Summary

The project presented in this report is aimed to develop a calculation tool for the economic evaluation of offshore wind power projects. This tool calculates the LCOE (levelized cost of energy), which is the total price that the electricity producer has to pay per each unit of electric energy produced. This calculation is based in the characteristics of the evaluated power plant, but also in the estimation of the production and the losses. The LCOE can be used to evaluate the viability of projects, its competitiveness in the energy market and to calculate the expected profit of projects.

In order to make an accurate tool, all the costs involved in the whole life cycle of offshore wind projects must be taken into account; for this reason the life cycle approach is used considering the costs of each phase of wind projects, from cradle to grave.

The project is divided in three main parts: the first part consisting in research on wind technology, costs, economic and energetic aspects, in order to make a mathematical model for the LCOE calculation. The resulting model has been compared to trustworthy data in order to evaluate the accuracy of the calculation. The second part of the project consisted in the programming of the software tool using the model established in the first part. A third part was dedicated to evaluating the economic and environmental impact of the project.
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Glossary

Acronyms

AWEA  American Wind Energy Association
CAPEX  Capital Expenditures
EERA  European Energy Research Alliance
EWEA  European Wind Energy Association
HICP  Harmonized Index of Consumer Prices
HVAC  High Voltage Alternative Current
HVDC  High Voltage Direct Current
IREC  Institute of Research on Energy of Catalonia
IRR  Internal Rate of Return
LCC  Life Cycle Cost
LCOE  Levelized Cost Of Energy
MVAC  Medium Voltage Alternative Current
NPV  Net Present Value
NREL  National Renewable Energy Laboratory
OPEX  Operation Expenditures
OWPP  Offshore Wind Power Plants
PPI  Industrial Producer Price Index
1. Foreword

1.1. Origin of the project

This project was proposed by the Electricity and power electronics area of the Institute for Research on Energy of Catalonia (IREC) in order to enlarge the institute’s know-how on economic evaluation of energy generation projects. The final objective was to develop a tool that could be used for economic evaluation of wind offshore projects with three main purposes:

- The tool shall be used in future projects related to offshore wind and presented to project partners to disseminate the institute potentials and experience on the field.
- The tool must serve as a model for the development of tools for other types of projects, for example onshore wind or photovoltaics.
- The tool must be interesting for industrial purposes in order to give the institute the possibility of exploiting the project results and creating links with industrial partners for the benefit of both parts.

Considering that the wind power industry is a currently growing sector and that both large investments and technological improvements are expected in the near future, it seemed wise to get prepared for managing economic and technological changes on the field. In this context, IREC’s research staff considered that it was a perfect time to develop a tool that could give support to the development of the sector and at the same time be prepared for the introduction of any changes that could appear.

1.2. Academic requirements

Given that this project represents the last stage of a degree in Industrial Engineering, it was considered necessary that the project had two main characteristics:

- The project should require knowledge and abilities of different nature acquired by the student during the Engineering degree, in order to serve as a proof of the student’s capabilities.
- The subject of the project should be interesting and give to the student the possibility of getting new knowledge and develop or improve his skills.

The first requirement has been fulfilled, considering that it has been necessary to have knowledge on energy technology, physics, electricity, economy, project management, mathematics and programming in order to complete the work. In addition the student has needed skills on information research, work organization, oral communication and technical writing.

Concerning the second requirement, the subject has given the student the chance to learn on wind power technology. In addition, it was the first time that the student worked on a research center and it allowed him to learn the methodologies used in this kind of institutions. As the main new skills developed, it should be mentioned the ability of looking
for trustworthy information, managing information sources and also the large acquisition of new knowledge in Matlab programming.

1.3. Motivation

Renewable energies are key technologies to face major environmental hazards caused by human societies that require more and more electricity every day. They are also essential to face the future challenge of reduction of the world fossil fuel reserves.

This project presented a chance of contributing to boost renewable energy by generating knowledge that could help the reduction of cost of wind technologies. This reduction of cost might be achieved through comparison between alternatives and identification of key elements for technical innovation thanks to the Cost Assessment Tool for Offshore Wind Power Plants, which was the object of the project.

This chance of contributing to make wind energy more competitive was the primary motivation for the development of this project, because that could have a positive impact in energy systems and consequently in our society and people lives.

1.4. Related and future work

The tool developed during this project has a close precedent named “Technical and economic assessment tool for Offshore Wind Power Plants connected to a single large VSC-HVDC converter operated at variable frequency (SLPC-VF concept)”. This tool was also developed at IREC as a part of a PhD work [1]. The two tools are similar in concept and operation. Nevertheless, there are major differences in objective and design. The previous tool was designed for the simulation of very specific technologies (variable frequency vs. fixed frequency) and technical aspects were emphasized more than economic aspects. The tool developed for this project is designed to simulate commonly used technologies and economic aspects are emphasized over technical ones.

The tool resulting from this project is expected to be a first version with potential to be easily improved. Further research will be valuable to improve the models and expand the options that the tool might offer (for example including wake effect, HVDC technologies or grid optimization). Future work in the tool programming could be useful for improving the user’s experience.
2. Introduction

2.1. Objectives of the project

The main objective of the project is to develop a tool for the calculation of the Levelized Cost of Energy (LCOE) applied to offshore wind power plants. This tool must be able to calculate this parameter for offshore wind projects based on the characteristics defined by the user. The tool must take into account all the costs included in the life cycle of a project, as well as calculate an accurate estimation of the production and losses during the life span of wind power plants.

In order to reach the main objective, the work has been divided into three parts. Each part has its particular objectives. The fulfillment of each one of the partial objectives shall lead to the success of the project. These three parts and objectives are listed below:

I. Scientific and technical background research part: With the objective of gathering all the knowledge and information needed for the design of the LCOE calculation model.

II. Development of the tool part: With the objectives of designing the calculation model, programming the tool and evaluating its accuracy.

III. Exploitation and environmental impact: With the objective of analyzing the results of the project itself, from the economic and environmental points of view.

2.2. Scope of the project

The tool developed in this project is expected to help making an economic assessment of offshore wind power plants. Other types of power plants are out of the scope, including land based wind.

The primary objective is to develop the most accurate model possible for calculating the cost of wind projects. The level of accuracy for the cost model shall be determined by the results of the research carried out, but the major effort shall be spent in this aspect.

Technical aspects of power plants will be included but technical accuracy is not the primary objective. Future work might improve these parts of the model.

