How does risk aversion shape overplanting in the design of offshore wind farms?

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Abstract. Offshore wind farms are subjected to a maximum export capacity set in their connection agreement with the Transmission System Operator (TSO). Generators can export up to their contracted maximum export capacity, with any additional generation curtailed by the TSO. However, given the fact that the majority of the time offshore wind farms are not generating at full power, overplanting wind farms by installing a higher wind farm capacity compared to the fixed electrical infrastructure can result in better overall economics despite power output being curtailed at generations’ peaks. The objective of this paper is to provide a framework to assess overplanting in the design of offshore wind farms when the underlying variables, such as wind speed and availability rates among others, are uncertain. The paper integrates site characteristics, technology specificities and financing constraints grounded in the mathematical framework of uncertainty quantification at the heart of the decision-making process. Generally speaking, the role of determining the optimal amount of overplanting comes down to the risk appetite of the developer, which in this paper is represented by a linear combination of the risk aversion and risk neutrality setting. A case study for a commercial offshore wind farm shows a 2% optimal overplanting for a Monte Carlo simulation, whereas this is found at 4% for a double Monte Carlo loop simulation regardless of the risk appetite considered. Furthermore, overplanting the farm by any value from 2% to 8% gives a better result than with no overplanting for a risk neutral setting. This paper will be of interest to developers, policy-makers and regulatory bodies confronted with uncertainty in overplanting the design of offshore wind farms.

1. Introduction

The connection of offshore wind farms is subjected to a maximum export capacity (MEC) set in their connection agreement with the Transmission System Operator (TSO). Generators can export up to their contracted MEC, with any additional generation curtailed by the TSO. For this reason, it has been common practice to size the capacity of offshore wind farms to its MEC, even though the majority of the time they are not generating at full power. Little thought has been put into designing offshore wind farms which optimise its farm capacity in regard to the fixed electrical connection capacity. In this paper, overplanting is defined as the process of installing additional wind farm capacity compared to its MEC.
In 2008, while planning the UK Offshore Wind Round 3, it came to the attention of National Grid that installing a higher installed generating capacity than the connection capacity could result in better overall economics for the development of offshore wind farms despite power being constrained at generations peaks [1]. In that report, a high level study was undertaken in Appendix 1 where 12% overplanting was suggested as an optimal setup, which meant that 1200 MW of offshore wind should be built for 1000 MW of grid connection. The report also looked at the sensitivity of ratio of connection costs to installed wind turbine costs, average wind speed and wind turbine availability. The findings of the study showed that (i) as the cost ratio increases there’s an asymptotic trend for the optimum size of the wind farm towards 111%, (ii) as the average wind speed increases there is little change in the optimum size, but if the mean wind speed is less than 9 m/s then the optimum size increases in order to maximise the utilisation of the available capacity and (iii) as the percentage of the wind turbine availability decreases, the installed capacity needs to increase to maximise the utilisation of the available capacity. Although this was a high level study and some of the assumptions are a bit conservative at the current state of the offshore wind sector, it opened up further points for analysis.

In 2011, The Irish Commission for Energy Regulation (CER) published a report where generators were allowed to overplant their onshore wind farm capacity up to 5%, value driven by wind farm cabling and transformer losses which would compensate for losses on the generator’s side of the grid connection and would allow the developer to export up to its MEC at the connection point [2]. In 2014, CER decided to update the earlier decision in light of potential economic benefits by increasing overplanting to 20% [3].

In 2012, Forewind looked at overplanting by factoring a number of variables: different turbine types, export and inter-array cable losses, wake losses, grid connection downtime and the total cost for wind turbines, including construction, operation and maintenance [4]. In this study it was also shown that adding more wind turbines improves the economics of the project, however further conclusions could not be drawn given the dependence of many site and technology-specific variables. Similar studies have mentioned the economic benefits of overplanting [5].

A clear example of overplanting in the offshore wind industry is given in the Netherlands for the Wind Farm Zone Borssele. The wind farm is divided into 5 sites. Site I, II and IV can accommodate 350 MW plus 30 MW of overplanting, whereas Site III can accommodate 330 MW plus 30 MW of overplanting. This is around 9 % of overplanting for both cases. TenneT, the Dutch TSO, contemplated the option of dynamic loading of the export cables. Namely, in case that Site I, II and IV was producing at full power, which would see a load of 380 MW being transferred through one of the export cables, this electricity could be handled by the cable and sent to the grid [6]. However, the capacity in excess of 350 MW is not always guaranteed by TenneT, but it is subjected to some constraints linked to the final soil resistivity values, temperature of the cable, final design of the cable system and voltage level of the system.

