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Citation	Nature Energy, vol. 3, pp. 494-500
Date	14.11.2018
DOI	10.1038/s41560-018-0137-9
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Effects of turbine technology and land use on wind power resource potential

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Article manuscript accepted for *Nature Energy*
doi:10.1038/s41560-018-0137-9

Abstract

Wind power potential estimates are relevant for decision making in energy policy and business. Those estimates are affected by several uncertain assumptions, most significantly related to wind turbine technology and land use. Here, we calculate the technical and economic onshore wind power potentials with the aim to evaluate the impact of those assumptions using the case study area of Finland as an example. We show that the assumptions regarding turbine technology and land use policy are highly significant for the potential estimate. Modern turbines with lower specific ratings and greater hub heights improve the wind power potential considerably even though it was assumed that the larger rotors decrease the installation density and increase the turbine investment costs. New technology also decreases the impact of strict land use policies. Uncertainty in estimating the cost of wind power technology limits the accuracy of assessing economic wind power potential.

The assessment of potentially available wind power generation over a certain geographical area can be divided into three phases, which all require significant amounts of data and assumptions. Geographical wind power potential refers to the land area available for wind turbine installations considering land use restrictions, technical potential to the (annual) electrical power generation at the geographical potential including losses and economic wind power potential to the technical potential that can be realised at costs below some reference level. [1] The required inputs are the wind resource data, choice of wind turbine technology including hub height, availability and efficiency of the wind power plants (WPPs), land use constraints as well as cost parameters for economic potential assessments. All these inputs contain inherent sources of uncertainty because assumptions have to be made for each study, or because of the lack of proper data.

Wind turbine development has seen a significant increase in all aspects of the turbine size: rated power, hub height, blade length and, consequently, the swept area [2–4]. This development has been made possible to a large extent by new materials as well as techniques and equipment for the erection of larger wind turbines. [5] Also blade designs are optimised in order to decrease material use and overall mass allowing longer and more efficient blades.

One of the key metrics in a turbine design is its *specific rating*: rated power per rotor swept area, expressed in watts per square meter ($\mathrm{W/m^2}$) [6]. Specific ratings of new installed wind turbines have been decreasing of late, as seen e.g. in the U.S. where the average specific rating of wind power projects installed between 1998 and 1999 was $394\ \mathrm{W/m^2}$ but had dropped to $246\ \mathrm{W/m^2}$ for projects installed in 2015 [4]. Low specific rating enables higher capacity factors also at sites with low to moderate wind speeds and taller towers reach higher and less perturbed winds [7], thus larger turbines have enabled decreasing levelized cost of electricity (LCOE) especially for sites with lower average wind speeds. Increasing hub height and rotor diameter also have greater potential in increasing annual production than improvements in turbine aerodynamics or other structures [5].

The power curve of a wind turbine describes the relationship between wind speed and generated output. Many studies use very coarse assumption on wind data (low heights [1, 8–12] or low horizontal resolution [1, 11–16]) or how the wind data is converted to power generation (not using a power curve [1] or only a single turbine model [8–12, 15, 16]). The latest studies already have better data [17–21], have used multiple turbine models in order to better match turbine design requirements [17, 22, 23] and have employed low-specific rating turbines (below $300\ \mathrm{W/m^2}$) [10, 14, 22]. However, they are still missing the comparison of different wind power technologies. Supplementary Table 1 shows a selection of recent literature with their assumptions on turbine specific rating and hub height.

To restrict the area that can be used for wind turbines, a set of assumptions is usually taken. For example, areas of poor quality wind regime or high altitude, urban areas,

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natural reserves and other protected areas as well as other competing land-use functions have been considered in the previous literature [1, 10, 13]. Also, long distances to consumption centres limit the suitability of a potential site as additional transmission capacity might be needed [16, 21]. Most studies only consider one set of assumptions, but some have attempted to construct at least one alternative scenario for land use [11, 16–18].

For economic potential, most studies have relied on external sources for the average capital and operational costs of wind power [10, 12, 16, 24]. Investment cost for different turbine types were estimated using statistical scaling and a reference turbine [1] or a component mass based cost model [14, 17, 22], but in both cases the methodologies are already somewhat outdated the latter being published in 2006 [25].

Global or continent-wide potential assessments usually rely on average wind turbine installation density (power density, $\mathrm{MW/km^2}$). This approach makes an assumption that similar wind turbines are installed with even spacing (on average) on all available land area. Power density was estimated based on existing installations [1, 10] or a spacing rule based on the used turbine model(s) to minimise array losses due to wake effects [9, 13, 22, 24, 26]. Studies for smaller areas have been able to use more detailed and more sophisticated methods for simulating the placement of potential WPPs or individual turbines [17, 23], but these require more detailed data and an increased computational effort.

