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Impact of different levels of geographical disaggregation of wind and PV electricity generation in large energy system models: A case study for Austria

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This paper assesses how different levels of geographical disaggregation of wind and photovoltaic energy resources could affect the outcomes of an energy system model by 2020 and 2050. Energy system models used for policy making typically have high technology detail but little spatial detail. However, the generation potential and integration costs of variable renewable energy sources and their time profile of production depend on geographic characteristics and infrastructure in place. For a case study for Austria we generate spatially highly resolved synthetic time series for potential production locations of wind power and PV. There are regional differences in the costs for wind turbines but not for PV. However, they are smaller than the cost reductions induced by technological learning from one modelled decade to the other. The wind availability shows significant regional differences where mainly the differences for summer days and winter nights are important. The solar availability for PV installations is more homogenous. We introduce these wind and PV data into the energy system model JRC-EU-TIMES with different levels of regional disaggregation. Results show that up to the point that the maximum potential is reached disaggregating wind regions significantly affects results causing lower electricity generation from wind and PV.

1. Introduction

The generation potential and integration cost of variable renewable energy sources (RES) and their time profile of production depend on geographic characteristics [1–3] and the time profile of demand [4]. The integration of variable RES into the energy system is therefore complex especially when this integration is constrained by currently installed infrastructure [5,6]. Consequently, modelling expansion pathways of renewable energy technologies can be made more accurate by considering these geospatial aspects [7].

Although large (national, regional or global) energy system models integrate the several components of the system from resource extraction, conversion into energy carriers till end-use consumption in the various economic sectors, they often have a simplified temporal resolution (e.g. an average year is divided in a low number of representative time-slices) along with a simplified geographical resolution (e.g. countries are represented as one aggregated region) [8–13]. Due to difficulties in obtaining the necessary data for all modelled regions, combined with increased computational complexity, regional differences are typically not taken into account in European Union (EU) wide energy system models used for policy support, as the POLES and PRIMES model

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(used for EU in the Energy 2050 Roadmap [14], the EU Energy Climate Policy Package [15] and the more recent 2030 climate and energy policy framework [16]).

Therefore, due to the low temporal and spatial resolution, the representation of renewable energy resources in energy systems models is usually highly stylized [17]. According to [18,19], combining long-term planning with an adequate representation of the spatial and temporal characteristics of RES is necessary to provide sufficient insights into the transition to a low carbon infrastructure. Increasing attention is given in the literature to detailed modelling of RES, especially focusing on temporal resolution. Many authors developed power sector models with higher temporal resolution, such as the electricity model for Japan with 10 min interval time-slices developed by Ref. [3] to assess maximum PV integration, or the one for EU with hourly data to assess the effects of North-African electricity imports on the European power system [20]. Kannan and Turton [21] introduce dispatch elements into the Swiss TIMES model. They implement 4 seasonal, 3 daily and 24 hourly time-slices. They conclude that introducing a higher temporal resolution allows more insights into the generation schedule but that the approach cannot replace a dispatch model. Ludig et al. [17] introduce a higher temporal resolution (modelled around electricity demand) into the LIMES model for Germany in order to represent fluctuating renewables better. They find an increase in the amount of flexible natural gas technologies. Kannan [22] increased the time-slices resolution from 12 to 20 in the MARKAL model for the UK. Lind et al. [23] increased the temporal resolution to 260 time-slices and introduced 6 regions in a TIMES model for Norway to study impacts of the RES target on the energy system. Other authors developed hybrid modelling approaches using soft-linking of aggregated energy system models with detailed temporal simulation models as done with TIMES Portugal and EnergyPLAN [24]. The authors assess the increased penetration of RES in the electricity mix to achieve significant CO_2 reductions. Other examples are [25] and [7], which present a coupling of a TIMES model with a dispatch model to assess the generation electricity plant portfolio results from TIMES. Complementarily to the systems modelling approach, the estimation of levelized costs of electricity (LCOE) is frequently used to compare different electricity generation options, across different technologies or sites [26–28]. However, LCOE has been criticized by some authors, as [29], particularly regarding intermittent RES.

From our literature review it is evident that most studies focus on an improvement of the temporal resolution in energy system models but they disregard the spatial resolution. As intermittent renewable energy sources vary with time and with their geographical locations, it is important to consider both characteristics. With this paper we fill the research gap of analysing the effects of spatial disaggregation on energy system model outcomes. We focus on quantifying the extent to which large energy system model results are affected by more detailed representations of RES. We model a set of scenarios with varying disaggregation of regional wind and photovoltaic resources. We use the region of Austria in a large energy system model for the 28 EU member countries (JRC-TIMES-EU) as our case study and propose an approach to address the following questions: Does spatial disaggregation lead to differences in generated electricity of variable RES? Are these differences relevant enough to affect the rest of the Austrian and European energy system? We designed our analysis as a step towards investigating the benefits of disaggregating large energy system models. For this reason we have included for now only a relatively small country as Austria. If for such a small country there are significant differences due to disaggregation that are relevant for the whole EU energy system, this then serves to prove the point that spatial disaggregation matters and should be considered even more for larger regions – in particular as meteorological conditions vary to a much larger extent if considering larger geographical extensions.

In the following section we discuss the theoretical considerations underlying our analysis. In section three we present in detail our method and assumptions used. In the last section we analyse the main results and present our conclusions.

2. Theoretical implications of space and time aggregation in energy systems modelling

We discuss in this section the impact of treating RES differently depending on the aggregation of geographical data on RES resource availability and electricity transmission infrastructure. Note that we do not discuss the stochastic nature of the renewable sources within the smallest timeframe or the smallest geographical resolution since energy system models use average cost and availability. Renewable energy sources and electricity demand vary with time and geographical location and the energy system is constrained by the location of the current infrastructure in place. The marginal value of a technology is therefore affected by the time profile of production [30], which is location dependent, and by the location of current infrastructure [30]. Measuring costs of RES using the LCOE approach only is a shortcoming, as their total energy system value depends on their time profile of production [31].

For RES such as wind and solar electricity generation, geographical averaging can lead to 'obscuring' the more extreme locations and time-slices both favourably and unfavourably [1]. By aggregating regions with different geographical characteristics in energy system models, an average value of various technology characteristics (e.g. investment costs, availability) is included as an input, whereas markets and energy planning have to consider the marginal parameters. For example, the annual average availability of the wind resources in the total technically possible potential sites for the whole of Austria is roughly 2480 h [2]. However, the wind availability across these sites varies significantly for the same period. For example, during the peak demand time-slice for electricity in spring sites have a maximum production of generated wind electricity ranging from 754 to 2943 h depending on the location. If the average aggregated availability factor allows a profitable operation of wind, with all other conditions being equal, in a cost minimization model the wind technology will be deployed to its maximum technical potential as long as there is demand for it. If the model alternatively considers differentiated availabilities of wind for different regions, then when estimating the optimal technology deployment, a supply cost-curve will be considered. Consequently, only regions with high enough availabilities will be considered for the solution. Economically speaking this is the equivalent of using long term marginal costs instead of average costs.

Moreover, by considering the different regional availabilities of the resources, it is consequently possible to include the different temporal resource distributions across these regions. This allows assessing the relative cost-effectiveness of solutions that, although they might have overall higher annual availability, have higher annual/seasonal/daily fluctuations of the resource or correlate less with demand. These fluctuations (when deviating from total demand and the demand profile) could create extra costs in terms of the need for balancing capacities and grid expansion. This is a trade-off between technical detail and model simplification [22,32] which sacrifices detailed modelling of grid and dispatch (e.g. assessing safety margin needs for ancillary services and emergencies) in order to gain long-term insights for the whole energy system [23]. However, the increase in deployment of intermittent non-dispatchable RES technologies might alter the balance of the

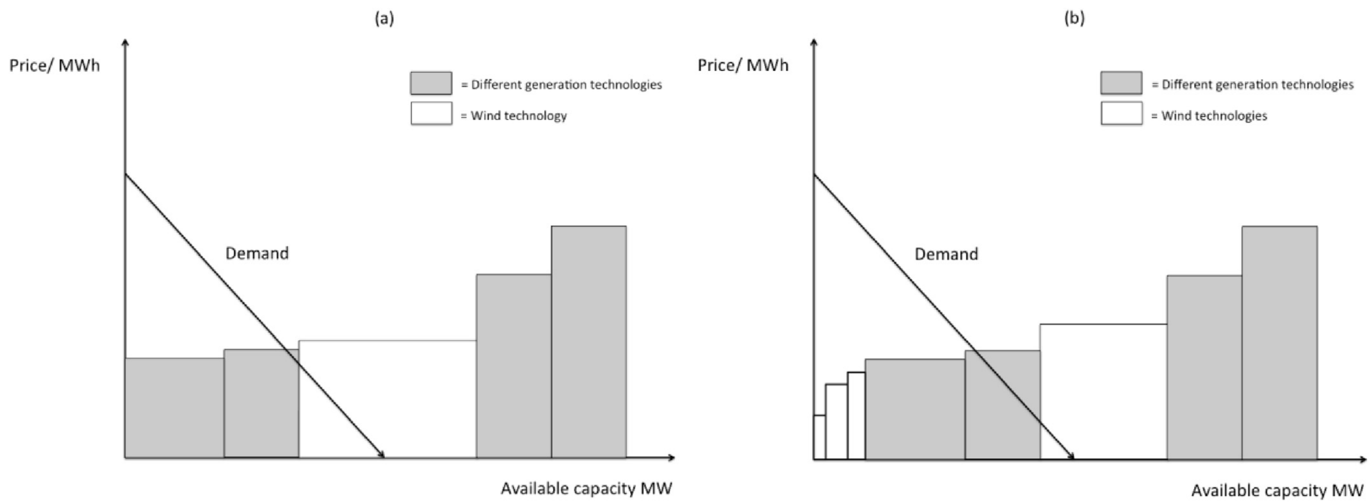

Fig. 1. Effects of the spatial resolution on the ordering of a long term supply curve in an energy system model: (a) model with one wind region, (b) model with fours wind regions.

mentioned trade-off.

Fig. 1 shows the effects of different spatial resolutions on the supply curve built into any energy system model. It illustrates the difference between using one average wind region represented by a single technology (a) and representing the locational differences by introducing several wind technologies (b). In Fig. 1 (a) averaging the wind regions costs leads to wind power being too costly to be included into the part of the supply curve which meets demand, while in Fig. 1 (b) three wind locations are part of the technologies satisfying demand.

Fig. 2 shows the effect of spatial disaggregation on the temporal availability of resources. We assume that there are two different locations with a different time profile of renewable power production, i.e. location 1 produces at full capacity in the first time-slice while it does not produce at all in the second one, while the opposite is assumed for location 2. When averaging the availability factor it seems as if the renewable source would be available at a capacity factor of 0.50 for both time-slices. However, the energy system may need a lot of capacity in the first time-slice due to, e.g. higher demand or lower availability of other resources such as hydro power. If we assume that there is no demand for the renewable source in the second time-slice, choosing this source would decrease the capacity factor to 0.25, as the source would be curtailed completely in the second time-slice. It is therefore unlikely that the source is chosen by the model in an aggregated model, while, with disaggregated locations, location 1 could be operated at a capacity factor of 0.50 and it may therefore be chosen by the model.

