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Multiparameter Analysis of Energy Generation and LCOE for the Planned Baltica II Wind Farm

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Abstract

This study presents a comprehensive multi-parameter analysis of key factors influencing the annual energy production (AEP) and levelized cost of energy (LCOE) for the planned Baltica II offshore wind farm. The analysis considers variations in the wake decay constant (k_w), turbine spacing (Dist), interest rate (i_{rate}), and turbine lifespan, resulting in 81 evaluated scenarios. The results demonstrate that wake effects significantly impact wind speed reductions across turbine rows, affecting overall energy yield. Higher wake decay constants and increased turbine spacing contribute to lower velocity deficits, enhancing energy production efficiency. The findings highlight that AEP is independent of interest rates, whereas LCOE is strongly affected by financial assumptions. The estimated minimum LCOE for Baltica II is projected to range between 143 $/MWh and 191 $/MWh, which is significantly higher than conventional fossil fuel and nuclear power generation costs. These findings emphasize the financial and operational challenges of offshore wind energy and the importance of optimizing wake effects, turbine placement, and financial assumptions for long-term feasibility.

Keywords: Offshore wind energy, Wake effects, LCOE, Baltica II.

Introduction

The European Commission Staff Working Document projects that to attain a 69% share of renewable electricity by 2030, an installation of 592 GW of solar photovoltaic systems and 510 GW of wind energy capacity is necessary, forcing annual increments of 48 GW and 36 GW, respectively [1]. In the year 2023, Europe achieved the installation of 18.3 GW of new wind power capacity, with the EU-27 accounting for a notable 16.2 GW. However, this figure represents only 50% of the capacity required to fulfil the climate and energy objectives set for 2030. Onshore wind represented 79% of the newly added capacity, whereas offshore installations achieved a historic milestone of 3.8 GW. In spite of the expansion of offshore installations, it is anticipated that two-thirds of the newly added wind capacity by 2030 will continue to be situated on land [2]. However, the regional cumulative offshore targets set by EU member states are planned to reach around 88 GW by 2030 and 360 GW by 2050 [3].

At the beginning of 2025, the Polish government officially announced and commenced the construction of the world's largest offshore wind farm in the Baltic Sea. The planned installed capacity of the Baltica 2 farm is expected to be 1.5 GW. The farm will consist of 107 wind turbines, each with a capacity of 14 MW, covering an area of 190 km² and located 40 km from the shoreline. The farm is scheduled to begin operation in 2027 [4]. Simultaneously, it was announced that the capital expenditure (CAPEX) for Baltica 2 would amount to 30 billion PLN, which, assuming an exchange rate of 4 PLN per USD, translates to approximately $5 million USD per MW of installed capacity [5].

This value appears to be very high, as almost all international agencies and laboratories, such as National Renewable Energy Laboratory (NREL), indicate that the CAPEX for running global offshore wind projects ranges from $1.8 to $7.0 million/MW for operating projects and $1.0 to $6.4 million/MW for announced projects [6]. Based on analyses conducted with the NREL Offshore Renewables Balance-of-System and

Installation Tool (ORBIT) [7], for offshore fixed-bottom turbines with a 30-year lifetime, CAPEX typically falls within the range of $3.4 to $4.0 million per MW of installed capacity.

CAPEX primarily consists of project management costs (e.g., geotechnical surveys, permitting, etc.), wind turbine costs, and balance of system (BOS) costs, including cabling, foundations, and other essential infrastructure. Based on NREL analyses, for wind resource classes with mean wind speeds at a 100 m height of 8.6–8.7 m/s (slightly lower than the location of Baltica 2 [8]) and a 40 km distance from shore, CAPEX should be approximately $3.7 million/MW [9]. A study by BVG Associates for a "typical" UK offshore wind farm estimated a total CAPEX of $3.38 million/MW, excluding decommissioning costs, which were estimated at $0.42 million/MW [10]. Other institutions, such as the International Energy Agency (IEA), estimate CAPEX for similar projects to Baltica 2 at $3.54 million/MW [11]. Some studies suggest even lower values, for instance, Liang estimates CAPEX as low as $3.05 million/MW [12].

In research focused on estimating LCOE values, institutions like those mentioned above are commonly referenced. An example is study [13], which estimated LCOE for multiple planned offshore wind farm locations along the U.S. Atlantic Coast. Despite these locations being more challenging in terms of construction and operation compared to the Baltic Sea, CAPEX was assumed to be $3.6 million/MW.

