

S1. Site characteristics and terrain complexity parameters

Table S1: Coordinates, elevation and relative position of the measurement point and turbine locations.

ID	Longitude	Latitude	Elevation	Distant to ms.point	TSI ₃₆₀ 5z_hub	TVI ₃₆₀ 5z_hub	TSI ₃₀ 5z_hub	TVI ₃₀ 5z_hub	TSI ₃₀ 10z_hub	TVI ₃₀ 10z_hub	TSI ₃₀ 20z_hub	TVI ₃₀ 20z_hub
	[°E]	[°N]	[m a.s.l.]	[m]	[°]	[%]	[°]	[%]	[°]	[%]	[°]	[%]
Measurement point (ms.point)	10.35206	51.79958	585.00	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Turbine T1	10.36589	51.81012	578.44	1,512	1.60	0.7%	0.82	1.4%	0.60	1.06%	0.60	1.04%
Turbine T2	10.36068	51.81657	590.37	1,977	2.03	0.8%	1.21	2.1%	0.98	1.71%	0.98	1.71%
Turbine T3	10.37290	51.80355	588.40	1,497	1.53	0.6%	0.98	1.7%	0.49	0.86%	0.49	0.85%
Turbine T4	10.37727	51.79651	602.44	1,776	1.52	0.7%	1.02	1.8%	0.72	1.26%	0.71	1.25%
Turbine T5	10.38265	51.79006	618.78	2,350	2.14	1.1%	1.11	1.9%	0.95	1.65%	0.97	1.69%
Turbine T6	10.38877	51.78342	586.19	3,105	3.86	1.5%	2.33	4.1%	1.60	2.80%	1.60	2.80%
Turbine T7	10.37061	51.82455	585.41	3,070	1.43	0.6%	0.77	1.3%	0.70	1.23%	0.70	1.22%
Turbine T8	10.37593	51.81805	550.29	2,634	3.74	1.3%	1.86	3.2%	1.24	2.16%	1.26	2.20%
Turbine T9	10.38187	51.81099	558.13	2,419	4.05	1.6%	2.89	5.0%	1.14	2.00%	1.16	2.02%
Turbine T10	10.38725	51.80443	583.38	2,490	2.07	0.8%	1.57	2.7%	0.78	1.35%	0.77	1.35%
Turbine T11	10.39263	51.79793	592.71	2,804	2.68	1.1%	1.67	2.9%	0.96	1.68%	0.95	1.66%
Turbine T12	10.36751	51.78831	604.04	1,640	1.83	0.8%	1.07	1.9%	0.61	1.06%	0.61	1.07%
Turbine T13	10.37303	51.78184	593.90	2,442	3.44	1.6%	2.26	3.9%	1.21	2.12%	1.21	2.12%
Turbine T14	10.37916	51.77505	520.07	3,303	6.22	2.4%	2.94	5.1%	2.15	3.76%	2.13	3.71%
Turbine T15	10.35217	51.78760	569.41	1,333	2.24	0.8%	0.95	1.7%	0.72	1.26%	0.73	1.27%
Turbine T16	10.35791	51.78007	580.08	2,193	2.43	0.9%	1.04	1.8%	1.28	2.24%	1.28	2.23%
Turbine T17	10.36350	51.77360	585.68	2,981	3.35	1.6%	1.29	2.3%	1.71	2.99%	1.71	2.99%
Turbine T18	10.34237	51.77811	549.67	2,471	2.94	0.7%	1.50	2.6%	1.36	2.37%	1.35	2.35%
Turbine T19	10.34857	51.77125	582.43	3,145	2.30	0.9%	1.50	2.6%	1.16	2.03%	1.16	2.02%
Turbine T20	10.35405	51.76491	589.52	3,865	5.25	2.3%	4.37	7.7%	2.70	4.72%	2.69	4.71%

Table S2: Threshold values of the terrain complexity categories Low, Moderate and High (Source: IEC 61400-1:2019)

Radius of circle area	Sector amplitude of fitted plane	Terrain slope index (<i>TSI</i>)			Terrain variation index (<i>TVI</i>)		
		Low	Moderate	High	Low	Moderate	High
5z hub	360°	10°	15°	20°	2%	4%	6%
5z hub	30°						
10z hub							
20z hub							