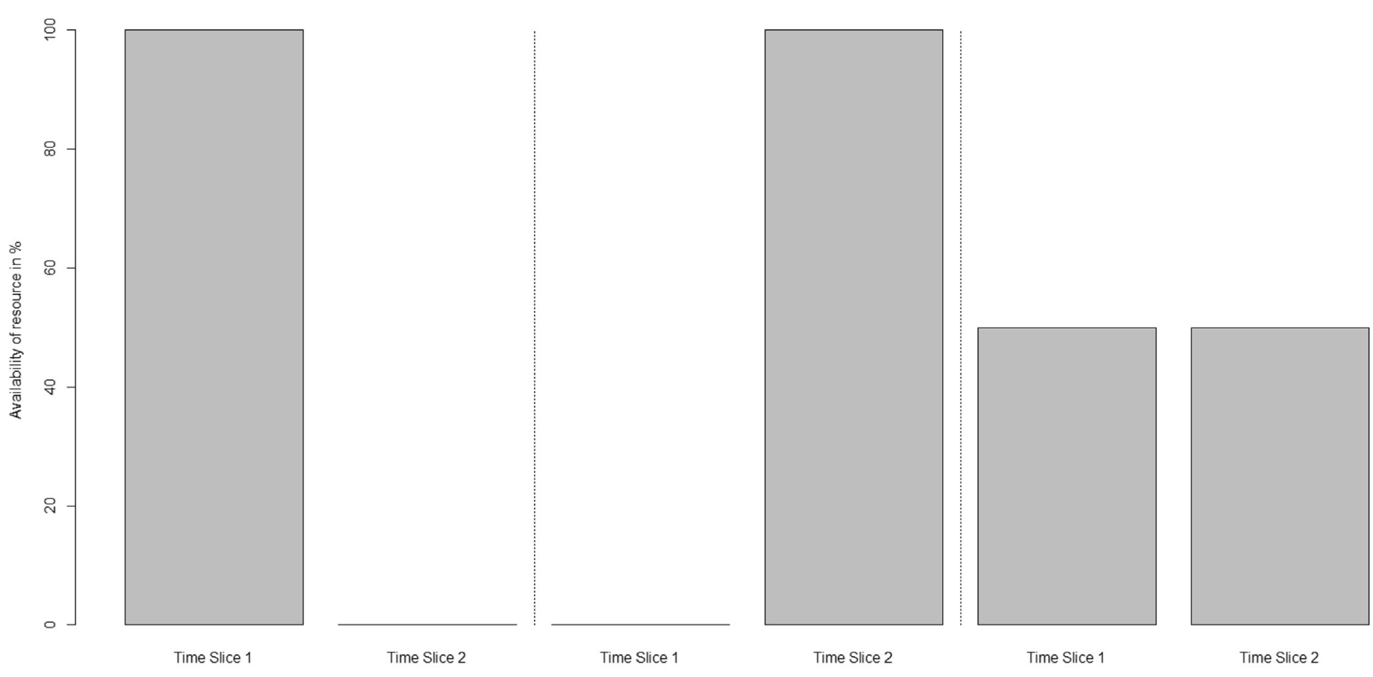

Fig. 2. Different temporal availability of RES.

3. Methods

The Renewable Energy Directive [33] of the European Union aims at increasing the share of renewable energy in the gross final energy consumption from 8.5% in 2005 to 20% in 2020. Consequently, the share of renewable energy generation has to be increased from 24.4% to 34% in Austria by 2020. According to the Austrian energy strategy, the share of renewable electricity in the total electricity production has to increase from 75% in 2005 to 80% in 2020 [34]. The low expansion potential for hydropower in Austria implies an increase in distributed, variable generation [35]. This makes Austria a very good case study.

Fig. 3 illustrates our methodology. We model in detail the wind and PV output for 79 wind and 5 PV regions. In order to represent the regions in the JRC-EU-TIMES model we introduce location specific technologies which differ in their availability factors (AFs), overall potential and connection costs (for wind). We then model 6 scenarios (2 regionally aggregated and 4 disaggregated) in order to determine the effects of considering different regions in a large energy systems model. The methodology will be described in more detail in the subsequent sections.

3.1. Overview of the JRC-EU-TIMES model

The JRC-EU-TIMES model is a linear optimization bottom-up technology model generated with the TIMES model generator

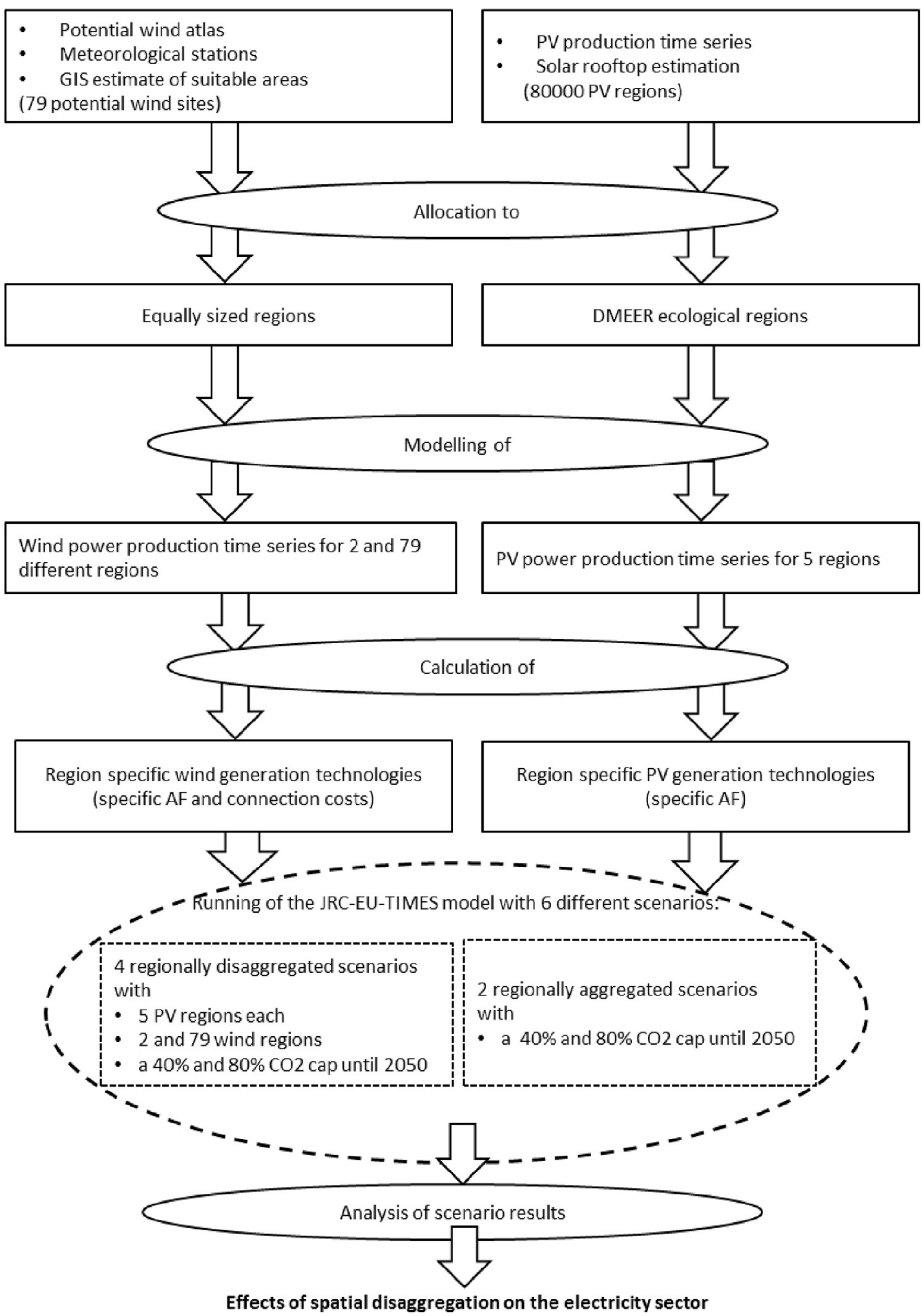

Fig. 3. Overview of the methodology.

Table 1
Overview of the technical RES potential for Europe considered in JRC-EU-TIMES.

RES	Methods	Main data sources	Assumed maximum possible technical potential capacity/activity for EU28	Assumed maximum possible technical potential capacity/activity for Austria
Wind onshore	Maximum activity and capacity restrictions disaggregated for different types of wind onshore technologies, considering different wind speed categories	[38] until 2020 followed by JRC-IET own assumptions, for Austria see 3.2	205 GW in 2020 and 283 GW in 2050	5.6 GW in 2020 and 8.3 GW in 2050, corresponding to 9.1 TWh in 2020 and 15.9 TWh in 2050
Wind offshore	Maximum activity and capacity restrictions disaggregated for different types of wind offshore technologies, considering different wind speed categories	[38] until 2020 followed by JRC-IET own assumptions	52 GW in 2020 and 158 GW in 2050	Not applicable
PV and CSP	Maximum activity and capacity restrictions disaggregated for different types of PV and for CSP	Adaptation from JRC-IET on [38], for Austria see 3.2	115 GW and 1970 TWh in 2020 and 1288 GW in 2050 for PV; 9 GW in 2020 and 10 GW in 2050 for CSP	For PV 13.4 GW in 2020 and 26.1 GW in 2050, corresponding to 12.9 TWh in 2020 and 25.6 TWh in 2050; no CSP
Geothermal electricity	Maximum capacity restriction in GW, aggregated for both EGS and hydrothermal with flash power plants	[38] until 2020 followed by JRC-IET own assumptions	1.6 GW in 2020 and 2.9 GW in 2050 for hot dry rock; 1.5 GW in 2020 and 1.9 GW in 2050 for dry steam &flash plants. 301 TWh generated in 2020 and 447 TWh in 2050	Not applicable
Ocean	Maximum activity restriction in TWh, aggregated for both tidal and wave	[38] until 2020 followed by JRC-IET own assumptions	117 TWh in 2020 and 170 TWh in 2050	Not applicable
Hydro	Maximum capacity restriction in GW, disaggregated for run-of-river and lake plants	[40]	22 GW in 2020 and 40 GW in 2050 for run-of-river. 197 GW in 2020 and 2050 for lake. 449 TWh generated in 2020 and 462 TWh in 2050	No additional capacity

from ETSAP of the International Energy Agency. More information on TIMES can be found in Refs. [36,37]. The JRC-EU-TIMES model represents the energy system of the 28 EU member countries plus Switzerland, Iceland and Norway (hereafter named as EU28+) from 2005 to 2050, where each country is one region. More information on the model can be found in Ref. [11] and in Appendix A. The most relevant model outputs are the annual stock and activity of energy supply and demand technologies for each region and period, with associated energy and material flows including emissions to air and fuel consumption for each energy carrier. Besides these, the model computes operation and maintenance costs, investment costs, energy and materials commodities prices. Each year is divided into 12 time-slices that represent an average of day, night and peak demand for each of the four seasons of the year. The modelling periods are the years of 2010, 2020, 2030 and 2050.