A number of studies have made a sensitivity analysis considering land use, turbine cost and other economic parameters [10, 14, 16, 18, 22]. However, linkages between turbine specific rating, power density, hub heights and installation costs have not been included.

The novelty of this paper is the consideration of recent technology development including wind turbine specific ratings and hub height, together with different land use scenarios and technology specific investment costs including uncertainty.

Our results demonstrate that the choice of turbine technology has a significant impact on the technical and economic wind power potential. Modern turbines with low specific ratings enable economically feasible generation at a higher number of sites, and thus decrease the effect of strict land use policies restricting the available land area. The results also show that without high quality cost data, estimates for economic wind power potential are highly uncertain.

Assessment of geographical and technical potential

Finnish onshore areas were used as a case study in order to evaluate turbine performance in a real geographical setting that had good quality data for the analysed parameters. We used Finnish Wind Atlas (FWA) [27, 28] as the wind resource data source. A larger geographic scope would have required us to rely on a more mixed set of data sources, and this could be detrimental to the consistency of the results. We believe the current data set is sufficient for demonstrating the effects of parameter choices to the wind power potential.

The area of interest was divided into calculation cells based on the wind resource data grid size (2.5 km by 2.5 km) and technical potential was calculated for each cell. We used the power density methodology (see e.g. Ref. 1), but in contrast to previous literature, we calculated the techincal potential using a number of turbine model, hub height and land use policy combinations in order to assess the impact of these individually. Power density was calculated for each turbine model to account for different rotor sizes. In addition to conversion losses due to availability and wake effects, we also considered losses due to icing and turbine degradation.

We used two technology vintages to describe wind turbine technology development. 'Vintage 2002–04' represented turbines from early 2000s, equipped with a 90-metre rotor and a doubly-fed induction generator (DFIG). 'Vintage 2015' represented more modern turbines equipped with an over 100-metre rotor and a full converter generator. Both vintages consisted of two wind turbine models, one for low to medium wind sites (IEC wind turbine classes [29] III and II, hereafter referred to as 'low winds') and one for medium to high wind sites (IEC classes II and I, 'high winds'). The turbine vintages overlapped in terms of the turbine specific rating, but still described the decreasing trend in it: a newer vintage turbine had a lower specific rating than the old one for the same wind type. Table 1 shows technical details about the chosen wind turbine models. Power densities were calculated using Equation (3). Independent from the turbine technology, alternatives for the hub height were 75, 100, 125 and 150 metres.

For describing changes in land use policies, we defined two land use scenarios: 'optimistic' which represented a more lenient policy for wind power development and 'strict' which had more restrictions and larger buffer zones around areas not suitable for wind power development. Table 2 lists all land use restrictions used in the study, and Supplementary Table 2 shows details on miscellaneous land use types including optional buffer radiuses around them.

The total onshore area of the calculation cells was 305.1 thousand $\mathrm{km^2}$. In the optimistic land use scenario the available area for wind power development was 109.2 thousand $\mathrm{km^2}$ (35.8 % of total) and in the strict scenario only 43.7 thousand $\mathrm{km^2}$ (14.3 %). The land use restrictions in the strict land use scenario are mapped in Supplementary Figure 1. Cumulative technical wind power potential ordered by decreasing capacity factor and the difference between optimistic and strict land use scenarios is shown in Supplementary Figure 2.

Assessment of economic potential

We calculated the LCOE (EUR/MWh) in all the calculation cells using all wind turbine model and hub height combinations, and the combination which resulted in lowest LCOE was chosen for each cell. Following the standard for IEC Wind turbine classes [29], only high wind speed

Table 1: Technical details of the turbine models used in the study. Turbine technology development was described using two vintages, each with two turbine models: one for high and one for low average wind speed speed conditions. (Data from Ref. 30, except for the years available since which are from Ref. 31 and power densities which were calculated in the study.)

Parameter	Vintage 2002–04		Vintage 2015	
	high winds	low winds	high winds	low winds
Turbine model	V90-3.0 MW	V90-2.0 MW	V117-3.45 MW	V136-3.45 MW
Manufacturer	Vestas	Vestas	Vestas	Vestas
Available since	2002	2004	2015	2015
Rated power (MW)	3.0	2.0	3.45	3.45
Rotor diameter (m)	90	90	117	136
Specific rating (W/m^2)	472	314	321	237
Cut-in wind speed (m/s)	3.5	3.0	3.0	2.5
Rated wind speed (m/s)	16.5	13.5	12.5	11.0
Cut-off wind speed (m/s)	25.0	25.0	25.0	22.0
Wind class (IEC)	IA/IIA	IIA/IIIA	IB/IIA	IIIA/IIB
Power density (MW/km^2)	10.6	7.1	7.2	5.3

Table 2: Land use restrictions and sources of data. Various land use functions were considered unsuitable for wind power development, optionally with a buffer radius around them. Miscellaneous land uses include e.g. urban fabric as well as commercial and recreational areas with buffers depending on the land use scenario.