S2. Energy yield model

S2.1 Measurement-to-turbine translation

Wind conditions at each turbine are derived from the measured data using a simplified WAsP theoretical framework [2]. The translation applies sector-wise speed-up factor $\mathbf{F}(\boldsymbol{\theta}, \mathbf{ms}, \mathbf{t})$ between measurement location to turbine location. This factor is derived from multiplicative contributions of orography (F.oro), terrain surface roughness (F.rou), and obstacle (F.obs) factors, as in the equation (S1) below:

$$\mathbf{F}(\boldsymbol{\theta}, \mathbf{ms}, \mathbf{t}) = \frac{\mathbf{F.oro}_t(\boldsymbol{\theta})}{\mathbf{F.oro}_{ms}(\boldsymbol{\theta})} \times \frac{\mathbf{F.rou}_t(\boldsymbol{\theta})}{\mathbf{F.rou}_{ms}(\boldsymbol{\theta})} \times \frac{\mathbf{F.obs}_t(\boldsymbol{\theta})}{\mathbf{F.obs}_{ms}(\boldsymbol{\theta})} \quad (\text{S1})$$

where for each sector θ :

- $U_{ms}(\theta)$: mean wind speed measured, at height $h_{ms} = 160\text{m}$
- $U_t(\theta)$: mean wind speed at the turbine hub height $h_{\text{hub}} = h_{msm} + \Delta e_{msm,t}$
- $\mathbf{F.oro}_{ms}(\theta)$: orographic factor at the measurement location
- $\mathbf{F.oro}_t(\theta)$: orographic factor at the turbine location
- $\mathbf{F.rou}_{ms}(\theta)$: roughness factor at the measurement location
- $\mathbf{F.rou}_t(\theta)$: roughness factor at the turbine location
- $\mathbf{F.obs}_{ms}(\theta)$: obstacle factor at the measurement location
- $\mathbf{F.obs}_t(\theta)$: obstacle factor at the turbine location

Orographic factor (F.oro): A local hill-slope approximation based on GLO-30 digital elevation map (DEM) [3]. For each sector θ , at each location with elevation (e_{start}), a transect $L = 1.000\text{m}$ is extracted. The mean elevation along this transect (e_{end}) is taken. As suggestion at [4], the orographic factor $\mathbf{F.oro}(\theta)$ is calculated based on the local hill-slope ($\frac{\Delta E}{L}$), with $\Delta E(\theta) = e_{\text{end}}(\theta) - e_{\text{start}}(\theta)$. Applying for measurement location and turbine is as in the equation (S2):

$$\frac{\mathbf{F.oro}_t(\boldsymbol{\theta})}{\mathbf{F.oro}_{ms}(\boldsymbol{\theta})} \approx \frac{1 + 1.6 \times \frac{\Delta E_t(\boldsymbol{\theta})}{L}}{1 + 1.6 \times \frac{\Delta E_{ms}(\boldsymbol{\theta})}{L}} \quad (\text{S2})$$

Roughness factor (F.rou): From global landcover map [5], for each sector θ , at each location, an mean roughness length ($z_0(\theta)$) for the area within radian of 10km from the location is extracted. Neutral-stratification log-law is assumed with friction velocity (U_*) and von Kármán constant (K) as below [6]. Under the assumption that U_* and K are the same for the generalized climate and the two sites in each sector, the relative roughness factor between measurement and turbine is:

$$\frac{F.rou_t(\theta)}{F.rou_{ms}(\theta)} \approx \frac{\ln\left(\frac{h_{hub}}{z_{0,t}(\theta)}\right)}{\ln\left(\frac{h_{msm}}{z_{0,ms}(\theta)}\right)} = \frac{\ln\left(\frac{h_{ms} + \Delta e_{ms,t}}{z_{0,t}(\theta)}\right)}{\ln\left(\frac{h_{ms}}{z_{0,ms}(\theta)}\right)} \quad (S3)$$

Obstacle factor (F. obs): In this study, the obstacle factor is strongly simplified:

- Obstacles are inferred qualitatively from land-cover map [5] and classes around the sites
- For each sector θ , the obstacle factors are assumed to be close to unity:
 $F. obs_t(\theta) \approx 1.0$ with relative adjustments applied where big differences are seen within the area.