Regarding the RES potentials for wind, solar, geothermal, marine and hydro we use a number of assumptions as in Table 1. The potentials for electricity from RES up to 2020 are based on maximum yearly electricity production provided by RES2020 [38] and updated during the REALISEGRID [39] project (for details see Ref. [11]). We consider country specific capacity factors for wind and solar availability from Ref. [20], except for Austria, where data is modelled in detail.

The JRC-EU-TIMES model is calibrated for 2005 and validated for 2010 and 2015 (2015 at the time of writing was in fact an average of the 2011–2012 period). The model results are checked for

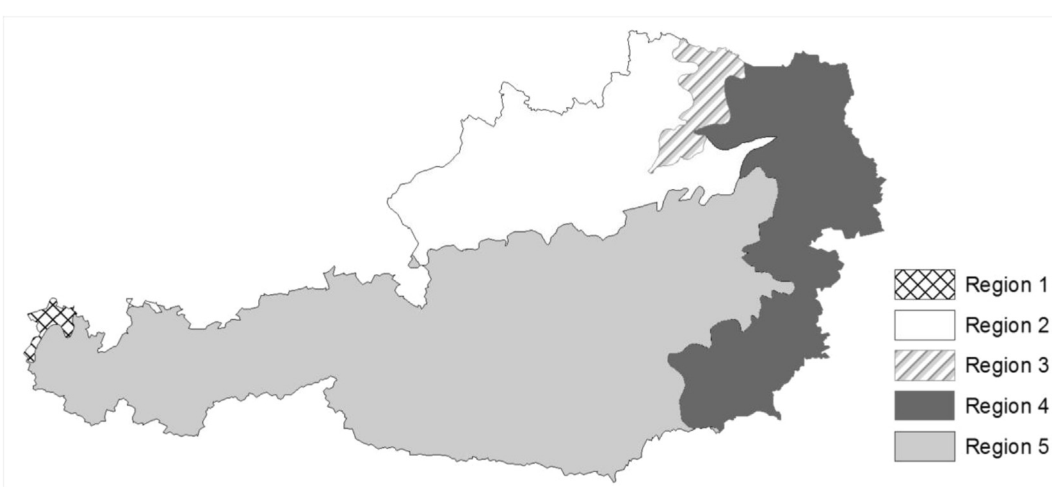

Fig. 4. The 5 PV regions.

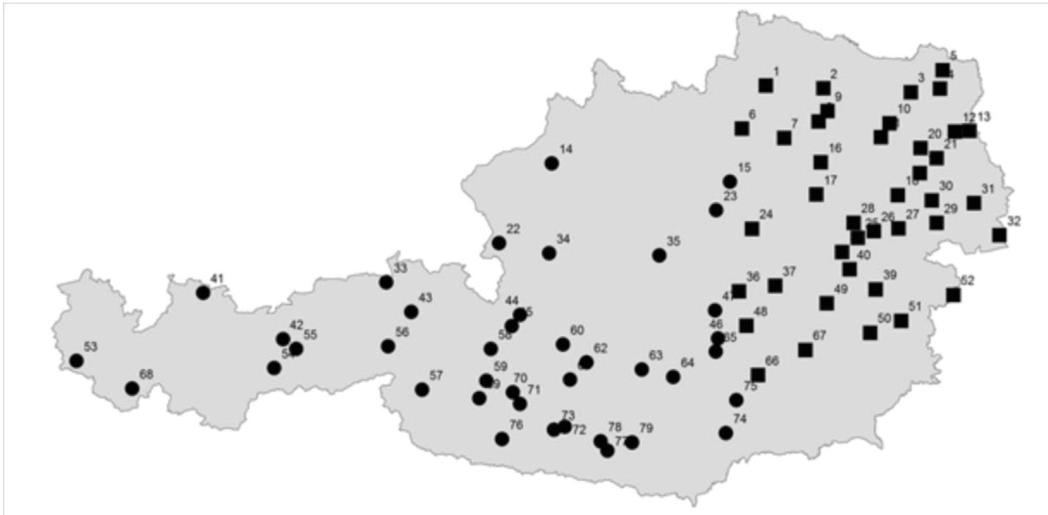

Fig. 5. Wind regions in Austria considered in the JRC-EU-TIMES model. Note: The numbers correspond to the number of the regions in the 79 region case. Boxes and circles indicate to which aggregation region the corresponding location belongs in the 2 region case.

consistency and bugs with the PRIMES model results used to support the European Commission's Energy policies. Moreover, the JRC-EU-TIMES model was subject to an in-depth peer-review by nine external experts during the autumn of 2013. This validation procedure is presented in detail in Ref. [11].

3.1.1. Solar data for Austria

In order to determine PV potentials in Austria we use hourly PV output data in Wh per 1 kWp installed capacity. The spatial resolution is 1km2. The calculation of PV energy output for a given location is made for fixed-mounted PV systems using crystalline silicon modules, facing south at the locally optimal angle, based on the algorithms described in Ref. [41], with the calculation of the optimum angle given in Ref. [42]. The solar radiation data are hourly values taken from the Climate Monitoring Satellite Application Facility (www.cmsaf.eu) [43]. Temperature data are from the ECMWF ERA-interim reanalysis (www.ecmwf.int). The effects of temperature and irradiance on the PV performance is calculated according to the model in Ref. [44].

The model distinguishes between rooftop and plant size PV systems. Since PV modules allow high flexibility concerning installation, policy makers mostly prefer building integrated/rooftop PV systems. The Austrian Energy Strategy states that the largest potential of PV deployment lies in building integration [34]. However, only rough estimations of available roof areas exist [45,46]. We perform a more detailed spatial estimation based on a regression analysis of a detailed solar potential cadastre for Austria's federal state of Vorarlberg [47]. Regression results are used to predict roof areas for the whole of Austria (see Appendix B), resulting in a total roof area available for PV of 902 km^2. Based on previous analysis of Vorarlberg in Ref. [48] the share of roof area where the installation of PV modules is technically feasible amounts to 26.69% on average. By applying this share, Austria's roof area effectively usable for PV production is 241 km^2. We assume that 8 m^2 are needed to install 1 kWp. We thus divide the total rooftop area by 8 and multiply it with the hourly solar PV output time series. This gives us the hourly PV output per 1 km^2. We aggregate the grid cells of 1 km^2 into 5 regions (see Fig. 4) with distinct climatic conditions based on the “Digital Map of European Ecological Regions DMEER”. For plant size PV data we use the potential that was estimated in the of RES2020 project [38] and allocate capacities across regions proportionally to their size.

3.1.2. Wind data

The Austrian wind atlas [49] provides the scale and shape parameters of the Weibull distribution of wind on a 100 m*100 m grid for Austria which we complement with hourly wind data from 265 meteorological stations to generate simulated time series of wind power production. The pre-processing of the wind atlas data includes the definition of feasible locations for placing wind turbines by using a geographic information system (GIS). The complete modelling steps are outlined in Ref. [2] and involve the exclusion of areas such as forests, transportation networks, settlements, and bodies of water. The remaining locations are reduced further by filtering locations which are economically infeasible by calculating LCOE for all locations and excluding the ones with LCOE above current feed-in tariff levels. We do so to reduce the number of feasible locations and therefore computational requirements within TIMES.

To generate time series of wind power production, randomly drawn wind speeds from the Weibull distributions are reordered to correlate with historical measured time series of wind speeds at the respective meteorological station using the Iman-Conover method [50], described in detail in Ref. [2].

The methodology results in 79 time series of wind power production at potential locations in Austria, shown in Fig. 5. To test the difference in JRC-EU-TIMES′ results with respect to different geographical aggregations, we aggregated the single 79 locations by generating two equally sized regions for Austria. The locations of the 79 and 2 regions are illustrated in Fig. 5.

3.2. Modelling of wind and PV electricity generation technologies in JRC-EU-TIMES

With respect to the modelling of the wind and solar (PV) climatic aspects in JRC-EU-TIMES, we have adopted a simplified modelling approach. We introduce changes in the model for Austria only. The generic wind and PV electricity generation technologies (not disaggregated) are presented in Appendix C. We created specific wind and PV electricity generation technologies for each of the regions in Austria for which the wind and solar resources availability were identified to be different. The assumptions on

Table 2
- Scenarios modelled in JRC-EU-TIMES.

Scenario name	Long term CO_2 cap in 2050 compared to 1990 emission levels[a]		Number of wind regions	Number of solar regions
	40% less	80% less[b]		
r1	X		1	1
r1c		X	1	1
r2	X		2	5
r2c		X	2	5
r79	X		79	5
r79c		X	79	5

[a] We include the national RES targets, biofuel targets and the EU ETS target till 2020. After 2020 we include the recent policy framework for climate and energy in the period from 2020 to 2030 [16], with the EU wide RES target of 27% in 2030, the EU-ETS trajectory from −43% in 2030 and -87% in 2050, and the EU-wide energy related CO_2 cap of −43% emissions than in 1990 in 2030, kept constant till 2050.

[b] The long-term CO_2 cap is applied for the whole of the EU with less 43% energy related CO_2 emissions in 2030 than in 1990, gradually reduced till less 80% in 2050.

investment costs, availability factor (AF) per time-slice and total generation potential can be found for each region in Appendices D and E. All other technology characteristics are kept identical to the country generic technologies. The AF is a TIMES model input that indicates the maximum percentage of a time-slice in which the technology can operate (i.e. without maintenance stops and/or stops due to low availability of variable RES), and thus is a function of the availability of wind and sun. In JRC-EU-TIMES the AF differs for each technology in each of the 12 time-slices considered in the model. The AF data for PV represents an average year and for wind the average of 6 years. We did not test extreme RES availability nor the impact of inter-annual variability, i.e. variations between different years. Regarding investment costs for each disaggregated technology across the 79 wind regions, we considered a cost difference reflecting the different costs for connecting to the grid based on the distance to the closest grid connection point. As a proxy for available grid connection points, we used locations of existing power plants (thermal, hydro, existing wind) and locations of settlements. The distances calculated are in the interval of 440 m and 9000 m. We assumed installation costs of 50 000€ per km transportation line [51] and that each wind turbine is individually connected to the grid. The cost estimate is therefore conservative, as in reality wind turbines which are close by can use the same transportation line. We assumed no difference in costs across solar regions. PV usually feeds into the distribution grid and the differences in grid upgrades are locally specific and can thus not be taken into account in a countrywide study.

Using JRC-EU-TIMES, we model a total of six scenarios from 2005 to 2050 with the following variations in the level of aggregation of wind and solar climatic data (Table 2):

i) Aggregated scenarios: Wind and PV RES technologies aggregated to one region in two scenarios for the whole of Austria with a 40% or 80% gradual EU-wide CO_2 cap up to 2050;
ii) Regional scenarios: Spatially differentiated wind and PV RES technologies across Austria in four scenarios considering 2 and 79 wind regions and always 5 PV regions with a 40% or 80% gradual EU-wide CO_2 cap up to 2050.