More recently, some authors have attempted to model overplanting for onshore and offshore wind farms [7, 8]. However, the models utilised in assessing overplanting did not capture the complex relationships between offshore wind engineering variables and financing constraints. Whereas the work of McInerney et al [7] sought to emphasize the benefits of overplanting from the economical point of view, it didn’t consider technical variables. Conversely, the work of Wolter et al [8] placed more weight on the technical variables but left aside important financing constraints. Nevertheless, there is enough evidence to suggest that overplanting can lead to further cost reductions in the maturing offshore wind sector. However, a tailored techno-economic model that integrates site characteristics, technology specificities and financing constraints is
needed to demonstrate the benefits of overplanting. Furthermore, this techno-economic model should be grounded in the framework of uncertainty quantification, where its model inputs are represented by probability distribution functions.

The contribution of the current paper is to provide a framework to assess overplanting under uncertainty in the design of offshore wind farms; allowing developers and regulatory bodies to identify pareto-optimal trade-offs between cost and uncertainty when deploying additional turbines for a given electrical infrastructure. The rest of this paper is structured as follows: Section 2 describes the detailed modelling of overplanting and its main assumptions. Section 3 applies the modelling techniques to a case study. Finally, a brief discussion and conclusions are drawn in Section 4.

2. Methodology
The modelling approach to assess overplanting is based around the Offshore Wind Cost Analysis Tool (OWCAT) developed at the EDF Energy R&D UK Centre. Further information regarding its inputs, outputs and interplay between them can be found in Appendix A.

2.1. Factors Affecting Overplanting
Overplanting is mainly driven by the following factors:

- Ratio of wind turbine expenditure to electrical infrastructure: higher costs of installing an additional turbine for a given electrical infrastructure makes it more difficult for developers to consider this option.
- Wind speed distribution: it describes the variation of wind speeds for a given site. Sites with low mean wind speed mean that the share of time generating at its MEC is low and so is the amount of curtailment; this encourages developers to increase the installation of additional capacity. On the contrary, sites with high mean wind speed mean that the share of time generating at its MEC is high and so is the amount of curtailment; this doesn’t favour the installation of additional capacity.
- Wind turbine availability: it is defined as the amount of time that the turbine is able to operate over a certain period of time divided by the total time in that period. Farms with high availability values mean that more turbines are operational at a given point in time and therefore it is expected a higher share of curtailment when overplanting. Likewise, low availabilities result in less amount of curtailment and favour overplanting.
- Inter-array cable availability: same rationale as wind turbine availability.
- Wake effect: they reduce the wind speed downstream a generating wind turbine. At high wind speeds the farm is able to produce at rated power. However, wake effects need to be taken into consideration for low wind speeds, which is the amount of generation that is not constrained.
- Electrical losses: they take place in transformers, collection wiring, substation and cables. Higher losses will encourage developers to overplant to be able to generate at MEC at the connection point.
- Degradation factor: wind turbine blades are subjected to environmental conditions that result in blade degradation over time, which directly reduces energy production and encourages overplanting.
2.2. Modelling of Overplanting
In order to determine the optimal size of an offshore wind farm relative to the electrical infrastructure it is important to capture the elements described in Section 2.1 within the modelling process. Two types of modelling are considered. Modelling Type 1 is based on constraining individual power curves as a function of the number of turbines and its MEC. As the number of additional turbines to the given MEC increases, the power that can be generated per turbine is reduced due to the electrical constraint of the connection capacity, as shown in Figure 1. In addition, wind turbine and inter-array cable availabilities are assumed to be fixed, following the work of National Grid [1]. Modelling Type 2 takes advantage of the stochastic capabilities of the cost modelling tool and propagates the uncertainties of the wind speed and availabilities to the power output via Monte Carlo simulation. Then, the resulting aggregated power transferred to the grid is obtained by constraining all those occurrences that are higher than the MEC, as shown in Figure 2.