In the context of the analysis presented in this study, it is important to emphasize that the Baltic Sea is a relatively shallow basin, and the planned offshore wind farm is located 40 km from shore. As indicated above, CAPEX should not exceed $4 million/MW, yet it has been estimated at approximately $5 million/MW [5]. It should be noted that this is only a preliminary estimate, and it is widely recognized that large-scale energy infrastructure projects often significantly exceed their planned budgets [14].

Given the officially announced CAPEX for the Baltica 2 wind farm, this study conducted a multi-parameter analysis of the LCOE indicator, which serves as a basis for estimating the minimal cost of electricity produced by the power plant. The study examined the impact of several factors on LCOE, including turbine spacing, assumed wind farm lifespan, aerodynamic wake effects behind turbines, and the interest rate, which represents the discount rate used to account for the time value of money in energy project financing.

Such a multi-scenario analysis is essential to determine the range of possible LCOE values, as the actual lifespan of the installation at this specific location, as well as the atmospheric conditions—particularly turbulence intensity, which significantly affects energy losses—are not precisely known a priori [15].

Methods

In the present study, the commonly used and widely accepted Jensen model was employed to calculate the losses of the analyzed wind farm and, consequently, to estimate its realistic annual energy production [16], [17]. The Jensen model, utilised for simulating the aerodynamic wake generated behind a wind turbine, represents one of the most basic semi-empirical models available. Comparative analysis with experimental data and other models revealed that the Jensen model exhibits reliability for large wind farms, applicable to both onshore and offshore environments, despite its simplicity [18].

The Jensen model, as illustrated in Figure 1, posits that only a single component of the wind velocity, orientated perpendicular to the turbine rotor, is taken into account, and it is assumed that the aerodynamic wake expands uniformly.

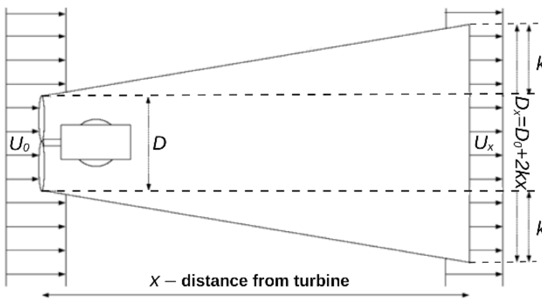


Figure 1: The control volume of the Jensen model: U_0 —wind speed in front of the turbine, U_x —wind speed at a distance x behind the turbine, k—wake decay constant

Using the law of conservation of linear momentum, the velocity Ux at a distance x from the turbine is calculated using the following equation:

$$1 - \frac{U_x}{U_0} = \frac{(1 - \sqrt{1 - C_T})}{(1 + 2k_w x / D)} \quad (1)$$

Where C_T is the thrust force coefficient U_0 is the atmospheric wind speed, *D* is the turbine diameter and k_w is the wake decay constant, which can be defined as follows :

$$k_w = \frac{0.5}{ln(\frac{H}{Z_0})} \quad (2)$$

where H is the turbine height and z_0 is the terrain roughness height.

Equation (2) assumes that k_w is proportional to the ratio of friction velocity to free stream wind velocity at the turbine hub height H, establishing a direct relationship with the law of the wall as introduced by von Karman . It is important to acknowledge that Equation (2) has the potential to produce values that are less than the widely accepted figures, which may lead to an underestimation of wake losses in low-roughness terrains [18]. An alternative methodology entails correlating the wake decay constant with atmospheric stability, turbulence intensity, and surface layer theory, leading to the subsequent formula

$$k_w^{It} = \kappa I_t^H \quad (3)$$

where κ is the Karman constant, whose value is assumed to be 0.4 and I_t^H is the turbulence intensity at height H defined as

$$I_t^H = \frac{\sigma_{uH}}{u_{\mathrm{H}}} \quad (4)$$

where σ_{uH} is the standard deviation of the free stream velocity u_H at turbine hub height.

Through the analysis of Equations (1)-(3), it is shown that the kinetic energy losses of wind occurring downstream of a wind turbine can be quantified by understanding the parameters that define wind conditions at a specific location. The parameters encompass turbulence intensity and the topographic characteristics of the terrain, including roughness height. When multiple turbines interact, it can be hypothesised that the kinetic energy deficit present in overlapping aerodynamic wakes corresponds to the cumulative deficits noted in the wake of a singular turbine. As a result, the velocity deficit in two intersecting aerodynamic wakes can be determined using the subsequent equation:

$$\left(1 - \frac{U_x}{U_0}\right)^2 = \left(1 - \frac{U_{x,1}}{U_0}\right)^2 + \left(1 - \frac{U_{x,2}}{U_0}\right)^2 \quad (5)$$

where $U_{x,i}$ represents the velocity in the aerodynamic wake behind the i-th turbine at a distance x from its rotor. It is important to observe that for N identical turbines, uniformly distributed at a distance L apart, equation (5) turns to :

$$\left(1 - \frac{U_x}{U_0}\right)^2 = N\left(1 - \frac{U_{x,L}}{U_0}\right)^2 \quad (6)$$

