for CHP	20	Power Heat	0.25 0.6
Fast pyrolysis	Fast pyrolysis for CHP	7	Power Heat	0.24 0.6
	Dry wood chips to pyrolysis oil, heat and steam	24	Power Heat Oil	0.021 0.26 0.65

2.4.1 Biomass feedstock

Two categories of biomass feedstock are investigated in this study, namely, forest and agricultural residues. The model considers ten types of forest residue and five types of agriculture residue for feedstock, as summarized in **Table 2**. The biomass data is taken from the S2Biom project database [31]. The S2Biom is a consortium project to support sustainable delivery of non-food biomass feedstock at the local, regional and pan European level by developing harmonized data sets, strategies, and roadmaps at different levels for the EU28, Western Balkans, Ukraine, Moldova and Turkey. Feedstock–technology matching is are carried out according to the Bio2Match tool of the S2Biom integrated tool set [32]. In aggregate, about 1300 TWh of forest and 1900 TWh of agricultural feedstock per year are available. The distribution of the feedstock over the countries considered in this study is extrapolated at the grid level based on the regional biomass atlas [33]. The spatial distribution map of the feedstock by type is presented in **Fig D.1**, Appendix D.

Table 2. Biomass feedstock—energy content and availability by type

Abb.	*Feedstock name*	*Moisture (%)*	*LHV (GJ/tonne)*	*Available (TWh/year)*
	Forest feedstocks			
S1	Stumps final fellings of non-conifer trees	48.3	11.1	85
S2	Stumps final fellings of conifer trees	53.9	11.1	130
SW1	Stemwood final fellings of non-conifer trees	48.3	10.4	240
SW2	Stemwood final fellings of conifer trees	53.6	8.4	260
SW3	Stemwood thinning of non-conifer trees	48.3	11.5	130
SW4	Stemwood thinning of conifer trees	53.6	11.6	195
LR1	Logging residues final fellings of non-conifer trees	48.3	10.2	65
LR2	Logging residues final fellings of conifer trees	53.6	8.4	80
LR3	Logging residues thinning of non-conifer trees	30.0	10.2	35
LR4	Logging residues thinning of conifer trees	30.0	8.4	55
	Agricultural feedstocks			
PG	Perennials grassy	24.4*	16.7**	375
PW	Perennials woody	38.0*	18.3**	145
SR	Straw residues	15.0*	16.0**	1080
PR	Pruning residues	36.0*	17.1**	25
GL	Grassland	68.9*	18.7**	275

*Average value ** GJ/tonne of dry matter

2.4.2 Biomass Logistics

The model also accounts for the logistics of biomass transport from source to power plants, assuming biomass can be traded between different regions within the geographical scope of the study. Trade with regions outside the studied area is not considered.

Possible routes for transport, the corresponding specific costs and GHG emissions are parametrized based on a geospatial transport network developed in the ArcGIS Network Analyst. Three modes of transport are considered: road, rail, and shipping. The transportation parameters used are presented in **Table 3**.

Table 3. Transportation parameters

	Unit	*Truck*	*Rail*	*Boat*
Load	ton/vehicle	27	1625	5700
Load factor	%	0.94	0.95	0.79
Fuel use	l/vehicle /km	0.31	5.1	35.3
Loading cost	€/ton	3.66	2.97	3.50
Emissions	gCO_2/ton/km	68	2.97	24

2.5 Solar PV and wind power

The hourly electricity generation potential from solar PV and wind technologies is derived based on the meteorological dataset [34] for the year 2010. The dataset has global coverage with a 3-hourly temporal and a 0.25° spatial resolution.

Details of the data processing required to derive the power generation estimates are reported in a previous publication by the authors [18]. The hourly mean capacity factors of solar PV and onshore wind sites for the sampled hours are presented in **Fig. 2**. The factors shown represent hourly mean values as obtained from the data source. In total, about 2900 sites are considered for each technology.

In the model, the investment and O&M costs of wind and PV technologies are considered according to the LCOE documented in **Fig. A1**, Appendix A.

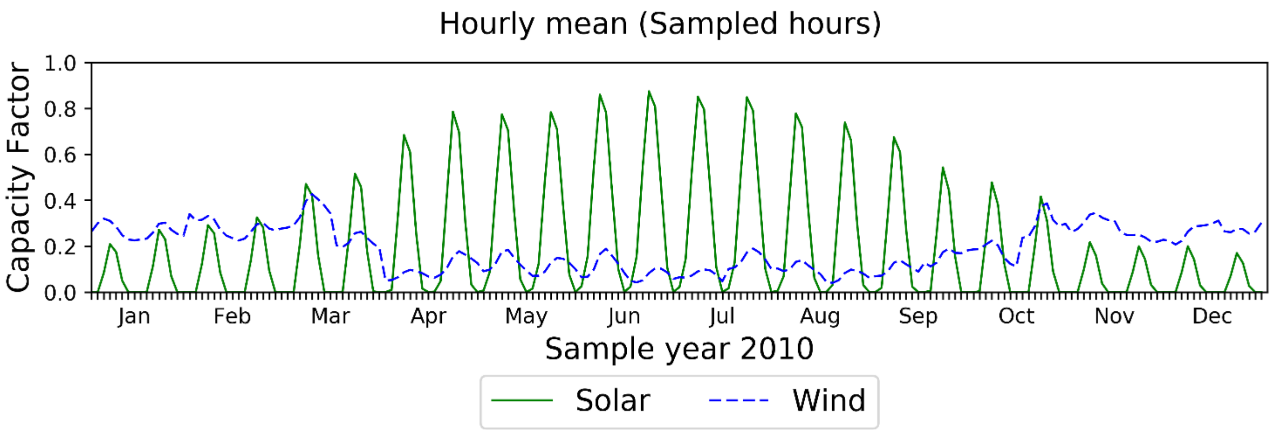

Fig. 2. Hourly mean capacity factors for solar and wind technologies

2.5.1 Protected areas

The deployment of intermittent RE technologies requires considerably more space than conventional thermal power generation units for the same amount of installed capacity. Hence, the expansion of RE technologies can cause conflicts related to the potential environmental impacts. To integrate biodiversity conservation and the sustainable use of the ecosystem services, we consider the protected areas designated by the IUCN [16]. To avoid potential environmental impacts and land degradation, the total area of the protected regions and their percentage within each grid cell are calculated and excluded from the available area for installing intermittent technologies. **Fig. 3** shows the results of the harmonization at the grid level. Accordingly, about 25% of the total area is unavailable, which thus puts additional constraints on the deployment of intermittent technologies.

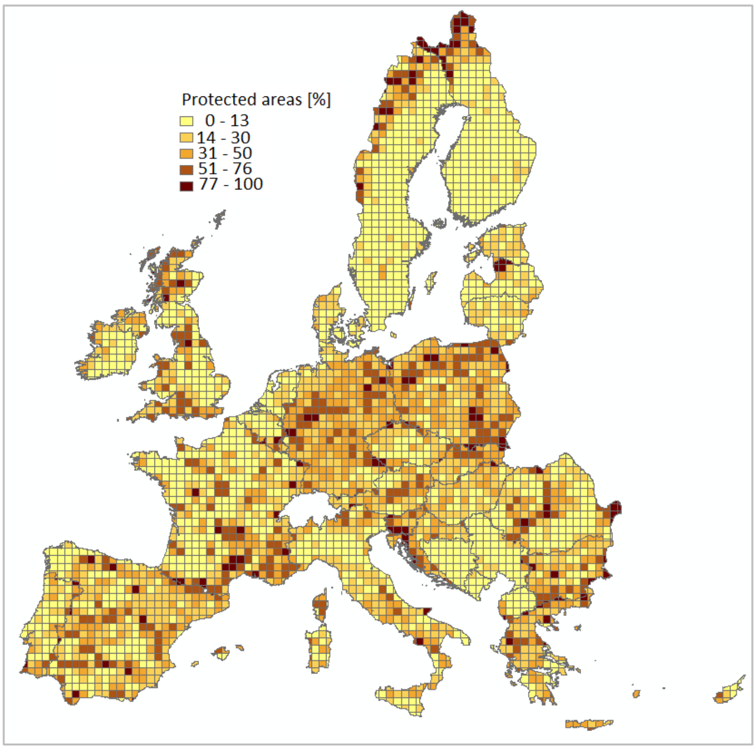

Fig. 3. Protected areas in percentage, harmonized IUCN categories I-VI [16]

2.6 Assessment Approach

A number of countries in Europe enforce national policy measures for stimulating and mapping the decarbonization pathways of their energy sectors. This, of course, is in addition to the EU emissions trading system (EU ETS), a policy cornerstone efforts against climate change. Examples of national policies include feed-in tariffs, carbon tax (additional tax on fossil fuels), bioenergy support (biofuels subsidy), and green electricity certificates (a program that awards a tradable certificate for every MWh of RE generation, e.g. in Sweden, Norway, and the UK). For an overview of national policies, see e.g., [35]. Due to the investigative nature of this study, we opted for a simplified approach that assumes a regionally enforced carbon tax over the entire EUWB region studied, in the range of 0 to 200 €/tCO_2 at an interval of 25 €/tCO_2.

The costs of emitting fossil CO_2 are internalized in the model, in that the carbon tax is applied on the CO_2 emissions associated with the resulting electricity production mix (existing and new production) and included in the objective function. Biomass and renewable waste are considered as emissions-neutral sources, and non-renewable waste as a positive contributor to emissions. The motivation behind this assumption is that forest and crop residuals, as well as waste, would otherwise contribute to landfill emissions, if left unutilized. The CO_2 emission factors used for the evaluation are listed in **Table C1** (electricity sector by fuel type) and **Table C2** (heat sector), Appendix C.

