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Climate proofing the renewable electricity deployment in Europe - Introducing climate variability in large energy systems models

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A R T I C L E I N F O

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A B S T R A C T

Climate and weather conditions influence energy demand. as well as electricity generation, especially due to the strong development of renewable energy. The changes of the European energy mix, together with ongoing climate change, raise a number of questions on impact on the electricity sector. In this paper we present results for the whole of the European power sector regarding on how considering current and future climate variability affects the results of a TIMES energy system model for the whole European power sector (eTIMES-EU) up to 2050. For each member-state we consider six climate projections to generate future capacity factors for wind, solar and hydro power generation. as well as temperature impact on electricity demand for heating and cooling. These are input into the eTIMES-EU model to assess how climate affects the optimal operation of the power system and if current EU-wide RES and emissions target deployment may be affected. Results show that although at EU-wide level there are no substantial changes, there are significant differences in countries RES deployment (especially wind and solar) and in electricity trade.

1. Introduction

The transition from fossil to renewable energy sources (RES) is seen as a precondition for preventing major climate disruption within the next decades [1]. This trajectory is in place: renewable electricity is expected to play a major role by providing nearly 30% of electricity demand, compared to 24% in 2017; also RES will meet more that 70% global electricity generation growth in 2023, led by solar PV, wind, hydro and bioenergy [2]. In the European Union the 2030 climate and energy framework aims to lower greenhouse gases (GHG) emissions by 40% by 2030, compared with 1990 levels [3]. Initially this involved increasing the share of RES to at least 27% and increasing energy efficiency by 27%, but this ambition has increased to 32% for RES [4,5], and recently a 2030 target of 33.7% RES is foreseen [6]. Finally, the proposal for a EU long-term strategy 'A Clean Planet for All', steers the EU towards a CO_2 emissions-free future by 2050 [7].

Yet, electricity supply with a large RES share necessitates a detailed assessment of the impact of future climate on the operation of the power system. Indeed, as RES electricity supply and demand are both strongly influenced by weather conditions, climate variability and climate change [8,9]. [10] assessed climate change impacts for different global warming scenarios on wind, solar photovoltaic (PV). hydropower and thermoelectric power generation in Europe. The authors concluded that climate change will have a negative impact on electricity generation in most countries and technologies, ranging from less 10% for PV and wind power up to less 20% generation for hydropower and thermal power plants. Such impacts are expected to be more significant in southern Europe than in northern Europe.

Besides RES, fossil thermal power plants and nuclear power plants (NPP) can also be affected by climate change [11]. According to Ref. [12], very high air temperatures can affect fuel efficiency due to a lower oxygen concentration in the air leading to a 0.1% or 0.5%

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efficiency reduction, respectively for gas/fuel thermal plants or NPP for each 1 °C temperature. Moreover, every 5 °C increase in water temperature represents a 1% loss of plant efficiency. According to Ref. [13], losses of efficiency in NPP can be higher, from less 0.7% output at low temperatures (around 0 °C) to less 2.3% at high temperatures (around 20 °C) with every increase of 1 °C in monthly ambient temperature.

[14] studied how electricity trade between European countries is affected by climate change due to the higher risk of water supply shortages caused by droughts and heatwaves. They found that strong declines in electricity generation due to climate change tend to occur (e.g. in Austria, France and Switzerland). Changes in generation and import/export balances due to local electricity shortages can be overcome, but prices tend to rise in some scenarios (e.g. 30% in France, 80% in Switzerland).

Likewise [15], investigate the vulnerability of electricity generation to increase of temperature in cooling water that can lead to less 6.3–19% summer average decrease for 2031–2060 depending on cooling system type and climate scenario [16]. further investigate the vulnerability of electricity generation to water stress in the European Union by assessing water needs for the cooling of 1326 power plants in 2020 and 2030. They point out that some plants will experience power reductions due to water stress, caused both by climate change and concurrent water uses.

Besides the impact on the supply-side of the power sector, increased temperature can lead to less electricity demand for heating in winter and climate adaptation options can cause increased electricity demand for cooling [17]. estimated that, due to climate change, there will be significant increases in average daily peak load and overall electricity consumption in southern and western Europe, coupled with a significant decrease in northern Europe, as well as a shift of seasonal peak load from winter to summer for 19 countries.

Besides climate change trends, extreme weather events can also significantly impact the power sector for both heat and cold waves [11] or the cold wave and ice storm in Poland in 2008 [18] which caused accumulation of snow in the transmission lines and a subsequent blackout.

A recent report by the European Environment Agency [19] acknowledges these challenges and addresses the adaptation needs for the European energy system. It further highlights the need for member states to "consider the impacts of climate change in the development of national climate and energy plans and long-term strategies under the Energy Union".

Several initiatives are being developed that use climate data to assess impacts for the power sector, from commercial products (e.g. POWEL software) to research (e.g. EUPORIAS [20]; ECEM [21] and CLIM4ENERGY [22], with the worthy more recent additions of the H2020 projects S2S4 E [23]), SECLI-FIRM [24] and PLAN4RES [25]. However, these are concentrating on individual RES impacts and not on combined effects on all of the mentioned impacts on the power system. As with the previously mentioned literature, so far these do not consider the combined effects of climate on all previously mentioned components of the power sector [26]. develop an index that integrated 14 quantitative influencing factors to assess susceptibility of 21 European countries' electricity system to climate change. However, these do not explicitly consider an integrated analysis with climate data.

In this context, the authors believe that a holistic approach is needed to fully assess effects of climate change in the power sector, integrating jointly impacts: (i) in PV, wind and hydropower capacity factors (CF); (ii) on the demand response to temperature; (iii) on losses of efficiency of thermal power plants due to air temperature increase, and (iv) on water stress affecting cooling systems. This is the goal of the Clim2Power (C2P) research project that aims to "climate-proof" the current European electricity systems operation and planning, ensuring that energy planning models respond to climate variability.

This paper presents the results of the C2P project where we study the combined climate change in availability of intermittent RES, in electricity demand and on the whole of European power sector. To do so, we introduce climate variability in the large European-wide power system model (eTIMES-EU). We model six long-term climate scenarios up to 2050 and assess impacts in the European power sector in terms of electricity generation portfolio, share of electricity generated from RES, GHG gas emissions and electricity trade across Europe. We assess its significance regarding EU-wide climate and energy plans. The following section 2 presents the methods adopted for translating climate data into energy system models. This is followed by an overview of the results and discussion in section 3. Section 4 concludes.

2. Methods

This section outlines the methods used for the analysis regarding considered climate data and its input into the eTIMES-EU energy system model, followed by a description of the developed eTIMES-EU, and an overview of the modelled scenarios. The overall approach to consider climate variability within eTIMES-EU was developed within the C2P project, as mentioned. and is depicted in Fig. 1.

A set of long-term climate projections from EURO-CORDEX for three climate models and two representative concentration pathways (RCP) scenarios (4.5 and 8.5) was used as a starting point. RCP4.5 translates an intermediate climate stabilisation pathways in which radiative forcing is stabilised at approximately 4.5 W m^{-2} by 2100, whereas RCP8.5 translates a pathway for which radiative forcing reaches greater than 8.5 W m^{-2} by 2100 [27]. The climate data was translated to timeseries of maximum capacity factors for RES electricity from hydro, wind and solar PV power, as well as impacts of temperature on energy demand using different approaches, from machine learning to specially developed simulation tools. This results in daily values disaggregated at NUT2 administrative regions level across Europe for PV and wind capacity factors. The hourly variation of electricity demand for space heating and cooling to temperature, as well as daily hydropower capacity factors, are obtained at national level only. Each of these are calculated at least for the 2020–2065 period (more details in the next section) and are used as inputs into the eTIMES-EU model. At this moment, it was necessary to consider only national values for wind and PV due to computational limitations of eTIMES-EU. The main outputs of the energy system model analysed in this paper are, for the years of 2030 and 2050, the generated electricity per energy carrier, the % of electricity generated from RES, the carbon intensity of the electricity mix, the investment needs for new capacity and effects on electricity trade.

2.1. Translating climate variability into energy system model inputs

In terms of climate model data, sixteen combinations of global and regional climate models (respectively GCM and RCM) were explored using simulations made available by the World Climate Research Programme's CORDEX initiative (www.euro-cordex.net). Further information on EURO-CORDEX can be found in. e.g. Refs. [28,29]. The spatial scale of the simulations available is 0.11° (around 12.5 km) and 0.44° (around 50 km). Nevertheless, the latter was disregarded considering the recognised added value of the higher-resolution dataset (EUR-11) regarding the local-scale climate features of the studied areas. Out of the whole GCM–RCM combinations, some were not available for all the selected variables and scenarios. For selecting the RCMs to be studied, the full set of RCMs was analysed over the Europe domain, in such a way that models with a lower degree of satisfaction simulating the climate of our study regions could be excluded [30]. From the models that perform adequately, a subset of 11 was identified such that each RCM is as "independent" as possible from the other RCMs as in Table 1.

Out of these 11 GCM-RCM combinations, in this paper we address three: DMI_EC-EARTH (hereafter mentioned as "D"). IPS_CM5A-MR ("F") and MPI_MPI-ESM-LR ("J"). Moreover, each of these combinations corresponds in fact to two climate RCP scenarios, namely RCP4.5 and RCP8.5, hereafter mentioned as a combination of the individual letter for each model combination and 45 or 85.

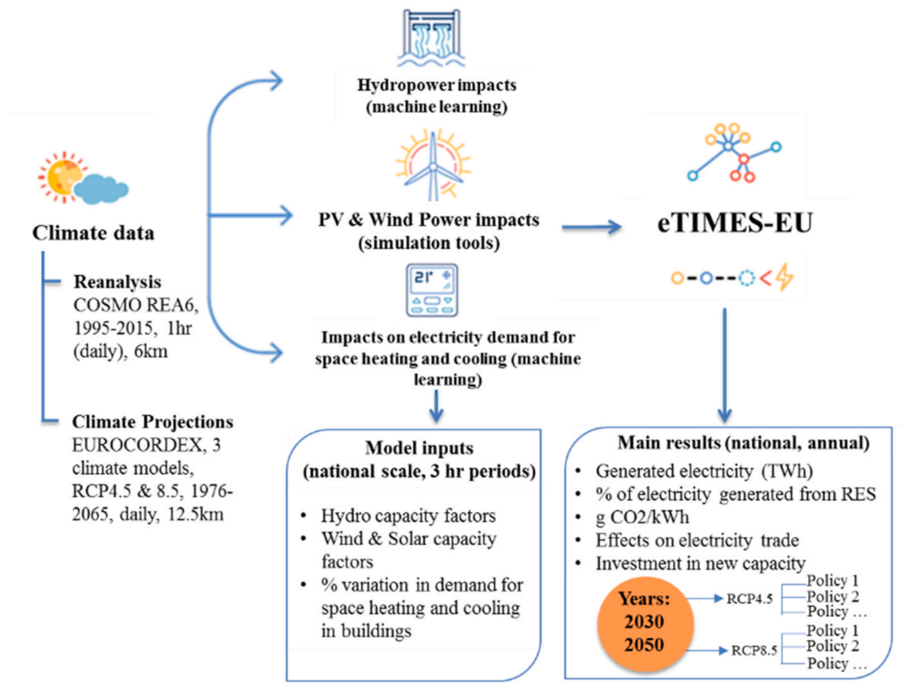

Fig. 1. Overview of the considered approach.

Table 1
List of climate models generating the climate projections and scenarios used in this paper.

Regional Climate Model	Driving GCM (Global Climate Model)	Short name	Short code	In this paper
CLMcom-CCLM4-8-17	CNRM-CERFACS-**CNRM-CM5**	**CLM_CNRM-CM5**	A45. A85	
CLMcom-CCLM4-8-17	ICHEC-**EC-EARTH**	**CLM_EC-EARTH**	B45·B85	
SMHI-RCA4	ICHEC-**EC-EARTH**	**SMHI_EC-EARTH**	C45·C85	
DMI-HIRHAM5	ICHEC-**EC-EARTH**	**DMI_EC-EARTH**	D45. D85	Yes
KNMI-RACMO22E	ICHEC-**EC-EARTH**	**KNMI_EC-EARTH**	E45. E85	
IPSL-INERIS-WRF331F	IPSL-IPSL-**CM5A-MR**	**IPSL_CM5A-MR**	F45·F85	Yes
SMHI-RCA4	IPSL-IPSL-**CM5A-MR**	**SMHI_CM5A-MR**	G45. G85	
KNMI-RACMO22E	MOHC-**HadGEM2-ES**	**KNMI_HadGEM2-ES**	H45·H85	
SMHI-RCA4	MOHC-**HadGEM2-ES**	**SMHI_HadGEM2-ES**	I45·I85	
MPI-CSC-REMO2009	MPI-*M*-**MPI-ESM-LR**	**MPI_MPI-ESM-LR**	J45. J85	Yes
DMI-HIRHAM5	NCC-**NorESM1-M**	**DMI_NorESM1-M**	L45. L85	

While the combinations agree on the overall mean climatology. differences can be pronounced over local regions, and different variables can respond differently (see Fig. 2 and Fig. 3 for precipitation and temperature anomalies over Europe for all 11 climate models combinations available in EURO-CORDEX). Although averaging across different climate models is quite common, this is difficult to interpret and might lead to misleading and physically meaningless results. Averaging models may cause effects of smoothing the spatially heterogeneous patterns of climate variability across Europe, as well as their temporal variability.

One of the key aspects considered in this dataset preparation was the model time horizons (near future and mid-century), as well as spatial dimensions. A forecast can be assessed regarding the future projections (e.g. hotter or colder than average season in the future) and looking at how that relates to the conditions in the past. The choice of spatial resolution may depend on the issue and variables being addressed. For example, too little resolution can fail to capture the small-scale variability of orographic precipitation, whereas too much resolution can cause the model to become computationally impracticable. A spatial scale of 0.11° (around 12.5 km) was expected to adequately fit the requirements of this research. However, at this stage the 0.11° scale was found too large for eTIMES-EU. The uncertainty associated with spatial scale should though be kept in perspective given other uncertainties affecting climate projections.

It is important to mention that climate projections are not an estimation of the year-to-year or season-to-season climate variables. Instead, they are estimations of the average conditions over decades. The three GCM-RCM combinations (i.e. six climate projections) considered in this paper are identified in Figs. 2 and 3 regarding precipitation and temperature anomalies for the near-future when compared with the historic time-series of 1976–2005. It becomes clear that they represent different possible future trends regarding climate evolution, from having a drier Portugal with less 50% precipitation (e.g. F45 scenario), or no change from the past (e.g. J45) or even an increase up to 20% of precipitation in the north of the country (e.g. H45). Indeed, despite the updated and detailed information on climate projections estimated from GCMs/RCMs, considerable uncertainties are involved, either resulting from the unknown future evolution of GHG concentrations and other forcing agents of the climate system, as well as climate model simplifications of the chaotic behaviour of the climate system [27,31,32].