Where $U_{x,L}$ denotes the velocity in the aerodynamic wake at a distance L from the turbine rotor, and U_x signifies the velocity in the aerodynamic wake behind the final, N-th turbine. Additionally, according to equation (5), the velocity deficit behind the n-th turbine can be determined as follows:

$$\delta_n = \left(\sum_{i=1}^{n} \delta_i^2\right)^{\frac{1}{2}} \quad (7)$$

where $\delta_n = 1 - U_n / U_0$

The current model utilises the integration of a turbine-specific thrust coefficient $C_T(U)$, which is contingent upon the atmospheric wind speed and is influenced by the characteristics of the wind turbine.

$$1 - \frac{U_x}{U_0} = \frac{\left(1 - \sqrt{1 - C_T(U)}\right)}{(1 + 2k_w x / D)^2} \quad (8)$$

In the conventional scenario, where C_T remains constant, the velocity deficit U_x exhibits a linear increase in relation to the atmospheric wind speed U. However, when employing $C_T(U)$ specific to a particular turbine, the direct impact of the thrust coefficient on the velocity deficit becomes apparent. Elevated C_T values are associated with an increased velocity deficit [19].

Wind characteristics of the Baltic Sea at an altitude of 100 m were employed, with particular values obtained from actual meteorological measurements recorded at the FINO 2 station with average atmospheric velocity 9.6 m/s and the Weibull shape parameter k = 2.33 [8].

The annual fluctuations in wind patterns can be characterized by the Weibull probability density distribution [20]:

$$f(U) = k\frac{U^{k-1}}{c^k}\exp\left(-\left(\frac{U}{c}\right)^k\right) \qquad (9)$$

where c represents the scale parameter, while k denotes the shape parameter of the distribution. The scale parameter c is characterised as:

$$c = \frac{U_{ave}}{\Gamma(1 + 1\,/\,k)} \qquad (10)$$

where U_{ave} is the annual average wind speed and Γ() is the Gamma function.

A critical consideration in the spatial arrangement of turbines within a wind farm is the inter-turbine interaction, which can markedly diminish the overall efficiency of the wind farm defined as:

$$\eta_{WF} = \frac{\text{wind farm AEP}}{\text{AEP of isolated turbine} \cdot \text{Number of turbines}} \qquad (11)$$

where AEP is annual energy production. Following Equation (11) the loss in a wind farm can be calculated as:

$$\zeta_{WF} = 1 - \eta_{WF} \qquad (12)$$

The power coefficient for wind farm is formulated as:

$$C_F^{WF} = \frac{E_{year}^{WF}}{P_z^{WF} \cdot 365 \cdot 24} \qquad (13)$$

where E_{year}^{WF} represents the total annual energy output of the wind farm measured in MWh. The term P_z^{WF} is defined as the cumulative (installed) rated capacity of the wind farm, calculated as the product of P_z^{WT}, which indicates the rated capacity of an individual turbine, and N, the total number of turbines present in the installation.

It is important to recognise that the coefficient C_F^{WF} (13) may exhibit significantly lower values compared to the power coefficient of an individual wind turbine. This reduction is attributable to losses ζ_{WF} (12) that arise from the interactions among wind turbines, as well as factors such as erosion, contamination, icing, and various other challenges [21].

The annual energy production for an isolated wind turbine, E_{year}^{WT} can be determined using the following,

$$E_{year}^{WT} = \int_{U_{in}}^{U_{out}} f(U)P(U)\,d(U) \qquad (14)$$

(U) is the power curve of the wind turbine, and $f(U)$ is the Weibull distribution of atmospheric wind speed defined by equation (9).

