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Production and Cost Assessment of Offshore Wind Power in the North Sea

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Abstract. A minimalistic model complex for determining the available wind power and associated costs related to the development of large-scale offshore wind power was recently developed by Sørensen and Larsen [1]. The model complex demands only a few global input parameters, such as turbine rotor diameter, nameplate capacity, area of wind farm, number of turbines, water depth, and mean wind speed Weibull parameters for the site. Using actual wind climate and bathymetric data for the North Sea, the model is in the present work used to map the annual energy production and levelized cost of energy (LCoE) for wind farms located in the North Sea. As a main conclusion, exploiting all locations with water depths down to about 45 m comply with the electrical power demand of Europe, which is about 3500 TWh/year. In this case, the LCoE is found to be about 7 €cents/kWh for wind farms consisting of 15 MW wind turbines and an interspacing between the wind turbines of 8 diameter, corresponding to 2 km.

1. Introduction

Although offshore wind energy has grown significantly over the past years, it presently only contributes with about 3% of the total deployed wind energy. Measured in terms of the investments and efforts by the European wind energy industry to reduce the cost of offshore wind power, it is clear that offshore wind power will become a very important part of the future European power production. As an illustration of this (see Fig. 1), 15 new large offshore wind farms, with an installed capacity of more than 4,000 MW, were either completed or are under development in Europe in 2019. On top of this many more offshore wind farms are presently being planned in the European seas [2]. An important question in relation to this is to what extent the North Sea can be exploited with respect to a massive penetration of wind energy and, related to that, what are the associated economic aspects? To answer these questions it is required to determine the available wind resources as well as the associated costs of erecting and operating wind turbines in the ocean. The first question regarding the available wind resources is not trivial, as the presence of the turbines, due to wake effects, alters the wind conditions inside a wind farm compared to ambient undisturbed conditions. Hence, erecting wind turbines close to each other will reduce the inflow wind speed and by this the efficiency of the total power production. On the other hand, if the turbines are too far from each other, the full potential of the wind resources in the ocean will not be utilised, and the cost of the internal wind farm grid will be excessive. The most important parameter in this context is the mutual distance between the turbines, measured in rotor diameters, which is a reference length for wind farms.
In a typical wind farm, such as the Danish Rødsand or Horns Rev wind farms, the turbines are located 6-7 diameters apart in order to diminish the wake effects. However, in a very large wind farm, covering a substantial part of the North Sea, this number may be different. Another important parameter is the size of the turbines, measured in installed generator power, or, alternatively, in rotor diameter. While the size of wind turbines erected onshore, due to logistics, visual impact, noise and other issues related to the lack of public acceptance, has stabilized on a maximum of about 3.5 MW, the size of wind turbines erected offshore is still increasing because of the influence of size on the reduction of cost of energy, which is much more pronounced offshore than onshore. Today, the biggest offshore wind turbines have a diameter of more than 200 m and an installed generator capacity of about 13 MW. An important parameter in a cost analysis of offshore wind turbines is water depth, as the price of foundations and substructures heavily depends on water depth. Therefore, an economic analysis requires to be complemented with a bathymetric analysis. Other important economic parameters are costs of installation (including cost of substation(s), the local wind farm grid and the onshore cable) as well as operation and maintenance, both of which are substantial compared to onshore conditions because of the harsh weather conditions appearing in the ocean.