In the optimization, the model has to select the least expensive generation mix based on the existing generation fleet, with the associated CO_2 emissions, a state of the art natural gas combined cycle (NGCC), a state of the art dispatchable natural gas turbine open cycle (NGOC), or new deployed RE units, in order to meet power demand at any given time. Cost minimization is superior to a load-matching optimization for real world applications, as cost is a primary driver of integration of variable generation into an electricity sector.

2.6.1 Business-as-usual (BAU) scenario

To track the impact of RE integration into the existing power dispatch system, a reference case, reproducing the generation mix based on 2016 installed capacities, is established. As described in Section 2.1, the year 2016 is used to avoid underestimation of installed capacity of solar PV and wind technologies, which in aggregate has more than doubled compared to the demand base year 2010 [1]. Further, the expansion in electricity generating capacity in the EU has been dominated by onshore wind, solar, and, to a lesser degree, biomass. The major CO_2-emitting technologies in the existing fleet, such as coal and oil, are being targeted for potential substitution with RE in response to the stringent European Commission directives for increasing the share of renewable energy and reducing emissions. Based on the record in the ENTSO-E database, between 2010 and 2015 no significant change is observed in the installed capacities of nuclear and hydropower in the three major countries, Germany, the UK and France. Conversely, a reduction is observed in combustion generation units (mainly coal and oil), particularly in the UK.

In this respect, the model uses technology specific installed capacities for 2016 and also the corresponding availability factors for each technology in the EUWB power supply system. These data are parameterized in the model, and the availability factors of the existing technologies are presented in **Table C1**.

2.6.2 Sensitivity analysis of cross-border transmission capacity expansion

As mentioned, particular attention is given to the role of the cross-border network of transmission in order to stabilize intermittency and to minimize curtailment. Thus, different expansion scenarios are evaluated, assuming transmission expansion factors of 2, 5 and 10 in addition to an ideally interconnected EUWB case (which assumes no limitation in transmission capacity for the existing connections). Historical NTC among the countries studied is used as a basis to elaborate the impact of potential future expansion to the capacity of cross-border network of transmission. It should be noted that the assumed expansion of the existing cross-border transmission capacities is not part of the optimization set-up; instead the model was run under the different expansion factors. The evaluation focuses on the impacts of transmissions on wind and solar generations due to their variable nature.

To shed light on the uncertainties regarding the future cost of technologies, a sensitivity analysis based on a low- and high-investment scenario is also discussed under the assumed transmission expansion factors.

3 RESULTS

The integration of RE into the power sector is influenced by different factors, most notably their generation costs relative to the conventional technologies they compete with, and the existence of policies to stimulate their deployment. Consequently, the results presented here primarily explore the influence of carbon taxation based on a €-2014 LCOE for the considered generating technologies (see **Fig. A1**, Appendix A**)**. Additionally, the results are discussed in contrast to the potential expansion of the existing NTC between the countries in the studied region. As described in section 2.6.1, a BAU scenario that considers existing generation mix and the reference transmission network is established for 2016 based on historical indicative capacities, as shown in **Fig. B2**, Appendix B.

3.1 Electricity Generation Mix

Fig. 4 shows the resulting power generation mix of the BAU case, as well as the modelled cases for a carbon tax range of 0–200 €/tCO_2 (evaluated in steps of 25 €/tCO_2). The dashed line indicates the modeled power demand. Accordingly, intermittent RE starts to appear in the mix even without carbon incentives. A carbon tax as low as 25 €/tCO_2 results in total replacement of oil and about 50% of coal with RE and natural gas, as natural gas emissions are about 50% lower per unit output. This assumption is consistent with the general consensus that new fossil based technologies need to achieve at least a 50% reduction in carbon emissions compared to their conventional counterparts.

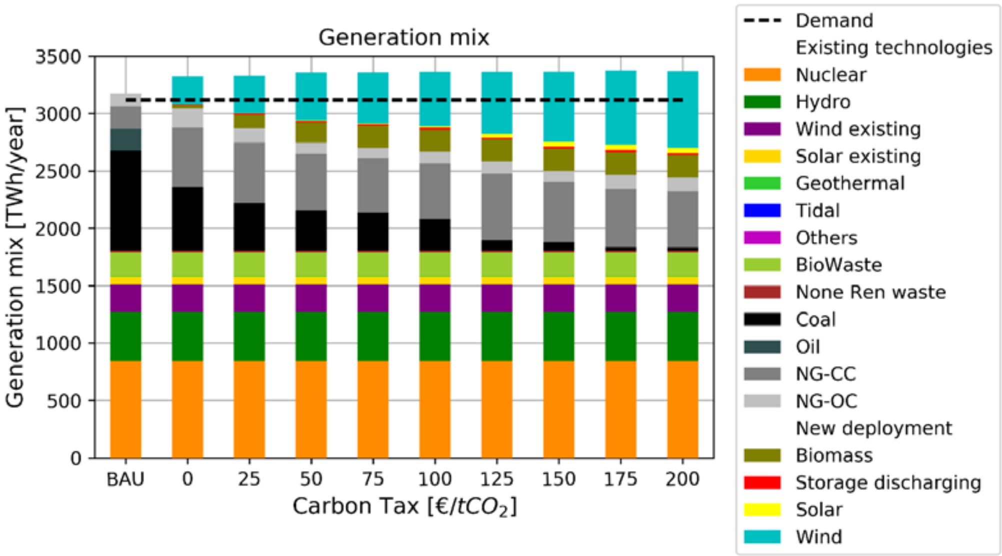

Fig. 4. EUWB power generation mix: BAU and carbon tax range of 0–200 €/tCO_2)

Moreover, with increasing carbon tax a steady increase in RE is observed, comprising between 9% and 39% of total generation. The share of intermittent power in the integrated RE falls between 70% and 90%, the high end of the range corresponding to low carbon prices. Of course, increased share of variable power causes grid-balancing problems, often leading to increased curtailment. Recently, studies tasked with identifying the barriers of large-scale integration of variable RE, based on real cases from the UK and Germany [4] and on the current electricity market of the EU [36], have recognized grid management and expansion measures as inevitable. The excess power generation phenomenon is also observed in **Fig. 4**, with supply progressively exceeding demand as increasing carbon tax increases. In the following subsection we explore the role of expanding existing transmission capacities in balancing the grid and reducing curtailment.

Fig. 5 shows a spatial distribution map of the optimal power generation mix for carbon tax 0-200 €/tCO_2. In comparison with the BAU case, natural gas (in the lower range of carbon tax) and intermittent technologies displace significant portions of oil and coal (the most CO_2-intensive technologies) across the entire region, most notably in France, Germany, Italy, Spain, Greece, Ireland, and the UK. Conversely, the use of biomass can be observed to increase progressively with a carbon price of up to 75 €/tCO_2, in Finland, Denmark, Sweden, the UK, Austria and Portugal.

In contrast to variable RE, bioelectricity shows strong dependence on carbon incentive, with its share in the integrated RE progressively increasing from 10% at 0 €/tCO_2 to a maximum of about 30% at 75 €/tCO_2. The main reason for such dependence is that the bioenergy conversion technologies considered produce heat as byproduct, which in the model is set to displace fossil use in the heating sector. The heating sector is more carbon intensive compared to the power sector, see **Table C2,** enabling progressive deployment of bioenergy with increasing carbon price.