Constraint	Source	Comments
Miscellaneous land uses	SYKE [32]	see Supplementary Table 2 for details
Natura 2000 areas	—"— [33]	Special Protection Areas[a] and Sites of Community Importance[b]
Other nature protection areas	—"— [34]	
Main roads	NLS Finland [35]	300 m buffer [36]
Russian border	—"—	3 km buffer in ‘optimistic’ scenario, 50 km in ‘strict’
Firing areas	—"—	
Railways	—"—	250 m buffer [36]
Height restriction areas	Finavia [37]	maximum height 200 m
Flight obstacle limitation surfaces	—"—	areas around airports

[a] Birds Directive 2009/147/EC
[b] Habitats directive 92/43/EEC

turbines could be installed in sites with annual average wind speed greater than 8.5 m/s.

To estimate the cost of different wind power technologies, we created a regression model to predict the specific investment costs of a turbine model and hub height configuration (WPP investment cost) using recent publications. Total 24 data points (dated 2010–2015) [38–40] with varying turbine hub heights, rotor diameters and rated powers were used to create the model. However, the cost of wind power has continued to decrease and the cost estimates in the paper are likely to be high. Note also that the cost model was not only used to extrapolate the costs of the new technology, but to find the specific investment cost for all turbine model and hub height configurations.

In addition to the turbine and tower installation costs, we considered the costs of building road and transmission grid connection to the site. This extends the methodology used in Ref. 10 by also taking into consideration the distances from sites to nearest roads. Including these site dependent costs generally decreases the economic wind power potential of remote locations even if the technical potential would be high.

Specific WPP investment costs at certain hub heights as predicted by our cost model are given in Table 3. Note that these costs are just an example, and the actual investment cost at each site depended on the turbine and hub height configuration which was optimal for the site. The uncertainty of WPP investment cost (excluding site dependent components) for all turbine models was approximately ±300 EUR/kW due to the standard errors of the fitted cost model parameters.

After introducing the site dependent cost components, road and grid construction, the specific total investment cost for each cell could be calculated by dividing the total installation costs by the installed capacity. Median values for the specific investment costs of all turbine model–hub height combinations in the strict land use scenario for vintages 2002–04 and 2015 were 1,590 EUR/kW and 1,740 EUR/kW, respectively. The costs did not include benefits from building large projects, which could not be included with the current methodology. Histograms of specific investment costs using both turbine tech-

Table 3: Calculated wind power plant investment costs. An example hub height is selected for each wind turbine, and the investment cost is predicted using a regression model based on existing data. Costs exclude location specific costs of grid connection and road construction.

Turbine vintage	Turbine type	Turbine model	Hub height (m)	Investment cost (EUR/kW)
2002–04	high winds	V90-3.0 MW	75	878
	low winds	V90-2.0 MW	100	1,321
2015	high winds	V117-3.45 MW	125	1,448
	low winds	V136-3.45 MW	150	1,701

nologies are shown in Figure 1.

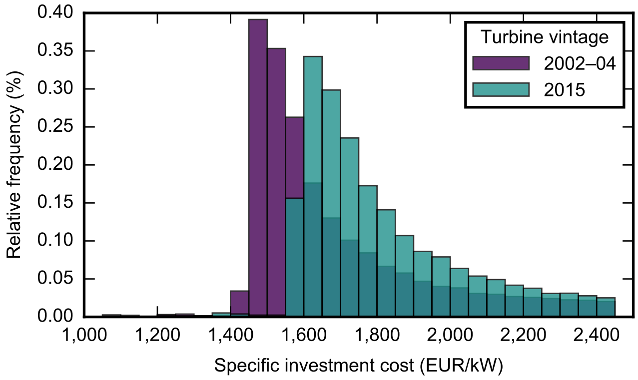

Figure 1: Histogram of specific investment costs. Costs were calculated for both turbine vintages in the strict land use scenario and include location dependent costs for road and electricity grid connection. Specific investment cost is the total wind power plant investment cost divided by the total generation capacity in the calculation cell. Relative frequency is the share of cells in the total number of calculation cells. Actual turbine model and hub height for each cell depended on local conditions.