2.1.1. Solar and wind capacity factors

For the calculation of solar PV capacity factors (or CF) the model f_{PV} developed in ECEM project [33] is used. In this approach, the cumulated PV power generation of every plant included in a raster cell is evaluated as a function of the known meteorological parameters by means of a physical approach. The total PV power generated in an area is estimated as the weighted sum of the values of the PV power generation obtained for different parameter sets A_i:

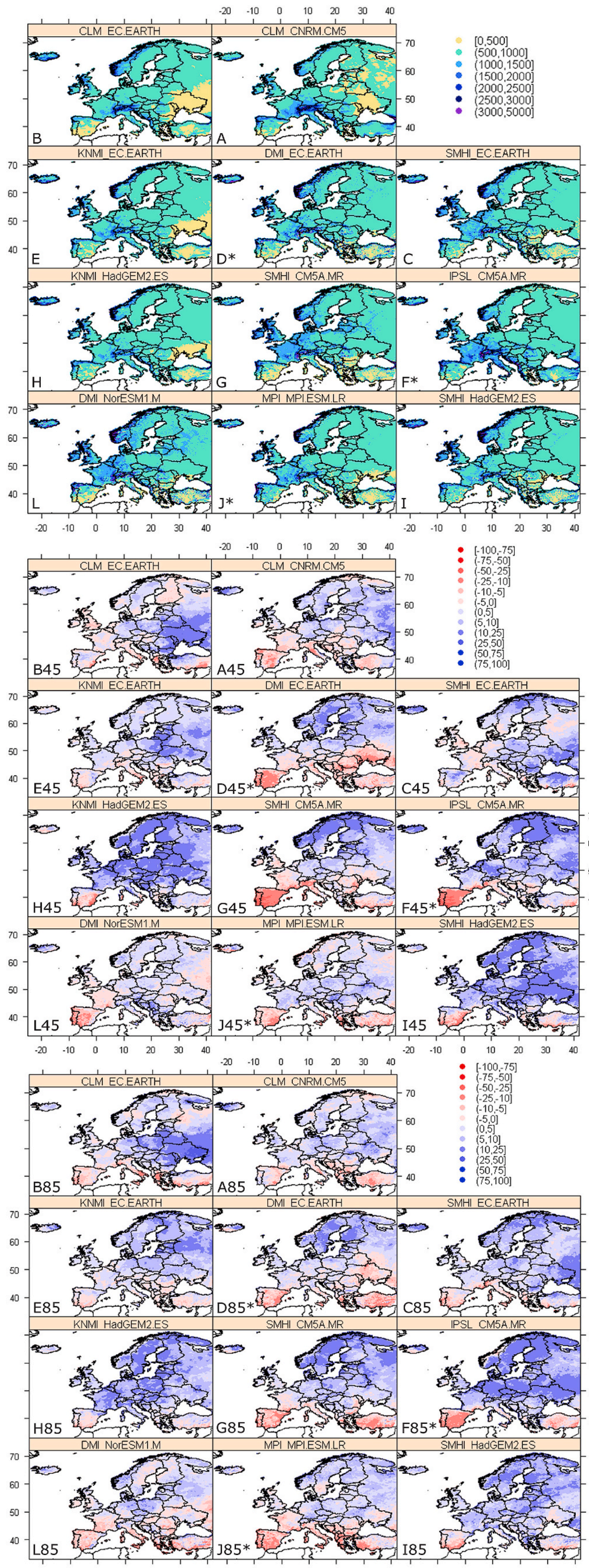

Fig. 2. Annual mean precipitation (mm) for the historical period (1976-2005) (upper figure) and anomalies (%) for the near future (2016-2045) based on 11 selected GCM–RCM combinations under RCP4.5 (middle figure) and 8.5 (bottom figure). The climate projections considered in this paper are signalled with an asterisk.

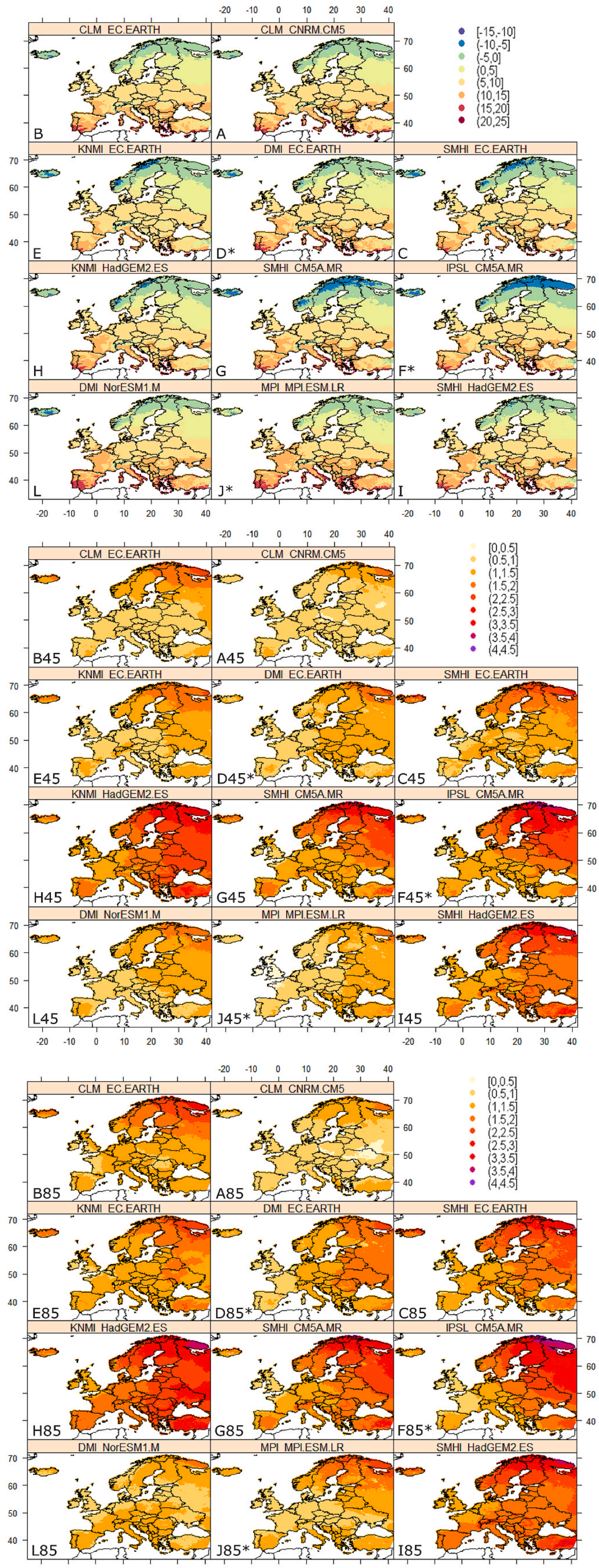

Fig. 3. Annual mean temperatures (°C) for the historical period (1976-2005) (upper figure) and anomalies (%) for the near future (2016-2045) based on 11 selected GCM–RCM combinations under RCP4.5 (middle figure) and 8.5 (bottom figure). The climate projections considered in this paper are signalled with an asterisk.

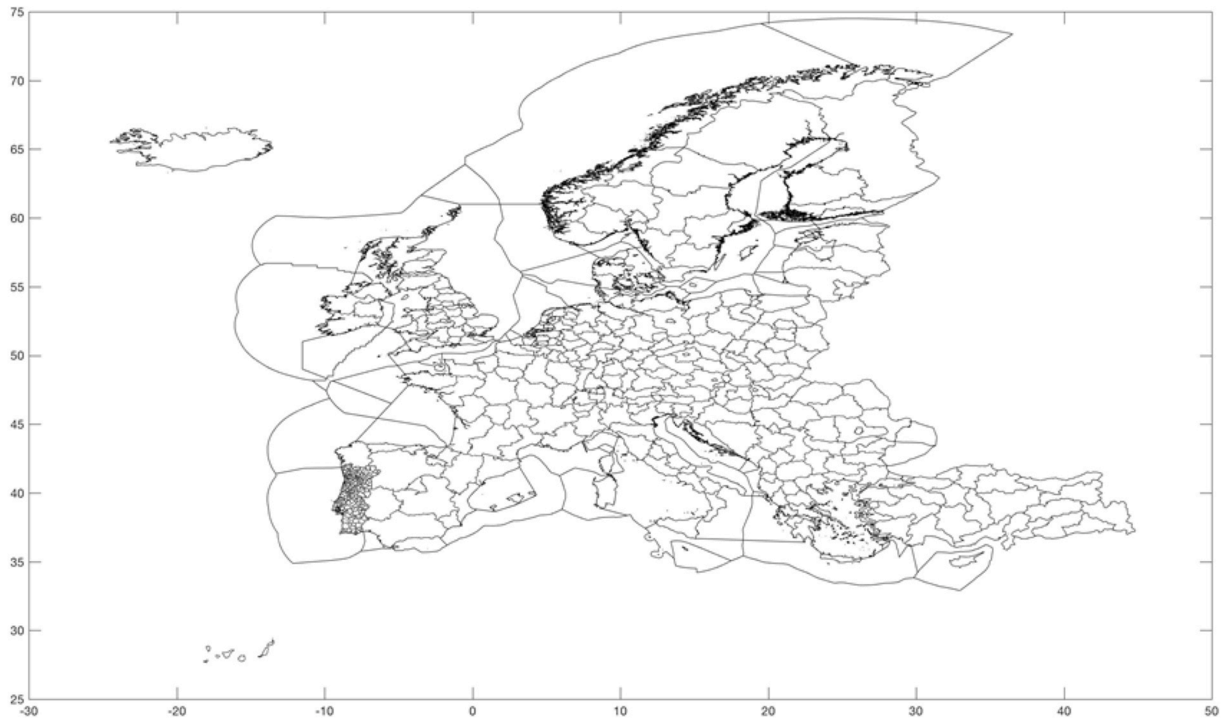

Fig. 4. Spatial disaggregation of the wind and PV capacity factors at NUT2 regions.

$$P_{PV}(x.t) = \sum_{i=1}^{n} w_i f_{PV}(x.t.\mathrm{GHI}\quad(x.t).\mathrm{Tamb}(x.t).A_i) \qquad (1)$$

where.

$P_{pv}(x.t)$ is an estimate of the power produced at time t by all PV plants located at x [W/W_p].

GHI (x.t) is the global horizontal irradiance at time t and location x [W/m^2].

Tamb(x.t) is the air temperature at time t and location x [°C].

$f_{PV}(\ldots)$ is a function representing the PV model used to calculate the normalized PV power [W/W_p].

A_i represents the set of plant parameters needed by the PV model

w_i is the probability of occurrence of a parameter set A_i

In Eq. (1), the parameter set Ai represents the input parameters of a model f_{PV} accounting for the characteristics of a PV plant (e.g. module orientation angles. temperature coefficient). A single PV power calculation is thus conducted for each configuration. The total PV power is then obtained by a weighted sum of the power value evaluated for each configuration. the weights being the share of plants with a configuration set A_i in the total capacity.

As detailed in Ref. [33], the PV system model is chosen to best compromise between a limited number of unknown and a good accuracy. To this end, state of the art models have been selected in the literature and the less important parameters set to representative values. The parameters Ai has been selected using a parameterisation depending on the geographically varying optimal tilt angle.

For wind CF (onshore and offshore), a similar approach to that adopted in the NINJA [34], EMHIRES [35] and ECEM projects has been used. The power production of each turbine installed in Europa has been calculated based on information provided by thewinpower.net database and model wind speed. The wind curve has been generated using the approach described in Ref. [36]. Finally, particular attention has been paid in choosing a model setup allowing a fast calculation. This has been achieved by using a LUT approach. More information on this approach can be found in Ref. [37]. It should be mentioned that because some countries currently have very low wind installed capacities, they will possibly be more sensitive to results. The adopted method is more robust for countries or areas with bigger wind capacities.

These wind and solar PV capacity factors are then aggregated per NUT2 regions of Europe (circa 263) and, for the case of wind offshore, 96 maritime regions (obtained by intersecting the International Hydrographic Organization sea limits and Exclusive Economic Zones areas) as in Fig. 4. The consideration of maritime region for the spatial aggregation of RES time series has been made to include offshore wind

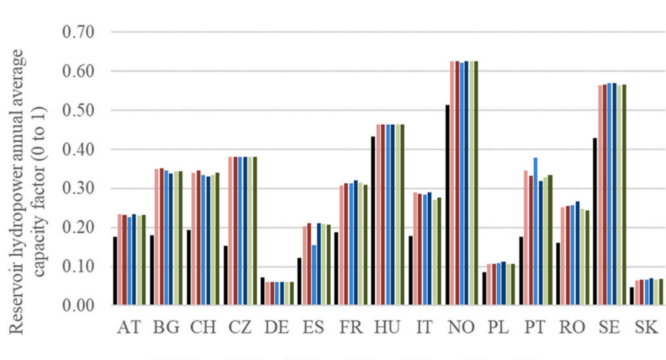

Fig. 5. Hydropower average annual capacity factor per country 2050.

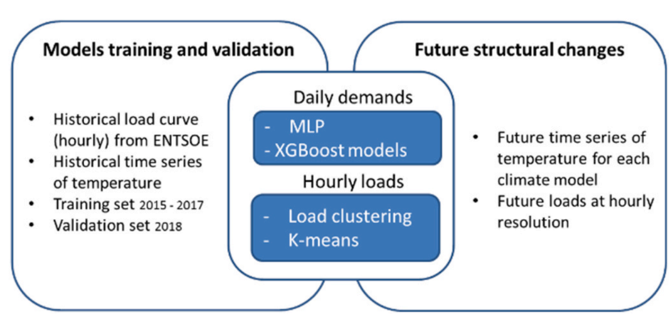

Fig. 6. Structural change model.

energy. The definition of these areas has been jointly developed in the C2P and C3S energy projects. The obtained results at annual level are in Annex 2.

2.1.2. Hydropower capacity factors

To translate climate data into potential hydropower production at the EU level, we used machine learning (ML) techniques. The procedure starts by training a so-called (supervised) learner with a set of data including the observed outcome and feature measurements. This leads to build a model, which enables predicting the unobserved outcome based on a different set of input features. A good learner is one that accurately predicts such an outcome.

In the case of the present project, the input features are daily time series of air temperature and precipitation aggregated at NUTS2 level, whereas the outcomes are the daily total national run-of-river and reservoir-based hydropower capacity factors.

For the training and validation of ML models, observed climate and energy data are required Assimilation climate data remapped to the 6 km COSMO-REA grid are from Deutscher Wetterdienst (DWD, 2019), whereas the historical energy data, i.e., capacity factors of the run-of-river and reservoir hydropower generation, are from the ENTSO-E Transparency platform [38]. Note that the lack of historical data of hydropower generation is a serious issue. Energy generation data at hourly time resolution for almost all countries in Europe is available only starting from January 2015. This means that for training and testing the ML models we can only use (both climate and hydropower) data corresponding to five years.

In order to select the ML technique that would provide the best prediction, five well-established ML algorithms were tested: Linear Regressor, Support Vector Machine, Boosted Ensemble of Trees, Random Forests (RF) and a hybrid algorithm [39]. These regression methods were implemented in the Statistics and Machine Learning Toolbox 11.4 in MATLAB® R2018b. In Ref. [40], we compare the performance of these five algorithms in terms of correlation coefficient, adjusted coefficient of determination, mean absolute and mean square percentage errors. This comparison indicated that the models based on Random Forests usually exhibit the best performance. Thus, the results in this paper are obtained feeding the RF prediction model with the climate projections adjusted with respect to the reanalysis data from DWD. The projections cover the period from 2020 to 2060, and for this paper is particularly relevant the years of 2030 and 2050 (which have policy relevance). The predicted hydropower CF for these years were obtained as the calendar mean of the 20 years' time series projections centred in 2030 and 2050, respectively. The obtained results for 2050 are depicted in Fig. 5 and in Annex 2.