To determine the electricity production for the entire wind farm, denoted as E_{year}^{WT}, it is essential to compute the AEP value for the turbines located in the subsequent rows of the wind farm. To achieve this, it is essential to consider the velocity deficit induced by the interaction of overlapping aerodynamic wakes. This phenomenon can be integrated by suitably adjusting the Weibull distributions in the following rows of the wind farm:

$$E_{year}^{WF} = C\sum_{n=1}^{N}\int_{U_{in}}^{U_0} f_n(U)P(U)\,d(U) \qquad (15)$$

The modified Weibull distribution $f_n(U)$ describes the probability distribution of wind speed reaching the n-th row of the wind farm, where N denotes the number of turbines in a single row of the wind farm and C represents the number of columns in the wind farm. Equation (15) assumes no mutual interaction between wind turbines located in different columns of the wind farm. This assumption makes the proposed method more conservative; however, it is justified because, by the time the aerodynamic wake reaches turbines in adjacent columns, its effect will be negligibly small.

Although Siemens Gamesa 14 MW turbines will be installed in Baltica 2, this study used Gamesa SG8 turbines with a rated power of 8 MW, whose characteristics are presented in Figure 2. This choice was made due to the lack of necessary information, such as the power curve and thrust coefficient characteristics for the 14 MW turbine. However, selecting the Gamesa SG8 turbine is justified, as the key parameter determining the capacity factor (CF) is the rated wind speed, which is very similar for both turbines, at approximately 12–13 m/s. To ensure the planned rated capacity of the wind farm, which is 1.5 GW, the studied wind farm was assumed to consist of 14 columns and 14 rows of Gamesa SG8 wind turbines.

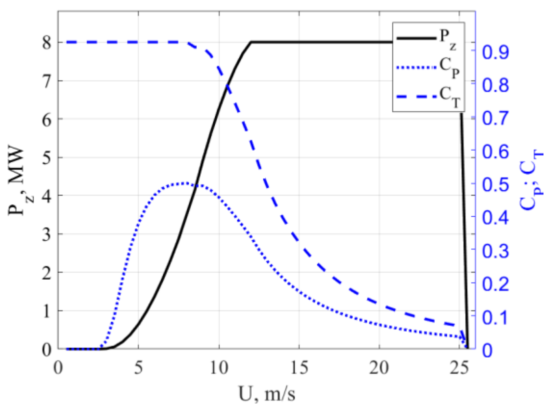


Figure 2: Power curve, power coefficient C_P, and trust force C_T of the Gamesa SG8 turbine

The key components of a levelized cost of energy (LCOE) model for offshore wind energy include capital expenditures, operating costs, discount rate, and projected power output. The projected power output is shaped by capacity factors of the individual turbines. However, power production is not constant and namely is affected by availability of wind but also the wake effect. The loss in power or velocity deficit is also due to wake merging which is caused by large scale wind farms. Previous studies have shown that wake effect is more prominent in offshore wind parks and travel up to several kilometers downstream of wind farms [22]. Around 5-20% reduction in total power output has been observed in the case of offshore wind farm in Europe [23].

The Levelized Cost of Energy (LCOE) is defined as:

$$\mathrm{LCOE} = \frac{\mathrm{CAPEX} \times \mathrm{CRF} + \mathrm{OPEX}}{\mathrm{AEP}} \qquad (16)$$

where, AEP is annual energy production, CAPEX is capital expenditure including all expenditures incurred during the construction period till the commissioning date of the wind farm, CRF is the capital recovery factor quantifies and OPEX is the operation and maintenance costs.

CFR is defined as:

$$CRF = \frac{i}{1-(1+i)^{-N}} \qquad (17)$$

where i is the discount/interest rate and N is the wind farm lifetime [24].

In the current study the OPEX was chosen to be 0.113 $million/MW/yr, which results from previous estimates for wind speeds slightly below 9 m/s at 100 m, 28 m water depth and 40 km from shoreline [9].

Results and Discussion

As mentioned earlier, the present study conducts a multi-parameter analysis of three factors influencing the annual energy production (AEP) and, consequently, the levelized cost of energy (LCOE) for the planned Baltica II wind farm. Three values of the wake decay constant were considered: k_w = (0.02, 0.03, 0.05), along with three different turbine spacing distances, Dist = (5D, 7.5D, 10D), three interest rates, i_{rate} = (0.05, 0.06, 0.07), and three values of the turbine life span = (20, 25 30) years. This results in a total of 81 different cases.

Figures 3 and 4 present selected velocity deficit results for the first three rows of the wind farm, illustrating the wind speed reduction reaching the downstream turbines. The first row is located at the front of the wind farm, where turbines are exposed to the undisturbed atmospheric wind speed *U*. Figure 3 shows results for Dist = 5D and k_w = (0.02, 0.03, 0.05). It can be observed that as k_w increases, which represents a faster dissipation of the aerodynamic wake in the surrounding flow, the velocity deficit decreases. This behavior is consistent with the Jensen model (see Equation 88).