![Figure 1](image1.png)

**Figure 1.** 8MW wind turbine constrained to 7MW due to overplanting in Modelling Type 1.

![Figure 2](image2.png)

**Figure 2.** 52 8MW wind turbines constrained to a MEC of 400 MW in Modelling Type 2.

The philosophy of modelling the wake effects lies on decreasing the energy available in the wind so that the total losses are equal to the known wake effects calculated through standard commercial tools \(f_{\text{wake}}\). Since it is assumed that each turbine produces the same energy over the lifetime of the farm, wake effects are obtained at wind farm level and not at individual turbines. The power output \(P(v)\) produced by a single turbine is modelled by a theoretical power curve, which is a function of the rated power \(P_{\text{rated}}\), cut-in speed \(v_{\text{cut-in}}\), cut-off speed \(v_{\text{cut-off}}\), Betz efficiency \(C_{\text{eff}}\), the air density \(\rho_{\text{air}}\), parameter \(\alpha = 1\), wind speed \(v\) and the rotor diameter \(D\), according to Equation 1.

The cut-in speed is defined as the speed at which the turbine begins to rotate, when applying sufficient torque on the rotor to generate power. At the other side of the curve, when the speed increases beyond a given threshold or cut-off speed, putting the integrity of the rotor at risk, the braking system is employed to bring the rotor to a standstill. Both situations result in a nil amount of power being produced. Otherwise, when the wind speed is found between the cut-in and cut-off speed, then the production is governed by Equation 1. It is worth noting that, whereas the Betz limit is a theoretical maximum of the wind energy that can be extracted, the Betz efficiency or \(C_{\text{eff}}\) has been considered as the efficiency of the wind turbine generator. From Equation 1 it is also possible to make a distinction between the energy available in the wind...
and the energy produced by a wind turbine generator, which is a preliminary step to model the wake effects in the cost modelling tool. We’ve assumed a parameter $\alpha = 1$, the challenge is now to work out $\alpha$ so that the total losses are equal to the known wake effects calculated through standard commercial tools $f_{\text{wake}}$. In order to solve this problem and obtain alpha, an iterative method is conducted and displayed in the flowchart of Figure 3.

\[
P(v) = \min \left( P_{\text{rated}} , \alpha \frac{1}{2} C_{\text{eff}} \frac{16}{27} \pi \rho_{\text{air}} \frac{D^2}{2} (v^3 - v_{\text{cut-in}}^3) \right) \forall v \in (v_{\text{cut-in}}, v_{\text{cut-off}}) \quad (1)
\]

Figure 4 shows a wind speed distribution associated with a given site. Figure 5 displays the theoretical wind turbine power curve for different alpha coefficients. An alpha coefficient of 1 means that there are no wake effects, while decreasing values imply higher wake effects. Figure 6 shows the aggregated power curve distribution for a 400 MW farm and alpha coefficients. Figure 7 shows the losses incurred for each alpha parameter. Once alpha has been determined, it is fixed for the rest of the calculations.

On another note, availability is defined in this paper as the amount of time that a component is able to operate over a certain period, divided by the amount of the time in the period. Whereas a constant wind turbine availability rate is assumed for Modelling Type 1, its stochastic counterpart, Modelling Type 2, uses a binomial distribution to represent the number of wind turbines and inter-array cables available for energy production at a given point in time. Figure 8 displays the cumulative distribution functions of the number of wind turbines available for energy production for given wind turbine availability rates. It becomes apparent that higher availability rates lead to a higher share of time where the same number of wind turbines are available. Modelling Type 1 assumes the expected value of the number of wind turbines available for energy production. However, overplanting means that we need to be careful on how to determine the share of time the electrical connection is constrained.

Adding additional turbines to a fixed electrical infrastructure and assuming constant availability rates could lead to an overestimation of the annual energy production. Firstly, there are times where the power produced by the number of available wind turbines is higher than the MEC, resulting in some curtailment by the TSO. Secondly, there are also times where the power flowing through the connection point is less than the MEC, meaning that less wind turbines are available for production than its expected number. Figure 9 shows the difference between considering a fixed wind turbine and inter-array cable availability rates and modelling its stochastic counterparts; this is to say Modelling Type 1 is compared against Modelling Type 2. Even though it is possible for a developer to optimise an offshore wind farm so that its aggregated power curve matches the MEC at its expected value, the full information on the stochastic behaviour should also be considered. Modelling Type 1 leads to the aggregated power curve in blue, whereas the one in red represents Modelling Type 2. In order to avoid an overestimation of the energy production, Modelling Type 2 is considered for the rest of the paper despite requiring a higher computational cost.
Figure 4. Wind speed represented by a Rayleigh distribution associated with a mean wind speed of 9 m/s.