Figure 2a shows the cumulative economic wind power potential ordered by increasing LCOE for both turbine vintages in the strict land use scenario. Uncertainty in the potential due to the investment cost model uncertainty is shown with a shaded area around the average value. (For comparison, electricity consumption in Finland in 2016 was 85.1 TWh [41].)

Marginal costs to generate 50 TWh onshore wind power annually (59 % of Finnish consumption in 2016) are plotted in Figure 2b. The cost ranges due to uncertainty in WPP specific investment cost are compared to the range of different land use restrictions. Table 4 shows the corresponding installed capacity, total costs and land area needed to achieve 50 TWh/a wind power generation. The table also shows differences between the land use scenarios. Average power densities were calculated over the total onshore area. Cost-optimal locations for the 50 TWh/a in the strict land use scenarios are mapped in Supplementary Figure 1, which shows quite high concentration to the areas with the best wind resources.

Figure **??** presents the change in economic wind power potential with increasing hub height in the strict land use scenario. At costs less than or equal to 50 EUR/MWh, the wind power potential using vintage 2002–04 turbines and maximum 150 m hub height was 3.2 times the potential using only 75 m hub height. Using the vintage 2015 turbines, the corresponding factor was 8.0.

Losses due to turbine unavailability were 5.0 %, wake effects 10 % and icing 0.50 to 10 % depending on site conditions. Turbine degradation contributed to a total energy loss of 2.7 % over the total project lifetime when using the vintage 2015 turbines and 4.1 % when using the vintage 2002–04 turbines.

Sensitivity analysis

In addition to the previously mentioned factors, turbine technology (specific rating and hub height) and land use, many other parameters influenced the results. Sensitivity of the wind power potential to the most important parameters is shown in Figure 4. Array efficiency and turbine availability affect the technical potential linearly and these have been left out of the figure for sake of clarity.

Figure 4 shows that the economic wind power potential (for a LCOE below 50 EUR/MWh) is sensitive to the WPP investment costs, the maximum hub height, and the power density, which is modified by changing the turbine spacing assumption. These were also the factors that have been analysed more thoroughly in the paper. The economic potential seems to be less sensitive towards the cost of road access, the grid connection fee and the cost of the transmission grid connection. If these would all move together in the same direction at the same time ('share of connection costs'), then their influence begins to approach the more influential set of parameters listed first. Although it is difficult to estimate how probable the changes in the different parameters are, Figure 4 gives a basis to concentrate on the first set of parameters.

Wind data and choice of technology explain differences

Our results for the onshore wind power potential in Finland ranged from 55 to 260 % of selected corresponding previous results . Differences in the results arose from different wind resource data or differing assumptions for turbine technology and land use restrictions. Supplementary Table 3 shows a comparison of selected studies to our results. The comparison to our results is done using the

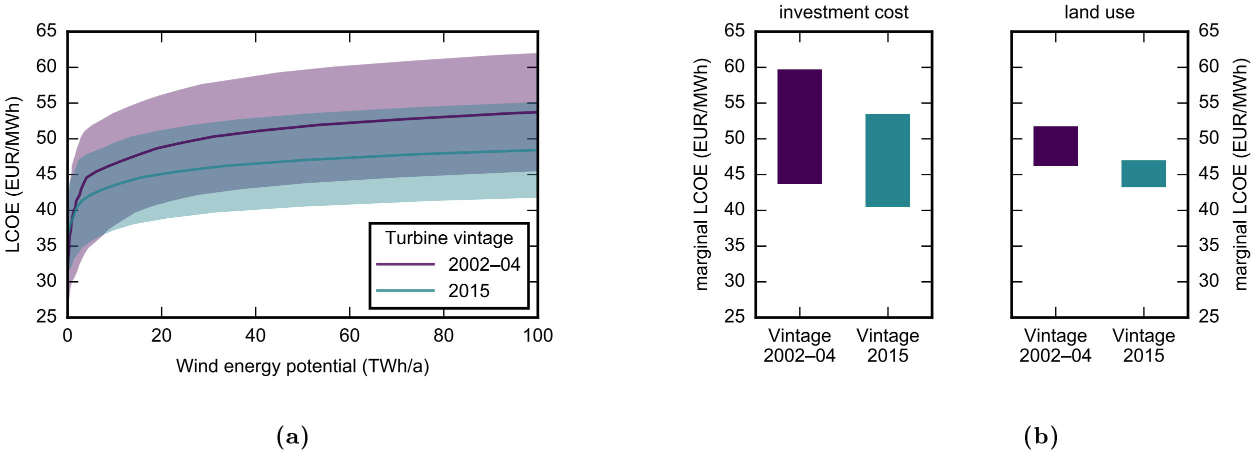

Figure 2: Economic wind power potential and marginal cost uncertainty. Left panel (a) shows cumulative potential for both turbine vintages in the strict land use scenario ordered by increasing levelized cost of electricity (LCOE). Shaded area shows the uncertainty due to wind power plant specific investment cost, mean investment cost with solid line. Right-hand panels (b) show the marginal cost uncertainty at 50 TWh/a potential due to investment cost uncertainty (strict land use scenario) and due to difference in land use scenarios (mean investment costs), respectively. In all cases, hub heights depend on site conditions.