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Summary: For each turbine and each of the 12 sectors, in relative with measured wind speed at the same sector, a total simplified WAsP-style speed-up factor is generated as in the equation (S1). Table S3 summarises all sector-wise speed-up factors that applied to the measured wind speed to obtain the sectoral wind climate at each turbine.

Table S3: Sector-wise speed-up factors for measurement-to-turbine extrapolation

Sector (θ)	1	2	3	4	5	6	7	8	9	10	11	12
Ms.point	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
F(θ, msm, t)												
T1	0.99	1.00	1.00	1.00	1.00	0.99	1.00	0.87	0.67	0.68	1.57	1.57
T2	1.26	1.51	1.00	1.00	0.67	0.67	1.01	0.87	0.67	0.68	1.57	1.04
T3	0.99	1.00	1.00	1.00	0.67	0.99	1.02	1.11	0.68	0.68	1.10	1.04
T4	0.98	1.01	0.99	1.01	1.00	0.99	1.48	1.28	0.68	0.69	1.04	1.05
T5	0.98	1.01	1.00	1.01	1.00	0.66	0.99	1.28	0.69	0.69	1.05	1.05
T6	1.47	1.52	1.50	1.50	0.67	0.66	0.99	0.85	0.67	1.03	1.59	1.58
T7	1.01	1.01	1.00	1.00	0.67	0.66	1.00	1.31	1.01	1.03	1.04	1.04
T8	1.51	1.01	1.12	1.00	0.67	0.99	1.50	1.31	1.01	1.02	1.57	1.55
T9	0.99	1.00	1.01	1.00	0.67	0.99	1.49	1.30	1.02	1.02	1.58	1.03
T10	0.98	1.01	1.00	1.00	0.67	0.66	1.49	1.28	1.04	1.02	1.05	1.03
T11	0.98	1.01	1.00	1.00	0.68	1.02	1.52	1.29	1.09	1.11	1.64	1.07
T12	0.99	1.01	1.50	1.50	0.68	0.68	1.52	0.86	0.73	0.73	1.09	1.21
T13	1.48	1.52	1.00	1.50	0.68	0.68	1.01	0.86	0.72	0.73	1.10	1.46
T14	1.48	1.52	1.50	1.50	0.68	0.68	1.01	1.29	1.08	1.09	1.66	1.66
T15	1.51	1.51	1.51	1.50	1.02	1.02	1.01	0.86	0.74	0.75	1.65	1.61
T16	1.52	1.52	1.50	0.99	0.68	0.68	1.30	0.86	0.73	0.75	1.10	1.08
T17	1.51	1.52	1.00	0.99	0.68	0.68	1.01	1.30	1.09	0.74	1.10	1.09
T18	1.52	1.52	1.50	1.48	1.02	1.01	1.52	1.32	0.74	0.76	1.65	1.62
T19	1.02	1.01	1.00	0.99	1.02	0.68	1.01	1.15	0.74	1.13	1.09	1.09
T20	1.02	1.01	0.99	0.99	0.68	0.68	1.01	0.89	0.74	0.75	1.09	1.10

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S2.2 Sector-wise Weibull fits

The Weibull probability density function (PDF), with two-parameters: the yielding shape $k_{\theta,t}$ and the scale $C_{\theta,t}$, is calculated as in the equation (S4) [7].

$$f_{t,\theta}(U_t) = \frac{k_{\theta,t}}{C_{\theta,t}} \left(\frac{U_t}{C_{\theta,t}} \right)^{k_{\theta,t}-1} \exp \left[-\frac{U_t}{C_{\theta,t}} \right]^{k_{\theta,t}} ; k_{\theta,t} > 0, C_{\theta,t} > 1, U_t > 0 \quad (S4)$$

where, $f_{t,\theta}(U_t)$ is the frequency of U_t , number between 0 and 1

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S2.3 Gross energy calculation

The expected power in sector θ is obtained by numerically integrating the product of the power curve $P(U_t)$ and $f_{\theta,t}(U_t)$ over wind speed, as in the equation (S5) [8], [9].

$$P_{\theta,t} = \int_{U_{in}}^{U_{out}} P(U_t) f_{t,\theta}(U_t) dU_t \quad (S5)$$

The mean power of turbine t , P_t , is calculated by weighting the sectoral expected powers $P_{\theta,t}$ with the wind direction occurrence frequency $\omega_{\theta,t}$ in each sector, as in the equation (S6).