Meanwhile, Figure 4 presents results for a fixed k_w = 0.03 and different spacing values, Dist = 7.5D and 10D. The case for Dist = 5D is displayed in the middle panel of Figure 3. It can be observed that the velocity deficit decreases with increasing Dist, which is also consistent with the Jensen model.

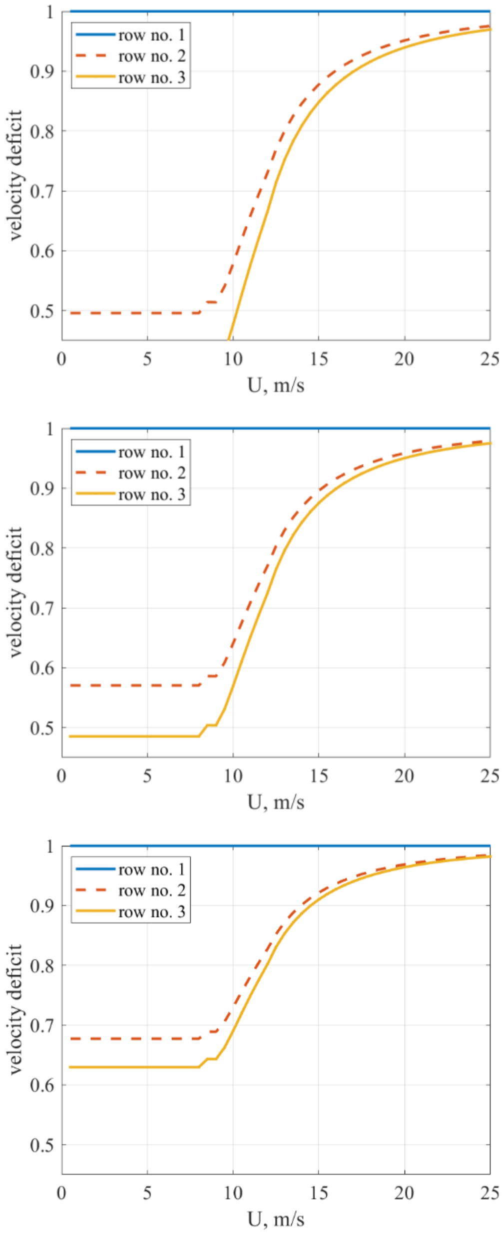


Figure 3: Velocity deficit in front of the turbines in consecutive rows as a function of atmospheric wind speed U. From top to bottom: exemplary results for Dist = 5D and k_w *= 0.02, 0.03, and 0.05.*

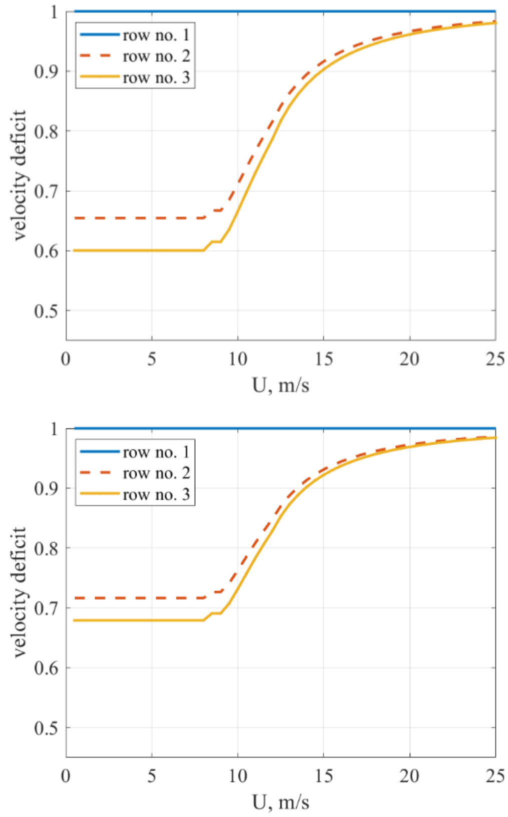


Figure 4: Velocity deficit in front of the turbines in consecutive rows as a function of atmospheric wind speed U. From top to bottom: exemplary results for k_w = 0.03 and Dist = 7.5 and 10D.

Figures 5 and 6 show the Weibull probability density distributions of the annual atmospheric wind speed U for different wake decay constants k_w and various spacing configurations among the Gamesa SG8 turbines, considering the first three rows of turbines. The first row receives undisturbed atmospheric wind, which follows a Weibull distribution with parameters specific to the Baltica II wind farm location, as detailed in the previous section of this article.