Today, there are several models in use for cost analysis of offshore wind farms and substantial experience of costs of wind farms has been gained based on published data of actual expenses and operational statistics. Some of this has been compiled and reported in technical reports and reviews (Ernst & Young [3], EWEA (European Wind Energy Association) ‘Wind Energy – The facts’ [4], Morthorst and Kitzing [5]). A recent review of Gonzalez-Rodriguez [6] gives a comprehensive overview of the most pertinent cost models, including historical data for the most important economic parameters, such as inflation rates and commodity prices. Some of the models aim at clarifying detailed costs of parts of wind turbines, such as Lundberg [7] and Castro-Santos [8], whereas others deal with simplifying global parametrizations to achieve parametrical studies on LCOE for understanding the key cost factors of wind farms (Ioannoua [9]). Furthermore, different international collaborate projects have been conducted for analysing different aspects and future trends of offshore wind power deployment. In the IEA (International Energy Agency) Wind Task 26 (Smart et al. [10] and Noonan [11]) a model based...
on a combination of bottom-up component modeling and higher-level industry data was employed to determine typical LCoE-values for offshore wind farms in different countries. In another study carried out under the auspices of the North Sea Wind Power Hub Consortium (Ruijgrok et al. [12]) a cost evaluation was carried out to assess the potential for the future wind energy exploitation of the North Sea. Although these works have accomplished a lot of information of value for decision makers, the content of the used integrated models are not sufficiently transparent to be utilized by potential users outside the project consortia.

In the following, we address the various issues related to a massive exploitation of offshore wind power by establishing a numerical framework for modelling the available wind power and the associated costs conditioned on the site wind climate characteristics and the site bathymetric conditions. This framework is subsequently used on the North Sea as an example. The North Sea case study includes an assessment of the available wind power, and - for a suggested farm layout - the associated economic analysis leading to an estimated cost of energy. As wind farm design parameters we employ the turbine size and the interspatial distance between the turbines, measured in rotor diameters. Furthermore, to simplify the analysis, issues and constraints, like fishery, sailing routes, taxation, political aspects, etc. are not taken into consideration. These aspects are certainly of importance, but outside the scope of the present analysis.

The paper is organized as follows. In chapter 2 we introduce the theory forming the model for the wind farm power production, and in chapter 3 the cost model for the associated economic assessment is presented. Chapter 4 shows and discusses the North Sea case study results, and in chapter 5 we conclude and summarize the main findings.

2. Wind Energy Assessment Model

In the following the various elements of the wind energy assessment model are presented. It is not the intention to go into details, but merely to present the main ideas and equations of the model. For more information, the reader is referred to the paper by Sørensen and Larsen [1], where all details are given.

The thrust and power coefficients are defined as

\[ C_T \equiv \frac{T}{\frac{1}{2} \rho A_k U^2}, \quad C_P \equiv \frac{P}{\frac{1}{2} \rho A_k U^3}, \quad (1) \]

where \( T \) is the axial force, or thrust, acting on the rotor, \( P \) is the power generated by the rotor, \( \rho \) is the air density, and \( A_k = \frac{\pi}{4} D^2 \) denotes the rotor area, with \( D \) being the rotor diameter. We assume that a wind turbine operates at its optimum (rated) condition, \( C_p = C_{p,\text{rated}} \), at wind speeds lower than the rated wind speed, \( U_r \), and at a constant power yield, \( P = P_G \), at wind speeds higher than the rated wind speed. This operational strategy is typical for modern wind turbines, which are operated with a variable tip speed at wind speeds below \( U_r \), and which are pitch-regulated at higher wind speeds.

The rated wind speed is determined from eq. (1) referring to the condition where the turbine operates at both maximum power and maximum (rated) power coefficient,

\[ U_r = \sqrt[3]{\frac{8P_G}{\rho \pi D^2 C_{p,\text{rated}}}}. \quad (2) \]

The wind turbine power curve is expressed as

\[ P(U) = \begin{cases} \alpha U^3 + \beta & ; \ U_{\text{in}} \leq U < U_r \\ P_G & ; \ U_r \leq U \leq U_{\text{out}} \end{cases}. \quad (3) \]

where the parameters \( \alpha \) and \( \beta \) in addition to the rated wind speed depends on the wind turbine cut-in wind speed, \( U_{\text{in}} \). The wind turbine cut-out wind speed is denoted as \( U_{\text{out}} \). In the subsequent model
applications it is assumed that \( U_{in} = 3 \text{ m/s} \) and \( U_{out} = 25 \text{ m/s} \). The corresponding thrust coefficient, \( C_T \), is approximated as

\[
C_T = \begin{cases} 
C_{T,\text{rated}} & ; U_{in} \leq U < U_r \\
C_{T,\text{rated}} \left( U_r / U \right)^{3/2} & ; U_r \leq U \leq U_{out}
\end{cases} .
\]

(4)

In the above expressions it is implicitly assumed that the wind speed, \( U \), refers to the inflow wind speed at hub height of the wind turbine. The values \( C_{T,\text{rated}} = 0.75 \) and \( C_{P,\text{rated}} = 0.48 \), which are typical values in practise, are employed in the following.