The resulting tool will take care of OWPP with AC grids operating at 50 Hz. Other technologies such as HVDC or variable frequency grids are not in the scope. However, some comments related to HVDC are included in this report as a part of the research results.

The simulation of aerodynamic shadows of turbines has been let out of the scope of the tool, but some comments are also included as a part of the research results.

Electric grids optimization is out of the scope, as it should be object of a separate project itself. The results of any future work in this field could help future improvements of the tool.
3. Methodology and organization of the project

3.1. Methodology

Considering that the project has three parts of different nature, the methodology used for each one of the parts is explained in the subsequent sections of the report. Additionally, a note on monetary update is included in this chapter in order to avoid ambiguities in monetary units.

3.1.1. Methodology for the research part

Considering that costing data is rarely available in comparison to technical data, this project needed to focus on gathering data on the main contributions to the energy cost, ignoring the features that have negligible impact in the cost, and getting sure that the few available data agreed with real project costs. This approach required to make some hypothesis for the cost calculation models and then to verify the results with trustworthy data about real projects.

The process started with the gathering of bibliography related to offshore wind. Most of the documents were focused on costs of projects but there were also documents on technical and environmental subjects.

All the information that could help building the models for the tool was kept, with the objective of building a complete model that could cover all the aspects required to program the tool. The first part of this report summarizes the scientific and technical background of the project acquired thanks to this research.

3.1.2. Methodology for the development part

This part of the project is related to the tool that has been implemented as a product of the project. The tool translates a calculation model developed thanks to the research results into a software that allows the user to define an OWPP and calculate the LCOE of the defined plant.

Based on the information sourced in all the bibliographical documents, the calculation model was designed. This model has several parts, from the modeling of the power plant to the calculation of the project costs and the energy yield.

All the parts of the model were partially tested during the defining process, particularly the parts related to CAPEX and OPEX, because they were the core of the project. Later, the model was implemented under the form of a software, and tested again.

The tool has been programmed in Matlab programming language and is designed in different parts that has been called blocks. Each block is related to a part of the researched model, in order to divide the general problem into small parts. This methodology allowed the programmer to find errors and make changes in small parts of the code without affecting the code related to other parts.

Each block has been designed with a graphical interphase that allows the user to introduce and visualize data and to command actions to the tool. Each block is also related to a code.
This code has been developed using simple actions and scripts that solve small parts of the calculations and data process. This also helped to divide a large problem into smaller ones, helping to find and correct any error.

Once the tool was completed, it was tested against real data in case studies. The second part of this report includes the description of every part of the model, the description of the tool and the case studies used for the tool validation.

### 3.1.3. Methodology for the exploitation and environmental impact part

An economic assessment and an environmental impact assessment are included in the third part of the report. As far as the only object pursued by this project is the development of the tool, for a matter of coherence both assessments are dedicated to this task.

The economic assessment, which is included in an exploitation plan, gives an account of the costs of development of the tool, expected monetary income and economic analysis to test the financial viability of the project.

The environmental impact assessment includes a calculation of the carbon footprint produced for the development of the tool.

### 3.1.4. Note on monetary update

A note on monetary update has been included in Annex D to discuss about monetary units used in this report.

### 3.2. Organization of the project

The project was divided into 5 main tasks:

1) Getting knowledge on the project subjects
2) Bibliography review
3) Designing the models for the tool
4) Programming the tool
5) Report writing

The original plan was to develop the project in 5 months starting from February 2015 and deadlines were set for each task. Due to the large amount of work required to accomplish the objectives, the project was extended one month in order to finish the tool. One additional month was used to get this report ready for publication. Figure 3.1 shows the original planning as well as the extended times.

![Figure 3.1 Diagram of project planning. Source: self-elaboration.](image-url)
PART I

Scientific and technical background research
4. Wind power technology

4.1. Physics of wind energy

4.1.1. The power of wind

Wind turbines are used to transform the kinetic energy of the wind into electrical energy. This process is made in two steps. In the first step, the rotor extracts kinetic energy from the wind and converts it into kinetic energy of the drive train. In the second step, the kinetic energy of the drive train is transformed into electrical current in a generator.

The extraction of the kinetic energy from the wind is made by reducing the wind speed through aerodynamic interaction between the moving air and the rotor. This aerodynamic interaction consists in the creation of forces: drag (if force is parallel to wind speed) and lift (if force is perpendicular to wind speed).

The kinetic energy \( E \) of a certain mass of air \( m \) flowing at a certain speed \( v \) is expressed in Eq. (4.1).

\[
E = \frac{1}{2} m v^2 \tag{4.1}
\]

The mass of air \( \dot{m} \) passing through a certain area \( A \) in a given time could be expressed as it is shown in Eq. (4.2), where \( x \) is the normal direction to section \( A \), \( t \) represents the time and \( \rho \) is the density of the air. The mass flow rate is proportional to the speed \( v \).

\[
\dot{m} = \rho A \frac{dx}{dt} = \rho A v \tag{4.2}
\]

The power of the air flow crossing the area is then the kinetic energy per unit of time \( \dot{E} \) of Eq. (4.6).

\[
\dot{E} = \frac{1}{2} \dot{m} v^2 \tag{4.3}
\]

Replacing terms from Eq. (4.2) in Eq. (4.3), the general expression of the power of wind crossing the area \( A \) can be write as in Eq. (4.4). The mechanical power of the wind is then proportional to air density, to the cross section area and to the third power of the flow speed.

\[
P_{\text{wind}} = \dot{E} = \frac{1}{2} \rho A v^3 \tag{4.4}
\]

The previous equations can be applied to wind turbines by identifying the cross section area with the area swept by the rotor blades in the plane of rotation. However, not all the mechanical power can be extracted from the wind, as it should mean that, while the wind flows at a certain speed upstream, the wind speed downstream must be reduced to zero. There is, as a consequence, a certain limit to the power than can be extracted from the wind to keep the air flowing.
4.1.2. Maximum theoretical extractable power from the wind

The research of Betz and Lanchester determined a certain limit for the extractable power from a wind flow [2]. Naming \( v_1 \) the air speed upstream, \( v_2 \) the air speed in the plane of blades rotation and \( v_3 \) the air speed far downstream, they found the relations between those variables that determined the law of the extracted power. The following paragraphs will explain this law.