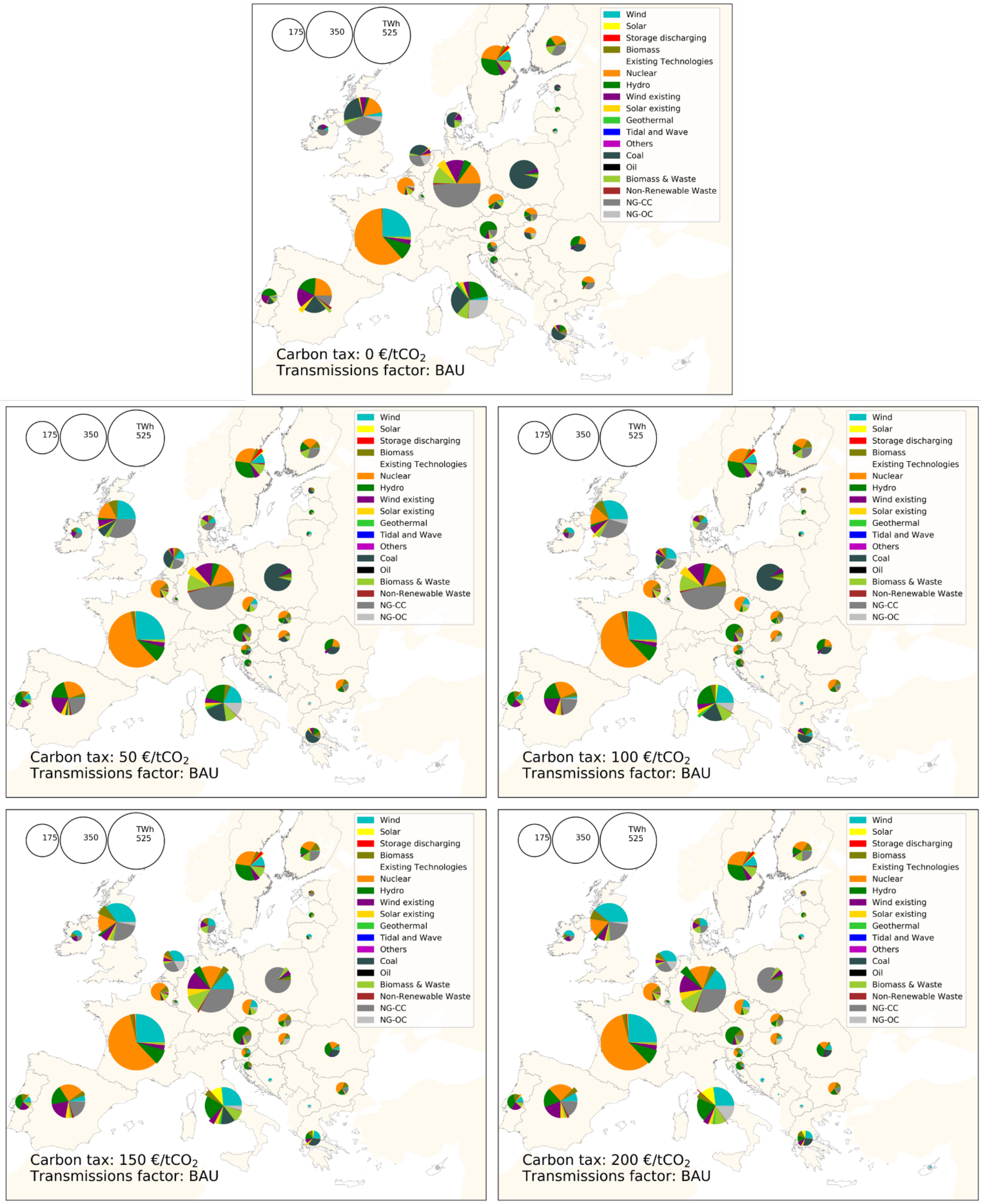

Fig. 5. Spatial distribution of EUWB power generation mix with an increasingly harmonized carbon tax

The economic implications of RE among the major drivers increasing their share of RE in the EUWB power sector is their economic implications, and rests squarely rests on the underlying assumptions formulated in the model. **Fig. 6** shows how the different technologies contribute to the evolution of the total system cost for the analyzed carbon price range of 0 to 200 €/tCO$_2$. Note that the aggregated total cost presented in **Fig. 6** is relative to the BAU, and would translate differently when down-scaled to a country level. This is due to differences in economic conditions, such as technology specific LCOE and the capital intensity of RE technology deployment, which in turn factors in labor costs, fuel prices, taxation, and other expenses at the country level.

The "existing technologies" category in **Fig. 6** covers the part of the existing generation fleet that does not produce net positive CO_2 emissions. Accordingly, about half of the total cost originates from the existing technologies over the entire carbon price range. Of this, nuclear and hydropower combined comprise about 80% of the existing technologies' contribution to the total cost, while existing wind and bio-wastes add about 9% and 7.5%, respectively. One can infer, by observing **Figs 4** and **6**, that for carbon prices above 125 €/tCO_2, natural gas remains the major technology responsible for emitting net positive CO_2 to the atmosphere, with trivial contributions from non-renewable waste and coal. On the renewables side, the share of variable RE in the total cost is dominated by the investment costs, ranging from 0–24% for wind and from 0–3% for solar PV, while the connecting transmission lines and grid integration costs add further 0–20% of the investments in RE technologies together.

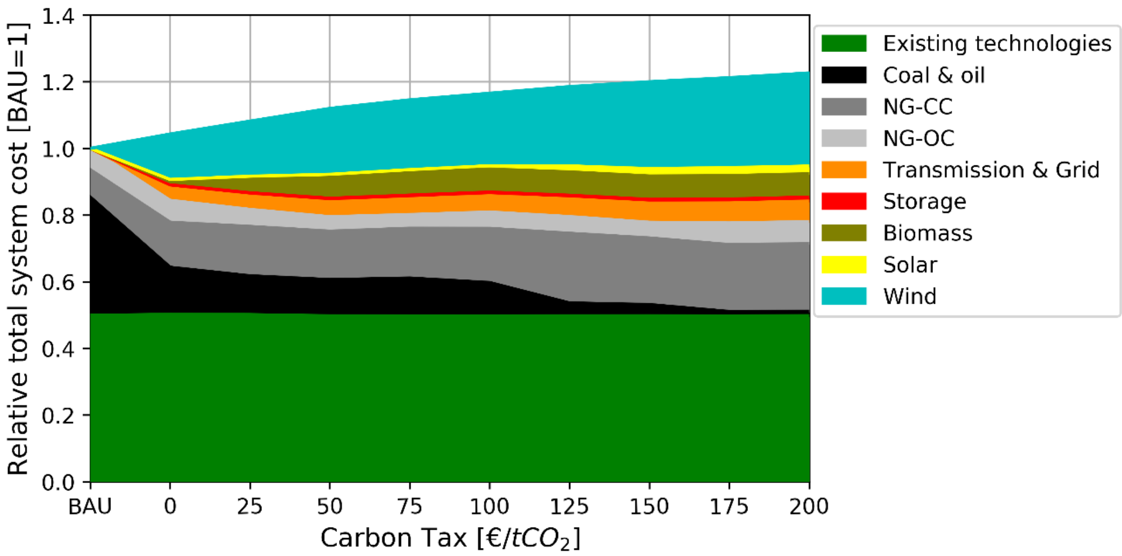

Fig. 6. Relative total system cost under harmonized carbon tax range of 0–200 €/tCO_2.

3.2 Cross-border Transmission Capacity Expansion

In the BAU assessment, the expansion allowance for cross-border transmission capacities is limited to the existing indicative NTC (net transfer capacities,) as reported by ENTSO-E. It does not therefore reflect factual capacities under expansion, construction, or planning phases; see e.g., [37]. In order to account for transmission capacity expansion, different expansion scenarios are applied to the existing cross-border transmission capacities in the sensitivity analysis, as described in Section 2.6.2. In this analysis expansion factors of 2, 5, and 10 are assumed, as well as an ideally interconnected EUWB case. Under the assumed transmission capacities, the evolution of the total system cost, deployment of variable RE, spatial distribution of the generation mix and curtailment are presented in this section.

Limiting the cross-border power exchange capacities increases the total system cost because it forces the generation mix in all the nodes to shift to a low carbon system. As shown in **Fig. 7**, the total cost is estimated to be in the range of 0.9–1.2 relative to the BAU case. The high and low ends of the range correspond to the scenarios under the BAU transmission capacities and the ideally interconnected

EUWB, respectively. Moreover, for all the transmission capacity expansion factors evaluated, the total system cost increases with increasing carbon tax.

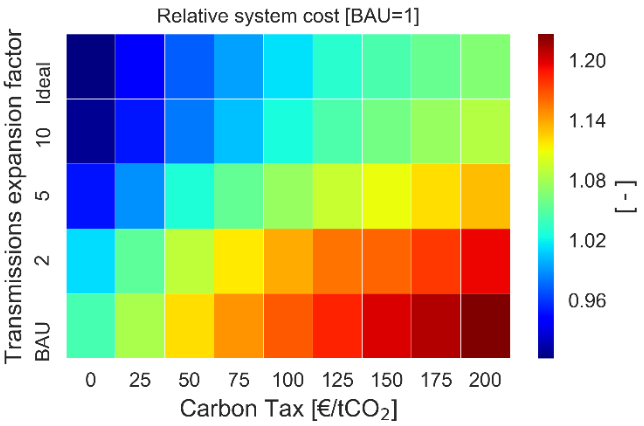

Fig. 7. Relative total system cost under harmonize carbon tax and the expansion factors applied to the BAU cross-border transmission capacities

The heatmaps in **Fig. 8** show the effects on intermittent RE production, depending on the assumed transmission capacity expansion scenario. The wind heatmap (**Fig. 8** left) shows that when the constraints on the transmission capacities are loosened, the deployment of wind technology diminishes. The consequence is a concentration of wind in countries where the resource appears to be abundant and the technology to be cheap, for example, the UK, Ireland, and Germany, as shown in **Fig. 9**. Conversely, solar deployment, which is an order of magnitude lower than wind (**Fig. 8** right), is localized to regions endowed with insolation, for example, Italy and Greece. Wind technology deployment is favored over solar, due to the better geographic and temporal distribution of wind, and because the technology requires lower capital investment; see **Fig. A1**.

Moreover, the reduction in wind generation due to expansion of the cross-border transmission capacities is counterbalanced by about the same amount of increase in the deployment of natural gas. This is mainly because the competing technologies are constrained to the installed capacities of the existing fleet, natural gas, wind, solar and biomass technologies. Note that an optimization with full access to the potential expansion of the renewable categories in the existing fleet, such as hydropower, geothermal and tidal, would likely lead to a different generation mix.