With the used approach, in practically all countries and all climate projections, is envisaged an increase in potential maximum capacity factor from 2015 to 2018 values. This is somewhat counter intuitive for southwest Europe, when looking at Fig. 2 where Iberian Peninsula and France are shown drier in most of the projections. However, in that figure anomalies are calculated comparing with the historic values from 1976 to 2005; in fact, Fig. 2, was included here mostly to illustrate differences between model combinations. To calculate CF, we use hydropower production data that it is only available from a much more recent (and limited) period. In the Annex 1, is shown a comparison of precipitation from 2015 to 2018 to a 20-year historic period (1995–2014). In general, focusing on the period post-2015, a pattern of positive and negative anomalies of annual precipitation is spread all over Europe. Moreover, when looking at the country level, the higher-than-average precipitation seems to be compensated by the lower-than-average values; anomalies are typically around ±25%. Nevertheless, a predominant wet bias for Finland, and dry bias over Portugal, Austria, and Czech Republic, suggests one must be careful in interpreting the final results for these countries.

2.1.3. Impact of temperature in demand

The impact of future temperatures on the demand for electricity is computed at country level and for each long-term time-series of climate variables also using machine learning techniques. Hourly demands were estimated using a two-stage approach: (i) quantifying structural changes expressed as the percentage of demand allocated to each time step and (ii) applying these structural changes to exogenously specified future demands in a second stage (Fig. 6).

Fig. 6 describes the methodological approach used to estimate climate induced structural changes in the load curve of electricity demand for each country. Based on historical temperature time series and hourly load values from ENTSO-E, was firstly built an estimator of future daily demands using two ML techniques: neural networks and XGBoost [41] using 2015, 2016 and 2017 data for model training and 2018 data for the test. Fig. 7 shows the observed mean absolute percentage error (MAPE) on the test data set for all countries.

To obtain hourly load curves, was used a load profiling approach to

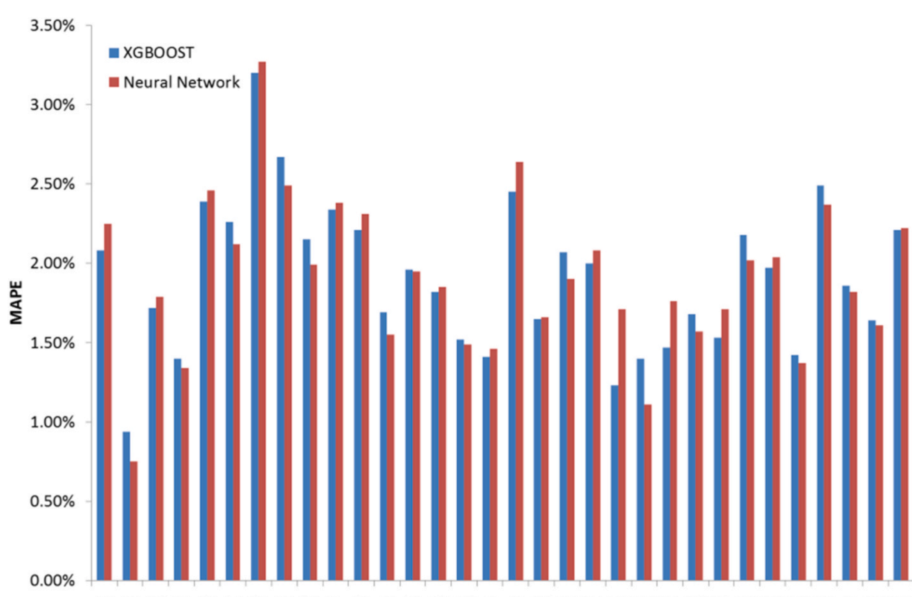

Fig. 7. Test set MAPE for the daily demand module.

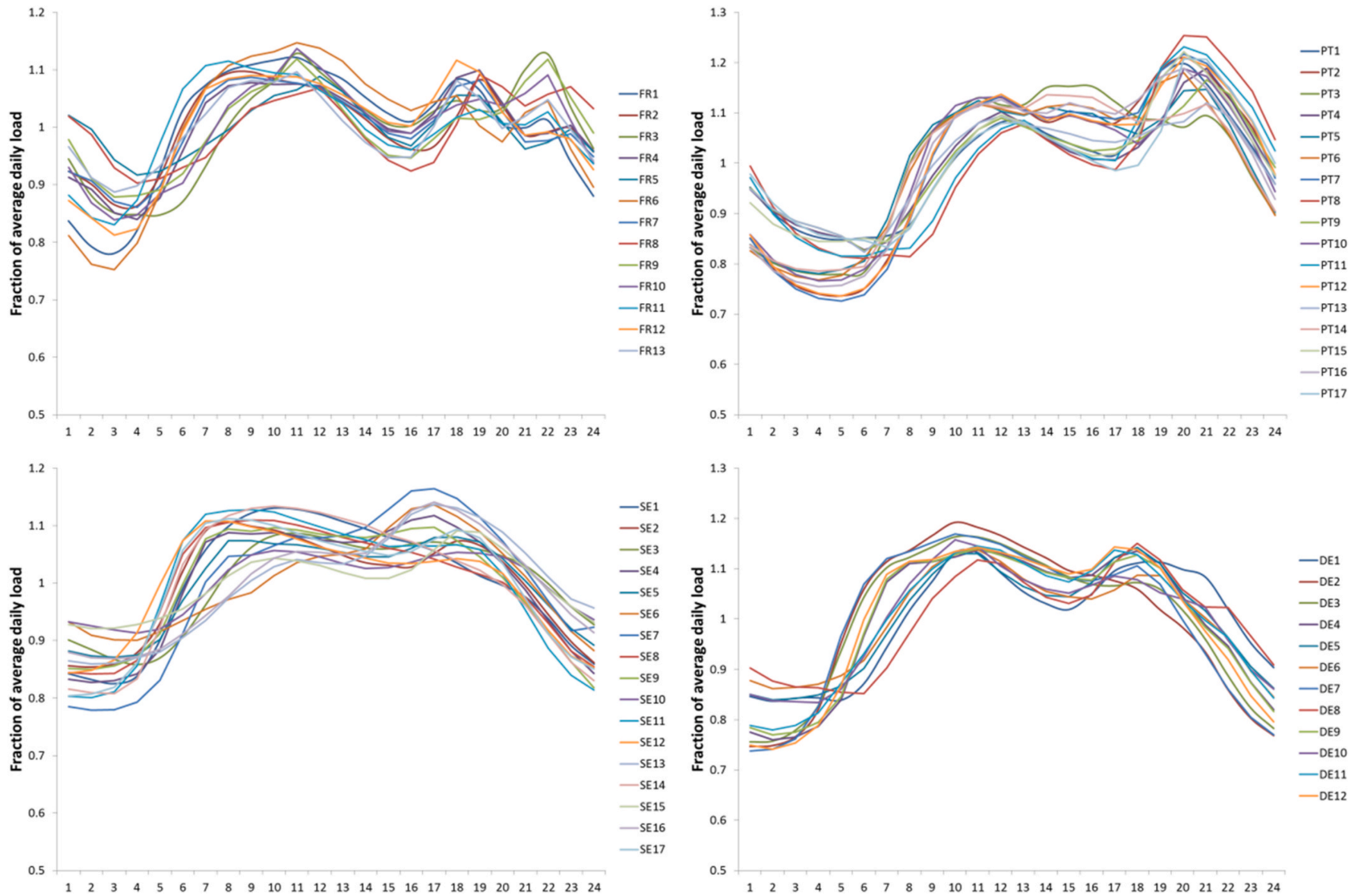

Fig. 8. Hourly load profile clusters for 4 countries: FR. PT. SE. DE.

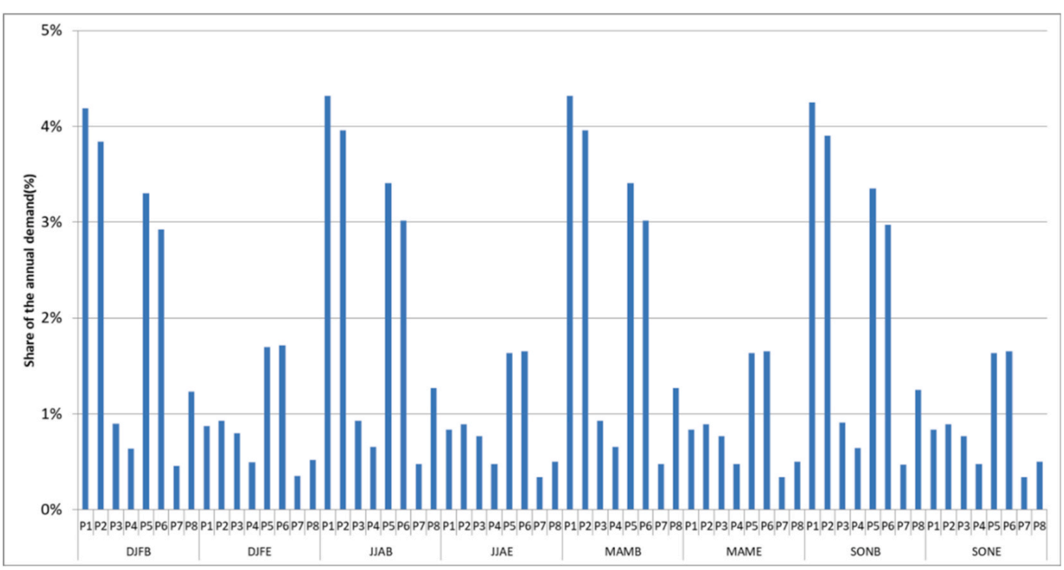

Fig. 9. Annual structural distribution of the electric vehicle demand. P1 to P8 are 3hrs periods staring from 00h00.

identifying typical load curves for each season, weekday and holidays. The K-means algorithm [42] was used as classifier to define a set of clusters explaining more than 90% of the variance. Each load profile is described by the hourly % of the average daily load. Applying the model to the future times-series provided by each climate model, it is possible to compute hourly structural changes per country for each consistent climate scenario. Fig. 8 shows the results for the countries of FR, PT, SE and DE. The approach finds the number of load patterns that captures the way electricity is consumed at daily level. In Fig. 8 each line is a cluster that describes one representative load profile for the considered country. The number of clusters depends on the number of profiles needed to explain most of the variance.

It should be noted that by using models trained on past data, this approach of structural changes assumes that observed temperature

Table 2
Considered countries and country groups in eTIMES-EU.

Country groups	Group code	Included countries name (and short code)
Alpine Peninsula	ALP	Italy (IT)
British Islands	BIS	Ireland (IE), United Kingdom (UK)
Iberian Peninsula	IBE	Spain (ES, Portugal (PT)
Central West Europe	CWE	Austria (AT), Belgium (BE), Switzerland (CH), Germany (DE). France (FR), Luxembourg (LU), Netherlands (NL)
Central East Europe	CEE	Czech Republic (CZ), Poland (PL)
Nordic & Western Nordic	NWN	Denmark (DK), Finland(FI), Norway (NO), Sweden (SE), Iceland (IS)
Nordic & Eastern Nordic	NEE	Estonia (EE), Lithuania (LT), Latvia (LV)
South Eastern Europe	SEE	Bulgaria (BG), Greece (GR), Croatia (HR), Hungary (HU), Romania (RO), Slovenia (SI), Slovakia (SK)

dependencies can provide meaningful information for the future. This assumption ignores the possible future changes in the role of electricity for heating and cooling, which could occur due to higher deployment of electric heat pumps and/or electric vehicles. Basically, these hourly load profiles can have a different shape in 2030 and 2050. To somewhat reduce the effect of this assumption, structural changes were applied to the projected demand of the EU Reference scenario considering the effect of electric vehicle's electricity demand (see Fig. 9). The structural allocation of the electric vehicle demand is the same across all the scenarios and corresponds to the dynamic management of the charging for the "Crescendo" scenario [43].

2.2. Overview of eTIMES-EU model

The maximum possible CF and impacts on demand are input into the bottom-up optimization TIMES energy system model [44]. A new TIMES model was developed for the whole of EU covering only the power sector (eTIMES-EU) which, as for any TIMES family models, has intertemporal optimization and minimizes the total discounted cost. eTIMES-EU has currently 29 regions, representing all countries in continental European Union (thus, it excludes Cyprus and Malta), plus Norway, Switzerland and Iceland (Table 2).

The model runs in 1- or 5-year time-steps from 2016 to 2060. Each year is disaggregated in 64 time slices, outlining the 4 seasons (DJF, MAM, JJA, SON), 2 typical days (weekdays and weekends) and 8-time sequential day periods (P1 to P8 of 3 h each).

eTIMES-EU is supported by a detailed database, with the following main exogenous inputs: (1) electricity demand from the 2016 Energy Reference Scenario [45]) and summarised in Table 3; (2) characteristics of the existing and future electricity generation technologies, such as efficiency. stock. availability. investment costs, operation and maintenance costs, and general discount rate of 8%; (3) present and future sources of primary energy supply and their potentials; and (4) policy constraints and assumptions.

2.2.1. Electricity generation technologies

Electricity generation data from Ref. [38] and Eurostat [46] was used to derive country-specific power balances, which determine the characterization of power generation technology profiles in the base year. Beyond the base year, possible new electricity generation technologies are compiled in an extensive database with detailed technical and economic features based on [47] summarised in Annex 3. CO_2 storage capacity and transport is possible as illustrated by different projects [48]. The model uses country-specific hydro, wind and solar annual availability profiles (introduced as maximum possible CF) for replicating the year of 2016 as in ENTSO-E Transparency Portal [38] for the 64 modelled time-slices. Concerning electricity grids, eTIMES-EU considers

Table 4
Primary energy import prices into EU considered in eTIMES-EU in EUR2010/PJ.

Fuel	2020	2030	2040	2050
Oil	16.33	17.49	19.08	20.52
Gas	8.77	9.06	9.5	9.9
Coal	2.93	3.04	3.09	3.17

Table 5
Overview of the technical RES potential considered in eTIMES-EU.

RES	Methods	Main data sources	Assumed maximum possible technical potential capacity/activity for Europe+
Wind onshore	Maximum activity and capacity restrictions per country	JRC-EU-TIMES model [51]	282 GW in 2020 and 302 GW in 2050
Wind offshore	Maximum activity and capacity restrictions per country	[52])	60 GW in 2020 and 271 GW in 2050
PV and Concentrated Solar Power	Maximum activity and capacity restrictions disaggregated for different types of PV and for CSP per country	JRC-EU-TIMES model [51]	620 GW in 2020 and 1316 GW in 2050 for PV & CSP
Geothermal electricity	Maximum capacity restriction in GW. aggregated for both EGS and hydrothermal with flash power plants	JRC-EU-TIMES model [51]	71 GW in 2020 and 124 GW in 2050
Ocean	Maximum capacity restriction in GW. aggregated for thermal. hydrokinetic. tidal and wave	JRC-EU-TIMES model [51] + own assumptions	691 GW in 2020 and 2050
Hydro	Maximum capacity restriction in GW. further disaggregated for run-of-river and dam plants	JRC-EU-TIMES model [51]	137 GW in 2020 and onwards for run-of-river and lake. 98 GW for dams

Table 3
Evolution of considered electricity demand per group of countries (TWh).