The energy extracted from the wind by a turbine will be the difference between the energy upstream and downstream, as per the principle of conservation of energy, neglecting losses. Applying Eq. (4.1) to the corresponding speed values and assuming no pressure difference and no losses, one can write Eq. (4.5).

\[
E_{\text{ex}} = \frac{1}{2} m (v_1^2 - v_3^2) \quad (4.5)
\]

By deriving Eq. (4.5) one can express the extracted power (Eq. (4.6)).

\[
\dot{E}_{\text{ex}} = \frac{1}{2} \dot{m} (v_1^2 - v_3^2) \quad (4.6)
\]

Analyzing Eq. (4.6) one can realize that the higher the difference between \( v_1 \) and \( v_3 \), the most power is extracted. However, there is a certain relation between the mass flow rate \( \dot{m} \) and the ratio \( v_3/v_1 \) that counter rest this tendency. Particularly, the mass flow rate depends on the speed at the rotor plane \( (v_2) \), as written in Eq. (4.7). The terms \( \rho \) and \( A \) are the air density and the reference area crossed by the air flow.

\[
\dot{m} = \rho A v_2 \quad (4.7)
\]

The relation between speeds is given by the Froude-Rankine Theorem [2]. For an ideal wind turbine, assuming that pressure far upstream and far downstream are equal, and velocity is continuous at rotor plane and using the principle of linear momentum and Bernoulli’s equations for energy balance, the resulting relation of speeds is stated in Eq. (4.8).

\[
v_2 = \frac{v_1 + v_3}{2} \quad (4.8)
\]

By substitution of terms from Eq. (4.7) and Eq. (4.8) in Eq. (4.6) and regrouping, one can find a new expression for the extracted power (Eq. (4.9)).

\[
\dot{E}_{\text{ex}} = \frac{1}{2} \rho A v_1^3 \left[ \frac{1}{2} \left( 1 + \frac{v_3}{v_1} \right) \left( 1 - \left( \frac{v_3}{v_1} \right)^2 \right) \right] \quad (4.9)
\]

The term between brackets in Eq. (4.9) is called the power coefficient \( (C_p) \), and its maximum value determines the maximum power that can be theoretically extracted from the wind by an ideal wind turbine. The shape of the curve \( C_p \) versus the ratio \( v_3/v_1 \) is shown in Figure 4.1.
The Betz's research found that the maximum theoretical extractable power is reached in the case where the wind speed far downstream is one third of the speed upstream ($v_3 = \frac{v_1}{3}$, and consequently $v_2 = 2v_1/3$). In that case the value of $C_p$ is maximum and is called the Betz' coefficient [2] (see Eq. (4.10)).

$$C_{p,\text{Betz}} = \frac{16}{27} = 0.59$$  \(4.10\)

The value of Betz' coefficient indicates that the maximum theoretical power that can be extracted from the wind is 59% of the wind power. This maximum extractable power $P_{\text{Betz}}$ is then written as in Eq. (4.11).

$$P_{\text{Betz}} = \frac{1}{2} \rho A v^3 C_{p,\text{Betz}}$$  \(4.11\)

Due to the losses produced in real wind turbines, the real coefficients are lower than Betz' coefficient. Values can be up to $C_p = 0.5$ for lift driven rotors [2].

### 4.1.3. Wind behavior

Wind is caused by differences in pressure and temperature in the Earth atmosphere which entail heat and mass flows. There are both global and local phenomena that influences wind behavior such as geostrophic wind, sea-land circulation and mountain-valley circulation [2]. However, this is not the purpose of this study to predict the wind behavior but rather to find models for specific sites based on measures or good approximations.

The speed of wind (or its content in energy) varies with time due to meteorological phenomena. These variations can be found at different scales:

- **Historical scale**: over a 100 year's record the annual energy content of wind has been found to oscillate in a range of ±25%.
- **Seasonal scale**: over a year, the atmospheric conditions vary seasonally.
- **Daily scale**: the influence of the Sun in the origin of the wind creates variations on different hours of the day.
- **Horary scale**: over periods of minutes, the speed of the wind is not a constant due to turbulence.

In addition, wind speed varies with height for a given instant of time. This variation is due to two different phenomena: friction with the ground, topography, orography and vertical distributions of temperature and pressure. These phenomena create an atmospheric boundary layer that influences the vertical wind profile. This wind profile goes from zero speed at ground level to the geostrophic wind speed, with a certain speed gradient and level of turbulence depending on the height.

The knowledge of the vertical wind profile allows us to estimate the wind speed at a certain height while knowing the wind speed at different height of the same location. For example, recording the wind speed with a measure mast at height $z_1$ one can calculate the wind speed at turbine hub height ($z_2$). A simplified model to do this calculation is given by Eq. (4.12), where $v_1$ and $v_2$ are the wind speeds at heights $z_1$ and $z_2$ respectively and $z_0$ is a parameter called roughness length dependent on the type of terrain.

$$v_2(z_2) = v_1(z_1) \cdot \frac{\ln z_2 - \ln z_0}{\ln z_1 - \ln z_0} \quad (4.12)$$

Values for $z_0$ can be found in Table 4.1. However, this model does not take into account the atmospheric stratification (the vertical profile of temperatures of the atmosphere).

<table>
<thead>
<tr>
<th>Type of terrain</th>
<th>$z_0$ [m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calm water</td>
<td>0.0001 to 0.001</td>
</tr>
<tr>
<td>Farm land</td>
<td>0.03</td>
</tr>
<tr>
<td>Heather with few bushes and trees</td>
<td>0.1</td>
</tr>
<tr>
<td>Forest</td>
<td>0.3 to 1.6</td>
</tr>
<tr>
<td>Suburb, flat building</td>
<td>1.5</td>
</tr>
<tr>
<td>City centers</td>
<td>2.0</td>
</tr>
</tbody>
</table>

In order to consider the variations of wind over time, a statistical approach is required. Figure 4.2 shows an example of measure of wind speed. Concepts such as mean value, variance and standard deviation could prove useful to simplify the data. Usually, another parameter called turbulence intensity ($I_v$) is used. The fluctuating wind is roughly described by the mean wind speed and the turbulence intensity.
The **mean wind speed** ($\bar{v}$) for a measuring period $T$ is defined

$$\bar{v} = \frac{1}{T} \int_{0}^{T} v(t) \, dt \quad (4.13)$$

The **variance** ($\bar{v}^2$) of the sample is defined by Eq. (4.14).

$$\bar{v}^2 = \frac{1}{T} \int_{0}^{T} (v(t) - \bar{v})^2 \, dt \quad (4.14)$$

The standard deviation is the square root of the variance (Eq. (4.15)).

$$\sigma_v = \sqrt{\bar{v}^2} \quad (4.15)$$

The **turbulence intensity** ($I_v$, in %) is defined in Eq. (4.16).

$$I_v = \frac{\sigma_v}{\bar{v}} \cdot 100 \quad (4.16)$$

The **turbulence intensity** depends strongly on wind speed, height and type of terrain. Usually, the higher the wind turbine is, the lowest turbulence will suffer. In addition, turbulence offshore is lower than in land (values of **turbulence intensity** at an offshore site could be expected to be of the order of one half of the values for an onshore site, according to [2]).