For all scenarios we consider the national RES target of Austria which is 34% of RES in the final energy consumption as outlined in the EU RES Directive [33]. All scenarios have in common the following assumptions: i) No consideration of specific RES policy incentives (e.g. feed-in tariffs, green certificates) as the objective is to assess deployment based solely on cost-effectiveness; ii) a maximum of 50% electricity can be generated from solar and wind and wind and solar PV cannot operate during the winter peak time-slice to account for concerns related to system adequacy and variable RES (see Ref. [11] [52] for details and motivation); iii) Countries without nuclear power plants (NPPs) will not install any in the future (Austria, Portugal, Greece, Cyprus, Malta, Italy, Denmark and Croatia). NPPs in Germany are not operating after 2020 and Belgium NPPs are not operating after 2025. Until 2025 the only new

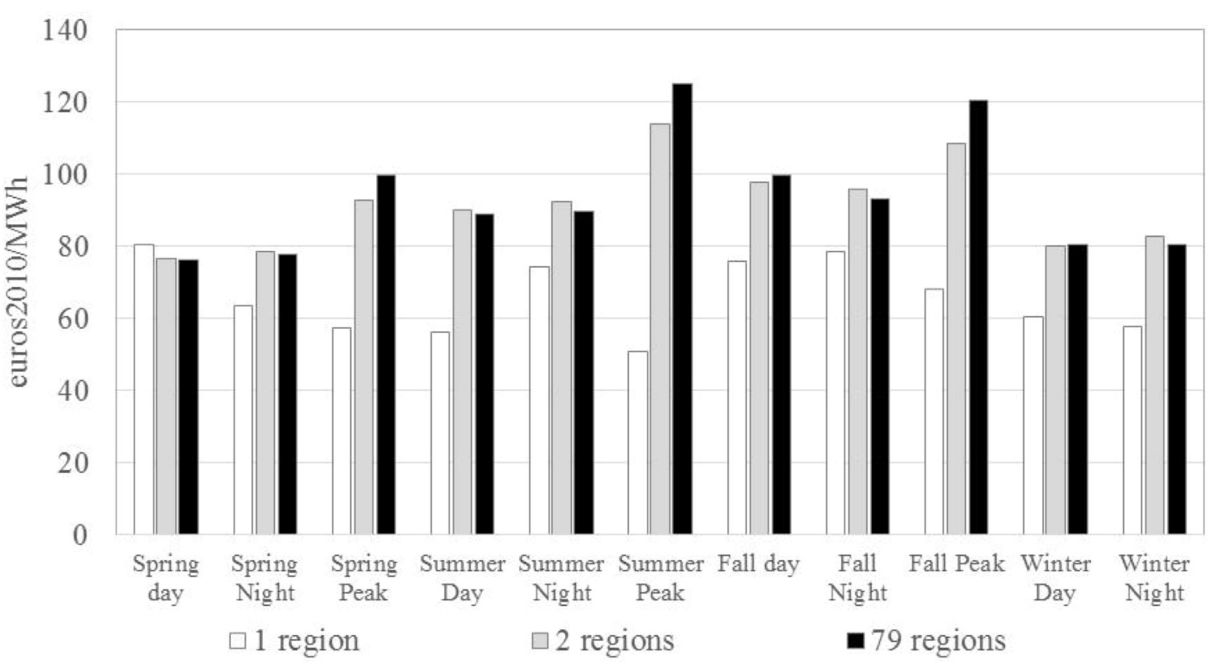

Fig. 6. Values of LCOE for wind electricity for the different levels of spatial aggregation estimated for the year 2020 per time-slice considering an 8% discount rate and 20 years technology lifetime. We have considered the median values of LCOE for the 2 and 79 regions.

Table 3
Generated electricity from PV and wind in Austria for the different spatial aggregation scenarios, considering both new and existing plants for both the 40% and 80% caps.

Scenario[a]	Total (TWh)			Wind (TWh)			PV (TWh)		
	2020	2035	2050	2020	2035	2050	2020	2035	2050
r1	95.73	100.92	101.52	9.09	15.94	15.94	0.47	4.13	10.17
r2	94.35	100.33	101.77	7.82	15.94	15.94	0.34	1.08	10.42
r79	93.94	100.34	101.77	7.40	15.94	15.94	0.34	1.08	10.42
r1c	96.17	99.74	119.04	9.09	15.94	15.94	0.47	4.13	25.09
r2c	94.61	99.29	118.68	7.82	15.94	15.94	0.34	5.59	24.76
r79c	88.65	99.28	118.68	1.85	15.94	15.94	0.34	5.59	24.76

[a] For solar only 5 regions of climatic data were considered (common to r2 and r79 scenarios) versus one region (r1). The results for PV electricity for r79 scenarios are identical to r2. The results for years before 2020 are identical and were not included.

NPPs to be deployed in EU28 are the ones being built in Finland and France and under discussion in Bulgaria, Czech Republic, Slovakia, Romania and United Kingdom. After 2025 all plants under discussion can be deployed but no additional projects are considered.

For each scenario we have run the model for the whole of EU28 in order to assess the interactions between Austria and neighbouring countries.

4. Results and discussion

In this section we assess the results of disaggregating wind and solar climatic regions considering geographical differences for RES in terms of electricity generation and energy system costs. Except when otherwise mentioned, the results presented here refer solely to Austria. To understand the results we start by the considered model assumptions regarding technology costs and availability. We then analyse the effects on the electricity sector by using JRC-EU-TIMES: general impacts, specific impacts with a 40% and 80% CO_2 cap as well as the implications of geographical disaggregation on costs. We additionally performed a sensitivity analysis varying the wind investment costs by 20%, presented in the end of this section.

4.1. Regional differences in cost and availability for wind and solar PV installations

In this section we explain the results of generating regionally disaggregated JRC-EU-TIMES input data for wind and PV technologies. We analyse the regional differences for wind, both in terms of costs and availability (Appendix D). The costs across the 79 regions are different. However, the differences are smaller than the cost reductions induced by wind technology learning from one decade to the other (Appendix C). The wind capacity factors show significant regional differences for summer days and winter nights. The highest variation (not including the peak time-slices that only represent a small fraction of the year) is where the capacity factor is 48% lower and 75% higher than the aggregated single value for Austria. The effects in terms of estimated LCOE for wind power for the year 2020 are shown in Fig. 6 using the median of LCOE values estimated for each region in each level of aggregation. The LCOE values are indicative for the economic value and include regional information such as capacity factor and connection costs. With the exception of the spring day time-slice, the LCOE estimated for wind power in 2020 for the single region is lower than the median LCOE of the 2 and 79 regions. Indeed, the LCOE data is skewed because many regions have a LCOE that is lower than the average for all regions. The differences in terms of wind LCOE for one region and the median of the 79 regions are between less 5% (spring day) and more 147% (summer peak) depending on the time-slice.

Regarding solar input data for the five solar regions (Appendix E), there are no differences in costs across sites and there are smaller differences in availability across regions compared to wind. The difference between solar availability of the aggregated single value for Austria and the five regions varies between −13% and +13% depending on the time-slice. The differences in terms of solar LCOE in 2020 for one single region and the median of the five regions are between −21% and +4% depending on the time-slice.

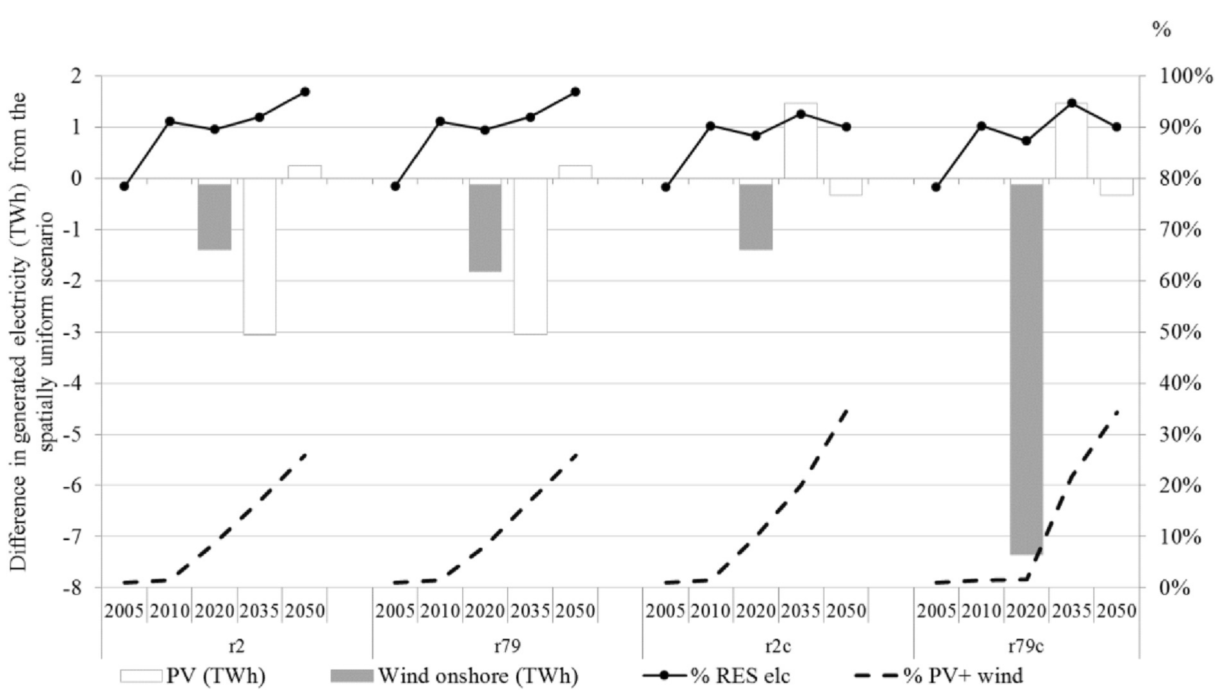

Fig. 7. PV and wind electricity production in Austria from 2005 till 2050 relative to the r1 and r1c aggregation (TWh, left scale); share of RES and variable RES (PV and wind) in total electricity production (%, right scale).

4.2. Effects of the spatial disaggregation in JRC-EU-TIMES

In the previous section we found that the regional variation of availability and costs for wind can be considerable. Without considering the other factors affecting the cost-effectiveness of wind in Austria (e.g. size of the regions, competing electricity technologies, shadow costs of CO_2, demand profile and trade with other countries), one would expect that the detailed spatial distribution would impact the energy system results for wind. However, it appears that in the case of solar in Austria the differences are seemingly not large enough to have a substantial impact on the JRC-EU-TIMES model results.