Year/Country group	ALP	BIS	CEE	CWE	EU	IBE	NEE	NWN	SEE
2020	304	361	203	1251	2915	294	25	248	229
2030	314	384	234	1314	3084	304	27	264	242
2040	359	426	258	1383	3317	320	28	281	262
2050	395	472	281	1463	3574	342	31	306	283
Evolution from 2020 to 2050 (%)	*30%*	*31%*	*38%*	*17%*	*23%*	*16%*	*24%*	*23%*	*24%*

Table 6
Modelled scenarios in eTIMES-EU.

Scenario	"Historic" climate variability assumed till 2050	Climate change variability from 2030 onwards (climate projections from EURO-CORDEX)	EU-wide CO_2 mitigation cap
BASE	yes	no	no
NEUTR	yes	no	Carbon neutrality modelled as linear mitigation trajectory from 2016 values till 100% below 2016 emissions in 2050
NEUTR_D45	No	D45	
NEUTR_D85	No	D85	
NEUTR_F45	No	F45	
NEUTR_F85	No	F85	
NEUTR_J45	No	J45	
NEUTR_J85	No	J85	

both import/export processes regarding the existing infrastructures (capacity and flows) and possible new investments based on the TYNDP2016 [49]. These investments are considered only within the 29 modelled countries. There are three levels of electricity voltage and conversion between levels. The electricity trade outside the modelled region is not considered. The internal and external trade capacity hypothesis are key assumptions with potential high impact on the results.

2.2.2. *Primary energy potentials and import costs*

The model considers current and future sources of primary energy (potentials and costs) and their constraints for each country. In this paper the reference fossil primary energy import prices into EU as in Ref. [50] (Table 4).

A number of assumptions and sources are adopted to derive the RES potentials in the modelled countries for wind, solar, geothermal, marine and hydro, as detailed in Table 5. More details can be obtained in Ref. [51] and Annex 4. At this stage, import of biofuels are not considered due to lack of reliable data. The use of biofuels in the base year is calibrated with [53]. For the rest of the period, biofuels consumption can grow up to 120% more than used in the base year. It should be mentioned that these technical potentials were selected from the most recent harmonised source for whole of Europe (JRC-EU-TIMES model). There are more recent works that provide other values for some of these RES technologies, but at this stage a full harmonisation of different RES technical potentials was not possible.

2.3. *Modelled scenarios*

As previously mentioned, we model six climate projections from 2016 till 2050. Besides these six scenarios, we also model a "BASE" scenario and a NEUTR scenario (Table 6). The BASE scenario is mainly used as a reference case and considers "historic" CF for wind, PV and hydropower, as well as observed load curves for electricity demand. The "historic" CF are the ones for 2016 from Ref. [38], that are maintained till 2050. The NEUTR scenario is identical to BASE, but it includes an ambitious 2050 CO_2 emissions mitigation cap of no emissions from the power sector modelled as a linear trajectory from 2016 emission values. The purpose of this scenario is to test the effect of changing the "historic" CF and demand structure in a highly-RES European power system. The other six scenarios are identical to NEUTR but have CF and modified intra-annual electricity demand structure according to the six considered climate projections (Table 6).

All modelled scenarios have in common the following assumptions:

i) No consideration of the specific policy incentives to RES (e.g. feed-in tariffs, green certificates) since the objective is to assess deployment based solely on cost-effectiveness;
ii) Countries currently without NPP will not have these in the future (AT. PT, GR, IT, DK, HR, NO and IS). NPPs lifetime expansion is

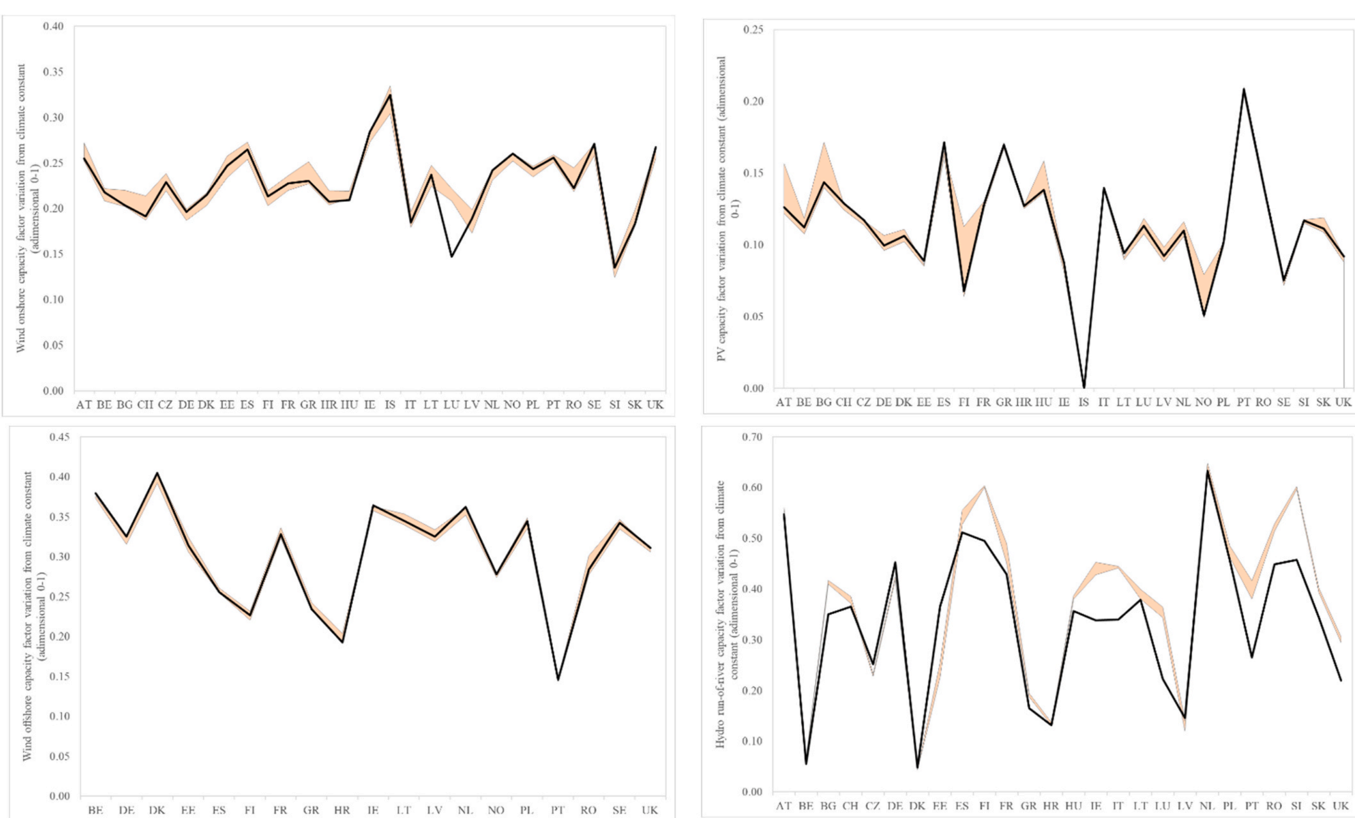

Fig. 10. Variation of inputs in annual average capacity factors in eTIMES-EU for 2050 for each considered country for wind onshore (upper left). solar PV (upper right). wind offshore (bottom left) and hydropower plants (bottom right). Note that wind offshore is not considered for landlocked countries, and for BG, IT, IS and SI. Run-of-river hydropower is not available in IS, NO, SE, UK. The "historic" capacity factor is depicted as the wider line.

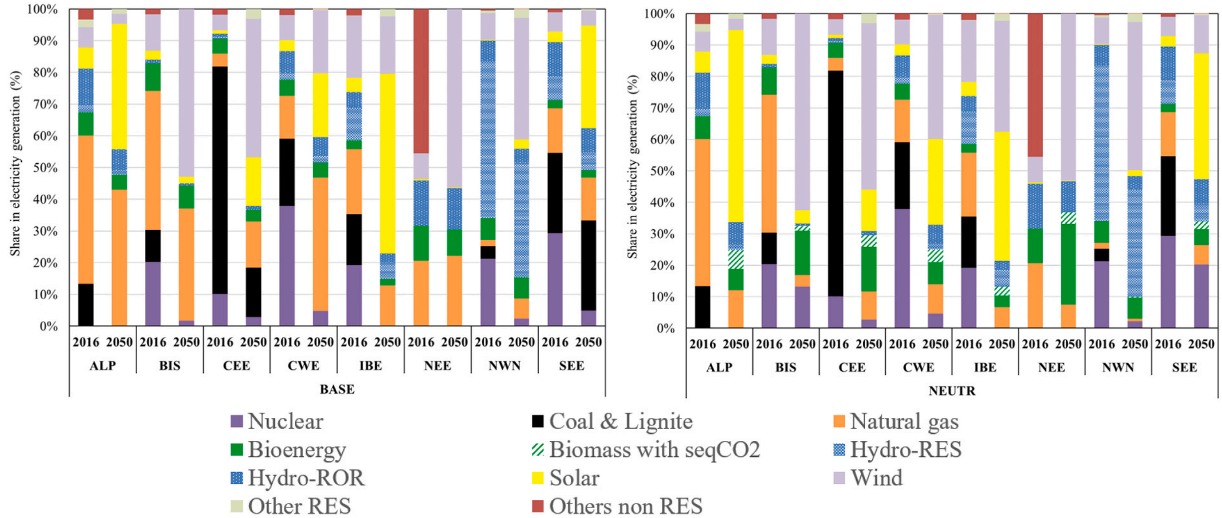

Fig. 11. Share of electricity generation in each region in 2016 and 2050 in the BASE (left) and NEUTR (right) scenarios.

authorized till 2040. Until 2025, the model has the choice between investing in a new capacity or extending the life of an existing plant. NPPs in DE are not operating after 2025;

iii) Coal plants in BE are not operating from 2017 onwards.

iv) No new coal plants to be built in AT, BE, CH, DK, FI, IE, IT, PT, UK, LT, LV, EE, LU and IS.

Based on the approach described in the previous section, the eTIMES-EU inputs on maximum possible capacity factors for wind (onshore and offshore). solar PV and hydropower plants vary across climate projection as in Annex 2 and in Fig. 10 for the year of 2050. Here we only represent the annual average CF, although in the model there are different CF for each one of the 64 considered time slices.

For **wind onshore,** across the six climate projections and countries, future annual average CF in 2050 can either increase up to +51% for LU or decrease to −9% in LV, compared to “historic” climate. In median terms for Europe, wind-onshore can either increase or decrease by 4%. Whereas for some countries most climate projections point to an increase in future CF (as for CH, BG, GR, HU, HR, LU, RO and SK), for other countries most projections point to decrease in future wind power (as DE, DK, IS, LT, PT, SI and UK). The highest differences in future CF are for LV, SI, CH, RO and GR. For all these countries the maximum wind onshore CF is more than 10% higher than the minimum one. On the contrary, the countries with a smaller range in maximum-minimum 2050 wind onshore CF are NL, SE, PL, HU, UK, IE, NO and PT (maximum CF only up to 5% higher than minimum CF). For **wind offshore**, future 2050 CF variations compared to “historic” CF are lower than for wind onshore ranging between +6% and −3% depending on countries and on climate projection. Most projections point to a −3% decrease for the case of BE, DE, DK, SE and UK, compared to “historic”

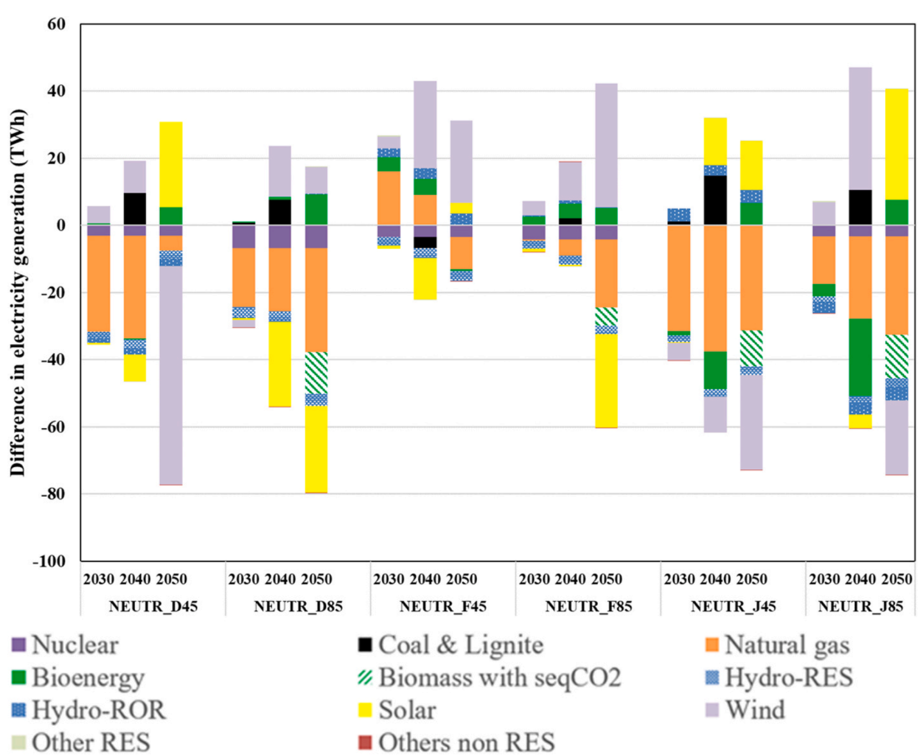

Fig. 12. Differences between electricity generation for the NEUTR scenario and for the different climate scenarios for the whole of Europe.

Table 7
Characterization of the RES electricity output variation in TWh per scenario in 2050.

Scenario/Type RES	Hydro	Bioenergy	Solar	Wind	Other RES
NEUTR_D45	478.6	468.3	1064.4	1611.5	50.2
NEUTR_D85	474.1	473.6	1089.9	1546.4	50.1
NEUTR_F45	475.1	465.1	1038.7	1619.4	50.2
NEUTR_F85	479.2	467.9	1067.5	1636.1	50.1
NEUTR_J45	476.1	468.3	1036.6	1648.4	50.1
NEUTR_J85	479.9	464.2	1078.9	1583.3	50.2
NEUTR	472.0	463.1	1097.4	1589.5	50.3
k = std/mean	0.6%	0.8%	2.2%	2.2%	0.1%

climate. Almost all projections point to a 6% increase in CF for HR and RO. The differences between maximum and minimum CF for the different climate projections are rather small, with the maximum annual average CF in 2050 only 8-1% higher than the minimum. The countries in this upper range are RO, HR and EE (maximum CF at least 5% higher than minimum CF).

For **solar PV**, the relative differences in CF compared with historic climate are higher, with 2050 CF increasing in more than 50% for FI and NO practically all projections. For AT and BG CF can increase up to 25% and HU by 15% compared to "historic" climate. For the other countries there are very small variations or there is a wide dispersion across the six projections. The countries with higher difference in PV CF are LV, SI, CH, RO and GR (maximum CF at least 10% higher than minimum CF). For **hydro power**, in most countries and climate projections it is foreseen an increase of the maximum possible CF in 2050. The maximum annual average CF in 2050 is 27–0% higher than the minimum. The countries in the upper range are ES, PT, RO, SK, IT and PL (maximum CF at least 5% higher than minimum CF). The countries with less difference in hydropower CF are CZ, NO and SE and CH (maximum CF only up to 2% higher than minimum CF).