In order to estimate the annual energy production of a wind power plant, the seasonal variation of the wind must be modeled. The mean wind speed and deviation are measured all over the year, usually in periods of 10 minutes. After gathering enough data the mean
values are sorted into classes by speed divisions and transformed into a histogram of wind speeds that indicates how many time divisions correspond to each wind class in a given time of study or, in other words, what is the temporal share of each wind class.

The above explained procedure to know the temporal share of each wind speed requires a large amount of data, which is not always available. One alternative is to use distribution functions to estimate the frequency of appearance of each wind speed. The most common function used to represent the annual wind distribution is the Weibull distribution function.

The Weibull distribution function depends in only two parameters: the scaling factor and the shape factor. Eq. (4.17) represents this function, where \( h_W(v) \) is the frequency of appearance of the speed \( v \), \( A \) is the scaling factor and \( k \) is the shape factor.

\[
h_W(v) = \frac{k}{A} \left( \frac{v}{A} \right)^{k-1} \exp \left( - \left( \frac{v}{A} \right)^k \right)
\]  

(4.17)

The shape factor defines the curve shape and depends on the wind fluctuations around the mean speed (the turbulence). Low turbulence correspond to high values of \( k \) and high turbulence correspond to low values of \( k \). The values of \( k \) are real values in the range between 1 and 4.

The scaling factor is a measure for the characteristic wind speed of the considered time period.

Figure 4.3 shows an example of Weibull distribution with a scaling factor \( A = 10.6 \) and a shape factor \( k = 3.9 \).

![Figure 4.3 Example of Weibull distribution with A=10,6 and k=3,9. Source: self-elaboration](image)

The relation between the mean wind speed and the Weibull parameters is shown in Eq. (4.18). The values of both parameters change with height.

\[
\bar{v} \approx A \left( 0.568 + \frac{0.434}{k} \right)^{1/k}
\]

(4.18)

For the calculation of the energy production of an offshore wind park, not only the frequency distribution of wind speed is required, but also the frequency distribution of wind directions. The direction of the wind flow can have an important impact to production due to the wake
effect. In order to model the frequency of wind direction a wind frequency rose is usually used. Figure 4.4 shows an example of wind rose indicating the frequency of each direction in %, for 12 different directions.

![Wind Frequency Rose](image)

Figure 4.4 Example of wind frequency rose in %. Source: self-elaboration

In order to have an accurate model for the wind behavior, it is recommended to have the wind rose and an independent distribution function for each direction, based on the mean speed of the different directions.

### 4.1.4. The wake effect

The Wake effect or aerodynamic shadow consists in the decrease of wind speed after passing through the turbine rotor. The shape of the shadow is a conical space downstream, with a certain expansion angle. The downstream wind has tendency to recover the original speed, which means that at a certain distance the wake effect has no impact. Figure 4.5 shows the geometrical shape of the shadow.

![Wake Effect Schematic Diagram](image)

Figure 4.5 Wake effect schematic diagram. Source: [1]

When a group of turbines are situated in a line on the wind stream direction, the wind speed at each turbine’s rotor will be affected by the wake effect of all the turbines located upstream.

When a group of turbines are located in a random arrangement with the wind blowing in a random direction, each one of the turbines have chances to be affected by one or several shadows. In addition the shadows can affect one turbine totally (if the rotor is completely
covered by the shadow) or partially (if the shadow impacts only a part of the rotor). Figure 4.6 shows the area affected by a partial wake.

Figure 4.6 Diagram of partial wake effect. Source: [1]

There are several methods to calculate the wake effect, from mathematical methods to CFD simulations. However, the research carried out in [1] gave as a result that the Jensen model gave similar results to other models with a much simpler formulation, saving computing time and resources. However, due to the geometrical complexity required to solve a random turbine configuration, this calculation has been let out of the scope for the implementation of the tool in the second part of the project. Nevertheless, this section is included here to give the reason to this decision.

4.2. Wind turbines

4.2.1. Types of wind energy converters

Depending on the forces developed to generate the rotor movement, wind turbines can be classified in two types: *drag driven turbines* or *lift driven turbines*.

*Drag driven turbines* are powered by *drag force* which is the pressure force created by a wind flow in the parallel direction to its speed field. It is the case of some types of windmills or cup anemometers.

*Lift driven turbines* are powered by *lift force* which is the force perpendicular to wind speed field created by pressure differences on the surfaces of an aerodynamic profile when the wind flow circulate across the profile. This is the case of wind turbines for electricity generation.

Depending on the orientation of the rotor, there are also two types: machines with vertical axis and machines with horizontal axis.

Even if there are some turbines for electricity generation with vertical axis, they are a minority and have few applications at present. The majority of turbines used for offshore wind power plants use horizontal axis.

From now on, all this rapport is dedicated to *lift driven wind turbines* for electricity generation with horizontal axis.
4.2.2. Main components of wind turbines

The core of any wind power plant are wind turbines. The cost of the turbines might represent around 40 to 50 % of the capital costs of an offshore wind power plant [3][4]. It was interesting to study the components that form wind turbines in order to get an idea of the weight of these components in the cost of the turbine.

Figure 4.7 shows the main components of a wind turbine on its most commonly used configuration. Other configurations and technologies, such as direct drive, and different types of generators could be used [1], however the major part of turbines are designed similarly to the example in the figure.

Figure 4.7 Main parts of a wind turbine. Source: [5]
In terms of costs, the tower represents around 17% of the manufacturing costs, while the rotor represents around 25% (of which only the blades are up to 17.5%). The gearbox might represent around 17% of the total cost of the turbine, converters around 5% and generator around 4%. Other components cost considerably less in proportion [4].