4.2.1. General effects on the electricity sector

Table 3 gives an overview of the impact of considering different levels of spatial aggregation for solar (1 and 5) and wind (1, 2, and 79) regions. The total electricity generated in Austria in the scenario with a 40% CO_2 cap shows small variations when disaggregating solar and wind climatic regions: 95.73 TWh in 2020, 100.92 TWh in 2030 and 101.92 TWh in 2050 for the one region scenario, r1, with differences of 1% or lower for the disaggregated scenarios. When including the stricter −80% CO_2 cap in 2050, because increased electrification is a mitigation strategy, the total generated electricity increases slightly to 96.17 TWh in r1c compared to 95.73 TWh in r1. This becomes more evident as the cap becomes more stringent in time. The differences in total generated electricity between the −80% cap disaggregated scenarios and r1c are of 2–8% in 2020 and 1% or lower in 2035 and 2050.

Fig. 7 shows PV and wind electricity production in Austria from 2005 till 2050 relative to the r1 and r1c aggregation as well as the share of RES and variable RES (PV and wind) in total electricity production. Both the cumulative share of PV plus wind generated electricity and the share of total RES electricity do not vary with the level of spatial aggregation (2–26% of total electricity from 2010 to 2050 in −40% CO_2 cap scenarios and 2–34% in the −80% cap scenarios). However, there are variations in the relative contribution of PV and of wind, showing that these technologies are competing with each other. Note that in the 80% cap scenarios in 2050 the total share of RES electricity in Austria is smaller than in 2035. This is because with this stringent CO_2 cap, the maximum RES potential is already deployed (for wind, solar and hydro) and biomass is required as biofuel in transport. Thus, it becomes cost-effective to install 1.44 GW CHP gas plants.

The results for wind and solar generated electricity are affected by the increasing stringency of the considered EU wide CO_2 caps. As the stringency in the caps increases towards 2050, the differences due to spatial disaggregation become less pronounced. This can be explained by the fact that more RES electricity is necessary to ensure the mitigation targets. Therefore, it then becomes cost-effective to deploy all technically possible RES power plants, regardless of location. Moreover, although in this paper we focus on Austria, the EU wide CO_2 caps also affect the configuration of the neighbouring countries' energy system, and thus their electricity trade with Austria.

4.2.2. Effects on the electricity sector considering a 40% CO_2 cap

4.2.2.1. Wind 2020. In 2020 considering spatially explicit wind climatic data (e.g. non uniform average investment costs and capacity factors) lowers the wind plants' cost-effectiveness. This leads to a decrease of wind generation in the disaggregated scenarios of 1.27 TWh to 1.69 TWh compared to the one region scenarios (i.e. a decrease of 14–19% wind generation) for the scenarios with the 40% cap. We explain this effect for r1 and r2 scenarios as a combination of both the capacity factor and investment costs across regions. When considering only one average wind region for the whole of Austria, the average investment cost for new plants in 2020 is of 1602 $euros_{2010}$/kW which can be deployed in 2020 up to a maximum potential of 7.97 TWh. When disaggregating in r2 for two wind regions, region 1 has an investment cost of 1633 $euros_{2010}$/kW and region 2 of 1596 $euros_{2010}$/kW. In addition, r2 has a higher capacity factor during the time-slices winter day, winter night and fall night, when the demand is higher. Thus, new wind power plants are deployed in region 2 up to its maximum potential, equivalent to 6.70 TWh in 2020, but not in region 1. Note that we include electricity generated from new and existing plants. The latter are not subject to model optimization and generate in 2020 1.12 TWh in all scenarios. Besides the difference in costs, the different capacity factors play an important role. The regions with annual wind availability profiles that, either individually, or as a group, or in combination with PV availability, follow the electricity demand, are preferred.

4.2.2.2. Wind 2035 and 2050. With the assumed technology cost decrease and increased stringency of CO_2 caps, in 2035 and 2050 wind onshore in Austria is so cost-effective that it is deployed up to its maximum technical potential (8.30 GW corresponding to 15.94 TWh). With these assumptions and for these periods, the level of spatial disaggregation does not add value in model results, as there are no differences in wind deployment across scenarios.

4.2.2.3. Solar 2020 and 2035. In the case of electricity generated from PV, considering 5 solar regions (scenarios r2 and r79) instead of one (r1) leads to differences mostly in 2035 and less in 2050. For simplification here we compare only r1 and r2, i.e. the scenarios with a CO_2 cap of 40%. In 2020 and 2035, considering more regions leads to a loss in cost-effectiveness of PV (a decrease of 0.12 TWh and 3.06 TWh in r2 compared to r1 in 2020 and 2035, i.e. a decrease of 27% and 74% of PV electricity).

4.2.2.4. Solar 2050. In 2050 PV generated electricity from r2 is 2% higher than from r1. This is because in 2050 the assumed decrease in PV costs and increase in CO_2 cap stringency makes PV cost-effective enough to become less sensitive to regional disaggregation, similarly to what happens to wind in 2035 and 2050. In other words, under the 40% CO_2 cap even solar regions with a lower capacity factor become cost-effective enough to be deployed, although not up to the maximum capacity.

Also in 2050, roof sized PV reaches the maximum potential in r2 only in two out of the five in regions 2 and 3 (6.25 TWh), where the annual profile of the capacity factor follows more closely the demand profile. It is worth mentioning that region 3 has higher overall solar availability and correspondingly is the first to be deployed. Region 2 is preferred over the other regions as it has a higher capacity factor during the winter day time-slice. Thus, similarly to wind plants, these intra-annual variations are relevant in defining the cost-effectiveness of a certain region as considered by the JRC-EU-TIMES model.

4.2.3. Effects on the electricity sector considering an 80% CO_2 cap

We discuss here the effects on the electricity sector considering an 80% cap as they are stronger compared to the 40% case. Both CO_2 targets show a similar effect of decreased cost-effectiveness of wind power plants with an increase in the spatial resolution.

4.2.3.1. Wind 2020. In 2020, the differences in wind power plants between r1c and the other disaggregated scenarios increase in magnitude when compared to the −40% CO_2 cap scenarios. With disaggregation a decrease of 1.27–7.24 TWh of wind power is observed in 2020 (i.e. a decrease of 14–80% compared to r1c). For the 80% cap scenarios, the differences between disaggregating into

2 or more regions are more relevant than with the 40% cap. In r1c and r2c it is cost-effective to deploy additional new wind plants in 2020 up to the maximum potential in r1 (7.97 TWh) and of only region 2 in r2c (6.70 TWh), similarly to what happened for r1 and r2. In r79c, only 7 regions with the higher wind availability are selected for deploying new wind power plants (1.85 TWh).

This is because the sensitivity of the model results to spatial disaggregation depends on the relative cost-effectiveness of the wind power plants within the Austrian and the EU28 energy system. The combined effect of lower cost-effectiveness of wind in Austria and the EU-wide 80% CO_2 cap also affects the energy system of the neighbouring countries. This makes it more cost-effective to use gas power plants in Germany than deploying wind power plants in Austria. In r79c 7.08 TWh of gas electricity are generated in Germany in 2020, which is not the case when wind is more cost effective (as in all the 40% scenarios and in r1c and r2c). It is more cost-effective to deploy less new wind power plants in r79c in Austria and reduce electricity exports from Austria to Germany.

4.2.3.2. Solar 2020 and 2035. Regarding PV generated electricity with the 80% CO_2 cap, spatial disaggregation leads to similar results as in the 40% cap up to 2020 (i.e. lower cost-effectiveness). However, for 2035 there is an opposite behaviour with disaggregation resulting in increased cost-effectiveness (in 2035 1.46 TWh or an increase of 35% of electricity generation from PV in r2c than in r1c). This is due to the more stringent CO_2 cap that makes PV plants more cost-effective than for the 40% cap as more electricity is needed regardless of spatial disaggregation. In the 40% scenarios in 2050 101.52–101.77 TWh are generated in total in Austria, whereas in the 80% scenarios this value is of 118.68–119.04 TWh.

In 2050 the differences in results due to disaggregation in terms of generated electricity from PV are marginal (as for the 40% cap).

4.2.4. Cost implications

We analyse the system costs for the different scenarios. System costs are costs incurred to satisfy the demand for energy services for all 28 countries throughout the whole modelled period (from 2005 till 2050). For the analysis we need to consider that the spatial disaggregation performed only directly affects Austria, a relatively small country in the whole of EU. The disaggregation of the wind regions in Austria leads to an increase in total European energy system costs of approximately 2.09–3.16 billion $euros_{2010}$ (0.003% higher for r2c to 0.005% higher for r79 than in the one region scenario). This corresponds to approximately 0.01% of the 2050 EU28 GDP as considered in our exogenous macroeconomic scenarios underlying this exercise or to 0.7–1.0% of the 2013 Austrian GDP.

Choosing a single region (r1 scenario) leads to an overestimation of the wind and solar power plants' cost-effectiveness in 2020 and consequently to between 148 $Meuros_{2010}$ and 669 $Meuros_{2010}$ higher annual investments into the Austrian power sector compared to the regionally differentiated scenarios (r2c and r79 scenario). In 2050, the differences in electricity sector investments between the one region and more disaggregated scenarios vary from a decrease of 49 $Meuros_{2010}$ with a 40% CO_2 cap to an increase of 104 $Meuros_{2010}$ with an 80% CO_2 cap.

4.3. Sensitivity of results to wind investment costs

We have performed an ± 20% variation in the investment and operation & maintenance costs of the wind technologies, for which we had considered region specific costs to assess their sensitivity to spatial disaggregation. We have made this analysis for the 40% cap scenarios only for 1, 2 and 79 regions and the results are summarised in Table 4.

Table 4
Sensitivity of generated electricity from wind to spatial disaggregation when considering costs 20% higher or 20% lower wind costs. Results as % difference from baseline case.

Scenario	Wind generated electricity (%)				
	2005	2010	2020	2035	2050
r1 low cost	0%	0%	0%	0%	0%
r2 low cost	0%	0%	16%	0%	0%
r79 low cost	0%	0%	23%	0%	0%
r1c high cost	0%	0%	−88%	0%	0%
r2c high cost	0%	0%	−86%	−14%	0%
r79c high cost	0%	0%	−40%	−19%	0%

When decreasing 20% the costs of wind power plants the tendency of the baseline of achieving the maximum potential in 2035 is anticipated to 2020. With 20% more expensive wind plants, wind is less cost-effective than in the baseline case and the effects previously described for 2020 now become also evident for 2035. In 2020, for the 80% cap scenarios in the baseline there were only new wind plants deployed in r2c and r79c. With more expensive plants, there are no longer new plants in 2020 for any of the levels of spatial disaggregation. Besides this shift in the periods for which the results are visible, there are no significant changes in the results and effects of spatial disaggregation previously described.

5. Conclusions

In this paper we propose an approach to assess the relevance of spatial level of detail for modelling wind and PV within an energy system model for EU28, the JRC-EU-TIMES. We have used Austria as a case study for the period 2005 till 2050 considering scenarios with different solar and wind climatic regions. We studied effects of spatial aggregation on the electricity generated from wind and PV in Austria, both for a climate policy scenario aligned with the 2030 climate and energy framework extended to 2050 and a more strict 80% cap on 2050 energy related CO_2 emissions below 1990 emissions.