3. Results and discussion

This section presents the gained insights on considering climate variability into large energy systems models and its implications for climate proofing RES electricity deployment in Europe. These results are structured starting with impacts on the electricity generation portfolio, followed by implications for investment in new power plants, effects on the share of electricity generated from RES, electricity carbon intensity, and finally impacts on electricity trade.

3.1. Electricity generation portfolio

In Fig. 11 we depict the different changes in the electric system in BASE and in NEUTR scenarios, not considering any climate projections for the different groups of countries. Even in the BASE scenario (without CO_2 cap), in many country groups RES are cost-effective by 2050, especially wind and hydro and, to a less extent, PV and bioenergy. In BASE scenario in 2050 wind and solar amount to 47% of generated electricity. In the NEUTR scenario, considering the emission cap and "constant" climate, coal and natural gas are phased out and replaced by RES. Wind and solar account here for more than 60% of the total electricity generated in 2050. Bioenergy's share in the mix is multiplied by 2.3 between 2030 and 2050 to replace natural gas and nuclear based electricity. The carbon neutral objective leads to different dynamics across regions. Considering variable renewable energy sources (VRES), wind generation is mostly deployed in BIS, CEE and NEE whereas in ALP and SEE solar generation is more cost-effective.

Table 8
Value of k by production technology for each group of countries in 2050.

Region/Type of RES	Hydro	Bioenergy	Solar	Wind	Other RES
Alpine Peninsula (ALP)	0.5%	0.2%	1.3%	32.7%	0.0%
British Islands (BIS)	2.2%	0.6%	33.7%	3.3%	0.0%
Central East Europe (CEE)	2.6%	0.7%	15.1%	2.2%	0.0%
Central Western Europe (CWE)	1.8%	1.3%	4.3%	4.5%	0.0%
Iberian (IBE)	3.5%	7.5%	8.0%	8.0%	0.0%
Nordic & Eastern Nordic (NEE)	3.1%	20.8%	1.5%	8.9%	0.0%
Nordic & Western Nordic (NWN)	0.1%	3.4%	38.0%	4.0%	0.4%
South Eastern Europe (SEE)	1.6%	1.2%	15.3%	30.3%	0.0%

These results for the constant climate assumption on the period from 2016 to 2050 indicate to which amount RES contribute to the decarbonisation of the European electricity sector. It is interesting to see, given these results, how the climate variability introduced in the six climate projections scenarios modifies the electricity mix. Fig. 12 shows the difference of the generation portfolio between the "historic" climate NEUTR scenario and each of the climate impacted future scenarios. As can be seen in Fig. 12, the production from solar and wind widely varies compared to the one of the NEUTR scenario. From 2030 to 2050, the total production of solar raises from 128 TWh to around 1068 TWh in the NEUTR scenario. By considering the climate projections variability, it is seen that depending on the climate scenario, the electricity generation from solar plants for the whole of Europe, can be overestimated by 3%. For wind, the 2050 generation in the climate scenarios varies from −7% to 3% over the 4526 TWh generated in the NEUTR scenario.

To characterize the variations observed, the indicator k (*coefficient of variation*). $k = \frac{std}{mean}$ was defined per group of RES power plants for the scenarios studied in 2050. The results are summarised in Table 7 below. In overall terms, for the whole of Europe for a highly RES-based electricity system in 2050, the highest variations in output is spotted for wind and solar and amounts to 2.2%. There are relatively small variations in output of the different groups of RES power plants as k is lower than 1%.

However, when considering the impacts at country (our groups of countries) level, there are substantial differences highlighting the role that future climate variability can play in the European power system. Table 8 shows the value of k for each group of countries in 2050 computed for NEUTR and all the six climate scenarios. For some parts of Europe, there could be significant differences in the role of different RES power plants for the electricity mix as is the case of solar in BIS, CEE, NWN and SEE regions, wind in ALP and SEE regions, and bioenergy in NEE.

The differences in generated electricity result from the different CF and demand structure change that in turn change the cost-effectiveness of some of the power plants in some countries and consequently also change the flows of electricity exports and imports across Europe. This can be seen in more detail in Fig. 13 that shows the differences of electricity generation portfolio in different groups of countries in 2030, 2040 and 2050 compared to the NEUTR scenario.

In the **ALP** group of countries, by considering the climate projections, PV and hydropower become more cost-effective in all scenarios in 2050, displacing the bioenergy crops with carbon capture and storage (BECCS) option to attain the carbon neutrality in 2050. In the D85 scenario there it is expected more wind in this region and a slightly high solar CF. This, complemented with a lower solar CF for DE, leads to higher solar and wind power generation.

In UK and IE (grouped as **BIS**), there will be less wind compared to NEUTR scenario which is compensated by more natural gas and/or imports of electricity (detailed in the next section). In **CEE,** changes in terms of generated electricity compared to NEUTR are mainly more solar generation in 2050 across projections. CEE countries rely more on electricity imports (detailed in the following section). Depending on the climate scenario and on the year, mainly wind power, gas and PV play a

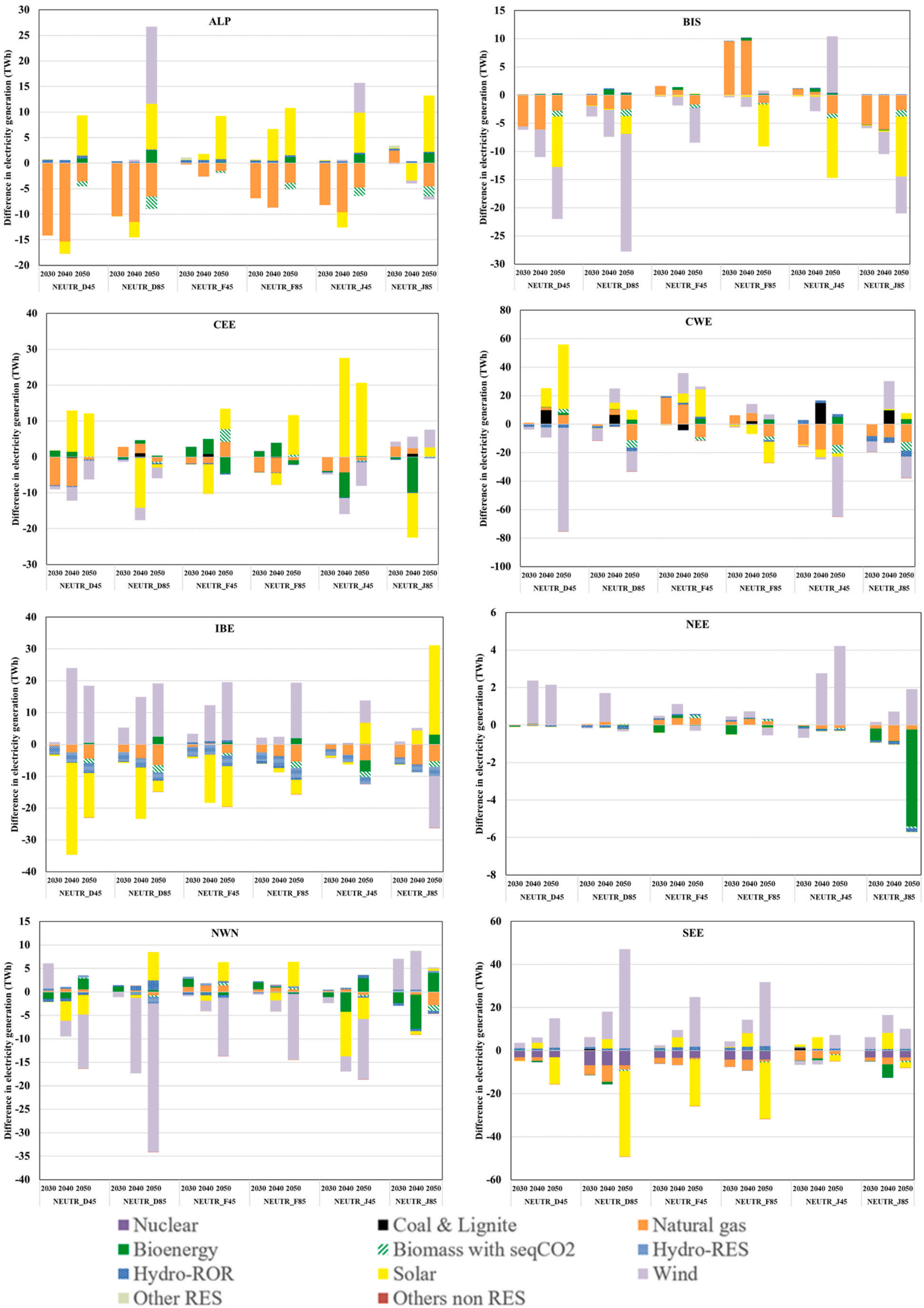

Fig. 13. Variation of generated electricity per country group in 2030 and 2050 compared to the NEUTR scenario.

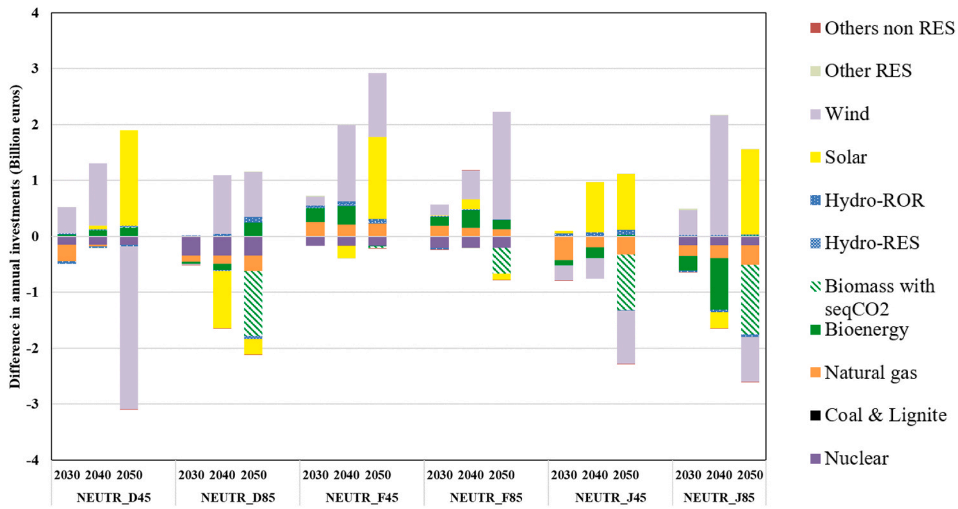

Fig. 14. Variation of the annual investments for whole of Europe compared to the NEUTR scenario.

different role. In the **CWE** group of countries there are substantial difference across climate projections that affect role of solar and wind. Power generated from bioenergy is cost-effective in 2050 across all climate projections. The interplay between PV, wind and gas leads to the highest magnitude of the variations when compared to NEUTR (i.e. −75 to +55 TWh in 2050) across regions. Less hydropower is generated in AT and DE in 2050.

In **IBE** the clearest change compared to NEUTR is the higher role of wind power in practically all scenarios, due to an expected increase in wind onshore (and to a lower extent offshore) in almost all climate scenarios, with the exception of J85 for which there is a lower CF for wind power. This can lead to variations in generated power in this region of ~30 TWh.

In the **NEE** group of countries, the cost effectiveness of solar is limited, due to the lower CF across practically all projections. Wind is set to play a more predominant role from 2030 to 2050 compared to the NEUTR scenario. The magnitude of the variations in TWh are rather small since this is also a small group of countries (- 5 to 4 TWh).

In **NWN,** considering future climate makes solar PV more cost-effective than wind power in almost all scenarios. Variations compared to NEUTR scenario are comprised between −34 and + 8 TWh. In FI, hydropower is more cost effective in all scenarios. Finally, in the **SEE** group of countries in all scenarios (in 2030 and 2050) there is a higher role of hydropower in RO and GR, less PV in 2050 (and less gas in 2030 and in 2050). This is mainly due to the higher hydro CF for these two countries, and also to the fact that there is still room to install new hydro power plants in both of them.

3.2. Climate variability impacts on power plants investment

The effect of considering the climate projections leads to a variation, not only in generated electricity per technology group as previously described, but also to changes in investment in new power plants (see Fig. 14 for the whole of Europe). Compared to the NEUTR scenario, by considering future climate projections variability, there could be a change in invested amounts ranging from ±0.5 BEuros in 2030 and from ±3 BEuros in 2050. It should be noted that in order to comply with the CO_2 mitigation cap, already in the NEUTR scenario there are substantial investment needs, mainly in wind and solar power plants. For the whole of Europe, the changes in investment are mostly obtained for wind and solar power plants in all climate scenarios, followed by bioenergy and, to a less extent, natural gas power plants and nuclear.

In terms of the different country groups (Fig. 15), it is seen that the investment in the following regions is more sensitive to a future changing climate: SEE (less solar investments in 2050), IBE and BIS (less investments in bioenergy with CCS in 2050), CWE and CEE (less investment in wind in 2050), ALP (more solar PV investments). There are also changes in investment in the other country groups, but smaller than 2 BEuros. These changes are also the result of the interplay in electricity trade across Europe.

3.3. CO_2 emissions and RES share

All the results previously mentioned affect the two indicators frequently used in EU energy and climate policies: carbon intensity of the electricity mix (Table 9) and RES share of the generated electricity (Table 10). In this case we show here the share of variables RES, i.e. wind and solar electricity.

Regarding CO_2 emissions intensity, this is here only calculated for the year of 2030, since all climate scenarios assume the NEUTR emission cap and thus in 2050 there are no CO_2 emissions by then. By considering the future climate variability for the six climate projections, there are changes in the carbon intensity of the electricity mix from −8% to +7% from the NEUTR scenario. The higher variability in this indicator is obtained for ALP and NEE. This could affect the compliance with the 2030 national energy and climate plans currently being submitted to the European Commission.

The share of variable RES electricity in 2030 varies by 2% points for SEE and NEE and by less than 1.5% for the other country groups. In 2050 the variation in this share of RES is higher in some regions, noticeably in NEE even though most of Europe is already close to fully renewable power following the very ambitious mitigation cap. This share varies by 14 points in NEE, 3% points in IBE and SEE and less than 2.5 points in other groups.

3.4. Electricity trade

Fig. 16 summarises the impacts of future climate variability into electricity traded across Europe in 2050. The table shows relative differences to NEUTR scenario for each group of countries for the six climate scenarios. The black arrows refer to increase in traded volumes when compared to NEUTR and the yellow arrows refer to decreases in trade. The width of the arrows translates magnitude of changes in trade. For instance, in the D45 scenario there is 514% more volume of electricity exports, from ALP to CWE compared to NEUTR scenario, while a reduction of 23% in imports compared to NEUTR scenario (see Annex 5 for more detailed results).