The wind farm topology is defined only in terms of the total number of wind turbines, \( N_T \), and the wind farm area, \( A \). Denoting the assumed uniform distance between the wind turbines as \( L_T \), the wind turbine interspacing, expressed in rotor diameters, is given as \( S = \frac{L_T}{D} \). Assuming, as a simplifying approximation, that the wind farm quadratic, the following equation gives the interspacing as function of wind farm area and number of turbines.

\[
S = \frac{\sqrt{A}}{D \left( \sqrt{N_T^2 - 1} \right)} .
\]

(5)

The wake model used to assess the wind power resource was originally developed by Templin [13] and later developed further by Frandsen [14], [15]. This model assumes that the wind farm is so large, that the wind field inside the wind farm is in equilibrium with the ambient atmospheric boundary layer (ABL) flow field. The model results in the following simple equation to determine the wake affected mean wind speed at hub height inside the wind farm

\[
\bar{U}_h = \frac{G}{1 + \ln \left( \frac{G}{c_t \cdot \kappa \cdot (h / z_{0,lo})^{2}} \right)},
\]

(6)

where \( h \) is the hub height, \( \kappa \) is the von Kármán constant (equal to 0.4), \( z_{0,lo} \) is the roughness length of the atmospheric boundary layer, \( G \) is the geostrophic wind speed, \( f = 2 \Omega \sin \phi \) is the Coriolis parameter, in which \( \Omega \) denotes the rotational speed of the earth, \( \phi \) is the latitude, which is characteristic for the North Sea region. The main parameter responsible for the influence of the wake on boundary layer profile is \( c_t = \frac{\pi C_T}{8 S^2} \). In most cases, only the undisturbed mean wind speed, \( \bar{U}_{H,0} \), at a given height, \( H \), is known for a given site. The geostrophic wind speed is then determined indirectly by setting \( c_t = 0 \) and solving eq. (6) for the geostrophic wind speed \( G \).

In order to determine the wind farm power production, and further to provide input to the applied cost model for wind farm O&M expenses, an estimate of the mean wind speed statistics both for the site without wind turbines (i.e. the ambient wind speed statistics) and for the internal wind farm flow field is needed. A two-parameter Weibull distribution is used to determine the average wind speed statistics over the year. The wind speed statistics inside a wind farm, however, is different from the wind speed statistics of the ambient undisturbed flow. This is due to the wind speed reduction caused by the wake effects from neighboring wind turbines. To determine the yearly power production of a turbine within the wind farm, the Weibull scale parameter are adjusted to the wind conditions at hub height of the turbines operating within the wind farm. For a derivation of the full set of equations forming the model, the reader is referred to Sørensen and Larsen [1].
Since the performance of the model introduced above is based on the presumption of a fully developed atmospheric boundary layer in equilibrium with an infinite wind farm, it is necessary to introduce a correction for the finiteness of a real wind farm. As a simple heuristic approximate expression for taking into account the finiteness of the farm, we use the following expression for the wind farm power production,

\[ P_E = (N_T - a\sqrt{N_T})P_{WF,y} + a\sqrt{N_T}P_y, \] 

where \( a \) is a correction constant. In the following, we employ the value \( a = 3 \), stating that the average number of wind turbines subject to freestream conditions corresponds to 3/4 of the turbines located along the edge of the wind farm. This choice has shown promising results when comparing wind farm production estimates with actual recorded values [1].