Figure 5. Theoretical wind turbine power curve for different alpha coefficients.

Figure 6. Wind power output distribution for different alpha coefficients.

Figure 7. Incurred losses for different alpha coefficients.

Figure 8. Binomial Cumulative Distribution Function of 50 WTG farm for given WTG availability rates.

Figure 9. Modelling Type 1 against Modelling Type 2; limitations of considering fixed availability rates.

Electrical losses are modelled as a function of the power factor, which is the ratio between the real and reactive power, the cross section of the cables, the operating voltage and efficiencies of the system. The degradation factor is modelled by as a coefficient which decreases the energy production as the asset ages based on the work of Staffell [9].
2.3. Modelling Risk Aversion
Risk aversion is modelled by risk metrics originated in the financial mathematics literature such as the Value at Risk (VaR) and Conditional Value at Risk (CVaR). The \textit{VaR}_\alpha gives the probability \alpha that a certain outcome is worse than a given threshold. Typically the probability \alpha represents the confidence level and \textit{VaR}_\alpha is regarded as the maximum value that will not be exceeded at this given confidence level. Building on \textit{VaR}_\alpha, \textit{CVaR}_\alpha gives the expected outcome given that the value is worse than \textit{VaR}_\alpha. The concept was first introduced in Rockafellar \cite{10} and further developed by him in \cite{11}. The mathematical formulation for \textit{VaR}_\alpha and \textit{CVaR}_\alpha for continuous functions is given in Equation 2 and 3, respectively.

\begin{align}
\text{VaR}_\alpha(LCOE) &= \min \left(c : P(LCOE \leq c) \geq \alpha \right) \quad (2) \\
\text{CVaR}_\alpha[LCOE] &= \mathbb{E}[LCOE|LCOE \geq \text{VaR}_\alpha(LCOE)] \quad (3)
\end{align}

Where LCOE is the Levelised Cost of Energy, \( P(LCOE \leq c) \) is the probability of the LCOE being less or equal than \( c \) and \( \mathbb{E} \) is the mathematical expectation operator. One of the main shortcomings of the \textit{VaR}_\alpha is that it provides no information on the extent to which values might materialise beyond the threshold amount indicated by the \textit{VaR}_\alpha itself, whereas \textit{CVaR}_\alpha does. In addition, \textit{CVaR}_\alpha has superior mathematical properties since this measure is coherent in the sense of Artzner \cite{12}. For this reason, we’ve selected \textit{CVaR}_\alpha as the preferred financial risk metric. In this approach risk aversion is modelled as a weighted average \( \lambda \) of the Median and \textit{CVaR}_\alpha of the LCOE values. Parameter \( \lambda \) can be varied from 0 (in a risk neutrality setting) to 1 (extreme risk aversion), based on the work of Munoz \cite{13} and displayed in Equation 4.

\begin{equation}
\rho_\alpha[\lambda, LCOE] = \lambda \text{CVaR}_\alpha[LCOE] + (1-\lambda)\text{Median}[LCOE] \quad (4)
\end{equation}

3. Case Study and Results
The case study is based on a 400MW commercial offshore wind farm; its project specifications are shown in Table 1. It is assumed, for the sake of simplicity, that the export cable length, construction and operational port distances are equal to the distance from shore. The MEC is 400MW and offshore wind farm capacities are varied from 400MW to 456MW, or from 0% to 14% of overplanting. The estimated mean wind speed is represented by a normal distribution with mean \( \mu \) and standard deviation \( \sigma \) as \( \mathcal{N}(\mu, \sigma^2) \). Likewise, availabilities are represented by uniform distributions with lower \( (a) \) and upper \( (b) \) bounds as \( \mathcal{U}(a, b) \).