The two regions highly sensitive to changes in electricity trade due to climate projections variability are NWN with BIS and ALP and CEE with CWE. Depending on the scenario, the trade can increase or decrease,

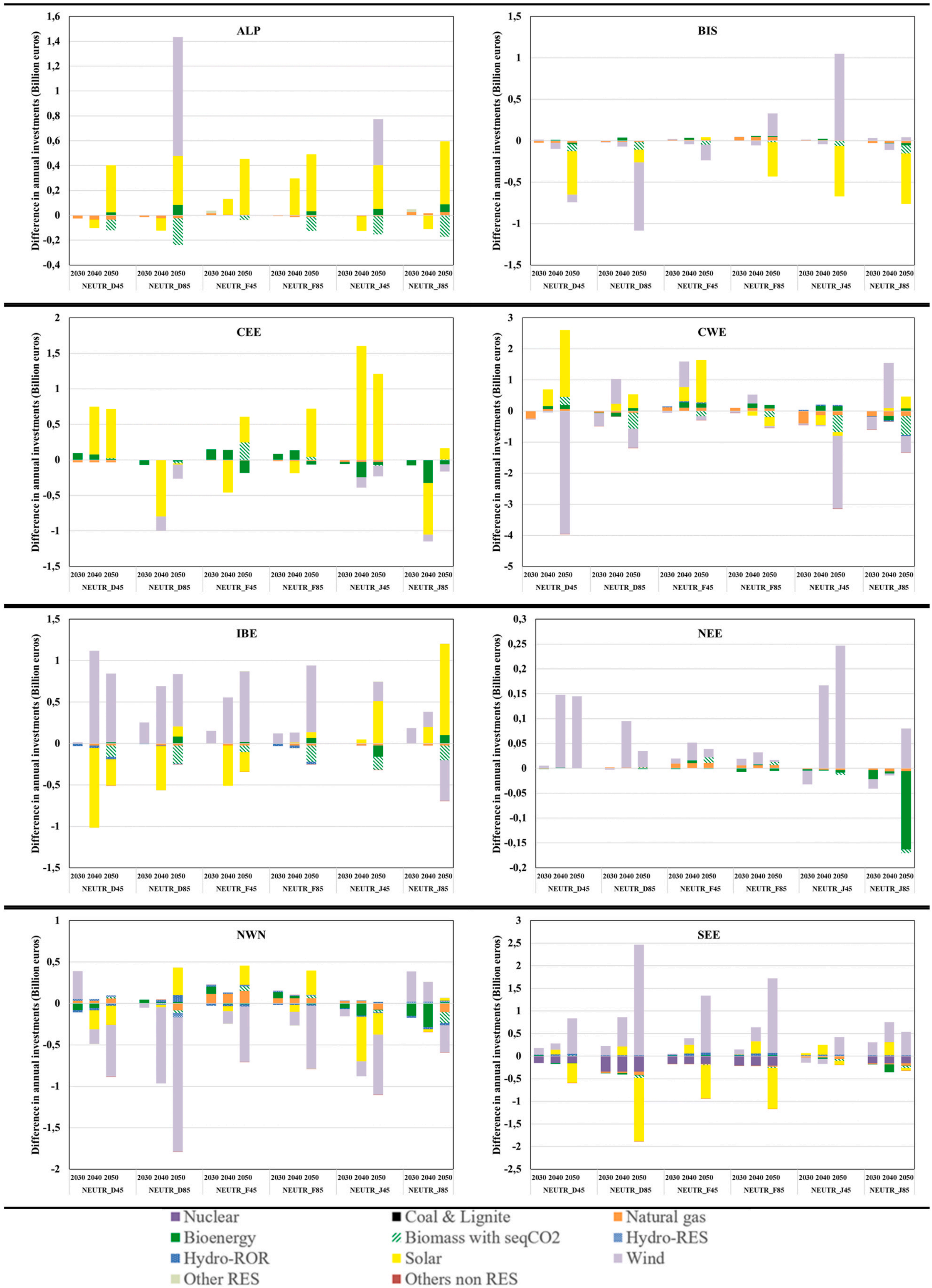

Fig. 15. Differences in annual investment costs per country group compared to the NEUTR scenario.

Table 9
CO_2 emissions intensity of the power sector in 2030 per country group in gCO_2/kWh.

Country group/ scenario	Alpine Peninsula	British Islands	Central East Europe	Central Western Europe	Iberian	Nordic & Eastern Nordic	Nordic & Western Nordic	South Eastern Europe
2030								
NEUTR	206.5	190.0	344.9	168.1	123.8	230.0	13.9	93.6
NEUTR_D45	208.9	185.9	335.7	170.0	125.7	228.0	13.9	91.2
NEUTR_D85	210.8	186.4	357.2	166.3	121.8	231.1	13.8	90.9
NEUTR_F45	205.4	183.4	340.6	169.6	119.2	214.6	14.6	88.4
NEUTR_F85	200.1	191.1	338.7	170.1	123.0	214.4	14.3	87.3
NEUTR_J45	212.7	188.8	344.2	168.3	124.7	233.1	14.0	91.3
NEUTR_J85	222.1	183.5	356.2	167.7	121.3	211.0	14.0	89.3
% difference to NEUTR	*−3% to + 7%*	*−3% to + 1%*	*−3% to + 3%*	*−1% to + 1%*	*−4% to + 2%*	*−8% to + 1%*	*−1% to + 6%*	*−7% to -3%*

Table 10
Variable RES (wind and solar) share in the power sector in 2030 and in 2050 per country group.

Country group/ scenario	Alpine Peninsula	British Islands	Central East Europe	Central Western Europe	Iberian	Nordic & Eastern Nordic	Nordic & Western Nordic	South Eastern Europe
2030								
NEUTR	13.2%	38.0%	29.5%	23.2%	47.7%	34.8%	25.7%	22.5%
NEUTR_D45	13.9%	38.4%	30.0%	23.1%	48.1%	34.9%	26.5%	23.6%
NEUTR_D85	13.7%	37.9%	29.1%	22.7%	49.0%	34.7%	25.4%	25.0%
NEUTR_F45	13.2%	37.8%	29.4%	22.8%	48.3%	35.1%	25.5%	23.3%
NEUTR_F85	13.5%	37.1%	29.8%	23.0%	48.7%	35.3%	25.5%	24.0%
NEUTR_J45	13.6%	37.9%	29.8%	23.3%	48.0%	34.1%	25.5%	22.4%
NEUTR_J85	13.1%	38.4%	29.6%	23.0%	48.5%	36.0%	26.7%	24.7%
2050								
NEUTR	64.6%	66.7%	66.1%	66.7%	76.3%	53.3%	48.9%	52.2%
NEUTR_D45	65.7%	65.9%	66.9%	65.8%	78.0%	56.1%	47.3%	52.7%
NEUTR_D85	67.4%	65.4%	66.0%	67.2%	78.6%	53.4%	46.6%	54.8%
NEUTR_F45	65.5%	66.5%	66.1%	67.4%	77.6%	52.1%	48.1%	52.9%
NEUTR_F85	65.9%	66.4%	67.5%	66.8%	78.6%	52.4%	48.1%	53.4%
NEUTR_J45	66.4%	67.1%	67.7%	66.3%	79.2%	58.8%	47.2%	52.9%
NEUTR_J85	66.1%	65.9%	66.9%	67.3%	78.1%	65.9%	49.0%	54.1%

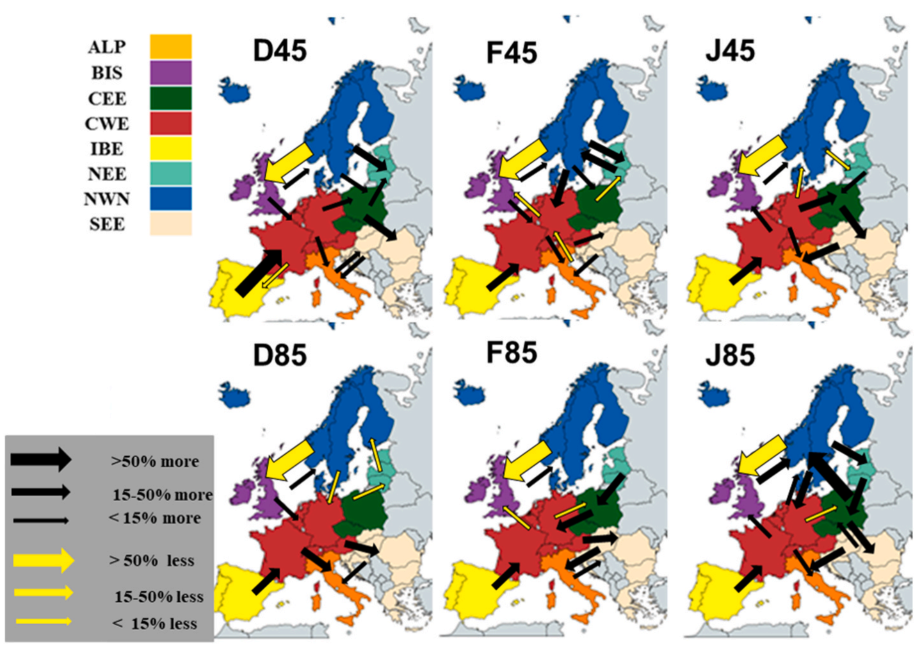

Fig. 16. Impact of climate projections on amounts of electricity exported in 2050 compared with NEUTR scenario.

reflecting the changes seen in the previous sections. Thus, at this level of granularity of the climate models outputs, it is possible to say that there is a sensitivity of electricity trade to climate, but it is not possible to advance on the "direction" of this sensitivity. Maybe the exception is the Nordic countries (NWN) that in all climate scenarios reduce their exports to BIS.

4. Conclusions

In this paper we have studied the effects of considering climate variability into energy systems models for Europe. Traditionally these models used for planning the power sector and for supporting energy and climate policies, consider historic availability of wind, solar and hydropower, assumed to be constant until 2050 or 2060. Here we assess effects of considering six climate projections from EURO-CORDEX in the eTIMES-EU technology optimization model for the European power sector for the years of 2030 and 2050. Climate projections are translated into the power sector as modified capacity factors for wind, solar PV and hydropower, as well as changes in the shape of the annual electricity demand curve due to temperature modifications. We assess results, for whole of Europe and for groups of countries, in terms of electricity mix, investments in new power plants, carbon intensity of electricity, share of RES and trade. All considered scenarios assume a very demanding CO_2 emissions mitigation cap in 2050, with no emissions from the power sector. This has the objective to assess effects in a highly renewable power system.

We have found that impacts of considering future climate projections in a large power systems model are relevant and significantly affect the interplay between hydropower, wind and solar PV (and other to a less extent). Although by 2050 for the whole of Europe the changes by considering climate can be around -3% to $+3\%$ generated solar PV or -4% to $+2\%$ wind power, there are more substantial changes for the different countries in the interconnected European power market. By 2030, just by considering climate variability, the carbon intensity of generated electricity can change from less 8% to more 6% compared to a scenario assuming "historic" capacity factors.

It should be highlighted the high variability of results reflecting the very diverse six climate projections used. Therefore, at this stage it is possible to say that there is uncertainty associated to the cost-effectiveness of solar and wind power across Europe under climate change, but it is not possible to say if their cost-effectiveness increases or decreases. Italy, UK, Finland, Norway and Sweden are some of the countries for which results vary the most. In any case, at this stage it is possible to say that by 2050 it is possible that UK, Ireland and Germany will have lower wind and solar power production than if there would be no climate change. "Peripheric" countries, as Romania, Portugal and Spain or Italy will supply more wind and solar power to ensure carbon neutrality is achieved. This means that it is fundamental to ensure rapid and reliable trade of large volumes of electricity across Europe to cope with a changing climate.

There are several limitations of work hereby presented, besides the uncertainty of the climate projections, already mentioned. At this stage we are considering only aggregated national capacity factors for wind, PV and hydro power, although climate changes across regions. Moreover, we had to downscale daily values of future CF to hourly values assuming that the intraday variability of the resource will not change in the future. Also, regarding the limitations associated to the estimate of impact of future climate in capacity factors, we have used machine learning for hydropower and, although this method works well for 'pure' run-of-river power plants, it shows limitations when operational decisions come into play as in the case of reservoir-based hydropower production. In both cases, the lack of historic hydropower generation data is a critical issue for machine learning based techniques. Regarding impacts of temperature in demand we so far did not consider total demand increase due to electrification of the European energy system which is very likely to occur in a carbon neutral scenario, nor changes in relative importance of electricity for heating and cooling in total electricity demand due to future deployment of heat pumps.

Nonetheless, this is a first attempt of a fully integrated analysis of climate impact on the power system and it serves to pinpoint both the complex methodological challenges faced, as well as the magnitude and relevance of potential effects for energy planning and energy and climate policy making. The next steps in this research will be to expand the set of considered climate projections, to improve estimate of hydropower future capacity factors with more bias correction of climate variables, to run the energy model for regional capacity factors and to explore possibilities of considering climate impacts on operation of thermal power plants, especially effect of temperature increase in cooling systems and overall plant efficiency.

Credit author statement

Sofia G. Simoes: Conceptualization, Methodology, Writing – original draft, Visualization, Supervision. Filipa Amorim: Methodology, Writing – review & editing, Visualization. Gildas Siggini: Investigation, Software, Writing, Visualization. Valentina Sessa: Investigation, Software, Writing – original draft. Yves-Marie Saint-Drenan: Conceptualization, Investigation, Software, Writing – original draft. Sílvia Carvalho: Investigation, Software, Writing – original draft, Visualization. Hamza Mraihi: Conceptualization, Methodology, Investigation, Software. Edi Assoumou: Conceptualization, Methodology, Software. Supervision.

Declaration of competing interest

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

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Appendix A. Comparison of precipitation from 2015 to 2018 to a 20-year historic period (1995–2014)

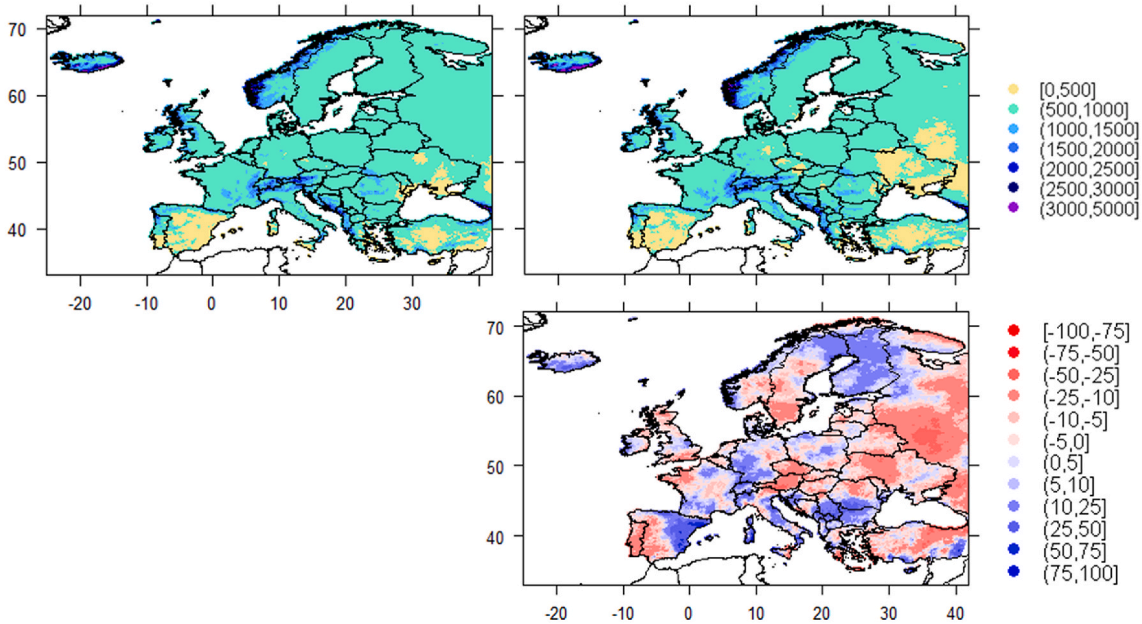

Fig. 17. Annual mean precipitation (mm) for the historical period (1995–2014) (upper-left figure) and the recent past years (2015–2018) (upper-right figure); anomalies (%) of annual mean precipitation between the two time periods. The dataset is based on COSMO REA-6 reanalysis.