3. Cost model

Adding up all costs, the estimated leveraged cost of energy (LCOE), expressed in terms of a kWh price and defined as capital expenditure plus O&M costs divided by the total production, is determined by

\[ LCoE = \left[ N_T \left[ C_{WT} + \gamma_F C_{FM} + (1-\gamma_F) C_{JM} + C_G \right] + \frac{0.81 - 0.06}{Y_{ref}} \right] + N_T N_P G_{O&M} \]

where \( N_T \) is the life time of the wind farm in years, \( \gamma_F \) is the fraction of wind turbines erected on monopole foundations, and \( (1-\gamma_F) \) is the fraction of wind turbines erected on jacket foundations, \( Y \) is the distance to nearest shore, \( Y_{ref} = 20 \) km is a reference distance, \( P_E \) is the yearly average power production for the windfarm, and the denominator is the total electricity production in kWh over the life time of the wind farm. For the present study, we assume a wind farm life time of \( N_T = 20 \) years. The costs taking into consideration are the cost of the wind turbine, \( C_{WT} \), the costs of support structures, \( C_{FM} \) and \( C_{JM} \), which are monopole structures (down to 30m water depth) and jacket structures (water depth larger than 30m), respectively, array cable costs, \( C_G \), and the operation and maintenance costs, \( C_{O&M} \). Other costs related to electrical infrastructure etc., which typically are in the order of 25%, are implicitly included by the divisor in the counter. The data forming the model are taken from various sources ([16]-[21]) and explained in detail in [1].

4. Results

In the following, the described model is employed to analyse the potential of a massive erection of wind turbines in the North Sea. In the former work [1], the model was validated against existing operating offshore wind farms located at different locations in Denmark. There the model was found to predict annual power production and capital expenditures within about 5% accuracy, as compared to actual production and investment costs (CAPEX). In the present work the model is applied to give a first assessment of the potential of a massive exploitation of the wind energy resources in the North Sea.

4.1 Wind Resources in the North Sea

A first part of the analysis is to map the wind data. For this purpose, we employ the wind map from the Global Wind Atlas (https://globalwindatlas.info/), where wind data from all over the world can be downloaded. Unfortunately, some data for the mid part of the North Sea is missing. Furthermore, the
data contains a considerable amount of scatter. It is therefore required to extrapolate a part of the data and further to introduce a filter in order to obtain a smooth and realistic representation of the data. This is accomplished by using a simple extrapolation procedure for the missing data combined with a simple second order numerical filter. The data contain the two Weibull parameters $\lambda$ and $k$, which are used to determine the annual wind farm power production. As an illustration, the $\lambda$-parameter is plotted in Fig. 2 for the southern part of the North Sea. It is seen that there is a big difference between the available wind resources close to the cost and in the middle of the ocean. The yearly mean wind speed is determined from the two Weibull parameters as $\bar{U} = \lambda \cdot \Gamma(1+1/k)$, where $\Gamma(*)$ is the Gamma function. Typical $k$-values for the North Sea are in the range from 2.0 to 2.5, which with very good accuracy gives that $\bar{U} = 0.886 \cdot \lambda$.

4.2 Overall Assessment of Power Density

We here analyze the power density of the wind resources in the North Sea as a function of wind turbine spacing and wind turbine size, i.e. rotor diameter. As a first overall estimate, we assume representative average Weibull parameters equal to $\lambda = 11$ and $k = 2.2$, corresponding to an average wind speed of 9.7 m/s at 100 m altitude.