Results show that in the long term for a model with limited temporal disaggregation like the JRC-EU-TIMES model and only small regional climatic differences as in our case study, the effect of regional disaggregation on model results is small especially for the whole energy system of Austria and the entire European Union. Total energy system cost differ but the main effects can be seen in the power sector for Austria: Results show that more accurate modelling of wind and PV location and availability lead to significant differences in the generated electricity for both wind and solar in Austria in the medium-term. This is because the relevance of the effects of spatial disaggregation depends on the cost-effectiveness of wind and PV within the studied energy system prior to disaggregation. In the Austrian case-study wind power is so cost-effective that it is deployed to its maximum capacity by 2035 and in this case, spatial disaggregation does not translate into different model results. However, in the periods or policy scenarios in which the cost-effectiveness of wind and PV is close to the threshold, spatial disaggregation leads to differences in generated electricity up to 80% less of wind generation or 35% more PV generation. This indicates that, depending on the energy system, on the available resources and on the policy objectives, it is relevant to further address spatial disaggregation in large energy system models.

We conclude that Levelized Costs of Electricity (LCOE) approaches cannot capture the temporal variability and complex interactions with other energy system processes, such as the relevance of generating electricity in the peak time-slices, or the cheaper possibilities for electricity generated in neighbouring countries. Nonetheless, LCOE should still be used in a complementary format with a large system model when considering its disaggregation. We have found that with an energy system model it is not possible to establish a direct relationship between the level of disaggregation and an increase or decrease in the deployment of intermittent renewables, since several complementary mechanisms determine the cost-effectiveness of the regional power plants: the differences and distribution of the region specific costs when compared to the nationally aggregated average, the suitability of the regional wind and solar profile to fit with the demand profile, as well as the distance between the electricity generation and demand locations. Moreover, because wind and PV interact with the remaining energy technologies, the consideration of a less favourable regional distribution of the resources can lead to abandoning those resources in favour of higher electricity trade with neighbouring countries. Because of this, we believe that the effects of spatial disaggregation can differ depending on the uniformity of the climatic data across the modelled territory. Therefore, we propose to analyse *a priori* the need for further disaggregation in an energy system model using LCOE. In simplified terms this could be done as follows: when facing the trade-off between improved RES representation and increased energy system model complexity, we suggest performing an initial analysis of the regional disaggregated data such as using an LCOE approach. This should be accompanied by an analysis, within the considered energy system model, of the level of cost-effectiveness of the RES technologies in the aggregated format. If the technologies are either very close to the maximum technical potential or if they are very far from entering the optimal solution, regional disaggregation might not bring much added value.

Moving to a system with a high share of variable RES makes it important to find the appropriate spatio-temporal representation of RES in long-term energy system models. The approach proposed can be extended to the whole EU. Looking at a spatially disaggregated representation of renewables may have larger effects for countries where difference in renewable production between locations are more pronounced. This would allow a more realistic and accurate modelling of EU's energy system and the transition towards a low carbon future. Further work should be done in assessing the effects of temporal variation, and in deriving extreme values of power production from the time series (i.e. times of very high or very low production) and their probabilities.

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Appendices

Appendix A – overview of major JRC-EU-TIMES model inputs

The equilibrium of JRC-EU-TIMES is driven by the maximization (via linear programming) of the discounted present value of total surplus, representing the sum of surplus of producers and consumers, which acts as a proxy for welfare in each region of the model. The maximization is subject to constraints such as supply bounds for the primary resources, technical constraints governing the deployment of each technology, balance constraints for all energy forms and emissions, timing of investment payments and other cash flows, and the satisfaction of a set of demands for energy services in all sectors of the economy. The model includes the following sectors: primary energy supply; electricity generation; industry; residential; commercial; agriculture; and transport.

The model is supported by a detailed database, with the following main exogenous inputs: (1) end-use energy services and materials demand; (2) characteristics of the existing and future energy related technologies, such as efficiency, stock, availability, investment costs, operation and maintenance costs, and discount rate; (3) present and future sources of primary energy supply and their potentials; and (4) policy constraints and assumptions. Here we present a condensed version of the detailed model inputs further described in Ref. [11].

The materials and energy demand projections for each country are differentiated by economic sector and end-use energy service, using as a start point historical 2005 data and macroeconomic projections from the GEM-E3 model [12] as detailed in Ref. [11]. These projections have as an underlying assumption an overall average annual EU28 GDP growth of 1.5–2% till 2050 and a population evolution following the values considered in the EU Energy Roadmap 2050 reference scenario [14]. From 2005 till 2050 the exogenous useful energy services demand grows 32% for agriculture, 56% for commercial buildings, 28% for other industry, 24% for passenger mobility and almost doubles (97%) for freight mobility. On the other hand, the exogenous useful energy services demand for residential buildings is assumed to be 12% lower in 2050 than in 2005 due to the assumptions on improving building stock (see Ref. [11] for details).

Table 5
Exogenous useful energy services and materials demand input into JRC-EU-TIMES for EU28.

Year	Agric. (PJ)	H&C Comm. (PJ)	Other Comm. (PJ)	H&C Resid. (PJ)	Other Resid. (PJ)	Al (Mt)	NH_3 (Mt)	Cl. (Mt)	Other Industry (PJ)	Cement (Mt)	Cu (Mt)	Glass (Mt)	Iron & Steel (Mt)	Paper (Mt)	Passenger mobility [a] (Bpkm)	Freight mobility [a] (Btkm)
2005	1302	3567	3496	8591	2593	6	12	2006	6959	236	2	31	196	100	6577	2 132 426
2010	1353	3784	3777	8434	2834	6	12	2091	6886	251	2	33	185	101	6815	2 264 363
2015	1376	3973	4027	8282	3180	7	13	2215	7375	269	2	36	195	104	7128	2547882
2020	1435	4155	4284	7998	3317	7	14	2483	7984	298	2	41	197	111	7361	2844396
2025	1492	4292	4511	7660	3449	7	15	2613	8188	340	2	47	194	125	7558	3062411
2030	1540	4476	4790	7368	3554	7	16	2683	8340	363	2	52	186	134	7748	3316167
2035	1601	4669	5048	7075	3571	8	16	2670	8321	389	2	57	186	142	7898	3570264
2040	1618	4861	5304	6790	3602	7	17	2820	8503	417	2	62	187	153	8012	3780567
2045	1639	5007	5518	6482	3597	7	18	2912	8504	437	2	68	183	160	8078	3965027
2050	1724	5230	5803	6273	3622	7	20	3117	8924	475	2	75	173	170	8176	4191499

Note: H&C stands for heating and cooling including space heating and cooling plus sanitary water heating. Al stands for aluminium production; NH_3 for ammonia production, Cl for chlorine production and Cu for copper production. [a] Passenger and freight mobility in this table does not include aviation and navigation as these are represented in the model in PJ not in pkm or tkm.

Table 6
Primary energy import prices into EU considered in JRC-EU-TIMES in USD_{2008}/boe.

Fuel	2010	2020	2030	2040	2050
Oil	84.6	88.4	105.9	116.2	126.8
Gas	53.5	62.1	76.6	86.8	98.4
Coal	22.6	28.7	32.6	32.6	33.5

The energy supply and demand technologies for the base-year are characterized considering the energy consumption data from Eurostat to set sector specific energy balances to which the technologies profiles must comply. The new energy supply and demand technologies are compiled in an extensive database with detailed technical and economic characteristics. The most relevant source of this database for electricity generation technologies is [53] as summarised in Appendix B. We model both technology-specific discount rates using the values considered in the PRIMES model as in Ref. [14], and a discount rate of 5% for social discounting. For centralised electricity generation, we consider a discount rate of 8%, for CHP and energy-intensive industry 12%; 14% for other industry and commercial sector; 11% for freight transport, busses and trains; 17% for the residential sector, and 18% for passenger cars.

The current and future sources (potentials and costs) of primary energy and their constraints for each country in the model are detailed in Ref. [11]. In this paper we considered the reference fossil primary energy import prices into EU as in the Energy 2050 Roadmap [14] (Table 6).

Besides energy import, JRC-EU-TIMES also models extraction of primary energy resources (RES and fossil) and conversion into final energy carriers within the EU28+. These commodities' prices are endogenous and depend on the country specific resource extraction and conversion costs. The model considers crude oil, natural gas, hard coal, and lignite. More details are presented in Ref. [11]. A similar approach is used for bioenergy which considers different types of energy carriers as from agricultural and forestry products and residues to several waste streams.

Appendix B — details on the estimation of PV data

A high-resolution (1 m^2) solar potential cadastre of Austria's federal state of Vorarlberg allows the identification of the roof-area potentially available for the installation of PV in Vorarlberg. In order to estimate Austria's total roof area available for PV installations, building stock data (with a 1 km^2 resolution) of the Austrian statistical office [54] has been used. This provides us with the number of employees, the effective useful building area and the total number of buildings per 1 km^2. By geo-referencing and overlaying these two data sets, the region of Vorarlberg can be used to predict the distribution of available roof area of the entire Austrian territory. In a first step this is done by developing a simple regression model in order to find determinants influencing the spatial distribution of roof areas in Vorarlberg:

$$roof_{area} = \beta_0 + \beta_1 occup + \beta_2 use_{area} + \beta_3 Nr_{build} + \varepsilon \qquad (1)$$

where

$roof_{area}$ = roof area available for PV production as provided by the solar cadastre aggregated to 1 km^2 cells
$occup$ = number of employees per 1 km^2
use_{area} = effective useful building area per 1 km^2
Nr_{build} = total number of buildings per 1 km^2
$\beta_0..\beta_3$ = Regression coefficients

In a second step, this linear regression model is applied to predict the spatial distribution of roof area for all 1 km^2 grid cells in the Austrian territory.