4.2.3. Operation and control

Modern turbines use active control of pitch and yaw rotations to adapt the point of operation to the current wind conditions and maximize the power output.

The pitch rotation is used to align the rotor perpendicularly to the wind flowing direction.

The yaw rotation turns the blades to maximize the aerodynamic performance of the turbine.

The turbines are not operate at wind speeds either too low or too high. The minimum and maximum values of speeds at which they are allowed to function are called cut-in and cut-out speeds.

4.2.4. Energy yield

The energy yield (energy output) of a wind turbine is calculated by integration of the power output for all the possible states by the operation time (T) [2]. The formula is stated in Eq. (4.19), where $E_{WT}$ is the energy yield, $h(v)$ the probability of a certain wind speed and $P(v)$ the power output corresponding to that wind speed.

$$E_{WT} = T \int_{0}^{\infty} h(v) \cdot P(v) \, dv$$  \hspace{1cm} (4.19)

Whenever the possible wind states are a discrete number, the terms $h(v)$ and $P(v)$ can only be calculated as discrete functions and the formula for calculating the energy output of a certain state $k$ is given by Eq. (4.20).

$$E_k = T \cdot h(v_k) \cdot P(v_k)$$  \hspace{1cm} (4.20)

The total energy yield of a turbine for a certain period of time $T$, is calculated by summing the energy yield of each possible state $k$, resulting in Eq. (4.21) [2].

$$E_{WT} = \sum_{k=1}^{n_k} E_k = T \cdot \sum_{k=1}^{n_k} h(v_k) \cdot P(v_k)$$  \hspace{1cm} (4.21)

Assuming that a certain state $k$ is given both by a wind direction and a wind speed, and knowing the distribution function of speeds for each possible direction, the discrete sum for calculating the energy yield of a turbine for a certain period of time $T$ is given by Eq. (4.22), where $E_{WT}$ is the total energy yield of the turbine during the period $T$, $i$ is the index for each possible wind direction with a total amount of possible directions $n_i$, $j$ is the index of each possible wind speed with a total amount of possible wind speeds $n_j$, $p_i$ is the probability
of occurrence of wind blowing in direction \( i \), \( h_i(v_j) \) is the probability of occurrence of wind blowing at speed \( v_j \) for the direction \( i \) and \( P(v_j) \) is the power output for the speed \( v_j \).

\[
E_{WT} = T \cdot \sum_{i=1}^{n_i} p_i \cdot \sum_{j=1}^{n_j} h_i(v_j) \cdot P(v_j)
\]  

(4.22)

The power output is calculated by means of Eq. (4.9). The term of the power coefficient for a certain turbine will depend on the operation point; however it can be simplified by assuming that the turbine is well regulated to give the maximum performance. In that case, the power coefficient for a certain turbine shall be considered a constant value. Then the power output for a certain \( v_j \) can be written like in Eq. (4.23).

\[
P(v_j) = \frac{1}{2} \rho A v_j^3 C_p
\]  

(4.23)

The distribution function for each wind direction shall be determined using the wind mean speed of the direction and the expected shape factor for the Weibull distribution using Eq. (4.17) and Eq. (4.18).

Usually, the wind turbines only operate in a certain range of wind speeds. Out of theses limits the blades are turned to a position of minimum lift and the brake is applied to the drive train. The inferior speed limit is called cut-in speed and the superior limit is called cut-out speed.

4.2.5. Types of foundations

The turbine tower is mounted on a structure fixed to the seabed. This structure, usually called foundation, could be of very different types. The most commonly used up to nowadays is the monopile foundation, but also gravity bases have been installed in low sea depths. In some few projects also jackets and tripiles have been installed. Research on floating structures is carried out at present and is expected to open possibilities to install offshore wind in higher sea depths in the future.

Figure 4.8 shows the different types of grounded structures.

Figure 4.8 Sample of different types of foundations. Source: [6]
5. Offshore wind power plants

5.1. State of the art

During year 2014 there were 128.8 GW of total installed wind power in the EU, representing 14.1% of the installed capacity. Only 8 GW of the total wind corresponded to offshore wind. The major part of these offshore plants are located in the North Sea (63.3%), the Atlantic Ocean (22.5%) and the Baltic Sea (14.2%) [6].

The wind industry is a relatively young industry that is still in a stage of growing. Since 2000, 29.4% of new installed capacity in the EU has been wind power [7]. Wind industry is gaining his place on the European energy market, where traditional technologies such are coal and fuel are decommissioning more power than installing new power. This fact is shown in Figure 5.1 for year 2014.

Concerning the offshore industry, it is younger than the land based wind and it is taking some delay on the market share. Nevertheless, it is growing more and more every year in the EU as it can be shown in Figure 5.2, and this trend is expected to continue.

Figure 5.1 Installed and decommissioned capacity of electricity-generating technologies in EU (2014). Source: [7].

Concerning the offshore industry, it is younger than the land based wind and it is taking some delay on the market share. Nevertheless, it is growing more and more every year in the EU as it can be shown in Figure 5.2, and this trend is expected to continue.

Figure 5.2 Record of annual offshore wind installed capacity in Europe. Source: [8].
Scenarios from EWEA for 2030 expect to have an increase on total wind installation of 95% compared to 2014 in a pessimistic scenario [9]. The optimistic scenario sets this increase to 204%. In the first case the offshore wind installed power would grow up to 45 GW, generating 5.2% of the EU electricity demand. The optimistic scenario expects to have up to 98 GW of installed power offshore, generating 11.3% of the demand.

From the economic point of view the offshore industry already represents a market of billions of euros and it is expected to grow in the short term.

5.2. Configurations and components

In order to establish the common components that must be included in the cost assessment of a wind power plant, it was necessary to distinguish between different configurations of power plants. The following classification is non-exhaustive, but has served to the building of the models used for the development of the cost assessment tool.

Common components in all wind power plants are wind turbines and electric grids. However, these grids can have different functions and operating characteristics. Offshore substations are used to step-up voltage in order to reduce the losses in the transmission to shore. However not all the plants include offshore substation. Due to its high cost, only large plants located away from the coast count one (or sometimes more than one) substation. When the electricity has to travel really long distances of sea, converting the current from AC to DC is suited because losses are still lower in HVDC.

Usually, the platforms that convert the power from HVAC to HVDC are shared by more than one wind plant. Table 5.1 shows the HVDC platforms already operating in Germany, as well as future planned projects.