It should be noted that the wind speed distributions reaching subsequent turbines are modified by the velocity deficit generated behind the preceding turbines, as shown in Figures 3 and 4. Only two subsequent rows are presented, as the distributions for the remaining rows show no significant differences.

Figure 5 presents results for Dist = 5D and k_w = (0.02, 0.03, 0.05), while Figure 6 displays results for a fixed k_w= 0.03 and different spacing values, Dist = 7.5D and 10D. The case for Dist = 5D is shown in the middle panel of Figure 5. It can be observed that changes in the Weibull distributions are directly related to the velocity deficit and, consequently, to the thrust force characteristics of the Gamesa SG8 turbine, as presented in Figure 2.

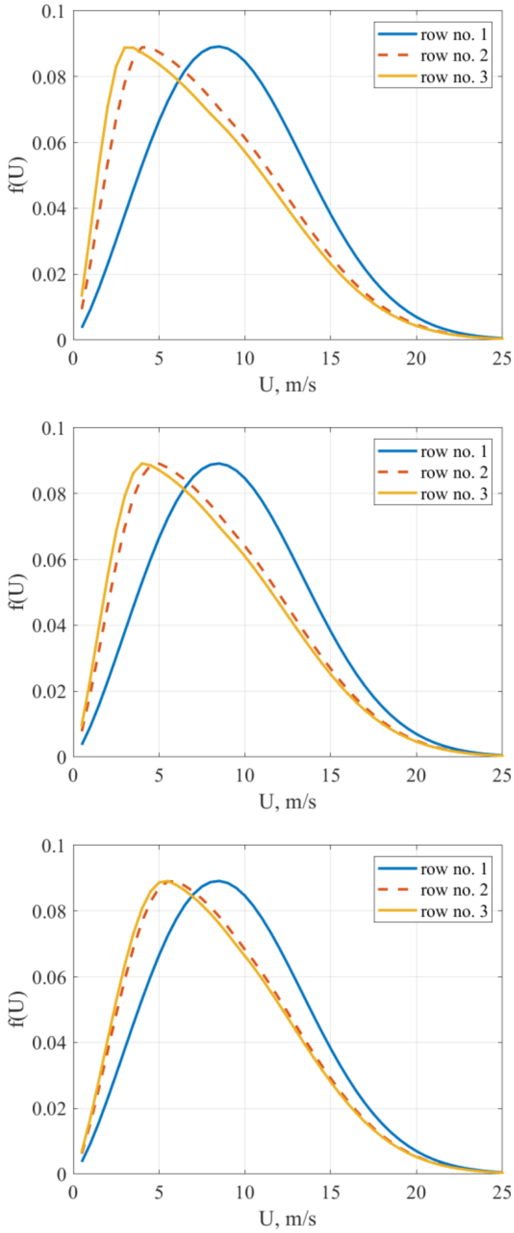
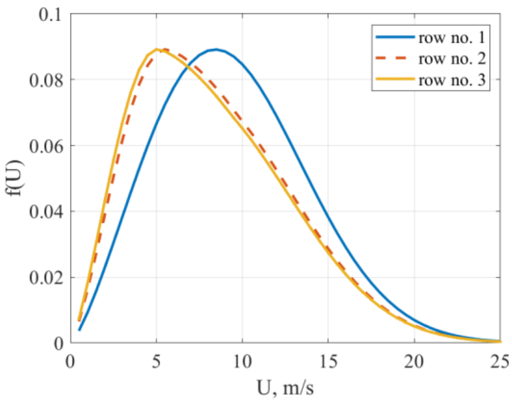


Figure 5: Influence of the velocity deficit on the shape of Weibull distributions for the first 3 rows of the considered wind farm. From top to bottom: exemplary for Dist = 5D and k_w = 0.02, 0.03, and 0.05.



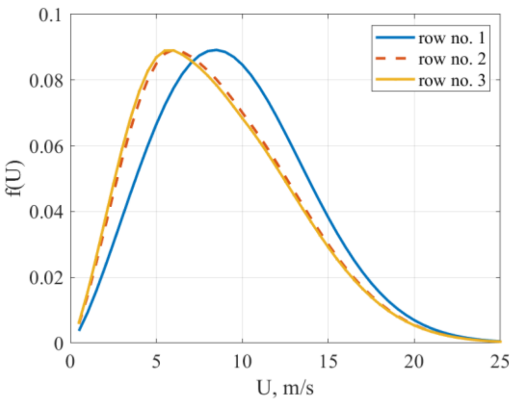


Figure 6: Influence of the velocity deficit on the shape of Weibull distributions for the first 3 rows of the considered wind farm. From top to bottom: exemplary k_w = 0.03 and Dist = 7.5 and 10D.