Table 4: Wind power capacity, total cost and land area needed to generate 50 TWh/a. Table shows results for both turbine vintages and land use scenarios. Note that less than one percent of land area is needed in all scenarios. Average power density is calculated over the total onshore area.

Turbine vintage	Land use scenario	Capacity (GW)	Total cost (billion EUR)	Area (km^2)	Area (% of total)	Avg. power density (MW/km^2)
2002–04	optimistic	16.5	1.91	1,758	0.58	0.054
	strict	17.7	2.21	2,110	0.69	0.058
2015	optimistic	13.6	1.94	2,416	0.79	0.045
	strict	14.4	2.14	2,636	0.86	0.047

vintage 2015 turbines in the strict land use scenario – the most probable case in our view.

Previously, wind speed data only at 10 m altitude was used and extrapolated to the hub height with the logarithmic profile law [10, 14]. This assumption might underestimate the wind resource potential in a densely forested country such as Finland. Also only 80 m hub height was used [10]. For studies where wind speed data at higher altitudes was used to get the hub height wind speed values with better accuracy [13, 19], the differences to our results can be explained with different turbine technology and lower hub heights as well as different and coarser land use assumptions.

Compared to the previous studies which used global reanalysis wind data, we used a local wind atlas as the wind resource data source. Data was available directly for the required hub heights, and no extrapolation was needed. On the other hand, experience from recently built WPPs has shown that the wind atlas is more likely to overestimate than underestimate the available wind resource.

Conclusions and discussion

We have shown that the chosen turbine technology had a significant impact on the wind resource potential. Technological development was clearly visible even though there were only about 11–13 years between the turbine vintages and we assumed that the larger rotors decrease the installation density and increase the turbine investment costs.

New turbine technology brings increasing benefit at sites with lower average wind speeds (higher LCOE). At best sites (lowest LCOE), the escalation of costs due to taller towers becomes larger than the benefit from increased annual wind energy generation. In these sites old technology remains competitive because of the lower investment costs based on our cost assumptions.

Land use restrictions also had significant impact on the result – interestingly new technology showed less impact of land use. We can therefore conclude that the new turbine technology is less affected by changes in the land use restrictions, as more sites can provide wind energy at similar cost levels.

We used publicly available sources for the estimation of turbine investment costs. However, the cost of wind power has continued to decrease and the cost estimates in the paper are likely to be high. The cost model was used to illustrate the difference between technologies, assuming that both turbine vintages were available as a choice today. It may also be that the cost differences related to the tower height and the rotor swept area have decreased, and this would increase the relative benefits of using tur-