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$$P_t = \sum_{\theta} P_{\theta,t} \omega_{\theta,t} \quad (S6)$$

The turbine's mean power is converted to the turbine's gross annual energy (GrossAEP_t) by multiplying it by the annual operating hours, as in the equation (S7):

$$\text{GrossAEP}_t = P_t \times 8760 \quad (S7)$$

S2.4 Loss assumption

A constant wake loss of 8% is assumed to affect downstream turbines [10]. Additional plant-wide losses are assumed as follows: availability 3% (L_{ava}), electrical 2% (L_{ele}), curtailment 1% (L_{cur}), and other 1% (L_{oth}) based on [10], [2]:

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$$\text{GrossAEP}_{t, \text{ afterwake}} = \text{GrossAEP}_t \times (1 - L_{wake}) \quad (S8)$$

$$\text{NetAEP} = \text{GrossAEP}_{\text{afterwake}} \times (1 - L_{ava} - L_{ele} - L_{cur} - L_{oth}) \quad (S9)$$

References of S2:

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S3. Debt sizing impacts to project NPV and LCOE

The DSCR is a financial ratio comparing cash available for debt service to scheduled debt obligations. The DSCR for year i is typically calculated as in the equation (S10) [11]:

$$\text{DSCR}_i = \frac{\text{CFADS}_i}{\text{PR}_i + \text{IR}_i} = \frac{\text{P90}_i \times \text{Tariff}_i - \text{OPEX}_i}{\text{PR}_i + \text{IR}_i} \quad (\text{S10})$$

where CFADS_i is the cash flow available for debt service (€), PR_i is principal repayment (€), IR_i is interest repayment (€),
75 Tariff_i is the realised average power price (€/MWh), and OPEX_i is operating expenditure (fixed and variable, €) in year i .

Debt capacity is the present value of the debt service series ($\text{PR}_i + \text{IR}_i$) over the entire loan term I years with interest rate r , as in the equation (S11) [11], [12]:

$$\text{Debt Capacity} = \sum_{i=1}^I \frac{\text{PR}_i + \text{IR}_i}{(1+r)^i} = \frac{1}{\text{DSCR target}} \times \sum_{i=1}^I \frac{\text{CFADS}_i}{(1+r)^i} \quad (\text{S11})$$

The DSCR-based debt capacity feeds into a standard project cash flow model to evaluate NPV and LCOE. NPV is defined here as the present value of equity cash flows minus the initial equity investment, as in the equation (S12). LCOE is defined
80 as the ratio of the discounted sum of all project costs to the discounted sum of net energy production [11], as in the equation (S13).

$$\text{NPV} = \sum_{i=1}^{25} \frac{\text{EBIT}_i (1 - \text{Tax})}{(1 + \text{WACC})^i} - \text{CAPEX} = \sum_{i=1}^{25} \frac{(\text{P90}_i \times \text{Tariff}_i - \text{OPEX}_i)(1 - \text{Tax})}{(1 + \text{WACC})^i} - \text{CAPEX} \quad (\text{S12})$$

where, EBIT_i is the earnings before interest and tax in year i , WACC is the weighted average cost of capital (i.e. the average rate a firm pays for using debt and equity).

$$\text{LCOE} = \frac{\text{CAPEX} + \sum_{i=1}^{25} \frac{\text{OPEX}_i}{(1 + \text{WACC})^i}}{\sum_{t=1}^{25} \frac{\text{P90}_t}{(1 + \text{WACC})^t}} \quad (\text{S13})$$

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