Figures 7, 8, and 9 summarize the obtained results in the form of a four-variable function. The vertical axis represents pairs of k_w values and the assumed lifespan of individual turbines, while the horizontal axis displays pairs of i_{rate} and Dist values. The individual table cells present the obtained values of annual energy production (AEP), the average capacity factor (CF) over the entire lifespan of the wind farm, and the levelized cost of energy (LCOE) for the values of the four corresponding parameters.

Analyzing Figure 7, it can be observed that the highest AEP value occurs for k_w = 0.05, the largest considered turbine spacing of Dist = 10D, and the longest turbine lifespan of 30 years. Conversely, the lowest values are observed for k_w = 0.05, the smallest considered turbine spacing of Dist = 5D, and the shortest turbine lifespan of 20 years. It should be noted that the AEP value is, of course, not affected by the interest rate i_{rate}.

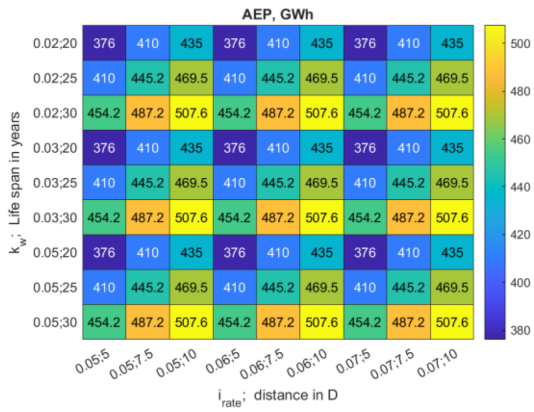


Figure 7: AEP for all the considered scenarios. For a detailed description of the figure, see the text.

Figure 8 presents the obtained average capacity factor values CF for the entire wind farm. Similar to AEP, the highest values occur for k_w = 0.05, the largest considered turbine spacing of Dist = 10D, and the longest turbine lifespan of 30 years. Conversely, the lowest values are observed for k_w = 0.05, the smallest considered turbine spacing of Dist = 5D, and the shortest turbine lifespan of 20 years. It should be noted that these capacity factor values do not account for the expected reduction in electricity production due to turbine aging and related erosion, as well as contamination and possible icing. The impact of these negative factors will be discussed in the following sections.

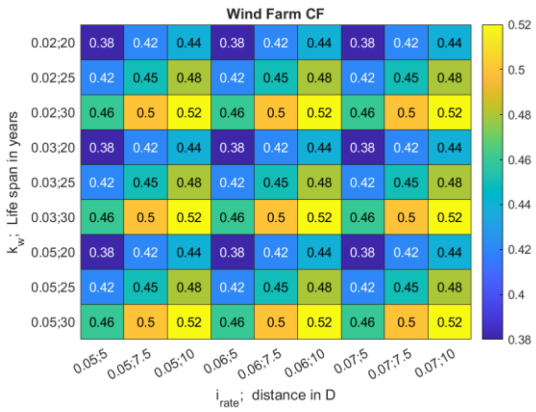


Figure 8: Wind farm capacity factor for all the considered scenarios.

Finally, Figure 9 presents the LCOE values, which naturally depend on the interest rate. The lowest and highest LCOE values occur for only a single combination of the considered parameters: respectively, for k_w, Life span, i_{rate}, Dist)=(0.05,30,0.05,10D) and (0.02, 20, 0.07, 5D).

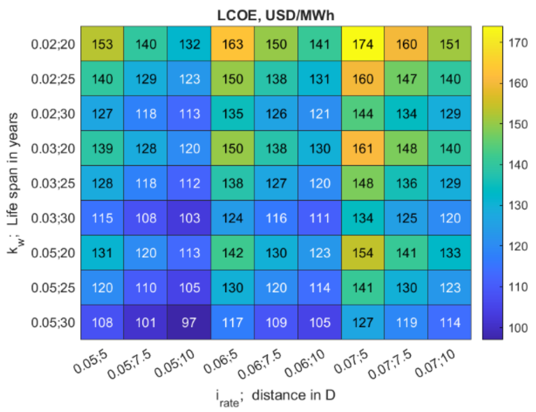


Figure 9: LCOE for all the considered scenarios.

It should be noted that the total area of Baltica 2 is 190 km², while the planned 14 MW turbines have a rotor diameter of 222 meters. Considering that the installed capacity of the Baltica 2 wind farm is expected to reach 1.5 GW, it can be assumed that it will consist of approximately 10 columns with 10 rows of turbines.