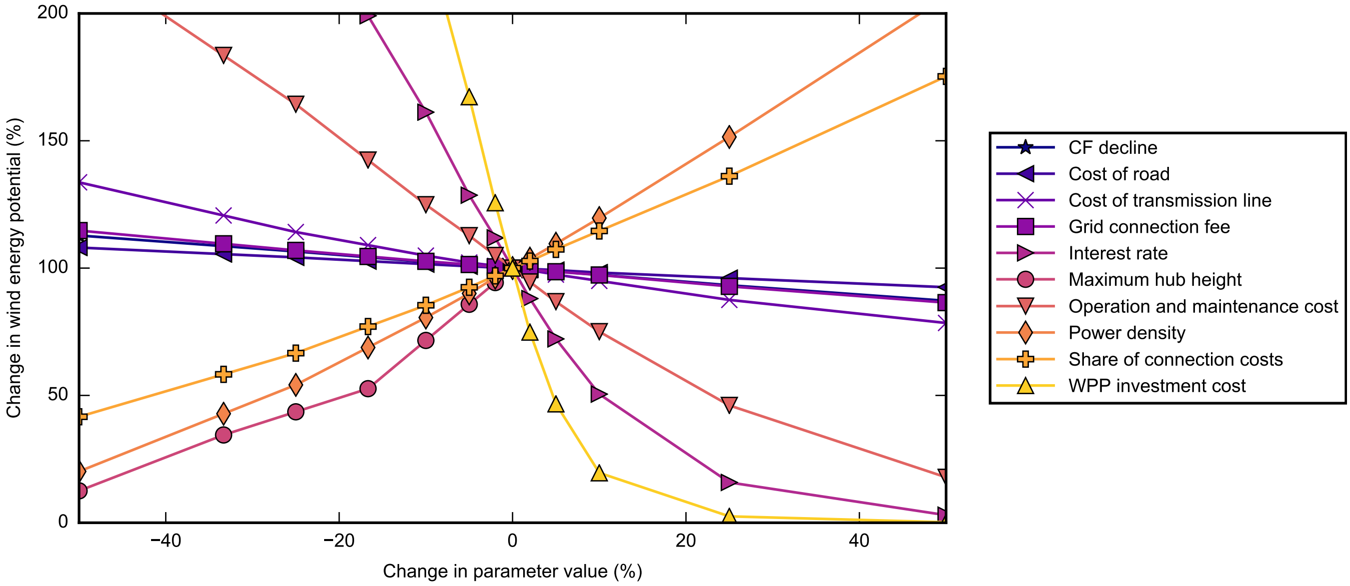

Figure 4: Parametric sensitivity of the wind power potential. Relative change in economic wind power potential for costs below 50 EUR/MWh was calculated using turbine vintage 2015 in the strict land use scenario when changing a number of calculation parameters.

bines based on more recent technology. The uncertainty from the turbine investment cost model was up to 3.5 times larger than the difference between the two land use scenarios. It should be noted that the parameters from the literature resulted in a relatively large WPP investment cost uncertainty (±300 EUR/kW), but more data could improve the precision of the cost model. Improving the accuracy still further would require a way to identify a more reliable data source for the future investment costs, even though predicting future costs will always be uncertain.

The methodology assumes that all available area is filled with wind turbines using the power density value for the turbine model. Concerns about affecting the wind resource with dense wind turbine deployment on large areas globally have been raised, and it has been estimated that the density in larger areas should not exceed 1 MW/km^2. [42] In our case, covering 59 % of the current electricity demand (50 TWh) with wind power resulted in an average density of only 0.047 MW/km^2 using the vintage 2015 turbines in the strict land use scenario. The limit of 1 MW/km^2 would only be reached when generating 905 TWh/a. The method, however, might lead to quite concentrated wind power deployment scenarios overall.

The employed land use restriction scenarios took into account many environmental and social factors limiting the construction of wind power plants. However, not everything could be modelled within the scope of the present work. Public acceptance could change with increasing number of turbines in the nearby landscape. Acceptable distances to residential and other land use functions may also depend on the turbine type, the size of the rotor and the hub height as well as general public acceptance, and this detail was not captured. Nature reserves and other such areas were ruled out of the available areas, but this does not compensate for all environmental impacts of wind power plants.

In addition to direct grid connection costs, large amounts of new generation capacity will at some point require potentially costly grid upgrades as the power needs to be securely evacuated to the consumption centres. These grid reinforcement costs were not included in the current modelling. Considering transmission in higher detail is a topic for further work.

Compared to the previous studies, our results show significant differences and a large increase in the economic potential due to new technology assumptions. While this study does not give evidence that new technology would increase the potential in other regions of the world as much as for our case study, it is probable that it has a significant impact. Considering a wider geographical area is a topic for future work as gathering high quality data from many different countries would also be a serious undertaking. Consequently, further studies with improved data sets using new technological assumptions are warranted in order to decrease the uncertainty in global and regional wind power potentials.

These results demonstrate the importance of choosing a technology that is well suited to maximising the energy capture in the prevailing wind conditions when making wind power potential estimates. Also, estimating future technology development is important to consider. Old potential assessments might be misleading if they are done assuming suboptimal wind turbine technology. This also has political significance if decisions are based on outdated figures. On the other hand, predictions using current technology or development trends might also overestimate the resource potential as increased wind power generation capacity will bring dynamic effects like the need for transmission reinforcements and possibly increased public opposition to new wind power plants.

Methods

Geographical potential. Some land use types were considered unavailable for siting wind turbines directly on them (e.g. industrial areas, nature reserves), and for some we defined an additional buffer distance to the closest WPP (e.g. residential housing). Supplementary Figure 3 shows a calculation cell with some areas which are not suitable for wind power.

We used Corine Land Cover (CLC) 2012 data [32] in raster format for miscellaneous land uses such as housing, commercial and industrial areas etc. CLC data has a horizontal resolution of 250 m. Depending on land use scenario and the land cover class of the raster tile, wind power development could be allowed, not allowed or not allowed with a buffer. Other restrictions were described by geographical polygons (vector format).