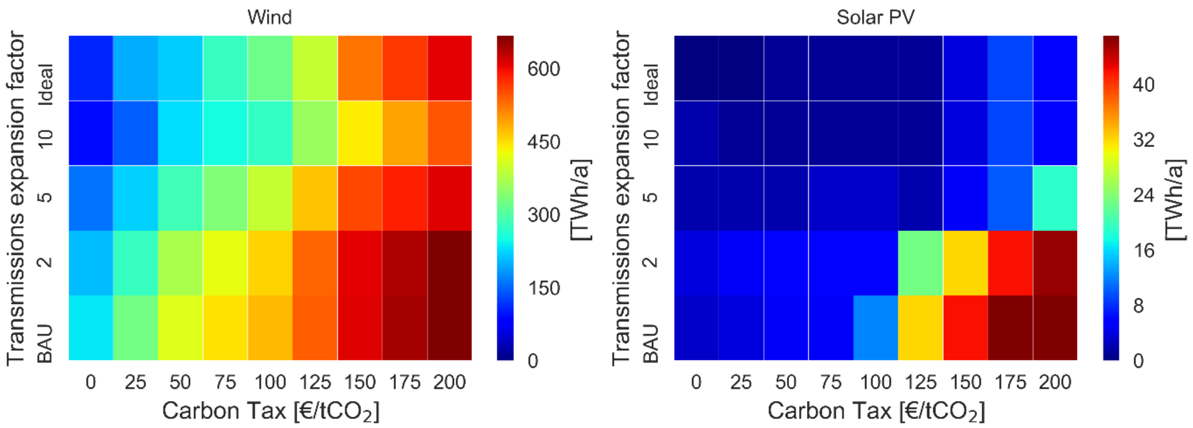

Fig. 8. Deployment of wind and solar under harmonized carbon tax and the expansion factors applied to BAU cross-border transmission capacities

The evolution of the spatial distribution of generation mix across the EUWB for the cross-border transmission capacities expansion scenarios (for the maximum carbon tax level of 200 €/tCO_2) is presented in **Fig. 9**. Accordingly, for an ideally interconnected EUWB, the shrinking generation capacities in countries, most notably the Netherlands, Spain, France, and Italy, are compensated for by capacity expansion of wind in the UK, Ireland and Denmark. Note that although some countries are not connected by a direct transmission corridor, it is possible for power to be exchanged via intermediate nations that play a balancing role, e.g., France.

In an ideally interconnected EUWB, combined generation is expected to be reduced, as the variability of intermittent RE is managed better by expanding the capacity of the BAU transmission network. To identify the economic balance between transmission capacity expansion and integration of RE, an optimization that also weighs in the investment regarding capacity expansion of the cross-border transmission network must be performed.

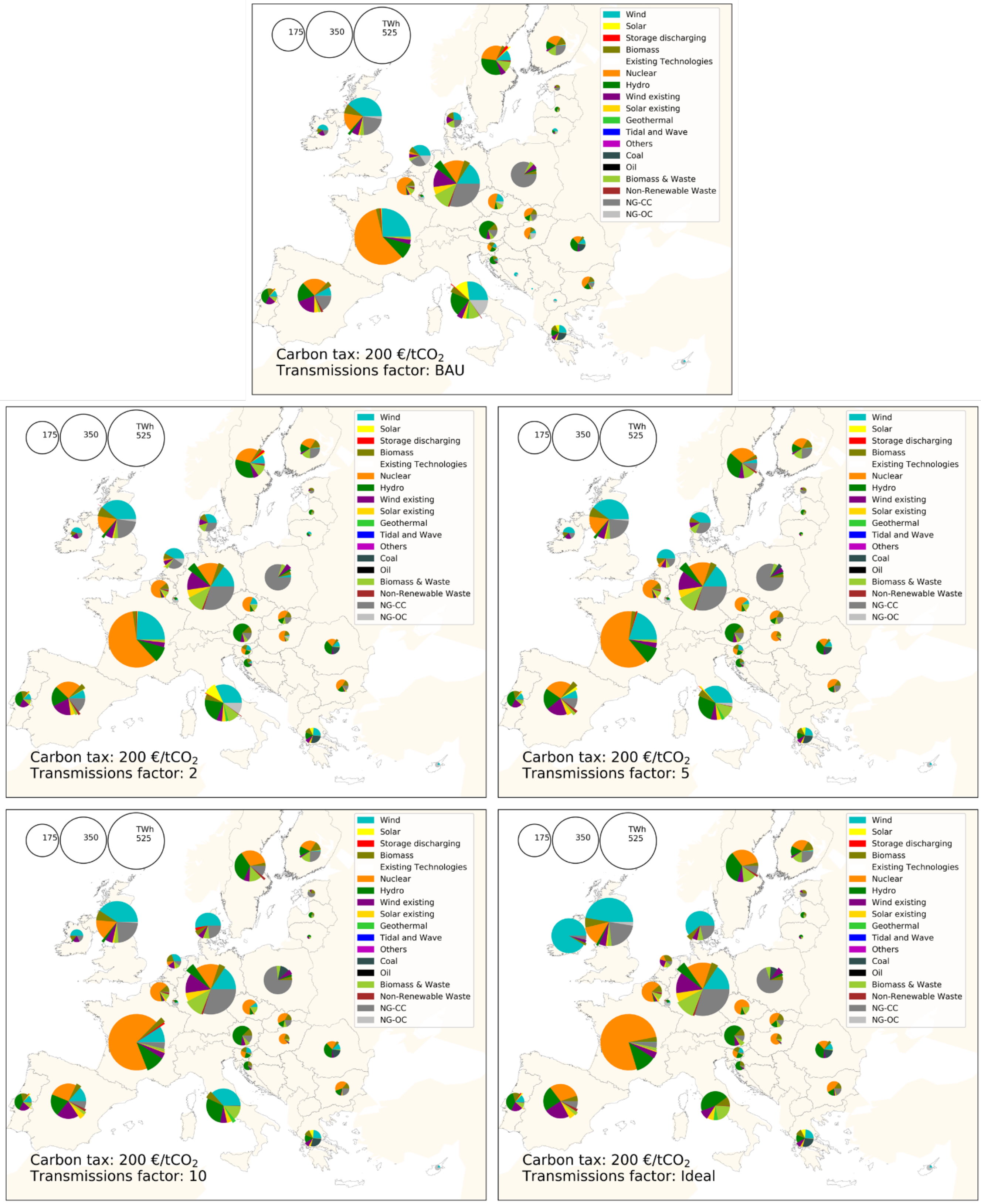

Fig. 9. Spatial distribution of generation mix at 200€/tCO$_2$ under the expansion factors applied to BAU cross-border transmission capacities

Moreover, maximizing the penetration of variable RE is likely to increase curtailment, due to the increased occurrence of periods when supply exceeds demand, primarily driven by the intermittent nature of wind and insolation. Many technologies are available to help even out this mismatch, such as battery storage, pumped hydro, and power-to-gas/power-to-liquid. In this study, the option to deploy battery storage is considered in the model, which builds on the assumption of economic feasibility of battery storage. The aforementioned capacity expansion scenarios of the existing transmission network are used as a sensitivity analysis aiming to assess the role of capacity expansion in minimizing curtailment.

Fig. 10 presents the total annual curtailment under the assumed capacities of cross-border transmission network. Accordingly, a five-fold capacity expansion of the existing transmission capacities reduces more than half of the curtailment that the BAU would require. This indicates that an optimal expansion of the transmission capacities can be achieved by considering an optimization set up that endogenously factors in the cost of building the extension to the existing transmission network.

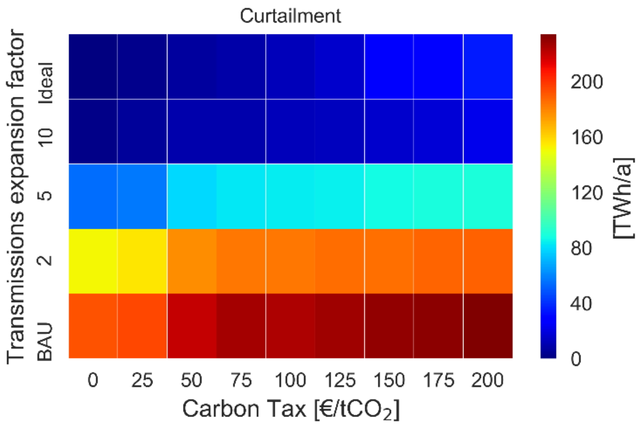

Fig. 10. Curtailment under harmonized carbon tax and the expansion factors applied to BAU cross-border transmission capacities

3.3 CO_2 Emissions

One of the main goals of this work is to assess the role of RE in decarbonizing the existing electricity generation fleet in the EUWB. **Fig. 11** presents the aggregated CO_2 emissions, assuming biomass and renewable waste as emission neutral sources and non-renewable waste as a positive contributor to emissions, as described in Section 2.6. Compared to variable RE, however, the contribution of biomass and waste to the generation mix is small, which is why the CO_2 emission assumption can be concluded as having little impact. Referring to **Fig. 11**, EUWB-scale deployment of RE would result in a CO_2 emissions reduction ranging between 28% and 72% compared to the BAU emissions (~432 $MtCO_2$), the lower and upper bound corresponding to the carbon price of 0 and 200 €/tCO_2, respectively. Consequently, about a third of the reduction potential is economically feasible even without incentives in the form of a carbon tax, which signifies that the cost of RE is already low enough for them to be economically competitive.

This observation accords with the argument that CO_2 emission reductions from the EUWB power sector over the 2005—2012 period were primarily driven by the increased share of RE rather than by carbon pricing [38]. Under the current price forecasts for solar PV and wind technologies, decarbonization of the EUWB power sector is thus likely to accelerate, regardless of carbon pricing policies.