| Characteristic               | Value   | Uncertainty |
|------------------------------|---------|-------------|
| Water Depth [m]              | 25      | None        |
| Distance from shore [km]     | 25      | None        |
| Mean Wind Speed @ 100m [m/s] | 9 \( \mathcal{N}(9, 0.1^2) \) |
| Wind Turbine Availability [%]| 95      | \( \mathcal{U}(90, 97) \) |
| Inter-Array Cable Availability [%]| 99 | \( \mathcal{U}(97, 99) \) |
| Foundation Type [-]          | Monopile| None        |
| Electrical Infrastructure [-] | HVAC    | None        |
| Wind Turbine Type [-]        | 164-8 MW| None        |
| Wake effect [%]              | 10      | None        |
| Degradation Factor [%]       | 0.05    | None        |

\footnote{0.1 m/s is a representative value combined from independent uncertainties, individually determined by normal distributions as seen in \cite{14, 15, 16}. A different choice doesn’t affect the optimal overplanting, as suggested by the sensitivity analysis on the mean wind speed}
The reference case is calculated through a Monte Carlo simulation with input parameters from Table 1 (without uncertainties). Figure 10 shows the difference between the unconstrained and constrained yield as a function of overplanting; the amount of constraint is minimum up to 2% overplanting, where the two lines start to diverge. This point is also reflected in Figure 11, suggesting that additional energy produced by the over installation of turbines doesn’t outweigh its wind turbine expenditure; a 2% overplanting is considered optimal for this farm.

![Figure 10](image1.png)  
**Figure 10.** Unconstrained versus constrained normalised yield as a function of overplanting.

A local sensitivity analysis on the wind speed, wake effects and wind turbine and inter-array cable availability has been conducted. Figure 12 shows the effects of an estimated mean wind speed of 8, 9 and 10 m/s, where the optimal amount of overplanting remains at 2%. Similar results are obtained by investigating the sensitivity of the wake effects and inter-array cable availability. However, as far as the wind turbine availability is concerned, this parameter is much more sensitive, resulting in an optimal overplanting of 6% when the availability is as low as 90%, as shown in Figure 13.

![Figure 12](image2.png)  
**Figure 12.** Local Sensitivity Analysis on mean wind speed.

![Figure 13](image3.png)  
**Figure 13.** Local Sensitivity Analysis on wind turbine availability.

Figure 14 shows the yearly cumulative utilization rate of the connection capacity for an estimated mean wind speed of 9 and 10 m/s and varying wind farm capacities. Although higher wind speeds lead to hitting the MEC cap earlier, they also produce more power for a
given utilization rate. The area underneath the aggregated power curve represents the total energy produced and overplanting is concerned about maximising this area. Since a change in wind speed does not significantly change this area, it remains a second order parameter to overplanting. On the contrary, overplanting low wind turbine availabilities significantly changes this area, as reflected in Figure 13. Notice that the same sequence of random numbers within the inner Monte Carlo has been used to generate the wind speed distributions for the different capacities so as to avoid the introduction of additional noise - otherwise the aggregated power curves may overlap.

![Figure 14. Utilization Rate Cumulative Distribution Function for 9 and 10 m/s wind speeds.](image)

For a clearer interpretation of the findings we have conditioned the LCOE distribution given the base case wind speed. The kernel density function (KDF) for wind speeds equal or greater than 9 m/s is given in Figure 15, whereas for less than 9 m/s is shown in Figure 16. Both figures reflect that when overplanting with a small amount, there’s a shift to the left in the KDF. However, for larger amounts of overplanting, the KDF is shifted to the right well beyond the reference case represented in blue.

![Figure 15. KDF sensitivity to overplanting for wind speeds equal or greater than 9 m/s.](image)

![Figure 16. KDF sensitivity to overplanting for wind speeds less than 9 m/s.](image)
The probability distribution function of the LCOE is obtained by 20,000 model evaluations of an outer Monte Carlo loop with parameters displayed in Table 1. It is worth bearing in mind that, for each model evaluation, an inner Monte Carlo simulation propagates the wind speed and availabilities with another 10,000 model evaluations within the Annual Energy Production module; this process is repeated for several degrees of overplanting. The risk metrics given by the expression $\lambda CVaR_{\alpha=0.05}[LCOE] + (1 - \lambda)\text{Median}[LCOE]$ are normalised with respect to the values obtained when no overplanting is applied, as displayed in Figure 17. Overplanting the farm from 2% to 8% results in risk metrics (in a risk neutrality setting) that improve the economics of the farm. However, the optimal design is found at 4% of overplanting regardless of the risk appetite.