The land cover raster image was processed with a binary dilation algorithm implemented in Python to create a masking raster of areas where wind turbines were not allowed to be built. For other restrictions with a buffer radius, we created buffer features around the geographical polygons which described the restricted areas or objects. All geographical data was then rasterised and resampled into 250 m horizontal resolution to decrease computational burden. As a result of the land availability analysis, we had two raster masks: one for each land use scenario. From these rasters, we calculated the land availability factors α_k for each calculation cell k by taking the fraction of masked 250 m by 250 m tiles to the total number of tiles in the cell N_k, as described by the formula

$$\alpha_k = 1 - \frac{\#(\text{masked tiles})}{N_k}. \tag{1}$$

For the FWA grid cells which are 2,500 m by 2,500 m, N_k equals 100.

Technical potential. Installation potential Φ_k (MW) in computation cell k was calculated using the formula

$$\Phi_k = \alpha_k A_k \rho, \tag{2}$$

where A_k is the total land area of cell k and ρ the power density for the current turbine model.

Power density depends on the spacing of wind turbines. Sufficient spacing is needed to avoid unacceptably high wake losses caused by other wind turbines in the area. We used 7 times rotor diameter (7D) spacing in the prevailing wind direction and 5D spacing across [43], which is in line with the previous literature. Power density was then calculated using the formula

$$\rho = \frac{P}{7D \times 5D}, \tag{3}$$

where P is the rated power (MW) of the turbine model and D is the rotor diameter (m).

From installation potential we then calculated technical potential E_k in each cell k using the formula

$$E_k = (1-\theta_k)\eta_{\mathrm{a}}\eta_{\mathrm{ar}}\Phi_k CF_k \times 8{,}766\,\mathrm{h}, \tag{4}$$

where θ_k is the production loss due to icing, η_{a} the availability factor, η_{ar} the array efficiency factor and CF_k the capacity factor for the current wind turbine model and hub height in the cell.

The average production loss due to icing was quantified using IEA Ice classes [44, Table 3-1]. We assumed lower limits of the production loss ranges. Wind Power Icing Atlas (http://www.vtt.fi/sites/wiceatlas) was used to determine the icing class of each computation cell at the same resolution as FWA.

For the overall availability due to technical failures etc. we used a value $\eta_{\mathrm{a}} = 0.95$ (literature values ranged from 0.94 to 0.98). Even with the spacing rule described above there are still some losses due to wake effects in the wind turbine arrays. We thus used a global array efficiency of $\eta_{\mathrm{ar}} = 0.90$ which is within the range used by other studies presented earlier (values range from 0.7 to 0.925).

Capacity factors. FWA holds wind speed and other related data at a horizontal resolution of 2,500 m over whole Finland at heights from 50 to 400 m above sea or ground level distributed into 12 wind direction sectors. We used the mean wind speed (variable 'V' in in the FWA database), Weibull distribution shape and scale parameters ('Weibull all data k' and 'Weibull all data A', respectively), and the frequencies of the wind sectors ('Frequency all data').

We divided the usable wind speed range (depending on cut-in and cut-out wind speeds of the turbine model) into bins of 0.5 m/s. For each bin, power generation level (fraction of maximum output) was calculated using the manufacturer power curve of the turbine model published in Ref. 45. To simulate a wind farm where each turbine experiences a slightly different wind speed, we used a normal distribution with variance $\sigma^2(v) = 0.2v + 0.6\,\mathrm{m/s}$ (where v is wind speed) to smooth (convolute) the original power curves [46, 47].

Using the parametrised Weibull probability density function as the occurrence probability of each wind speed bin and the sector frequencies, we calculated the expected long-term average generation level, i.e. capacity factor, over all wind speed bins and all wind directions.

The calculation of the capacity factor for cell k is described by the formula

$$CF_k = \mathop{\mathbb{E}}_{i,s} g(v_i) \approx \sum_{s=1}^{12} f_{k,s} \sum_{i=1}^{N} p_{k,s}(v_i) g(v_i) \Delta v, \tag{5}$$

where g is the smoothed power curve function, v_i the mean wind speed of bin i, $f_{k,s}$ the frequency of occurrence of wind direction sector s in cell k, N the number of wind speed bins, $p_{k,s}(v)$ the Weibull probability density function for sector s in cell k and Δv the width of the wind speed bin. Operator $\mathbb{E}_{i,s}$ stands for expected value over bins i and wind directions s.

Economic potential. From technical potential, the economic wind power potential for each cell could be calculated. LCOE at cell k was calculated using formula

$$LCOE_k = \frac{I_k + \sum_{t=1}^{T} \frac{E_{k,t} o_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_{k,t}}{(1+r)^t}}, \tag{6}$$

where I_k denotes the overnight installation costs at cell k, T the expected lifetime of the turbines, $E_{k,t}$ the generated electricity and o_t the operation and maintenance costs in year t and r the chosen interest rate. For operation and maintenance costs, we used 7.7 EUR/MWh, which was also used in a recent Finnish generation cost study [48]. Lifetime of turbines was 20 years and interest rate 5.0 %.