Table 5.1 List of projects using HVDC transmissions in Germany (existing and future). Source: [10]

<table>
<thead>
<tr>
<th>Project name</th>
<th>Installation year</th>
<th>Capacity [MW]</th>
<th>Project name</th>
<th>Installation year</th>
<th>Capacity [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>BorWin1</td>
<td>2009</td>
<td>400</td>
<td>DolWin3</td>
<td>2017</td>
<td>900</td>
</tr>
<tr>
<td>BorWin2</td>
<td>2013</td>
<td>800</td>
<td>NOR-1-1</td>
<td>2021</td>
<td>-</td>
</tr>
<tr>
<td>HelWin1</td>
<td>2013</td>
<td>576</td>
<td>NOR-3-2</td>
<td>2023</td>
<td>-</td>
</tr>
<tr>
<td>DolWin1</td>
<td>2013</td>
<td>800</td>
<td>NOR-3-3</td>
<td>2021</td>
<td>-</td>
</tr>
<tr>
<td>SylWin1</td>
<td>2014</td>
<td>864</td>
<td>NOR-5-2</td>
<td>2023</td>
<td>-</td>
</tr>
<tr>
<td>HelWin2</td>
<td>2015</td>
<td>690</td>
<td>NOR-7-1</td>
<td>2022</td>
<td>-</td>
</tr>
<tr>
<td>DolWin2</td>
<td>2015</td>
<td>916</td>
<td>NOR-7-2</td>
<td>2024</td>
<td>-</td>
</tr>
</tbody>
</table>

The differences briefly explained below lead to the decision of classifying OWPP in three main types.

The OWPP type 1 (see Figure 5.3) is composed of a collection grid connecting the wind turbines and transmission cables between the plant and the shore. Both the collection grid and the transmission are operated in MVAC. In this configuration there is no offshore
substation platform. This configuration is usually used for small plants located close to shore (less than 10 km).

**Figure 5.3 Offshore wind power plant type 1**

The OWPP type 2 (see Figure 5.4) is composed of a collection grid operated in MVAC, a substation to step-up voltage and a transmission system connecting to shore operated in HVAC. This configuration is the most used currently for plants of any rated power, but the connection in HVAC has a limit in the distance to shore, as far as increasing this distance increase considerably the electric losses.

**Figure 5.4 Offshore wind power plant type 2**

The OWPP type 3 (see Figure 5.5) is composed of a collection grid operated in MVAC, a substation to step-up voltage and convert to DC and a transmission system operated in HVDC. This configuration is useful when the plant is located at long distances from the shore.
5.3. Examples

The following table (Table 5.2) shows the characteristics of some European projects. It gives an idea of usual power ratings, distances to shore, sea depths, types of foundations and types of transmission systems. More information on these and other projects can be found in Annex C.

Table 5.2 Data on European offshore projects. Source: [11]

<table>
<thead>
<tr>
<th>Name and country</th>
<th>Power [MW]</th>
<th>Turbines</th>
<th>Distance to shore [km]</th>
<th>Water depth [m]</th>
<th>Foundation type</th>
<th>Substation</th>
<th>Export voltage [kV]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horns Rev</td>
<td>DK</td>
<td>160</td>
<td>80x2MW</td>
<td>14</td>
<td>6-14</td>
<td>Monopile</td>
<td>Offshore</td>
</tr>
<tr>
<td>Nysted</td>
<td>DK</td>
<td>165,6</td>
<td>72x2.3MW</td>
<td>9</td>
<td>6-9,5</td>
<td>Gravity</td>
<td>Offshore</td>
</tr>
<tr>
<td>Scroby Sands</td>
<td>UK</td>
<td>60</td>
<td>30x2MW</td>
<td>2,5</td>
<td>3-12</td>
<td>Monopiles</td>
<td>Onshore</td>
</tr>
<tr>
<td>OWEZ</td>
<td>NL</td>
<td>108</td>
<td>36x3MW</td>
<td>10-18</td>
<td>15-20</td>
<td>Monopiles</td>
<td>Offshore</td>
</tr>
<tr>
<td>C-Power</td>
<td>BG</td>
<td>325</td>
<td>6x5MW</td>
<td>13,8</td>
<td>10-24</td>
<td>Gravity</td>
<td>Offshore</td>
</tr>
<tr>
<td></td>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lilgrund</td>
<td>SW</td>
<td>110</td>
<td>48x2.3MW</td>
<td>10</td>
<td>4-13</td>
<td>Gravity</td>
<td>Offshore</td>
</tr>
<tr>
<td>Prinses Amaliawindpark</td>
<td>NL</td>
<td>120</td>
<td>60x2MW</td>
<td>23</td>
<td>19-24</td>
<td>Monopiles</td>
<td>Offshore</td>
</tr>
<tr>
<td>Alpha Ventus</td>
<td>DE</td>
<td>60</td>
<td>12x5MW</td>
<td>45</td>
<td>30</td>
<td>Tripod &amp; Jacket</td>
<td>Offshore</td>
</tr>
<tr>
<td>Belwind 1</td>
<td>BE</td>
<td>165</td>
<td>55x3MW</td>
<td>46</td>
<td>15-37</td>
<td>Monopiles</td>
<td>Offshore</td>
</tr>
<tr>
<td>Greater Gabbard</td>
<td>UK</td>
<td>504</td>
<td>140x3.6MW</td>
<td>23</td>
<td>4-10</td>
<td>Monopiles</td>
<td>Offshore(x2)</td>
</tr>
<tr>
<td>Sheringham Shoal</td>
<td>UK</td>
<td>317</td>
<td>88x3.6</td>
<td>17-23</td>
<td>17-22</td>
<td>Monopiles</td>
<td>Offshore(x2)</td>
</tr>
<tr>
<td>Butendiek</td>
<td>DE</td>
<td>288</td>
<td>80x3.6MW</td>
<td>34</td>
<td>16-20</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
6. Life cycle cost analysis

6.1. Life cycle costs of offshore projects

In order to calculate the cost of energy produced by a certain power plant, it is necessary to take into account all the costs involved in the whole life of the power plant. For this reason, all the different phases of power plant life need to be analyzed and the costs involved in each phase must be identified.

In addition, the costs related to the different phases of the project can be of different natures. Some costs are fixed and some are variable. Some costs can be distributed with certain flexibility along time and some are related to a certain period of time. The differentiation of the costs involved in each phase of a project allows us to manage each type of cost with the most appropriate treatment.