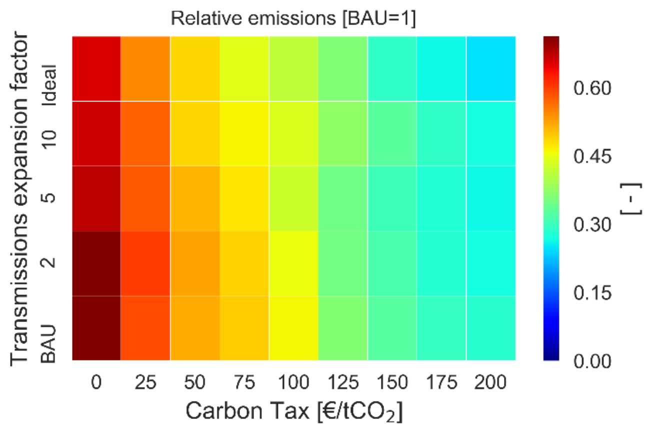

Fig. 11. Relative CO_2 emissions under harmonized carbon tax and the expansion factors applied to existing cross-border transmission capacities

Allowing the capacity of the existing transmission network to expand makes only a marginal difference with respect to mitigating CO_2 emissions. Any positive results are overshadowed by the fact that the state-of-the-art natural gas–based emissions are too low to respond to carbon pricing. As is evident in **Fig. 11**, the ideally interconnected EUWB scenario and the other cases follow a similar emissions-reduction pathways. The results from this model analysis show that, from a CO_2 emissions-mitigation perspective, a full transmission capacity expansion has no clear advantage. To further investigate the relationship between CO_2 emissions reduction and capacity expansion of the existing network of transmission, targets for RE integration and emissions could be set in the optimization, thus enforcing simultaneous transformation of the power sector at the country level.

4 DISCUSSIONS

The BeWhere version used in this study has been especially tailored to investigate the integration of RE into the power system of the EUWB. Other versions of BeWhere, e.g. [18,21,26], are well suited to grid-level assessment of the bioenergy supply chain from feedstock acquisition to product delivery—and this vital feature of the model has been used as a foundation to further enhance its capabilities with respect to analyzing the integration of variable RE. In this work, the problem is formulated based both on the deterministic optimization of the operation of all the technologies in the existing power system of the EUBW and on the operation and capacity of variable renewables, bioenergy, and state-of-the-art natural gas units. The model optimizes over a time horizon of one year under the systematically chosen temporal and spatial resolution described in Section 2.1.

In contrast to other studies of similar scope, e.g. [5,7,9], the effectiveness of our approach lies in its spatially explicit analyses of the supply chain of variable renewables and bioenergy, which are derived at the grid level, as well as in explicitly assessing the generation mix of the existing power system at the country level. Therefore, the policy and technological assumptions made in this study are implemented based on the status quo of the EUWB power system at the country level. This approach helps to visualize the impact of harmonized policy measures, such as carbon taxation, as is the case here, on the transformation of the power system at a country level and at the EUWB level. As the results show, these formulations have allowed the visualization of country-level transformation of the power generation mix, RE, and storage deployment, curtailment, and the degree of decarbonization under the assumed emissions policy.

Another important enhancement, compared to other versions of BeWhere, is the introduction of a network of electricity transmission for between the EUWB nations. For the BAU case power transfer is constrained by the existing cross-border transmission capacities derived from the historical NTC. Four cases assuming different expansion factors for the BAU cross-border transmission capacities, including an ideally interconnected case, are also investigated. This has helped to map the effect of the expansion of transmission capacities expansion on the deployment of variable RE and storage and, consequently, on the magnitude of decarbonization achieved. Note that when the expansion of the BAU transmission capacities are considered, only the capacity constraints are allowed to relax without considering the associated investment cost involved in realizing it. This assumption applies to the cross-border transmission network. In contrast, the cost of construction of transmission lines connecting new RE plant installations to major power substations is endogenously accounted for in the model. Hence, the LCOE of variable RE is explicitly augmented with the costs of both grid integration and the transmission lines connecting them to the nearest power substation. As Joos et al. [4] have shown not taking into account the balancing and grid integration costs of variable RE in the LCOE of solar PV and wind turbines leads to excessive management expenditure driven by grid congestion and curtailment costs. Likewise, our results showed that the endogenously evaluated costs of connecting transmission lines, grid integration and storage increase with the increasing penetration of variable RE. The results further show that storage deployment is more sensitive to solar PV than to wind.

The output of the model runs revealed that when the capacity of the existing transmission network across the EUWB states was allowed to expand in capacity, the deployment of variable RE and storage tended to localize in regions endowed with the insolation and wind resources or in countries where, economically, it was more likely to be feasible. This would likely lead to a complex decarbonization pathway, in which the carbon emissions budget would have to be managed at the EUWB level. In reality, countries adhere to their national policies for cutting carbon emissions and those for achieving the targets set at the national or EU level. To refine these outcomes, additional constraints reflecting country-level RE deployment ambitions need to be introduced into the model. Even without explicit country-level RE targets, however, the results of the case studies presented in Section 3 have highlighted the capabilities of the approach to capturing the impact of interconnectivity and harmonized policy measures on the EUWB power system.

Biomass-based power production was shown to make only a marginal contribution as a low-carbon baseload under the considered technologies, due to its the intrinsic interdependency with the heating sector. From this it can be concluded that with alternative low carbon–baseload technologies, primarily nuclear and hydropower, biomass can be freed up for use in the decarbonization of other sectors; for example, it can be used as a feedstock for transport fuels or as fossil energy or reductant replacement in different industry sectors. However, biomass can still contribute to the management of variable RE and facilitate their penetration into the power sector. Recent studies, e.g., [39], showed that the production of biofuels via gasification could utilize excess variable RE to achieve economy of scale throughputs and to facilitate commercialization. The direct utilization of variable RE for heating in electric boilers, e.g., [40], could further boost the availability of biomass for the production of value added chemicals and biofuels via thermochemical conversion, e.g.,[41].

The spatially explicit approach used in this study has helped elucidate systems aspects of the European electricity network that can be useful in the continued dispatch of intermittent RE technologies. The results have also highlighted a number of aspects that needing further investigation. Examples are the relationship between the electricity and heating sectors, the potential contradictions between targets for

RE integration and CO_2 emission reduction at the country level compared to at the EUWB level, and the effects on the overall European RE integration potential of, for example, the increased environmental protection of large land areas, continued expansion of electrification of the industry and the transport sector, and phase-out of nuclear production. The modeling approach used in this study is well suited to these types of investigation, due to its high spatial and temporal resolution and to its modular modeling framework which makes expansion of the base model relatively straight-forward.

Given the distribution of the renewable resources, the techno-economics of the conversion units and the constraints on installation space, the model is able to identify the potential localization of the utility scale RE plants for the different scenarios. Fairly robust optimal plant localization is observed for the range of CO_2 tax evaluated, and the maps (**Appendix E**) show that most of the plant localizations held their position while the total number of plants increased with the progressive penetration of RE.

Another way in which the effectiveness of our approach is shown lies in the way it defines the objective function, which explicitly accounts for the associated CO_2 emissions of all the technologies considered. We do not set targets for the deployment of variable RE or bioenergy. Rather, the upper limit constrained either by the availability of the resources, such as biomass, wind, and insolation, or by the environmental limitation, such as available space to build new installations in the case of variable RE, or by economic feasibility.

The economic feasibility, mainly driven by the investment cost of technologies, is of paramount importance because of the uncertainties regarding the future cost of technologies. Hence, it is considered important to elaborate on the impact of the investment under both a low- and high-cost scenario. **Fig. 12** sheds light on the impact of capital expenditure on the expansion of RE based on two investment scenarios, low (left) and high (right), using technology cost parameters recalculated based on the maximum and minimum investment estimates reported in [42]. Under the low investment scenario, the variable RE heatmaps (**Fig. 12b**) show that the deployment of wind dominates and progressively displaces coal and oil as CO_2 prices increase. Even at the high end of the CO_2 price range, natural gas technologies remain at around 11% (baseload NGCC, 8%, and peak load NGOC, 3%) of the total generation, emphasizing how costly it will be to achieve the final percentages toward a 100% renewable system. Furthermore, at the lower end of the CO_2 price range, the wind heatmap shows that relaxation of the existing cross-border transmission capacities means that fewer wind turbines are deployed (Fig 12b) but greater emission reductions are achieved, as shown on the emissions heatmap (**Fig. 12c**). Under the high investment scenario (Fig. 12 right) the expansion of wind technology is relatively slow and the model tends to favor natural gas technologies for replacing coal and oil, resulting in a generation mix composed of NGCC 18%, NGOC 2%, and coal 4% at the high end of the carbon tax. While the heatmaps of wind and solar (**Fig. 12e**) and emissions (**Fig. 12f**) in general exhibit similar relationships in terms of the cross-border transmission capacity expansion as described by the low investment scenario (Fig. 12 left), even though the deployment of solar PV becomes more feasible and the reduction of emissions is significantly lower.