![Figure 17. Risk aversion represented by $\rho_{\alpha}[\lambda,\text{overplanting}]$.](image)

4. Discussion and Conclusion
This paper has presented the development of a novel framework to assess overplanting in the design of offshore wind farms when the underlying variables, such as the wind speed and availability rates, among others, are uncertain. Two types of modelling have been compared, taking into consideration the estimated mean wind speed, wind speed distribution, availability rates, electrical losses, wake effects and a degradation factor. Although Modelling Type 1 is easier to implement than Modelling Type 2, it can lead to an overestimation of the annual energy production. Modelling Type 2 addresses this problem via an inner Monte Carlo simulation despite requiring higher computational costs by assessing the percentage of time the MEC is constrained, and it has therefore been the preferred method for this paper.

A local sensitivity analysis has revealed that the wind turbine availability is the most sensitive parameter to overplanting, whereas the estimated mean wind speed, wake effects and inter-array cable availability play a secondary role. As the wind turbine availability increases, overplanting becomes less valuable. This suggests that previous studies on overplanting, which were based on low wind turbine availabilities rates from UK Round 1 offshore wind farms (in the order of 90%) or on Modelling Type 1, need to be revisited. New studies on overplanting must consider current offshore wind turbine availability rates as well as Modelling Type 2 or a similar methodology whereby the effects of uncertainty are integrated in the decision-making process.
Without considering the uncertainties in the different parameters represented by the outer Monte Carlo loop, it appears that the optimal amount of overplanting is 2% for our reference offshore wind farm. Generally speaking, the role of determining the optimal setup comes down to the risk appetite of the developer, which in this case is represented by a linear combination of the risk aversion and risk neutrality setting, governed by the $\lambda$ parameter. However, when conducting the double loop Monte Carlo simulation, the optimal setup is found at 4% regardless of the risk appetite considered. Furthermore, overplanting the farm by any value from 2% to 8% gives a better result than with no overplanting for a risk neutral setting, meaning that overplanting can be used as a hedging instrument.

Future work will take advantage of the framework developed in this paper to investigate several offshore wind farm configurations in terms of its suitability to overplanting. How is overplanting influenced by larger wind turbines and sites located further from shore? and how does risk aversion influence the investment decision for these new sites? we will investigate the ratio of wind turbine expenditure to electrical infrastructure. Also, the degradation factor has been taken into account after the constraint, but we would expect greater amounts of overplanting if this was taken before the constraint.

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Appendix A. Offshore Wind Cost Modelling Tool

The Offshore Wind Cost Analysis Tool (OWCAT) developed at the EDF Energy R&D UK Centre has been used in the past for comparative evaluation of multiple sites, detailed evaluation of specific project layouts and sensitivity studies on both design/technology choices and cost variations [17]. The tool has been validated against cost data from the Navitus Bay, Courseulles-sur-Mer and Neart na Gaoithe projects and shown to be accurate within ± 15% for these cases.

The cost modelling tool consists of four main modules: a wind farm design module, a cost calculation module, a financial module and an overarching stochastic module which allows inputs to be represented by probability distribution functions. The first stage of the module concerns the wind farm design. In order to evaluate the costs of the project, it is necessary to have information about the number and type of wind turbines, foundations, inter-array cabling and the export system. In other words, the wind farm itself must be modelled. Designing an offshore wind farm requires interaction between teams from different disciplines; for example, the wind turbine team will have to interact with the foundation team to make sure that the loads of the turbine are correctly passed onto the foundation, and the foundation team will need to make sure that the electrical connections are correctly secured within the foundation. As such, a cost model must capture the same interactions as the design process and cannot be a simple accumulation of models from separate disciplines.