For the sake of simplification, assuming that the wind farm has a square shape with dimensions of approximately 14×14 km and that the turbines are evenly spaced, the distance between them would be around Dist = 6D. A similar configuration applies to the turbines used in this study, which have a rotor diameter of 167 meters, but with 14 turbines per column.

Analyzing the results presented in Figure 9 and adopting a conservative approach, it can be estimated that the LCOE of the planned wind farm should not be lower than the values obtained for Dist = 7.5D and should not exceed those for Dist = 5D.

It should be noted that AEP and the corresponding LCOE value strongly depend on the wake decay constant k_w. As indicated by literature sources, k_w is difficult to estimate, but in the case of offshore wind farms, it should generally be assumed to be lower. This is because k_w is directly related to turbulence intensity and surface roughness, both of which are relatively low in offshore locations [15], [25], [26], [27], [28]. However, there are certain offshore locations where k_w may be higher.

Additionally, when analyzing the data from the Figures 7, 8 and 9 as a whole, it can be observed that the distributions of AEP, CF, and LCOE values are not equally spaced around their respective mean values. This is evident in Table 1, which presents the minimum, average, and maximum values of these quantities. This indicates that in a realistic assessment of the minimum electricity selling price for the considered wind farm, a more conservative scenario should be adopted.

Table 1: Minimum, average, and maximum values of LCOE, AEP, and CF for the considered.

	min	average	max
LCOE $/MWh	97	130	174
AEP GWh	376	444	508
CF^{WF}	0.38	0.45	0.52

Additionally, considering the effects of wind turbine aging, potential soiling, and other environmental factors, the life time values of AEP should be decreased by approximately 10% and correspondingly the LCOE values should be increased by 10% [21] [19]. These adjusted values are presented in Table 2.

Table 2: Minimum, average, and maximum values of LCOE, AEP, and CF for the considered scenarios after accounting for the effects of aging and contamination.

	min	average	max
LCOE $/MWh	107	143	191

While adopting a conservative approach, which should be applied when assessing the economic viability of offshore wind farms throughout their entire lifespan, it should be assumed that the minimum LCOE value for the Baltica II wind farm should range between 143 $/MWh and 191 $/MWh. It is important to note that these values are significantly higher than those of coal, gas, and even nuclear power plants [29].

Conclusion

This study conducted a comprehensive multi-parameter analysis of key factors affecting the annual energy production (AEP) and levelized cost of energy (LCOE) for the planned Baltica II offshore wind farm. The analysis considered variations in the wake decay constant, turbine spacing, interest rates, and turbine lifespan, resulting in a total of 81 evaluated scenarios.

The results demonstrate a significant impact of wake effects on wind speed reduction across turbine rows. The findings confirm that increasing the wake decay constant leads to a lower velocity deficit, in accordance with the Jensen model. Moreover, greater turbine spacing reduces wake-`induced losses, thereby improving energy production efficiency.

Analysis reveals that the highest AEP and capacity factor values occur for the most favorable conditions: k_w = 0.05, Dist = 10D, and a turbine lifespan of 30 years. Conversely, the lowest values correspond to k_w = 0.02, Dist = 5D, and a turbine lifespan of 20 years.

The study also highlights that the distributions of AEP, CF, and LCOE values are not symmetrically distributed around their means. It suggests that a conservative approach should be taken when estimating minimum electricity selling prices for offshore wind projects. The estimated LCOE values strongly depend on k_w , which, according to literature, is challenging to estimate but generally lower in offshore environments due to reduced turbulence and surface roughness.

A conservative approach to economic evaluation suggests that the minimum expected LCOE for Baltica II should range from 143 $/MWh to 191 $/MWh. These values remain significantly higher than those associated with coal, gas, and nuclear power generation, emphasizing the financial challenges of offshore wind energy development.

The obtained results indicate that relying on wind farms as the basis of a national energy system is economically unjustified, as it would lead to significantly higher electricity prices. A more reasonable approach is to base the system on stable technologies with lower LCOE, such as nuclear, supercritical coal, biomass and gas power plants. Large-scale renewable energy installations should serve as a supplementary component, ideally contributing no more than 20–30% of the total energy mix.

Smaller wind and solar technologies, on the other hand, can be highly effective in prosumer energy systems, provided they are designed to maximize self-consumption, ensuring maximum energy independence for prosumers. An energy system built on these two pillars appears to be the most optimal in terms of security, economics, and flexibility.

Acknowledgments

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