Appendix B. Considered average capacity factors for Base case and for each climate projection

7.1Solar average annual capacity factors

Country	«Historic»	D45	D85	F45	F85	J45	J85	Std/mean	D45	D85	F45	F85	J45	J85	Std/mean
		2030							2050						
AT	0.11	0.11	0.11	0.11	0.11	0.12	0.11	2%	0.11	0.11	0.11	0.11	0.11	0.11	1%
BE	0.11	0.11	0.11	0.11	0.10	0.10	0.11	2%	0.11	0.11	0.11	0.10	0.10	0.10	2%
BG	0.16	0.16	0.16	0.16	0.16	0.16	0.16	1%	0.15	0.16	0.16	0.15	0.16	0.16	1%
CH	0.09	0.09	0.09	0.09	0.09	0.09	0.09	1%	0.09	0.09	0.09	0.09	0.09	0.09	1%
CZ	0.12	0.12	0.12	0.12	0.12	0.12	0.12	1%	0.12	0.12	0.12	0.11	0.12	0.12	2%
DE	0.11	0.11	0.11	0.11	0.10	0.11	0.11	2%	0.11	0.11	0.10	0.10	0.10	0.10	2%
DK	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1%	0.10	0.10	0.10	0.10	0.09	0.09	2%
EE	0.04	0.04	0.04	0.04	0.04	0.04	0.04	3%	0.04	0.04	0.04	0.04	0.04	0.04	2%
ES	0.22	0.22	0.22	0.21	0.22	0.21	0.22	1%	0.22	0.22	0.21	0.22	0.21	0.21	1%
FI	0.06	0.05	0.05	0.05	0.05	0.05	0.06	5%	0.05	0.05	0.05	0.05	0.05	0.05	6%
FR	0.13	0.13	0.13	0.13	0.13	0.13	0.13	1%	0.13	0.13	0.13	0.12	0.13	0.13	2%
GR	0.17	0.17	0.17	0.17	0.17	0.17	0.17	1%	0.17	0.17	0.17	0.17	0.17	0.17	1%
HR	0.13	0.13	0.13	0.13	0.13	0.13	0.13	1%	0.13	0.13	0.13	0.13	0.13	0.13	1%
HU	0.10	0.10	0.10	0.10	0.10	0.11	0.10	2%	0.10	0.10	0.10	0.10	0.10	0.10	1%
IE	0.08	0.08	0.07	0.07	0.07	0.07	0.07	3%	0.07	0.07	0.07	0.07	0.07	0.07	4%
IS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2%	0.01	0.01	0.01	0.01	0.01	0.01	3%
IT	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0%	0.13	0.13	0.13	0.13	0.13	0.13	1%
LT	0.11	0.11	0.11	0.11	0.11	0.11	0.11	2%	0.10	0.10	0.10	0.10	0.10	0.10	3%
LU	0.09	0.09	0.09	0.09	0.09	0.09	0.09	2%	0.09	0.09	0.09	0.09	0.09	0.09	2%
LV	0.05	0.05	0.05	0.05	0.05	0.05	0.05	2%	0.05	0.05	0.05	0.05	0.05	0.05	3%
NL	0.09	0.09	0.09	0.09	0.08	0.08	0.09	3%	0.09	0.09	0.09	0.08	0.08	0.08	3%
NO	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2%	0.01	0.01	0.01	0.01	0.01	0.01	3%
PL	0.08	0.07	0.07	0.07	0.07	0.07	0.07	3%	0.07	0.07	0.07	0.07	0.07	0.07	4%
PT	0.20	0.20	0.20	0.20	0.21	0.20	0.21	2%	0.20	0.21	0.20	0.21	0.20	0.20	1%
RO	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1%	0.15	0.15	0.15	0.15	0.15	0.15	1%
SE	0.11	0.10	0.10	0.10	0.10	0.10	0.10	3%	0.10	0.10	0.10	0.10	0.10	0.10	3%
SI	0.13	0.13	0.13	0.13	0.13	0.13	0.13	1%	0.13	0.13	0.13	0.13	0.13	0.13	1%
SK	0.11	0.11	0.11	0.11	0.11	0.11	0.11	1%	0.11	0.11	0.11	0.11	0.11	0.11	1%
UK	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1%	0.10	0.10	0.10	0.10	0.10	0.10	2%

7.2 Wind onshore average annual capacity factors

Country	«Historic»	D45	D85	F45	F85	J45	J85	Std/mean	D45	D85	F45	F85	J45	J85	Std/mean
		2030							2050						
AT	0.23	0.23	0.23	0.23	0.23	0.22	0.24	2%	0.22	0.24	0.23	0.23	0.23	0.23	2%
BE	0.21	0.21	0.20	0.21	0.21	0.21	0.20	3%	0.20	0.19	0.21	0.21	0.19	0.20	4%
BG	0.22	0.22	0.23	0.24	0.24	0.22	0.23	4%	0.22	0.25	0.24	0.24	0.22	0.23	5%
CH	0.09	0.09	0.08	0.09	0.09	0.09	0.08	3%	0.08	0.10	0.09	0.09	0.08	0.09	6%
CZ	0.20	0.19	0.19	0.20	0.20	0.19	0.21	3%	0.19	0.21	0.20	0.20	0.19	0.20	4%
DE	0.17	0.17	0.17	0.17	0.17	0.17	0.17	2%	0.16	0.17	0.17	0.17	0.16	0.17	3%
DK	0.24	0.24	0.24	0.24	0.24	0.24	0.24	1%	0.24	0.23	0.25	0.25	0.24	0.23	3%
EE	0.22	0.22	0.21	0.21	0.21	0.22	0.23	3%	0.22	0.20	0.21	0.21	0.22	0.23	4%
ES	0.25	0.25	0.25	0.25	0.25	0.25	0.24	2%	0.25	0.26	0.25	0.25	0.25	0.24	3%
FI	0.22	0.22	0.22	0.22	0.22	0.22	0.23	3%	0.22	0.21	0.21	0.21	0.21	0.22	3%
FR	0.22	0.22	0.22	0.22	0.22	0.22	0.21	2%	0.21	0.22	0.23	0.23	0.21	0.21	3%
GR	0.24	0.24	0.25	0.26	0.26	0.24	0.25	3%	0.24	0.27	0.26	0.26	0.24	0.25	4%
HR	0.25	0.26	0.26	0.26	0.26	0.26	0.25	2%	0.25	0.27	0.26	0.26	0.27	0.25	3%
HU	0.24	0.25	0.25	0.25	0.25	0.24	0.25	2%	0.25	0.26	0.25	0.25	0.25	0.25	3%
IE	0.27	0.27	0.27	0.27	0.27	0.27	0.27	1%	0.26	0.27	0.27	0.27	0.26	0.27	1%
IS	0.40	0.41	0.40	0.41	0.41	0.40	0.39	2%	0.42	0.41	0.40	0.40	0.39	0.38	3%
IT	0.21	0.21	0.21	0.22	0.22	0.22	0.21	2%	0.21	0.23	0.22	0.22	0.22	0.21	3%
LT	0.25	0.24	0.25	0.25	0.25	0.24	0.26	2%	0.25	0.24	0.24	0.24	0.24	0.26	2%
LU	0.22	0.21	0.21	0.22	0.22	0.22	0.21	2%	0.21	0.22	0.22	0.22	0.21	0.21	4%
LV	0.23	0.22	0.23	0.22	0.22	0.23	0.24	2%	0.23	0.21	0.22	0.22	0.23	0.24	4%
NL	0.16	0.15	0.15	0.16	0.16	0.16	0.15	2%	0.15	0.15	0.16	0.16	0.15	0.15	3%
NO	0.26	0.26	0.26	0.26	0.26	0.27	0.27	2%	0.26	0.26	0.25	0.25	0.26	0.26	1%
PL	0.25	0.24	0.25	0.25	0.25	0.25	0.26	3%	0.24	0.25	0.25	0.25	0.24	0.25	2%
PT	0.29	0.29	0.29	0.29	0.29	0.29	0.28	2%	0.27	0.28	0.29	0.29	0.29	0.28	3%
RO	0.24	0.24	0.25	0.25	0.25	0.24	0.25	2%	0.24	0.27	0.25	0.25	0.23	0.25	4%
SE	0.27	0.27	0.27	0.27	0.27	0.27	0.28	1%	0.27	0.26	0.27	0.27	0.27	0.27	2%
SI	0.13	0.14	0.14	0.14	0.14	0.13	0.13	4%	0.13	0.14	0.14	0.14	0.13	0.13	4%
SK	0.25	0.25	0.26	0.25	0.25	0.24	0.26	2%	0.25	0.27	0.25	0.25	0.24	0.25	4%
UK	0.27	0.27	0.26	0.27	0.27	0.27	0.27	1%	0.26	0.26	0.27	0.27	0.26	0.26	2%

7.3 Wind offshore average annual capacity factors

Country	«Historic»	D45	D85	F45	F85	J45	J85	Std/mean	D45	D85	F45	F85	J45	J85	Std/mean
		2030							2050						
AT	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
BE	0.57	0.57	0.56	0.57	0.57	0.57	0.57	1%	0.56	0.56	0.57	0.57	0.57	0.56	1%
BG	0.32	0.33	0.33	0.35	0.35	0.33	0.33	3%	0.32	0.34	0.35	0.35	0.33	0.33	4%
CH	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
CZ	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
DE	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0%	0.51	0.5	0.51	0.51	0.5	0.49	2%
DK	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0%	0.56	0.54	0.56	0.56	0.56	0.55	2%
EE	0.50	0.52	0.5	0.49	0.49	0.51	0.52	3%	0.52	0.49	0.49	0.49	0.51	0.51	3%
ES	0.38	0.39	0.38	0.38	0.38	0.39	0.38	1%	0.39	0.38	0.38	0.38	0.39	0.38	1%
FI	0.56	0.58	0.56	0.55	0.55	0.57	0.58	3%	0.57	0.55	0.55	0.55	0.57	0.57	2%
FR	0.46	0.46	0.46	0.46	0.46	0.46	0.45	1%	0.45	0.46	0.47	0.47	0.46	0.45	2%
GR	0.30	0.3	0.31	0.31	0.31	0.3	0.3	2%	0.3	0.32	0.31	0.31	0.31	0.3	2%
HR	0.26	0.26	0.26	0.26	0.26	0.27	0.26	1%	0.26	0.27	0.27	0.27	0.28	0.26	2%
HU	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
IE	0.62	0.61	0.61	0.62	0.62	0.62	0.62	0%	0.61	0.61	0.62	0.62	0.62	0.61	0%
IS	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
IT	0.30	0.3	0.3	0.31	0.31	0.3	0.3	1%	0.3	0.31	0.31	0.31	0.31	0.3	2%
LT	0.53	0.54	0.53	0.52	0.52	0.54	0.54	2%	0.54	0.52	0.52	0.52	0.54	0.53	2%
LU	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
LV	0.49	0.5	0.49	0.48	0.48	0.5	0.51	2%	0.51	0.48	0.48	0.48	0.5	0.5	2%
NL	0.55	0.55	0.54	0.55	0.55	0.55	0.55	0%	0.55	0.54	0.55	0.55	0.55	0.53	1%
NO	0.54	0.54	0.55	0.55	0.55	0.55	0.54	1%	0.54	0.54	0.55	0.55	0.54	0.54	1%
PL	0.53	0.53	0.52	0.53	0.53	0.53	0.53	0%	0.54	0.51	0.53	0.53	0.53	0.52	2%
PT	0.48	0.47	0.48	0.47	0.47	0.47	0.47	0%	0.48	0.48	0.48	0.48	0.48	0.47	1%
RO	0.37	0.37	0.38	0.4	0.4	0.37	0.37	4%	0.36	0.39	0.4	0.4	0.37	0.37	4%
SE	0.54	0.55	0.54	0.54	0.54	0.55	0.55	1%	0.55	0.53	0.54	0.54	0.55	0.54	2%
SI	0.17	0.18	0.18	0.18	0.18	0.17	0.17	4%	0.18	0.19	0.19	0.19	0.17	0.16	5%
SK	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
UK	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0%	0.59	0.59	0.59	0.59	0.59	0.59	1%

n.a. – not applicable.

7.4 Hydro power average annual capacity factors

Country	«Historic»	D45	D85	F45	F85	J45	J85	Std/mean	D45	D85	F45	F85	J45	J85	Std/mean
		2030							2050						
AT	0.40	0.42	0.42	0.46	0.46	0.42	0.43	4%	0.42	0.42	0.46	0.47	0.42	0.42	5%
BE	0.06	0.07	0.06	0.09	0.09	0.08	0.07	14%	0.06	0.07	0.09	0.09	0.08	0.07	14%
BG	0.28	0.23	0.22	0.28	0.29	0.22	0.22	13%	0.23	0.24	0.28	0.28	0.22	0.21	13%
CH	0.22	0.23	0.23	0.23	0.23	0.23	0.23	0%	0.23	0.23	0.23	0.23	0.23	0.23	0%
CZ	0.20	0.20	0.20	0.21	0.21	0.20	0.19	4%	0.20	0.20	0.21	0.21	0.20	0.19	3%
DE	0.35	0.35	0.35	0.37	0.37	0.36	0.36	2%	0.35	0.35	0.37	0.37	0.36	0.35	2%
DK	0.04	0.05	0.04	0.05	0.05	0.05	0.05	5%	0.04	0.04	0.05	0.05	0.05	0.05	6%
EE	0.41	0.41	0.41	0.41	0.40	0.40	0.41	0%	0.41	0.41	0.40	0.41	0.40	0.41	0%
ES	0.49	0.59	0.59	0.59	0.60	0.60	0.58	1%	0.58	0.58	0.60	0.59	0.59	0.58	2%
FI	0.51	0.53	0.53	0.56	0.55	0.54	0.54	2%	0.53	0.53	0.55	0.57	0.55	0.55	3%
FR	0.33	0.38	0.38	0.40	0.41	0.38	0.37	4%	0.37	0.37	0.40	0.40	0.37	0.36	4%
GR	0.02	0.02	0.02	0.03	0.03	0.02	0.02	8%	0.02	0.02	0.03	0.03	0.02	0.02	9%
HR	0.03	0.03	0.03	0.03	0.04	0.03	0.03	8%	0.03	0.03	0.04	0.04	0.03	0.03	9%
HU	0.42	0.43	0.42	0.41	0.42	0.42	0.42	1%	0.42	0.42	0.41	0.41	0.42	0.41	1%
IE	0.35	0.45	0.45	0.43	0.43	0.48	0.48	5%	0.43	0.44	0.43	0.44	0.48	0.48	5%
IS	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0%
IT	0.30	0.32	0.33	0.34	0.35	0.31	0.30	6%	0.32	0.33	0.34	0.34	0.31	0.30	5%
LT	0.36	0.37	0.37	0.35	0.35	0.35	0.35	2%	0.37	0.36	0.35	0.34	0.35	0.35	3%
LU	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0%
LV	0.22	0.23	0.23	0.22	0.22	0.22	0.22	2%	0.23	0.22	0.22	0.22	0.22	0.21	3%
NL	0.12	0.14	0.12	0.17	0.18	0.17	0.16	13%	0.13	0.13	0.18	0.18	0.16	0.16	13%
NO	0.55	0.57	0.57	0.57	0.57	0.55	0.55	2%	0.57	0.56	0.57	0.56	0.55	0.54	2%
PL	0.38	0.40	0.39	0.39	0.39	0.38	0.38	2%	0.40	0.39	0.39	0.39	0.38	0.38	2%
PT	0.30	0.34	0.35	0.32	0.33	0.40	0.37	8%	0.32	0.33	0.33	0.33	0.39	0.37	8%
RO	0.31	0.30	0.30	0.31	0.31	0.30	0.30	2%	0.30	0.30	0.31	0.31	0.29	0.29	2%
SE	0.47	0.47	0.47	0.47	0.47	0.46	0.46	1%	0.47	0.47	0.47	0.47	0.46	0.46	1%
SI	0.44	0.48	0.48	0.51	0.52	0.63	0.46	12%	0.48	0.48	0.52	0.53	0.63	0.46	12%
SK	0.27	0.28	0.29	0.27	0.27	0.36	0.28	12%	0.29	0.29	0.26	0.26	0.37	0.28	13%
UK	0.23	0.24	0.24	0.25	0.25	0.35	0.25	16%	0.24	0.24	0.25	0.25	0.36	0.26	17%