Appendix C — assumptions on techno-economic characteristics for electricity generation technologies considered in JRC-EU-TIMES (excludes CHP)

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 (%)
		2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
Hard coal/ lignite	Subcritical	1365/ 1552	1365/ 1552	1365/ 1552	1365/ 1552	27/33	27/ 33	27/ 33	27/ 33	37/ 35	38/ 35	39/ 37	41/ 38	35	80/75	0
600 MWel	Supercritical	1705/ 1552	1700/ 1856	1700/ 1856	1700/ 1856	34/39	34/ 39	34/ 43	33/ 45	45/ 43	46/ 45	49/ 47	49/ 49	35	80/75	0
	Fluidized bed	2507/ 2758	2507/ 2489	2507/ 2247	2507/ 1830	50/55	50/ 50	50/ 45	50/ 37	40/ 36	41/ 37	44/ 40	46/ 43	35	75/75	0
	IGCC	2758/ 3009	2489/ 2716	2247/ 2451	1830/ 1996	55/48	50/ 43	45/ 39	37/ 32	45/ 42	46/ 44	48/ 48	50/ 51	30	80/75	0
	Supercritical + post comb capture		2450/ 2555	2209/ 2479	2018/ 2381		43/ 49	41/ 43	34/ 38	30/ 29	32/ 31	36/ 35	39/ 38	35	75/75	88
	Supercritical + oxy-fuelling capture		3028/ 3330	2287/ 2516	1876/ 2063		38/ 45	37/ 41	31/ 35	28/ 27	31/ 30	36/ 35	40/ 39	35	75/75	90
	IGCC pre-comb capture		2689/ 2953	2447/ 2366	2030/ 2006		47/ 71	40/ 64	38/ 58	31/ 30	33/ 32	39/ 38	44/ 42	30	75/75	89
Natural Gas	Steam turbine	750	750	750	750	19	19	19	19	42	42	42	43	35	45	0
550 MWel	OCGT Peak device advanced	568	568	568	568	17	17	17	17	42	45	45	45	15	20	0
	Combined-cycle	855	855	855	855	26	21	20	20	58	60	62	64	25	60	0
	Combined-cycle + post comb capture		1244	1155	1093		44	41	39	42	44	49	53	25	55	88
	OCGT Peak device conventional	486	486	476	472	12	12	12	12	39	39	40	41	15	20	0
Nuclear 1000	3rd generation LWR planned	5000	5000	5000	5000	specific values for each reactor from IAEA										
MWel	3rd generation non-planned	5000	4625	4250	3500	43	43	42	42	34	34	36	36	50	82	0
	4th generation Fast reactor				4400	91	85	80	69	34	34	36	40	50	82	0

(*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 (%)
		2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
Wind onshore	Wind onshore 1 low/2 medium (IEC class III/II)	1300/ 1400	1200/ 1270	1050/ 1190	950/ 1110	32/34	25/ 27	23/ 24	20/ 21	100	100	100	100	25	16/21	0
	Wind onshore 3 high/very high (IEC class I/S)	1600/ 1700	1380/ 1430	1270/ 1320	1190/ 1240	36/40	29/ 32	27/ 29	25/ 27	100	100	100	100	25	30/40	0
Wind offshore	Wind offshore 1 low/medium (IEC class II)	2500/ 3000	2000/ 2600	1800/ 2380	1500/ 1950	106/ 106	80/ 80	63/ 63	54/ 54	100	100	100	100	25	15/32	0
	Wind offshore 3 high deeper waters (IEC class I)/4 very high floating	4300/ 6000	3400/ 4200	2700/ 3300	2100/ 2700	130/ 170	95/ 120	75/ 90	60/ 70	100	100	100	100	25	40/51	0
Hydro	Lake very small hydroelectricity <1 MW	7300/ 1800	7300/ 1800	7300/ 1800	7300/ 1800	73/18	73/ 18	73/ 18	73/ 18	100	100	100	100	75	42	0
	Lake medium scale hydroelectricity 1–10 MW	5500/ 1400	5500/ 1400	5500/ 1400	5500/ 1400	55/14	55/ 14	55/ 14	55/ 14	100	100	100	100	75	42	0
	Lake large scale hydroelectricity > 10 MW	4600/ 1200	4600/ 1200	4600/ 1200	4600/ 1200	46/12	46/ 12	46/ 12	46/ 12	100	100	100	100	75	38	0
	Run of River hydroelectricity	1454	1712	1575	1575	15	17	16	16	100	100	100	100	75	36	0
Solar	Solar PV utility scale fixed systems > 10 MW	3165	895	805	650	47	13	12	10	100	100	100	100	30	24	0
	Solar PV roof <0.1 MWp/0.1–10 MWp	3663/ 3378	1420/ 1065	1135/ 850	775/675	55/51	21/ 16	17/ 13	12/ 10	100	100	100	100	30	24	0
	Solar PV high concentration	6959	2698	2157	1473	104	40	32	22	100	100	100	100	30	27	0
	Solar CSP 50 MWel	5200	2960	2400	1840	104	89	72	37	100	100	100	100	30	35	0
Biomass	Steam turbine biomass solid conventional	3069	2595	2306	2018	107	91	81	71	34	35	36	38	20	90	0
	IGCC Biomass 100 MWel	3960	3574	3225	2627	139	125	113	92	37	37	43	48	20	90	0
	Biomass with carbon sequestration	4297	3373	2652	2321	150	118	93	81	33	34	35	36	20	61	85
	Anaerobic dig. biogas + gas engine 3 MWel	3713	3639	3566	3426	130	127	125	120	36	38	40	45	25	80	0
Geothermal	Geo hydrothermal with flash power plants	2400	2200	2000	2000	84	77	70	70	100	100	100	100	30	90	0
	Enhanced geothermal systems	10000	8000	6000	6000	350	280	210	210	100	100	100	100	30	90	0
Ocean	Wave 5 MWel	5650	4070	3350	2200	86	76	67	47	100	100	100	100	30	22	0
	Tidal energy stream and range 10 MWel	4340	3285	2960	2200	66	62	59	47	100	100	100	100	30	22	0

Appendix D – assumptions on wind technologies for the different considered spatial resolution levels

Scenario	Region	Investment cost euros 2010/kW				Availability factor												Max Pot TWh gen electricity		
		2010	2020	2030	2050	FD	FN	FP	RD	RN	RP	SD	SN	SP	WD	WN	WP	2015	2020	2030 and 2050
1r	n.a.	1766	1554	1483	1384	0.24	0.26	0.22	0.30	0.31	0.25	0.25	0.26	0.20	0.33	0.34		5.23	10.47	20.94
2r	Region 1	1800	1584	1512	1411	0.27	0.25	0.24	0.35	0.31	0.29	0.32	0.28	0.26	0.28	0.26		0.83	1.66	3.33
2r	Region 2	1759	1548	1478	1379	0.24	0.27	0.22	0.29	0.31	0.24	0.24	0.26	0.19	0.34	0.35		4.40	8.80	17.61
79r	Region 1	1734	1526	1457	1360	0.21	0.26	0.14	0.32	0.35	0.19	0.24	0.28	0.11	0.32	0.34		0.01	0.01	0.03
79r	Region 2	1774	1561	1490	1391	0.24	0.27	0.19	0.33	0.33	0.21	0.27	0.28	0.16	0.31	0.32		0.00	0.01	0.01
79r	Region 3	1740	1531	1461	1364	0.28	0.28	0.28	0.25	0.26	0.25	0.23	0.22	0.22	0.37	0.38		0.00	0.00	0.00
79r	Region 4	1750	1540	1470	1372	0.23	0.28	0.19	0.27	0.31	0.21	0.24	0.28	0.16	0.34	0.36		0.01	0.01	0.02
79r	Region 5	1745	1536	1466	1368	0.23	0.28	0.17	0.32	0.35	0.25	0.22	0.25	0.15	0.33	0.35		0.00	0.01	0.01
79r	Region 6	1724	1517	1448	1352	0.27	0.28	0.28	0.30	0.30	0.31	0.20	0.23	0.18	0.33	0.33		0.01	0.02	0.04
79r	Region 7	1726	1519	1450	1353	0.30	0.28	0.31	0.28	0.25	0.30	0.20	0.20	0.21	0.37	0.37		0.01	0.01	0.02
79r	Region 8	1767	1555	1485	1386	0.22	0.24	0.18	0.35	0.33	0.25	0.28	0.27	0.21	0.31	0.30		0.01	0.01	0.02
79r	Region 9	1768	1556	1485	1386	0.22	0.28	0.17	0.33	0.38	0.18	0.25	0.29	0.12	0.28	0.30		0.08	0.17	0.33
79r	Region 10	1740	1531	1461	1364	0.26	0.29	0.23	0.30	0.31	0.24	0.20	0.21	0.15	0.35	0.34		0.00	0.00	0.01
79r	Region 11	1729	1522	1453	1356	0.24	0.26	0.20	0.28	0.28	0.22	0.24	0.27	0.19	0.35	0.35		0.01	0.01	0.02
79r	Region 12	1752	1542	1472	1374	0.23	0.27	0.20	0.27	0.31	0.21	0.24	0.27	0.16	0.33	0.34		0.09	0.18	0.35
79r	Region 13	1749	1539	1469	1371	0.24	0.28	0.21	0.27	0.30	0.21	0.20	0.23	0.13	0.36	0.37		0.01	0.03	0.06
79r	Region 14	1731	1524	1454	1357	0.17	0.20	0.15	0.31	0.34	0.24	0.19	0.20	0.13	0.40	0.42		0.05	0.09	0.19

(*continued on next page*)

(*continued*)