All the costs involved in a wind park development have been divided into three types (as it has been observed as the usual method in all the information sources consulted). These three types are:

- Capital expenditures (CAPEX): include all the capital needed to develop the project and build the wind farm. These costs are fixed (not dependent on the production, life span of the plant or failures).
- Operation expenditures (OPEX): include all the costs related to the operation and maintenance of the plant. These costs are variable (dependent on use conditions of the plant, the life span and the equipment failures).
- Decommissioning expenditures (DECEX): include all the capital costs needed for the decommissioning, dismantling, recycling and disposal of the plant components.

In some literature DECEX are not a type in itself but rather a part of the CAPEX. It is true that the nature of the costs is the same, but as their time of investment is different it has been decided to differentiate between the two. While the CAPEX is required before starting the power generation, no income is available and the whole amount should be gathered by financial methods (loans, investors, public funding or others). On the contrary, DECEX is required to be spent at the end of the project life, when it is logic to expect that some profit has been earned during the 20 years of exploitation, and the decommissioning costs might come from these benefits.

There is an additional type of cost, used in some sources, which is the cost of losses of production. This cost is indirect, and could be treated as an economic cost or not. It could be treated as a cost if evaluated, then transformed into economic value and added to the operational expenditures. However, in this project a more realistic approach have been done: the energy losses have been assessed and discounted from the energy production. The final result is the same, but the losses are not treated as an economic expense (a cost) but treated as a loss of income due to less production to sell. This method have been used because only losses due to unavailability of the wind turbines are, sometimes, treated as a cost; however, there are other losses of different nature, such as electrical losses in the...
grid. With the method used, all the energy losses are treated equally, giving coherence to the method.

Gathering the costs by type (CAPEX, OPEX and DECEX) is useful for calculating the LCOE; however, it is necessary to identify all the components that should be included in each type. In order not to forget any important cost, each phase of the life cycle is studied and the main components of each phase are taken into account and then distributed in the proper type of cost.

The cut-off value for components selected for this project is 1%. This means than any component assessed to cost under 1% of CAPEX or 1% of OPEX or 1% of DECEX will not necessarily be included in the cost model.

The next sections of this chapter explain the phases of the life cycle of an offshore wind power plant and the different types of costs involved in each phase, as well as the main contributors to the different costs.

6.1.1. The life cycle of an offshore wind power plant

The Life Cycle of a wind power plant have been divided into five main phases, identified using a Cradle to Grave Analysis approach. The life of the power plant starts with the works previous to the consenting of the competent authorities (works as surveys and viability studies) and finishes with the dismantling of the power plant and eventual recycling or disposal of materials. The five main phases are the following:

I. Development and consenting
II. Production and acquisition
III. Installation and commissioning
IV. Operation and maintenance
V. Decommissioning

The duration of phases I, II and III will depend on several factors including political, social, financial, geographic and technological issues. Nevertheless, the operative life span of a wind power plant (phase IV) is used to be set to 20 years. There is large consensus on this value for all the sources consulted during the development of this project.

The reasons for defining the operative life span of the power plant to 20 years are that offshore wind is a capital-intensive technology. That means that the initial investment to build a generation plant is very high compared to other electricity generation technologies. This fact requires the capital investment to be shared in a long operational life in order to reduce the cost per unit of energy generated and be competitive in comparison to other technologies.

It would be logic to think that longer life spans will be better for reducing the total cost of energy, but that is not so if the maintenance costs are taken into account. The failure rate of equipment is known to follow a bathtub curve shape over time (Figure 6.1), which means that the corrective maintenance costs and unavailability costs are quite constant up to a certain point; from this point on, the failures increase as well as costs do. In order to avoid these costs caused by failures, the operation of a wind power plant is stopped before that
time. Wind turbines and electric equipment is estimated to have constant failure rates up to 20 years of use.

![Bathtub-shaped curve](image1)

**Figure 6.1** Failures over time. Bathtub-shaped curve. Source: [12]

In some cases, the operative life span can be extended by replacing the turbines and the electrical equipment that is expected to fail, while some elements such as foundations, substation platform, operation port and so forth are re-used. This allows the wind farm owners to continue to get benefits from the power plant with a reduced capital investment, compared to the investment required to build a new power plant.

There are very few data concerning decommissioning of offshore wind farms because all the wind farms build up to now are still in service (with minor exceptions such as demonstration plants). For this reason there is no estimated duration of decommissioning (Phase V) in this work, but that has no impact on the results of the project.

For this project, enlarging the operative life of a power plant by replacing some of the equipment is not contemplated. The operative life is fixed to a certain number of years from the definition of the wind farm, by default 20 years. The sequence of the different phases of the *Life Cycle* is summarized in a diagram on Figure 6.2.

![Life Cycle phases](image2)

**Figure 6.2** Life Cycle phases
6.1.2. Costs of Phase I: Development and consenting

The costs of this phase of the project are fixed costs related to the contracting of services as well as the purchase or rent of some equipment (e.g. survey vessels or meteorological surveying equipment). These costs make part of the capital investment required by the project and are expended in early stages of the projects.

The main contributors to the development and consenting costs are the following:

- Project management and development services
- Sea bed surveys
- Front end engineering and design (FEED)
- Meteorological station and surveys
- Environmental surveys
- Port and staging

All the costs of development (port is not included) are known to sum a total amount of approximately the 4% of the total capital expenditures [4]. In addition, it has been considered that the cost of operation port could be included in the costs of Phase I. The cost of the port is worth approximately 1% of the total CAPEX [4]. The breakdown of total cost of the Phase I is shown in Figure 6.3.

![Figure 6.3 Phase I: cost breakdown for a 500 MW wind park. Source: [13], [4]](image)

6.1.3. Costs of Phase II: Production and acquisition

The costs of this phase of the project are fixed costs related to the purchase of equipment including the costs of manufacture and delivery to operation port. These costs make part of the capital expenditures of the project and are expended at early stages of the project development.

The main contributors to the production and acquisition costs are:

- Wind turbines
- Foundations
- Electric collection system
- Electric integration system
The total costs of this phase are expected to sum a total amount approximately of the 71% of the total CAPEX of the project. Particularly, wind turbines represent 39% of the total CAPEX, foundations are around 20% of total CAPEX and the whole electric systems are around 12% of the total CAPEX. The usual costs’ breakdown of Phase II is shown in Figure 6.4.