The outcome of this analysis is shown in Fig. 3a, which depicts the power density as a function of wind turbine interspacing, $S$, spanning the range from 4 diameters to 11 diameters, and for four different rotor
diameters. In this range it is seen that the power density decreases monotonically from about 4.5 W/m² for S = 4 to about 1 W/m² for S = 11. It should be noted that the power density attains a maximum at a spacing of about 1.5D – 2D, which, depending of rotor size, goes from 4 W/m² for D = 100 m to 7.5 W/m² for D = 200 m. For a ‘standard’ value of S = 7 and D = 150 m, we get a power intensity of about 2 W/m². For a comparison, in a similar study by Frandsen et al. [22], the power density was found to vary in the range from 1.9 W/m² to 4 W/m², depending on rotor size and wind turbine spacing. For existing wind farms, such as the Danish Nysted or Horns Rev wind farms, the power intensity is measured to range from 2.7 W/m² to 4 W/m², and in general the power density associated with offshore wind turbines are found to vary between 1 W/m² to about 7 W/m² ([23]). The corresponding capacity factor, defined as the annually averaged power production divided by the installed (nameplate) generator power, is in Fig. 3b seen to vary from about 0.15 to 0.4, again depending on turbine distance and diameter.

4.3 Bathymeric Mapping of the North Sea
An important prerequisite for assessing the potential of a massive exploitation of wind energy in the North Sea is to map the bathymetry of the area in focus. To this end, we exploit the General Bathymetric Chart of the Oceans (GEBCO), which aims to provide the most authoritative, publicly available bathymetry data sets for the world’s oceans. The result is shown in Fig. 4 displaying the water depths in the southern part of the North Sea. It is seen that, measured from the costs of Denmark, the water depth gradually increases down to 50 m. Hence, in this area there is a large potential for erecting offshore wind turbines. Furthermore, the Dogger Bank, which is seen to be located nearly in the middle of the plot, contains a large area of shallow waters, with depths around 10 m. As can be seen in Fig. 1, this is also one the areas, in which a large development of wind farms is anticipated.

![Figure 4: Water depth in the North Sea (source: www.gebco.net).](image)

The potential energy production in various parts of the North Sea is obtained by combining the bathymetry of the North Sea with the actual annual energy production per area unit for a given combination of rotor size and wind turbine interspacing. As an example, assuming a rotor diameter D = 200 m and a turbine interspacing S = 7, we find an energy production distributed on different water depths as shown in Fig. 5a. The cumulated energy production on all water depths is shown in Fig. 5b. From the two figures, it is seen that most energy production can in fact be obtained at relatively shallow waters depths. Hence, about half of the available energy can be harvested at water depths below 45 m.
This is crucial for the economics, as cost of wind turbine foundations increases significantly with water depth outside the shallow water regime. This corresponds to an area of about 190,000 km² or 1/3 of area of the North Sea, where the potential is about 3500 TWh/year. To put this in perspective, the electricity production in EU is about 2800 TWh/year and in all of Europe about 3500 TWh/year [24].

4.4 Influence of Water Depth on Cost of Energy

By combining the bathymetry of the North Sea with the developed cost model, it is possible to determine the levelized cost of energy (LCoE) as a function of water depth. In order to limit the number of variables we first assume a fixed rotor diameter of $D = 200$ m, and then subsequently compute the LCoE for different wind turbine interspacing as a function of water depth. The result is shown in Fig. 6a, from which it is seen that the LCoE increases monotonically as a function of water depth, illustrating the added expenses of the substructures at deeper waters.

From Fig. 6a it is also seen that the LCoE reduces when placing the turbines further apart from each other, i.e. at increasing $S$-values. The reason for this is partly that the wind resources increase, as wake effects becomes less pronounced at higher $S$-values, and partly that the loading, and thus in turn the O&M expenses, decreases when erecting the turbines further away from each other, also due to less pronounced wake effects. On the other hand, the cable costs for the internal wind farm grid increase when increasing $S$. This, however, is less crucial as compared to the cost decrease caused by the reduced wake effects. Fixing the interspacing at $S = 8$ and varying the rotor size (Fig. 6b), it is seen that the lowest cost of energy is obtained for the biggest rotor size. This can partly be explained by increased
wind resources, as the tower height increases for increasing rotor diameters (for simplicity, it is here assumed that the tower height equals the rotor diameter). From the figures, the LCoE is seen to vary from about 5 €cents/kWh for large rotors located near the coast to nearly 18 €cents/kWh for small rotors penetrating all water depths up to about 100 m. As determined earlier, it is required to exploit locations at all water depth down to about 45 m to comply with the electrical power demand of Europe. In this case, the LCoE is found to be in the range from 6 €cents/kWh to 14 €cents/kWh, depending on rotor size and the interspacing between the wind turbines.