Scenario	Region	Investment cost euros 2010/kW				Availability factor												Max Pot TWh gen electricity		
		2010	2020	2030	2050	FD	FN	FP	RD	RN	RP	SD	SN	SP	WD	WN	WP	2015	2020	2030 and 2050
79r	Region 15	1740	1532	1462	1364	0.24	0.28	0.19	0.30	0.34	0.22	0.20	0.22	0.13	0.38	0.39		0.01	0.01	0.03
79r	Region 16	1742	1533	1463	1366	0.23	0.26	0.18	0.28	0.32	0.22	0.26	0.32	0.19	0.35	0.37		0.00	0.00	0.01
79r	Region 17	1758	1547	1477	1378	0.24	0.24	0.25	0.29	0.28	0.29	0.22	0.21	0.21	0.38	0.39		0.00	0.01	0.01
79r	Region 18	1747	1538	1468	1370	0.20	0.27	0.14	0.29	0.35	0.15	0.22	0.27	0.11	0.35	0.37		0.00	0.00	0.00
79r	Region 19	1758	1547	1477	1378	0.26	0.27	0.23	0.31	0.31	0.26	0.28	0.27	0.22	0.36	0.36		0.00	0.00	0.00
79r	Region 20	1739	1530	1460	1363	0.21	0.25	0.18	0.27	0.30	0.20	0.24	0.27	0.17	0.34	0.36		0.01	0.01	0.03
79r	Region 21	1746	1537	1467	1369	0.23	0.28	0.20	0.29	0.31	0.21	0.25	0.28	0.17	0.35	0.37		0.15	0.30	0.61
79r	Region 22	1777	1564	1493	1393	0.21	0.24	0.12	0.42	0.39	0.30	0.32	0.29	0.18	0.32	0.33		0.02	0.04	0.07
79r	Region 23	1754	1543	1473	1375	0.24	0.28	0.17	0.29	0.32	0.19	0.23	0.27	0.14	0.35	0.36		0.07	0.13	0.27
79r	Region 24	1818	1600	1527	1425	0.28	0.31	0.23	0.33	0.34	0.19	0.27	0.28	0.15	0.33	0.33		0.05	0.11	0.21
79r	Region 25	1742	1533	1464	1366	0.22	0.25	0.20	0.28	0.32	0.23	0.23	0.27	0.18	0.36	0.37		0.00	0.01	0.01
79r	Region 26	1737	1529	1459	1362	0.25	0.25	0.26	0.30	0.29	0.28	0.29	0.28	0.29	0.29	0.29		0.01	0.02	0.04
79r	Region 27	1756	1546	1475	1377	0.24	0.27	0.20	0.34	0.34	0.23	0.30	0.31	0.21	0.32	0.33		0.00	0.00	0.00
79r	Region 28	1754	1544	1474	1375	0.26	0.29	0.27	0.32	0.35	0.32	0.30	0.31	0.28	0.26	0.29		0.00	0.00	0.00
79r	Region 29	1760	1549	1478	1380	0.25	0.26	0.22	0.30	0.32	0.25	0.28	0.28	0.27	0.29	0.30		0.00	0.00	0.01
79r	Region 30	1741	1532	1462	1365	0.26	0.26	0.23	0.28	0.29	0.21	0.22	0.23	0.16	0.36	0.37		0.00	0.01	0.01
79r	Region 31	1768	1556	1485	1386	0.24	0.25	0.24	0.31	0.32	0.29	0.21	0.21	0.17	0.37	0.38		0.00	0.00	0.00
79r	Region 32	1788	1573	1502	1402	0.22	0.26	0.18	0.29	0.34	0.22	0.25	0.30	0.17	0.30	0.33		0.05	0.10	0.20
79r	Region 33	1819	1601	1528	1426	0.28	0.28	0.18	0.37	0.36	0.26	0.32	0.28	0.18	0.29	0.31		0.01	0.01	0.03
79r	Region 34	1812	1595	1522	1421	0.25	0.32	0.18	0.30	0.33	0.19	0.30	0.33	0.18	0.31	0.34		0.04	0.08	0.16
79r	Region 35	1814	1596	1524	1422	0.28	0.27	0.21	0.37	0.32	0.30	0.33	0.29	0.22	0.32	0.29		0.03	0.05	0.10
79r	Region 36	1758	1547	1477	1378	0.24	0.31	0.23	0.24	0.32	0.19	0.21	0.26	0.14	0.33	0.36		0.02	0.03	0.06
79r	Region 37	1824	1605	1532	1430	0.33	0.24	0.21	0.43	0.29	0.41	0.41	0.26	0.47	0.29	0.24		0.00	0.01	0.01
79r	Region 38	1828	1608	1535	1433	0.31	0.28	0.34	0.27	0.24	0.30	0.27	0.24	0.31	0.40	0.37		0.13	0.25	0.51
79r	Region 39	1748	1538	1468	1370	0.30	0.29	0.32	0.32	0.30	0.34	0.30	0.28	0.34	0.29	0.29		0.05	0.10	0.21
79r	Region 40	1795	1580	1508	1408	0.27	0.29	0.29	0.27	0.28	0.28	0.24	0.24	0.25	0.33	0.35		5.23	10.47	20.94
79r	Region 41	1754	1543	1473	1375	0.31	0.27	0.17	0.37	0.31	0.21	0.35	0.33	0.17	0.25	0.21		0.00	0.00	0.00
79r	Region 42	1808	1591	1519	1418	0.27	0.24	0.19	0.40	0.28	0.29	0.35	0.22	0.21	0.27	0.25		0.00	0.00	0.00
79r	Region 43	1832	1612	1539	1436	0.25	0.21	0.27	0.34	0.27	0.38	0.26	0.18	0.27	0.34	0.34		0.00	0.00	0.00
79r	Region 44	1832	1612	1539	1436	0.27	0.25	0.18	0.40	0.30	0.22	0.35	0.27	0.20	0.27	0.26		0.00	0.00	0.00
79r	Region 45	1805	1588	1516	1415	0.26	0.26	0.18	0.43	0.32	0.33	0.37	0.30	0.25	0.20	0.19		0.00	0.00	0.00
79r	Region 46	1801	1585	1513	1412	0.30	0.19	0.37	0.42	0.27	0.44	0.35	0.22	0.38	0.29	0.21		0.00	0.00	0.00
79r	Region 47	1768	1556	1485	1386	0.22	0.27	0.18	0.30	0.33	0.21	0.25	0.28	0.16	0.32	0.34		0.00	0.00	0.00
79r	Region 48	1754	1544	1474	1375	0.23	0.27	0.15	0.37	0.32	0.24	0.29	0.26	0.16	0.29	0.29		0.00	0.00	0.00
79r	Region 49	1765	1553	1483	1384	0.24	0.24	0.21	0.32	0.33	0.27	0.32	0.31	0.28	0.27	0.28		0.00	0.00	0.00
79r	Region 50	1784	1570	1499	1399	0.23	0.25	0.15	0.35	0.32	0.24	0.30	0.30	0.16	0.27	0.25		0.00	0.00	0.00
79r	Region 51	1738	1529	1460	1362	0.22	0.27	0.18	0.34	0.36	0.25	0.28	0.31	0.20	0.28	0.28		0.00	0.00	0.00
79r	Region 52	1757	1546	1476	1378	0.24	0.29	0.21	0.33	0.36	0.24	0.24	0.27	0.17	0.32	0.34		0.00	0.00	0.00
79r	Region 53	1794	1578	1507	1406	0.25	0.25	0.22	0.34	0.35	0.23	0.27	0.28	0.17	0.28	0.26		0.00	0.00	0.00
79r	Region 54	1787	1573	1501	1401	0.26	0.20	0.25	0.42	0.32	0.41	0.31	0.24	0.26	0.29	0.25		0.00	0.00	0.00
79r	Region 55	1794	1579	1507	1407	0.28	0.25	0.30	0.30	0.28	0.30	0.28	0.27	0.27	0.29	0.28		0.00	0.00	0.00
79r	Region 56	1850	1628	1554	1450	0.23	0.26	0.22	0.36	0.36	0.26	0.29	0.31	0.22	0.25	0.23		0.00	0.00	0.00
79r	Region 57	1815	1597	1524	1423	0.22	0.27	0.13	0.39	0.34	0.21	0.35	0.33	0.16	0.22	0.22		0.00	0.00	0.00
79r	Region 58	1744	1535	1465	1367	0.25	0.26	0.20	0.35	0.34	0.22	0.29	0.31	0.18	0.27	0.24		0.00	0.00	0.00
79r	Region 59	1752	1542	1472	1374	0.26	0.26	0.27	0.25	0.25	0.26	0.17	0.18	0.18	0.38	0.39		0.00	0.00	0.00
79r	Region 60	1794	1579	1507	1407	0.25	0.26	0.26	0.23	0.27	0.22	0.16	0.18	0.15	0.39	0.40		0.00	0.00	0.00
79r	Region 61	1802	1586	1513	1413	0.27	0.28	0.24	0.27	0.30	0.24	0.25	0.26	0.20	0.33	0.33		0.00	0.00	0.00
79r	Region 62	1792	1577	1505	1405	0.26	0.21	0.22	0.37	0.29	0.29	0.33	0.25	0.27	0.31	0.26		0.00	0.00	0.00
79r	Region 63	1795	1580	1508	1407	0.28	0.24	0.16	0.36	0.29	0.21	0.35	0.31	0.19	0.26	0.22		0.00	0.00	0.00
79r	Region 64	1823	1605	1532	1430	0.26	0.24	0.15	0.36	0.33	0.24	0.33	0.29	0.19	0.28	0.24		0.00	0.00	0.00
79r	Region 65	1822	1603	1530	1428	0.27	0.20	0.21	0.43	0.27	0.34	0.38	0.23	0.31	0.29	0.21		0.00	0.00	0.00
79r	Region 66	1826	1607	1534	1432	0.31	0.30	0.19	0.28	0.28	0.18	0.26	0.25	0.21	0.31	0.29		0.00	0.00	0.00
79r	Region 67	1856	1633	1559	1455	0.32	0.31	0.33	0.26	0.22	0.29	0.25	0.22	0.27	0.32	0.32		0.00	0.00	0.00
79r	Region 68	1792	1577	1505	1405	0.28	0.23	0.21	0.31	0.26	0.27	0.36	0.27	0.28	0.28	0.26		0.00	0.00	0.00
79r	Region 69	1796	1580	1509	1408	0.24	0.25	0.17	0.40	0.36	0.28	0.35	0.31	0.25	0.26	0.22		0.00	0.00	0.00
79r	Region 70	1790	1575	1503	1403	0.23	0.24	0.20	0.32	0.31	0.26	0.30	0.28	0.26	0.32	0.31		0.00	0.00	0.00
79r	Region 71	1877	1652	1577	1472	0.21	0.26	0.16	0.36	0.36	0.23	0.32	0.32	0.21	0.24	0.24		0.00	0.00	0.00
79r	Region 72	1831	1611	1538	1435	0.29	0.23	0.35	0.35	0.25	0.40	0.40	0.29	0.50	0.25	0.20		0.00	0.00	0.00
79r	Region 73	1804	1587	1515	1414	0.21	0.26	0.13	0.40	0.33	0.24	0.38	0.33	0.25	0.22	0.23		0.00	0.00	0.00
79r	Region 74	1841	1620	1546	1443	0.21	0.22	0.15	0.42	0.36	0.31	0.35	0.30	0.25	0.23	0.23		0.00	0.00	0.00
79r	Region 75	1844	1623	1549	1446	0.29	0.24	0.29	0.39	0.33	0.38	0.29	0.23	0.27	0.29	0.26		0.00	0.00	0.00
79r	Region 76	1843	1622	1548	1445	0.25	0.27	0.16	0.38	0.29	0.25	0.43	0.32	0.36	0.20	0.20		0.00	0.00	0.00
79r	Region 77	1794	1579	1507	1406	0.32	0.25	0.37	0.33	0.23	0.42	0.28	0.18	0.38	0.33	0.30		0.00	0.00	0.00
79r	Region 78	1789	1574	1502	1402	0.28	0.24	0.36	0.39	0.34	0.39	0.34	0.29	0.34	0.24	0.20		0.00	0.00	0.00
79r	Region 79	1780	1566	1495	1396	0.26	0.21	0.17	0.44	0.32	0.30	0.44	0.30	0.34	0.22	0.17		0.00	0.00	0.00

Appendix E — assumptions on PV technologies for the different considered spatial resolution levels

Region	Technology	Max potential TWh generated electricity		Investment cost euros 2010/kW	Availability factor (identical plant size and the two types of roof size technologies)											
		2020	2050	2020	FD	FN	FP	RD	RN	RP	SD	SN	SP	WD	WN	WP
1	Plant size	0.03	0.06	895	0.20	0.00	0.00	0.27	0.01	0.12	0.30	0.01	0.64	0.07	0.00	0.00
	Roof size large	0.14	0.28	1745												
	Roof size small	0.03	0.28	2041												
2	Plant size	0.52	1.04	895	0.20	0.00	0.00	0.28	0.01	0.11	0.31	0.01	0.65	0.09	0.00	0.00
	Roof size large	1.46	2.93	1745												
	Roof size small	0.52	2.93	2041												
3	Plant size	0.04	0.07	895	0.20	0.00	0.00	0.31	0.01	0.25	0.34	0.01	0.68	0.08	0.00	0.00
	Roof size large	0.10	0.20	1745												
	Roof size small	0.04	0.20	2041												
4	Plant size		1.42	895	0.21	0.00	0.00	0.31	0.01	0.16	0.32	0.01	0.63	0.07	0.00	0.00
	Roof size large		4.01	1745												
	Roof size small	0.71	4.01	2041												
5	Plant size		1.29	895	0.19	0.00	0.00	0.29	0.01	0.09	0.32	0.02	0.68	0.08	0.00	0.00
	Roof size large		3.35	1745												
	Roof size small	0.64	3.35	2041												

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