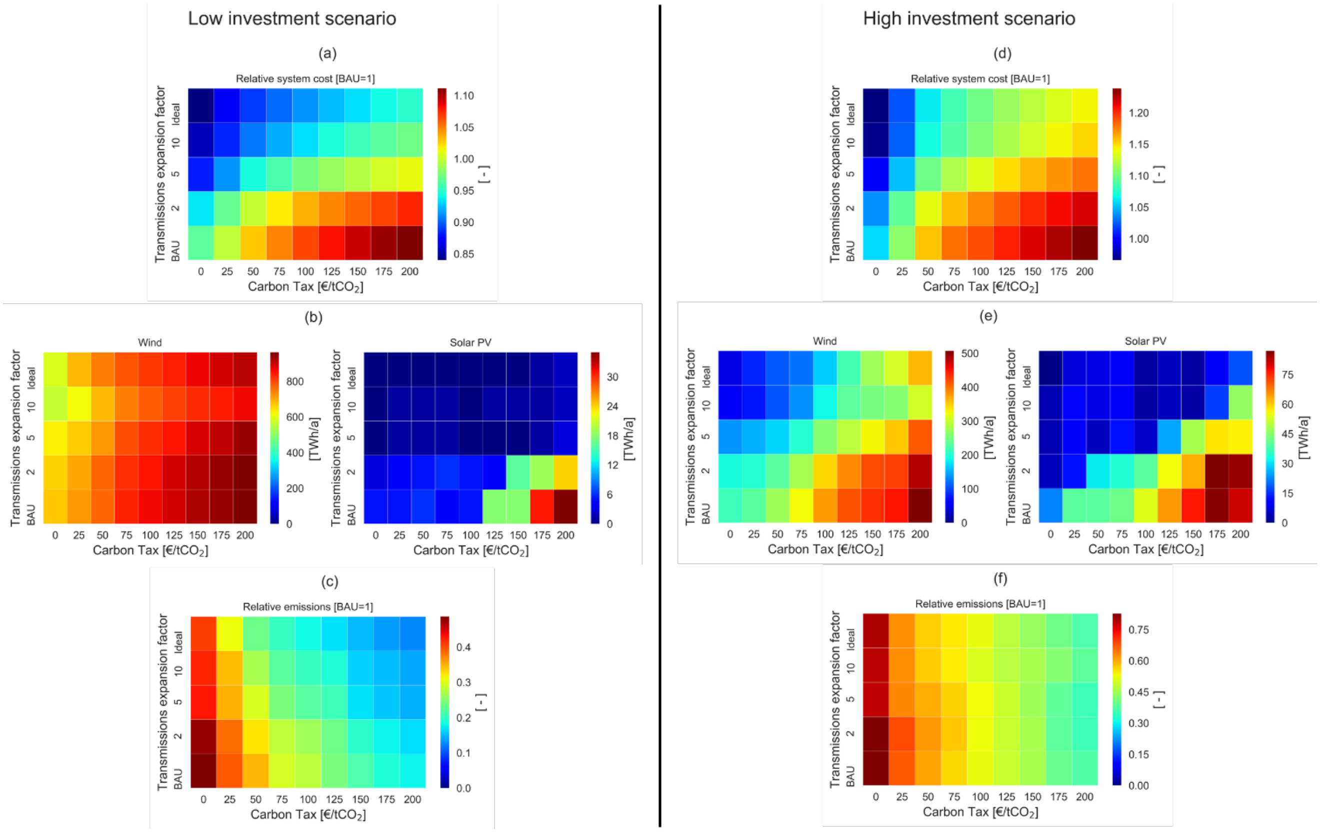

Fig. 12. Transformation of the EUWB power system under low and high investment scenario

5 CONCLUDING REMARKS

This study investigated the short-term potential for expansion of bioenergy and variable RE, the potential benefits of expanding the cross-border power transfer capacities and, consequently, the potential for emissions mitigation in the EUWB region. The assessment uses an optimization approach that combines high spatial and temporal resolution, in order to illustrate the potential of deploying utility-scale intermittent RE to aggressively reduce CO_2 emissions in the EUWB electricity sector.

The findings showed that the least expensive generation mix converges into a 28% lower carbon–intensive system, even without a carbon incentive. Thus, about 35% of the variable RE integration that would be motivated by a carbon price of 200 €/tCO_2, was shown to be economically attractive already at 0 €/tCO_2. Moreover, for the main case, the integration of variable RE showed a rather moderate response to increasing carbon prices, which indicates that the cost of wind technologies is already low enough to be competitive against conventional electricity generation units.

Under the assumed economic conditions, integration of variable RE can make an important contribution comprising between 9% and 39% of the total electricity generation, even with the existing transmissions capacity. Not surprisingly, allowing for up to a five-fold expansion of the existing transmission capacities could significantly help offset the effects of the intermittency of wind and solar technologies. However, the results further show that expansion of the existing transmission capacities will not necessarily lead to reduced system wide CO_2 emissions, as it also has an effect in the form of diminished installed capacity of variable RE at the EUWB level, and a relative increase in the installed capacity of state-of-the-art natural gas plants with higher associated CO_2 emissions. The fact that the least contribution of natural gas in the generation mix remained around 11%, i.e., under the low investment scenario and at the high end of the carbon price range, indicates the final percentages toward a 100% renewable electricity mix will likely be costly to achieve.

Depending on the carbon price, the reduction in CO_2 emissions could be as much as 28–72% of the BAU case (~432 $MtCO_2$). Capture and industrial use of CO_2, for example in power-to-gas and power-to-liquid applications, could help marginalize the carbon tax, as shown in previous studies [43,44].

Considering the carbon intensity of the EUWB power sector, carbon pricing may not be the most effective tool to achieve deep decarbonization matching the pledged climate mitigation goals. Besides, recognizing the limited contribution of biomass and the limited technical potential for new hydropower, RE expansion is likely to be dominated by wind and solar. Thus, as highlighted in the discussions, a much more efficient way of transforming the EUWB power sector would be to set targets for the share of variable RE at the country level and to introduce advanced grid management techniques that match their penetration, including flexible backup units, storage, mobilize electrified transport, and demand alignment, to optimize its utilization.

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APPENDIX A—COST PARAMETERS

Biomass conversion technologies

The model takes into account the expenses of the entire bioenergy supply chain (i.e., from procurement of feedstock to delivery of final products) when commissioning new bioenergy plants. When a technology is selected three cost categories are evaluated and parameterized into the model, namely, direct, indirect and general expenses. The direct expenses account for feedstock cost, maintenance and repair, M&R, (2-10% of capex), operating supplies (10-20% of M&R) and ash disposal (25€/tonne). The indirect expenses consider overhead cost (60% of labor and M&R), local taxes (1.5% of capex) and insurance (0.7% of capex). The general expenses deal with administrative costs (25% of overhead) and product delivery (10% of total expenses). Labor expenses (i.e., administrative and engineering staff and plant operators) are calculated according to country-respective income rates. In addition, bioenergy technologies factor in the spatial impact of biomass acquisition (i.e., logistics cost [harvesting and transportation] and cost of emissions from the transport of biomass to the conversion plants.

Table A1. Bioenergy cost parameters [30]

Description	Feed (PJ/year)	Invest. (M€)	Load hours	Lifetime (years)
Circulating fluidized bed for CHP (CFBCHP)	0.72	35	7000	30
Circulating fluidized bed for IGCC (CFBIGCC)	5.04	150	7000	30
Bubbling fluidized bed for CHP (BFBCHP)	0.39	18	6500	30
Circulating fluidized bed for CHP (CFBCHP2)	3.24	140	5000	35
Fixed bed combustion for CHP (FBCHP)	0.36	25	5000	40
Fast pyrolysis for CHP (FPCHP)	0.19	3	8000	25
Dry wood chips to pyrolysis oil, heat and steam (DWPOCHP)	0.6	15	7000	25

Levelized cost of electricity (LCOE)

The LCOE for the technologies featured in the existing system and new installations of variable renewables (solar PV and onshore wind), NGOC and NGCC are shown in **Fig. A1**. The monetary values are based on €$_{2014.}$ The LCOE are calculated based on the average investment values reported in [42]. The objective function of the BeWhere model is to minimize the total system cost, which comprises investment, operating and maintenance, and fuel cost, according to technology-respective levelized cost of electricity (LCOE) evaluated using eq. (A1) as well as the cost emissions, calculated based on the technology-respective emission factors reported in **Table C1**.

On the variable renewables side, the LCOE obtained from eq. (1) is augmented with grid connection and transmission costs to the nearest transmission hub, which is calculated as the total new capacity installations multiplied by the sum of capacity rated grid connection cost and the product of transmission cost and the distance from the installation site to the nearest transmission hub, **Fig B1**.

$$LCOE_{c,te} = \frac{\alpha_c I_{te} + FOM_{c,te}}{LH_{c,te}} + VOM_{c,te} + \frac{FC_{c,te}}{\eta_{te}} \qquad \text{(A1)}$$

Where

Subscripts:

c *country*

te *conventional and variable renewable technology*

Parameters:

LH *load hours [h/a]*

I *investment cost [€/MW]*

LCOE *levelized cost of electricity [€/MWh]*

FOM *fixed operation and maintenance cost [€/MW]*

VOM *operation and maintenance cost [€/MWh]*

FC *fuel cost (€/MWh)*

Symbols:

α *Capital recovery factor [%]*

η *Fuel conversion efficiency [%]*

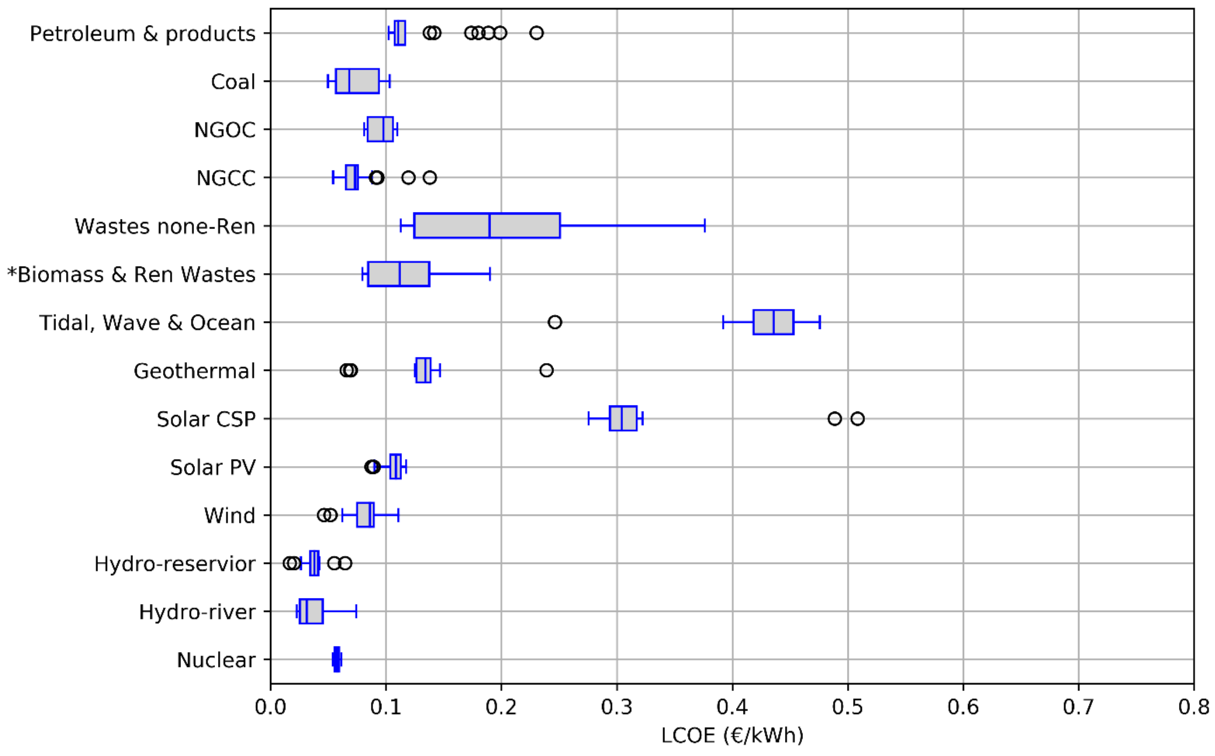

Fig. A1. Economic performance of technologies (*Category does not include dedicated-biomass)

APPENDIX B—TRANSMISSION NETWORK PARAMETERS

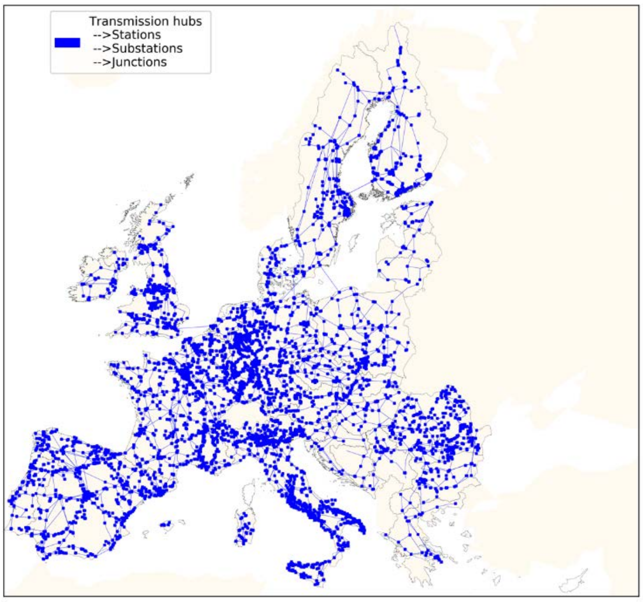

Fig. B1. Major power transmission hubs and junctions for the region considered in this study (potential locations for grid integration of variable RE generation units) [45]

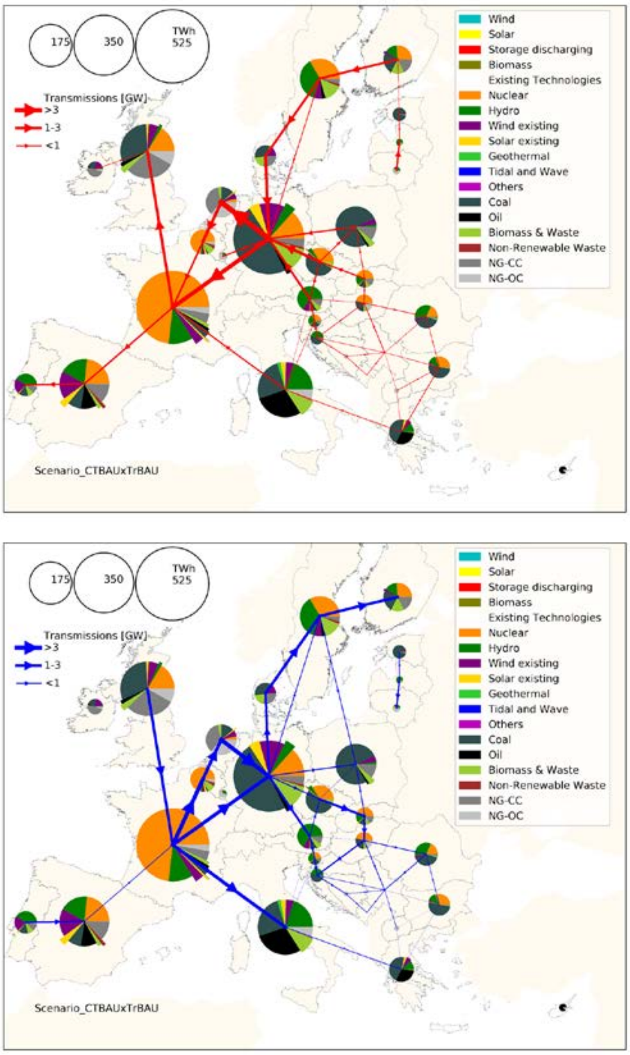

Fig. B2. Simulation of the BAU generation mix and unidirectional transmissions capacity

APPENDIX C—AVAILABILITY AND CO_2 EMISSION PARAMETERS

Table C1. Availability and CO_2 emission factors for power generation technologies

Technology type	Availability factor [5]	Emission factor tCO_2/MWh [46]
Nuclear	0.9	0.00
Hydro	0.95	0.00
Wind	0.92	0.00
Solar PV	0.92	0.00
Solar thermal	0.92	0.00
Geothermal	0.95	0.26
Tide, Wave and Ocean	0.85	0.00
Coal	0.9	0.33*
Petroleum and Products	0.89	0.31 *
Biomass and renewable wastes	0.89	0.00**
Wastes non-RES	0.9	0.14 ***
Natural gas	0.85	0.18

* Value averaged over different fuel types under the same category
** Category is assumed carbon neutral
*** Category excluded from carbon taxing, but emissions are counted positive

Table C2. Annual heat demand [47] and emission factors for the heat sector

		Heat demand*	Emissions**
Country	ID	TWh/year	tCO_2/MWh
Austria	AT	15411	0.45
Belgium	BE	6394	0.39
Bosnia and Herzegovina	BA	1	1.18
Bulgaria	BG	15000	0.74
Croatia	HR	3639	0.47
Cyprus	CY	2	0.58
Czech Republic	CZ	40873	0.80
Denmark	DK	36106	0.50
Estonia	EE	7112	1.12
Finland	FI	47329	0.37
France	FR	30226	0.22
Germany	DE	108495	0.66
Greece	GR	281	0.77
Hungary	HU	17771	0.47
Ireland	IE	35	0.64
Italy	IT	8249	0.53
Latvia	LV	9310	0.26
Lithuania	LT	12309	0.43
Luxembourg	LU	541	0.56
Montenegro	ME	1	0.78
Netherlands	NL	31934	0.56

Poland	PL	102282	0.84
Portugal	PT	2624	0.50
Republic of Serbia	RS	1	0.98
Romania	RO	41889	0.47
Slovakia	SK	15441	0.54
Slovenia	SI	2657	0.51
Spain	ES	33	0.53
Sweden	SE	51470	0.22
Former Yugoslav Republic of Macedonia	MK	1	0.92
United Kingdom	GB	20894	0.62

*Data for heat demand are down-scaled to the grid level based on population density and seasonally classified assuming three seasons per year before being parameterized into the model. The seasonal classification assumes different factors depending on the geographical location.