Appendix C. Considered technical and economic assumptions for the power production technologies

Fuel	Technology	Specific investments costs (overnight) (eur_{2010}/kW)					Fixed operating and maintenance costs (eur_{2010}/kW)					Electric net efficiency (condensing mode) (%)					Tech. life (yr.)	Availability factor (%)	CO_2 capture rate (%)	
		2017	2020	2030	2040	2050	2017	2020	2030	2040	2050	2017	2020	2030	2040	2050			2030	2050
Coal	Hard coal/lignite 600 MWel																			
	Supercritical	1700	1506	1506	1506	1506	30	30	30	30	30	40	44	44	44	46	30	80		
	Supercritical + (post comb./oxyfuelling) capture	5500	4872	4430	4252	4252	35	35	35	35	35	32	38	38	38	42	30	80	89	90
	FB	2457	2098	2005	1973	1940	30	30	30	30	30	40	42	42	42	44	30	80		
	FB + capture	7994	6728	5761	5422	5313	35	35	35	35	35	32	37	37	37	40	30	80	89	90
	IGCC	2500	2215	2082	2038	2038	33	33	33	33	33	40	45	45	45	50	35	80		
	IGCC pre-comb capture	5850	5183	4651	4385	4385	39	39	39	39	39	32	39	39	39	45	35	80	89	90
	CHP BackPressure	3107	2753	2753	2753	2753	55	55	55	55	55	Country specific values					35	Country specific		
Natural Gas	**Combined Cycle Small**	1104	978	978	978	978	20	20	20	20	20	60	60	63	63	63	35	85		
	Combined Cycle Large	1000	886	886	886	886	18	18	18	18	18	60	60	63	63	63	35	85		
	Combined-cycle + post comb. capture	3100	2746	2481	2348	2348	53	53	53	53	53	54	56	57	57	57	35	85	89	90
	Peak Turbine	220	220	220	220	220	12	12	12	12	12	40	38	38	38	38	30	85		
	CHP Int Comb Small	2500	2500	2500	2500	2500	65	65	65	65	65	Country specific value					15	Country specific value		
	CHP Int Comb Medium	1050	1050	1050	1050	1050	45	45	45	45	45						15			
	CHP Int Comb Large	750	750	750	750	750	35	35	35	35	35						18			
	CHP Combined-cycle Small	1521	1347	1347	1347	1347	30	30	30	30	30						35			
	CHP Combined-cycle Large	1300	1152	1152	1152	1152	25	25	25	25	25						35			
Nuclear 1000 MWel	**3rd generation**	6563	5315	4518	3987	3745	39	39	38	38	38	36	36	36	36	36	60	85		
	4th generation				7773	6500				28	28				38	38	60	85		
Wind onshore	**Wind onshore 1 low/2 medium (IEC class III/II)**	1840	1577	1524	1488	1470	40	40	40	40	40	100	100	100	100	100	20	23		
Wind offshore	**Wind offshore 1 low/medium (IEC class II)**	4600	3411	2835	2569	2539	60	60	60	60	60	100	100	100	100	100	20	40		
Hydro	**Lake**	2650	2348	2348	2348	2320	45	45	45	45	45	93	93	93	93	93	80	60		
	Run of river small	4429	3924	3924	3924	3878	45	45	45	45	45	93	93	93	93	93	60	60		
	Run of river medium	4164	3689	3689	3689	3646	45	45	45	45	45	93	93	93	93	93	70	60		
	Run of river large	2650	2348	2348	2348	2320	45	45	45	45	45	93	93	93	93	93	80	60		
Solar	**Solar PV utility scale fixed systems > 10 MW**	1320	921	762	691	683	29	29	29	19	19	100	100	100	100	100	25	25		
	Solar PV roof < 0.1 MWp/0.1–10 MWp	1600	1134	957	868	858	40	40	40	40	40	100	100	100	100	100	25	25		
	Solar CSP 50 MWel	5700	4518	3765	3322	3283	45	45	41	38	38	100	100	100	100	100	25	25		
Biomass	**Steam turbine biomass solid conventional**	2400	2082	2038	1993	1970	64	64	64	64	64	35	35	35	35	36	35	80		

(*continued on next page*)

(*continued*)

Fuel	Technology	Specific investments costs (overnight) (eur_{2010}/kW)					Fixed operating and maintenance costs (eur_{2010}/kW)					Electric net efficiency (condensing mode) (%)					Tech. life (yr.)	Availability factor (%)	CO_2 capture rate (%)	
		2017	2020	2030	2040	2050	2017	2020	2030	2040	2050	2017	2020	2030	2040	2050			2030	2050
	Steam turbine biomass solid conventional HT	2010	1743	1706	1669	1650	45	45	45	45	45	38	39	39	39	39	25	80		
	IGCC Biomass 100 MWel		2863	2489	2295	2236	2226	54	54	54	54	54	14	14	14	36	57	25	80	
	IGCC Biomass 100 MWel + capture	7112	6300	5727	5498	5498	63	63	63	63	63	29	34	34	34	36	25	80	89	90
	CHP IGCC	4680	4146	4146	4146	4146	143	143	124	90	90	14	14	14	37	37	25	Country		
	CHP Steam Turb condensing	3750	3278	3233	3145	3108	72	72	72	72	72	14	14	14	31	31	25	specific		
Geothermal	**Hot Dry Rock geotthermal**	2900	2481	2392	2303	2276	194	194	175	136	136	20	20	21	22	22	20	85		
Ocean	**Wave 5 MWel**	6950	5891	4119	3056	3021	160	160	160	160	160	100	100	100	100	100	25	40		
	Tidal energy stream and range 10 MWel	5414	4589	3209	2381	2533	92	92	92	92	92	100	100	100	100	100	80	25		
	Thermal	30,000	30,000	13,000	13,000	13,000	120	120	120	120	120	100	100	100	100	100	25	91		
	Hydrokinectic	7894	6692	4679	3472	3431	120	120	120	120	120	100	100	100	100	100	25	40		
Biogas	**CHP Internal Combustion Small**	4000	4000	4000	4000	4000	115	115	115	115	115	30	30	30	34	34	15	Country specific		
	CHP Internal Combustion Large	2350	2350	2350	2350	2350	115	115	115	115	115	30	30	30	39	39	15			
Oil	**CHP Internal Combustion Small**	2210	1958	1958	1958	1958	65	65	65	65	65	30	30	30	30	30	18	Country specific		
	CHP Internal Combustion Medium	2730	2419	2419	2419	2419	45	45	45	45	45	30	30	30	30	36	15			
	CHP Internal Combustion Large	750	750	750	750	750	35	35	35	35	35	30	30	30	30	42	18			
	Supercritical HFO	1916	1671	1636	1617	1604	21	21	21	21	21	30	30	30	30	63	35	85		
	Supercritical HFO + capture	1413	1342	1264	1264	1215	24	24	24	24	24	36	41	41	41	43	35	80	89	90
	Turb Diesel	875	775	775	775	775	18	18	18	18	18	34	34	34	63	63	35	85		
Waste	**Steam**	2190	1900	1860	1819	1798	33	33	33	33	33	14	14	14	20	25	20	68		
	CHP Steam Turb Condensing	7450	6511	6423	6290	6216	74	74	74	74	74	14	14	14	25	25	20	Country specific		

Appendix D. Maximum potential installed capacity for RES electricity power plants per country considered in eTIMES-EU (GW)

Country/Year	Hydropower[a]			PV[a]			Wind onshore[a]			Wind offshore			Ocean		
	2020	2030	2050	2020	2030	2020	2030	2050	2050	2020	2030	2050	2020	2030	2050
AT	8.9	10.0	13.3	5.4	21.0	0.0	0.0	0.0	21.0	4.0	7.2	7.2	0.0	0.0	0.0
BE	0.1	0.1	0.1	21.2	28.0	1.2	3.2	7.2	28.0	2.3	2.3	2.3	3.9	3.9	3.9
BG	2.3	3.0	6.4	19.0	19.0	1.2	3.2	7.2	19.0	3.5	3.5	3.5	0.0	0.0	0.0
CH	13.6	14.3	16.3	5.6	20.0	0.0	0.0	0.0	20.0	0.1	0.8	1.1	0.0	0.0	0.0
CZ	1.1	1.2	1.4	25.8	27.0	0.0	0.0	0.0	27.0	1.1	5.1	5.1	0.0	0.0	0.0
DE	4.5	4.5	4.7	100.8	209.0	0.0	0.0	0.0	209.0	55.9	55.9	55.9	20.6	31.1	31.1
DK	0.0	0.0	0.0	11.4	14.0	1.2	3.2	7.2	14.0	4.1	4.1	4.1	5.4	5.4	5.4
EE	0.0	0.0	0.0	3.0	3.0	0.0	0.0	0.0	3.0	0.9	0.9	0.9	0.1	0.6	0.9
ES	17.0	20.8	34.2	25.5	102.9	1.2	3.2	7.2	117.0	30.3	44.2	44.2	0.1	0.4	14.3
FI	3.2	3.5	4.1	0.6	7.5	1.2	3.2	7.2	14.0	2.6	2.6	2.6	0.7	3.3	4.0
FR	18.5	20.9	28.1	28.9	118.6	1.2	3.2	7.2	160.0	16.1	29.9	49.5	0.0	0.2	10.0
GR	2.7	3.9	10.0	23.8	29.0	1.2	3.2	7.2	29.0	7.4	10.0	10.0	0.1	0.6	5.0
HR	1.8	1.9	2.2	11.0	11.0	1.2	3.2	7.2	11.0	1.3	1.3	1.3	0.0	0.0	0.0
HU	0.1	0.1	0.1	21.4	26.0	0.0	0.0	0.0	26.0	1.7	1.7	1.7	0.0	0.0	0.0
IE	0.2	0.3	0.4	0.1	2.2	1.2	3.2	7.2	11.0	6.9	6.9	6.9	0.2	1.1	1.1
IS	2.0	2.7	6.2	0.0	0.4	0.0	0.0	0.0	1.0	3.1	3.1	3.1	0.0	0.0	0.0
IT	14.3	15.4	18.3	90.6	154.0	1.2	3.2	7.2	154.0	13.2	23.0	23.0	0.0	0.0	0.0
LT	0.1	0.1	0.2	8.0	8.0	1.2	3.2	7.2	8.0	1.4	1.4	1.4	0.1	0.6	0.6
LU	0.0	0.0	0.1	0.5	1.0	0.0	0.0	0.0	1.0	0.2	0.2	0.2	0.0	0.0	0.0
LV	1.6	1.6	1.8	6.0	6.0	0.0	0.0	0.0	6.0	0.7	0.7	0.7	0.1	0.2	0.2
NL	0.0	0.0	0.0	8.9	42.0	1.2	3.2	7.2	42.0	4.3	5.2	5.2	5.6	15.7	72.8
NO	30.4	34.1	45.4	0.5	6.6	1.2	3.2	7.2	12.0	4.2	14.3	14.3	0.0	0.2	7.3
PL	0.6	1.0	3.8	3.3	32.7	1.2	3.2	7.2	97.0	9.0	9.0	9.0	0.0	0.0	0.0
PT	4.7	6.2	12.4	1.8	14.8	1.2	3.2	7.2	27.0	6.7	9.5	9.5	0.0	0.2	3.4
RO	6.6	8.6	16.3	22.6	55.0	1.2	3.2	7.2	55.0	3.7	3.7	3.7	0.1	0.6	1.1
SE	16.4	19.9	32.5	1.1	10.8	1.2	3.2	7.2	24.0	8.8	13.6	13.6	0.7	2.3	11.0
SI	1.3	1.4	1.9	5.0	5.0	1.2	3.2	7.2	5.0	0.9	0.9	0.9	0.0	0.0	0.0
SK	1.6	1.8	2.5	14.0	14.0	0.0	0.0	0.0	14.0	1.2	1.2	1.2	0.0	0.0	0.0
UK	1.9	1.9	2.0	48.3	158.0	0.2	2.2	6.2	158.0	16.7	19.4	19.4	22.4	49.1	98.2

[a] Based on [51]; b Based on [52]).

Appendix E. Impact of climate projections on amounts of electricity exported in 2050 compared with NEUTR scenario

Group	ALP	BIS	CEE	CWE	IBE	NEE	NWN	SEE	ALP	BIS	CEE	CWE	IBE	NEE	NWN	SEE
	NEUTR_D45								NEUTR_D85							
ALP				1%				12%				15%				9%
BIS				-13%			-100%					-11%			-83%	
CEE				2%		4%	6%	2%				-5%		-6%	5%	-3%
CWE	0%	11%	-3%		82%		-5%	-10%	-2%	6%	11%		17%		-11%	2%
IBE				-4%								-5%				
NEE			6%				17%				3%				5%	
NWN		10%	2%	-1%		3%				13%	-5%	-1%		-10%		
SEE	6%		-27%	-1%					-3%		-10%	40%				
	NEUTR_F45								NEUTR_F85							
ALP				4%				18%				13%				30%
BIS				-7%			-74%					8%			-81%	
CEE				-3%		24%	14%	8%				0%		15%	10%	4%
CWE	-9%	10%	-1%		18%		23%	-4%	-4%	-7%	-17%		- 27%		-2%	-5%
IBE				-3%								-1%				
NEE			-10%				15%				-5%				14%	
NWN		5%	-2%	-4%		3%				1%	-4%	-3%		-1%		
SEE	0%		-4%	8%					2%		5%	23%				
	NEUTR_J45								NEUTR_J85							
ALP				7%				32%				3%				20%
BIS				1%			-85%					-4%			-100%	
CEE				15%		6%	12%	5%				4%		-21%	-4%	5%
CWE	-1%	-6%	-6%		25%		-17%	0%	-7%	2%	-10%		18%		-30%	10%
IBE				-2%								-4%				
NEE			0%				27%				1%				-27%	
NWN		7%	-3%	-2%		-7%				34%	0%	2%		66%		
SEE	-4%		-35%	-2%					-8%		-16%	1%				

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