The design outputs of the first module are fed as inputs into the second module, which calculates the costs of the different offshore wind farm components. The cost module can be divided into Development Expenditure (DEVEX), Capital Expenditure (CAPEX), Operational Expenditure (OPEX) and Decommissioning Expenditure (DECEX). DEVEX covers the costs of all the processes up to the financial close or placing firm orders to proceed with the construction. CAPEX calculates the supply and installation costs of the wind farm, including wind turbines, foundations, inter-array cables, offshore substations, export cables and onshore substations. Indirect costs such as Engineering, Procurement, and Construction Management (EPCM) costs and insurance are also included in the CAPEX breakdown. OPEX includes direct costs for the operation and maintenance of the wind farm, as well as transmission charges, insurance, taxes and royalties. DECEX accounts for the decommissioning of the wind turbines, foundations and offshore substations.

The cost outputs of the second module are passed into the third module, which is the financial model of the wind farm project. The financial model takes into consideration the different cash flows throughout the life of the wind farm, as well as the financing structure put in place to supply the initial capital investment. Based on the resulting free cash flows and financing costs, the LCOE can be determined, together with other financial performance indicators. The financial module allows for corporate and project financing modelling.

The OWCAT structure is shown in Figure A1. This information has been divided into:

- (i) Project Specifications
- (ii) Technical Specifications
- (iii) Economic and Financial Specifications
- (iv) Vessel Specifications
- (v) Structural Masses and Electrical Components Database
(i) refers to the project offshore wind farm characteristics such as the capacity of the farm, the wind speed at a given referenced height, the average water depth, the soil conditions, the distance from shore, the wind turbine model, foundation type and export system specifications among others. Since no two projects will have the same characteristics, project specifications attempt to model each particular site. (ii) addresses the details of the offshore wind technology, representing wind turbine, foundation, inter-array cable, export system and grid parameters. For example, as far as the wind turbine is concerned, parameters such as the wind turbine availability, the installation vessel associated with the wind turbine, the average loading, installation and commissioning times are accounted for. In addition, a decommissioning factor is used for all offshore wind farm components to account for a reduction in time from the installation phase. (iii) concerns the reference year for real prices, the risk-free rate and cost of debt, insurance and insurance premium tax rates, contingency requirements, corporation taxes, seabed rent, exchange rates and inflation. (iv) involves the different vessel characteristics used in the installation and decommissioning of the offshore wind farms. As an example, heavy-lift jack-up vessel parameters comprise the day rate, vessel transit speed, vessel positioning time, vessel mobilisation time, operational weather window and carrying capacities in regard to different components. (v) consists of the data used to establish the foundation mass correlations, which are the basis for the CAPEX estimation in the foundation procurement. It also considers the correlations used to estimate the cost of different electrical components.

The final design contains not only the design of the offshore wind farm, where the foundations masses, inter-array and export system are sized, but also the procurement, vessel charter model and the Annual Energy Production (AEP) as displayed in Figure A1. Procurement stores all the information concerning wind turbines, foundations and the electrical system, in terms of the type, number of elements and size (also length if required), giving rise to a procurement catalogue which forms the basis for the cost module. The vessel charter model is based on the work of Kaiser [18], whereas the AEPs is built upon industry’s best practices assuming respectively either a logarithmic- or power-law wind profile in conjunction with a Rayleigh or Weibull probability distribution to model the wind speed. Wake losses and electrical losses are also accounted for in the AEP submodule.

As far as the financial module is concerned, the calculation itself entails not only one but a twofold iterative process. The external loop consists of determining the value of \( \lambda \) that makes Equation A.1 equal to 0.

\[
LCOE = \lambda \sum_{t=1}^{n} \frac{FCF_t(t)}{(1 + MARR)^t} = 0; \quad (A.1)
\]

Where \( FCF \) are the free cash flows, \( MARR \) is the desired Minimum Acceptable Rate of Return (MARR) and \( \lambda_0 \) is the initial guess obtained from a simplified financial model. The LCOE financial metric is calculated as the constant inflation-linked real electricity price required to meet the desired MARR. The internal loop is used in the project finance setting and concerns the debt sizing or sculpting, which determines the maximum amount of project finance debt that the offshore wind farm can sustain based on the bank’s requirements. Project lenders usually specify the borrowing capacity on the basis of debt service ratio and covenants. As such, parameters such as the Debt Service Coverage Ratio (DSCR), the maximum leverage and the Cash Flow Available for Debt Service (CFADS) have been considered.

Lastly, the stochastic module (depicted in orange in Figure A1) allows the model to be embedded in the framework of uncertainty quantification.
Figure A1. Stochastic OWCAT Structure
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