**Values calculated based on the guidelines outlined in [48].

APPENDIX D—BIOMASS FEEDSTOCK AVAILABILITY

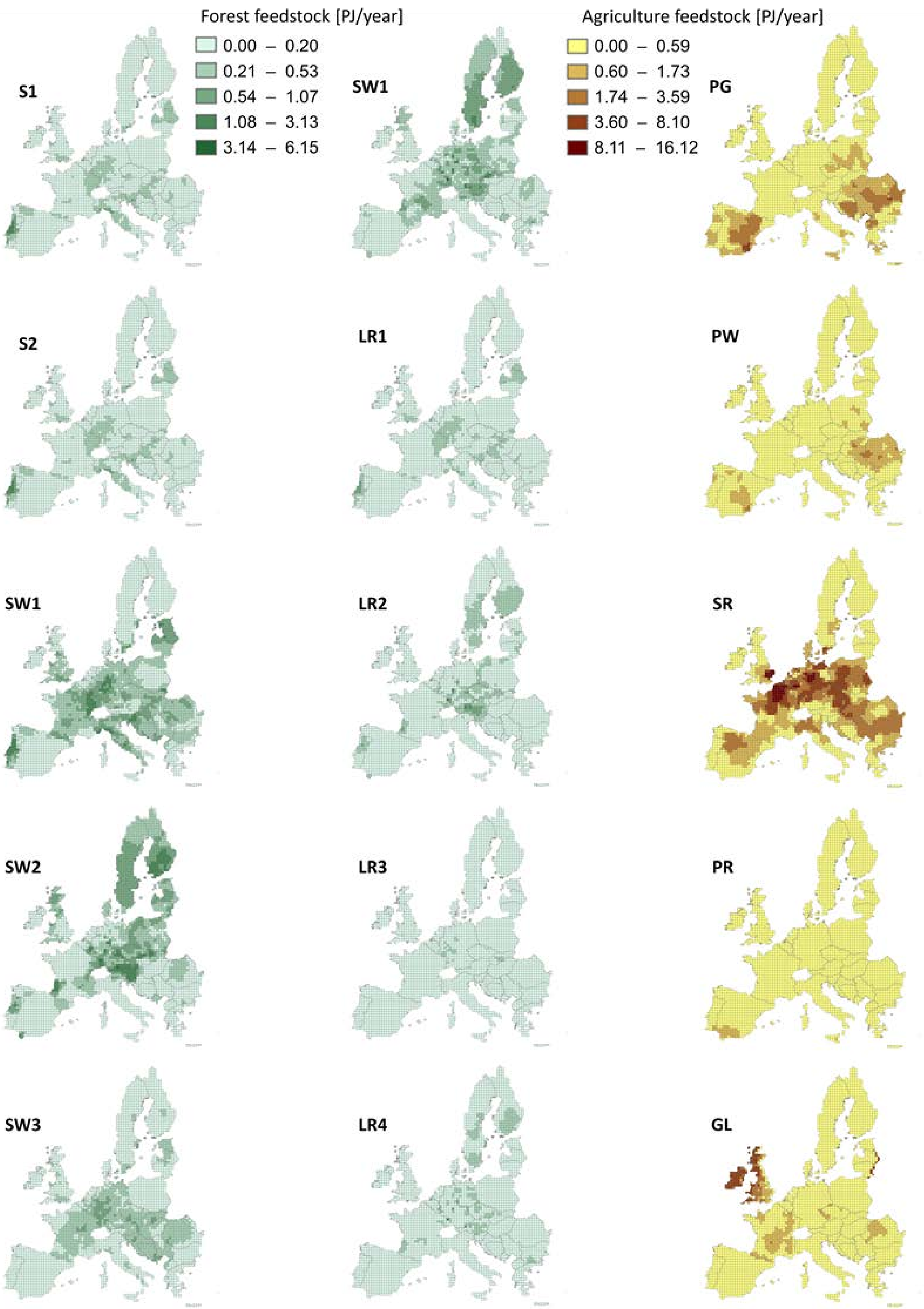

Fig. D1. Spatial distribution map of forest and agricultural feedstock by type and amount [33]

APPENDIX E—SPATIAL MAP FOR RE INSTALLATIONS

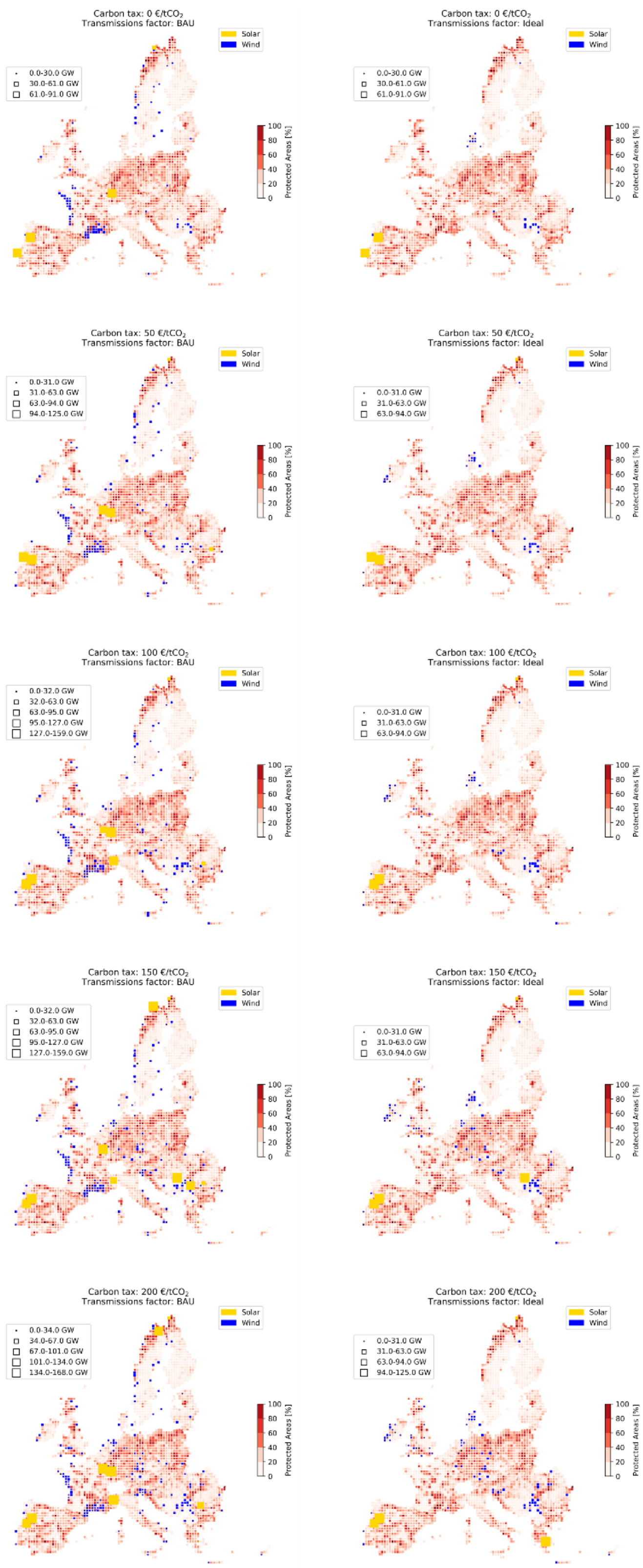

Fig. E1. Spatial localization of wind and solar plants for the optimal solution for carbon price range of 0—200€/tCO_2 for the BAU and ideally interconnected EUWB

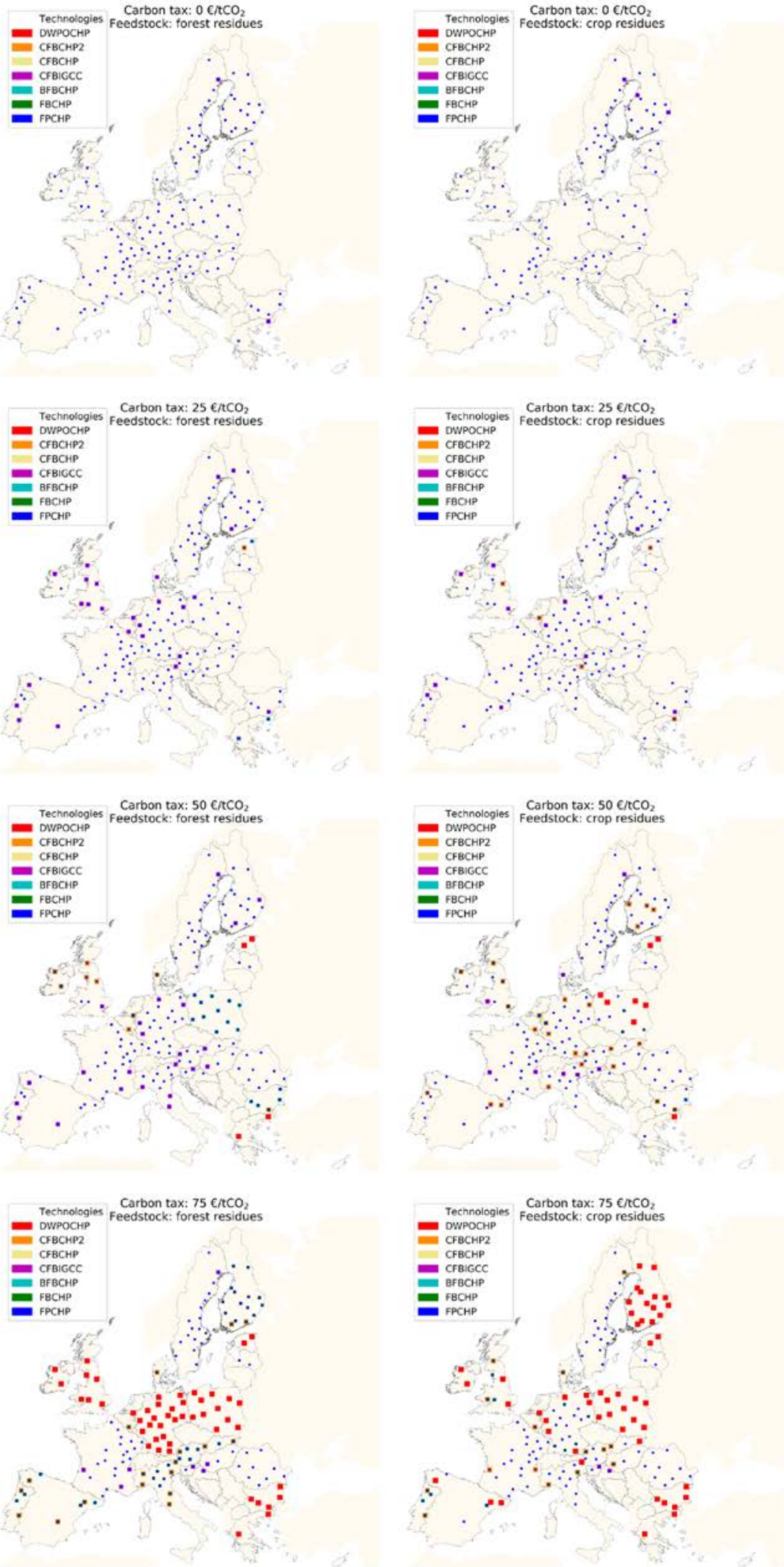

Fig. E2. Spatial localization of bioenergy conversion technologies for carbon price range of 0–75€/tCO_2. On the maps, different size markers and colors are assigned to avoid masking when multiple technology installations are made in the same grid. Note that the capacities of the installed plants and the acronyms are as indicated in Table A1.