Wind farm performance declines with age. In order to take turbine degradation into account during the whole lifetime of the WPP, we followed the methodology presented by Olausson et al. [49], where the capacity factors of WPPs decline by a fixed amount each year. Olausson et al. found that in cold climate countries the rate of decline ranges from 0.10 to 0.20 percentage points per year, and we used 0.10 pp/a for new technology and 0.15 pp/a for old technology.
To estimate the installation costs of different turbine models, we built a model based on literature values. Specific investment costs (EUR/kW) could then be predicted using turbine hub height and specific rating of the chosen models. For the details of the cost model, see below.
Total installation costs (EUR) were calculated using formula

$$I_k = (1-\gamma)\Phi_k y + G_k, \tag{7}$$

where γ is the share of grid and road connection from the total installation costs, y the specific installation costs (EUR/MW) given by the cost model and G_k costs of grid and road connection for cell k. According to Moné et al. [40], the share of electrical infrastructure and site access and staging costs for wind power projects is 11.6 %. We used slightly smaller value, $\gamma = 10.0\,\%$, taking into account that some of the electrical infrastructure costs are not site dependent.
For each cell, we calculated the (direct) distance to the nearest road and electricity transmission grid part. Grid connection cost was calculated as the cost of building a new transmission line and connecting to the nearest 110 kV grid part. According to the Finnish TSO Fingrid, the fee for connecting to an existing 110 kV transmission line is 0.6 million EUR. [50] The average costs of building overhead transmission lines and roads (EUR/km) were acquired through interviewing Finnish wind power developers. (Own research in fall 2016, results contain eight developer responses.) Supplementary Table 4 gives a summary of cost parameters.

Wind turbine cost model. A regression model was fitted to the data using weighted least squares. We based the model on three independent variables: turbine hub height (x_1, m), its specific rating (x_2, W/m^2) and the age of the data point (x_3, years before 2016). The dependent variable y, specific investment costs (normalized to 2016 euros), was fitted to the data using formula

$$y = \beta_1 f_1(x_1) + \beta_2 f_2(x_2) + \beta_3 f_3(x_3) + C, \tag{8}$$

where β_k are the model coefficients and C is the constant term. Functions f_k could be one of $f(x) = x$, $f(x) = x^2$, $f(x) = \ln x$ and $f(x) = \sqrt{x}$. We used weight 1.0 for the data points by Deutsche WindGuard and weight 0.1 for the data points by NREL to give more importance to the European data. Two data points were dropped and the model was fitted only to the remaining 22 data points because the residuals were not normally distributed. Currency exchange rates and inflation rates for calculating money present value were taken from European Central Bank (http://sdw.ecb.europa.eu/). We performed a leave-one-out cross-validation to evaluate the different model formulas, and the results are shown in Supplementary Table 5. We chose root mean square error (RMSE) as the score of the models to avoid large residuals. Also mean absolute error (MAE) and bias were computed for each model. The model with the lowest RMSE was chosen as the final cost model: $f_1(x_1) = \ln x$, $f_2(x) = x$ and $f_3(x) = \sqrt{x}$. Fitting the whole dataset using this model gave following results: $\beta_1 = 620 \pm 44$, $\beta_2 = -1.68 \pm 0.15$, $\beta_3 = 182 \pm 19$ and $C = -1005 \pm 231$ (omitting the units). Adjusted coefficient of determination of the model was 0.960.

Data availability. Capacity factors for all the turbine models used in the study are available in Zenodo with the identifier doi:10.5281/zenodo.582537 (Ref. 51). Other data that support the plots within this paper and other findings of this study are available from the corresponding author upon reasonable request.

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Acknowledgements

This work has been supported by the Strategic Research Council at the Academy of Finland, project 'Transition to a resource efficient and climate neutral electricity system (EL-TRAN)', grant number 314319.
We thank Esa Peltola and Petteri Antikainen at VTT Technical Research Centre of Finland for the buffer radius estimates around miscellaneous land use functions (see Supplementary Table 2).

Author contributions

E.R. made the analysis, wrote the manuscript draft and was responsible for the final manuscript. H.N. and J.K. participated in the study design and participated in the writing of the manuscript. S.R. calculated distances to roads and transmission grid and assessed icing losses as well as developed the methodology for calculating grid connection costs. All authors contributed in commenting the manuscript.

Additional information

Competing financial interests: The authors declare no competing financial interests.