4.5 Mapping of Levelized Cost of Energy
Using the model described above, with input data from the mapped distributions of Weibull parameters and bathymetric data, the LCoE for locations of a ‘sample’ wind farm size of 100 turbines have been computed. This is clearly not the ideal way of planning wind farms, but give an overall assessment of the energy potential and the associated costs of harvesting wind power in the North Sea. As an example, in Fig. 7 we show the power density when erecting 15 MW wind turbines with a rotor diameter of 250 m everywhere with a mutual distance of 9 diameters between the turbines. From the plot it is seen that the power density for this configuration ranges from about 2 to 4 W/m², depending on the location of the wind farm. In Fig. 8 we depict the associated LCoE as function of position. As expected, due to increased water depths, the energy costs increase as a function of the distance from the shore line. The LCoE is seen to vary from about 5 €cents/kWh close to the shore and up to more than 20 €cents/kWh in the north-western part of the ocean. Furthermore, it is seen that the Dogger Bank as expected constitutes an area with low LCoE, due to a favourable combination of high wind resources and shallow water bathymetric conditions. However, it should be emphasized that there are some additional costs due to overseas cables, which are not included in the model when going far away from the coast. Therefore, the shown numbers should be taken as indication of the costs. Hence, more work is required to adapt the model to all possible cases. On the other hand, the model gives an excellent overview of the favorable locations, where wind farms potentially may be located and also on relative costs at the various locations.

Figure 7: Power density (MW/km² or, equivalently, W/m²) for the southern part of the North Sea covered with 15 MW wind turbines with an average mutual distance of 9 diameters.
5. Conclusions

Using a newly developed numerical framework for energy production and cost assessment of offshore wind farms, the potential of a massive exploitation of wind power in the North Sea has been investigated. The study combines a simple meteorological model for large wind farms, with the wind farm flow field being in equilibrium with the ambient atmospheric boundary layer, with an economic analysis including the bathymetry of the North Sea. The analysis comprises both an assessment of the wind power potential in the North Sea and an estimate of the economic aspects associated with a large-scale exploitation of wind power in the North Sea. The main parameters of the model are wind turbine size, interspatial distance between the turbines as well as wind resources and water depths conditioned on specific locations within the North Sea. The cost model includes expressions for the most essential wind farm cost elements, such as costs of wind turbines, support structures, cables and electrical substations, as well as costs of operation and maintenance - all as function of wind climate, rotor size, interspatial distance between the turbines and water depth.

In the present work, the model was combined with a full mapping of the wind resources and the bathymetric data of North Sea, enabling full contour plots of power density and LCOE for a case in which the North Sea was covered with 15 MW wind turbines, erected in clusters of 100 turbines with a mutual distance of 9 diameters. The computed results showed that the power density for this configuration ranges from about 2 to 4 W/m², depending on the location of the wind turbines. As expected, the levelized cost of energy increases as a function of the distance from shore line, varying from about 5 €cents/kWh close to the shore and up to more than 20 €cents/kWh in the north-western part of the ocean. Furthermore, it was demonstrated that the Dogger Bank constitutes an area of special interest which, primary because of the shallow water conditions combined with favourable wind resources, exhibits as low LCoE values as 5-10 €cents/kWh. As a main conclusion, exploiting all locations at water depths down to about 45 m comply with the electrical power demand of Europe, which is about 3500 TWh/year. In this case, the LCoE is found to be about 7 €cents/kWh for wind farms consisting of 15 MW wind turbines and an interspacing between the wind turbines of 8 diameter, corresponding to 2 km.

Figure 8: Map of LCoE (€cent/kWh) for the southern part of the North Sea covered with 15 MW wind turbines erected with an interspacing of 9 diameters.
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