![Figure 6.4 Phase II: costs breakdown for a 500 MW wind park. Source: [4]](Image)

6.1.4. Costs of Phase III: Installation and commissioning

The costs of this phase of the project are fixed costs related to the contracting of works and rent of equipment, including the costs of erection of foundations and turbines, the installation of cables, the rent of vessels, the cost of transportation from port to site and so forth. These costs make part of the capital expenditures of the project and are expended in the years prior to start the operation.

The main contributors to the installation and commissioning costs are:

- Wind turbines installation
- Foundations installation
- Integration system installation
- Transmission system installation

Concerning the integration and regulation systems, the consulted sources do not differentiate between the cost of acquisition and the cost of installation. For these reason, the whole costs of the integration system (offshore substation) and regulation system (onshore substation, SCADA,...) are included in Phase II. The costs of installation of electric systems considered in all the information sources consulted are mainly focused in the installation of submarine cables.
The total costs of this phase are expected to sum a total amount approximately of the 25% of the total CAPEX of the project. The usual costs’ breakdown of Phase III is shown in Figure 6.5.

![Cost breakdown of Phase III](image)

**Figure 6.5 Phase III: Cost breakdown for a 500 MW wind park. Source: [4]**

### 6.1.5. Costs of Phase IV: Operation and maintenance

The costs of this phase are variable costs related to the contracting of maintenance services, insurance and material purchase.

The main contributors to the operation and maintenance costs are:

- Maintenance and repair
- Service agreement
- Insurance
- Administration
- Reserves for contingencies
- Miscellaneous expenses not included in agreement

Usually a fixed quantity is paid to a third party to develop the maintenance operations by the signature of a service agreement. However, in order to determine the quantity to be paid, a different approach can be useful. This approach will consist in determine the real cost of developing the maintenance (salaries, transport, materials, and so forth). In that case the costs could be divided in two categories: costs of planned maintenance and costs of unplanned maintenance.

The costs of planned maintenance (also called predictive maintenance) can be seen as fixed, while the costs of unplanned maintenance (also called corrective maintenance) varies depending on equipment failures. The shares of this two types of costs, according to [3] can be seen in Figure 6.6.
6.1.6. Costs of Phase V: Decommissioning

There is very few information published on decommissioning and dismantling operations and the few one that is available is mainly focused on environmental issues. That happens because of the fact that very few offshore wind plants have been dismantled (the life of a plant lasts 20 years and the offshore market is not that old).

However, the information that circulates among experts concerning decommissioning gives an idea of the types of operations foreseen, mainly removal of turbines, foundations and other platforms as well as transport to recycle or landfill sites. All the material that can be recycled (mainly steel from the tower and foundations and other metallic components) will be sold. The income from selling these materials shall be discounted from decommissioning expenses.

Concerning the electrical grid, the dismantling will strongly depend on the state environmental laws. Even if cable cores are recyclable, as a general rule, if the law does not oblige to completely remove the installation, the buried cables will be left in place, as far as the cost of removal is higher than the material selling price.

Another type of decommissioning operations consists in the reuse of the site and some of the equipment for a new project. In cases like that, only the turbines and maybe substation components are removed before installing the new ones. This process decrease significantly the cost of decommissioning as well as reduces the capital investment in the new project by taking advantage of the foundations and electrical grids in place.

As it can be seen, the decommissioning operations depend on each project and very few data is available to estimate its costs. By these reasons, the costs of this last phase will not be included in the models for the LCOE calculation for the moment. The error committed by doing this must be assessed once the model will be completed by doing further research on this matter.
6.2. **Capital expenditures**

The capital expenditures (CAPEX) will include all the capital costs required to develop the offshore wind project and the costs to build and start running the plant. These costs correspond to all the items identified as contributors to the life cycle phases I, II and III (see sections 6.1.2 to 6.1.4).

The main unit used in the model will be € at 2014's value. The total CAPEX will be usually expressed in €/MW in order to have a specific unit useful for comparison between projects or between alternatives.

6.3. **Operation expenditures**

The operation expenditures (OPEX) will include all the costs included needed for the functioning of the power plant. These costs correspond to the items identified as contributors to the life cycle phase IV (see chapter 6.1.5).

The main unit used in the model will be €/year at 2014’s money value. The total OPEX will be usually expressed in €/(MW· year) in order to have a specific unit useful for comparison between projects or between alternatives.

Additionally, after the energy production is assessed, the OPEX could be transformed to €/MWh (or €/kWh) as it is a usual unit found in literature and it gives an idea of which part of each unit of electricity produced is dedicated to operation costs.

6.4. **Production and losses**

In addition to costs, calculating the energetic output of the power plant is required to make an economic assessment of a generation project.

The procedure to calculate the real energetic output consists in calculating the energy generated in normal conditions and subtract any losses that might be produced.

The production in normal conditions depends on the turbines rated power (the maximum generating capacity at a certain moment of time) and the wind conditions over a period of time.

The losses depend on unavailability of the equipment due to failure as well as on the physics of electrical grids.

In order to calculate these features, two different approaches are possible:

1. **The estimation approach**: calculating an average value based on literature made from other power plants.
2. **The simulation approach**: calculating the real value taking into account the specificities of the power plant.

An example of calculating the production with the estimation approach is calculating first the maximum energy that can be produced over a period of time (full-load production) and then multiply by a typical load factor for offshore wind found in literature. This value would
serve for any other power plant of the same rated power, with independence of turbines layout, geographic location, and so forth.

The production calculated by the simulation approach would be calculated with wind speed distributions considering also different wind directions, wake effect, cut-in and cut-off speeds for the turbines and so forth. This value will serve only for a specific power plant in a specific location and a specific wind model.

An example of losses calculation by the estimation approach will consist in subtracting a certain % of the production, based on information from other projects. The losses due to unavailability will not be assessed as far as they should be included in the load factor. This value will serve to any power plant, with independence of the specific features of the electrical grids and equipment.

The losses calculated by the simulation approach would be calculated by assessing the components failures and time to repair for the unavailability and calculating the electrical losses based on the real electrical grid using the power, voltages, impedances and cable lengths. This value is specific to the grid simulated.

As it can be seen the estimation approach is easier to apply and that's why it is used almost everywhere for a quick energetic assessment of a project. However, this approach forgets the specificities of each power plant.

The simulation approach, even if difficult to apply, is much more suited for the purposes of this project. As well as changes in the plant equipment could make changes in the costs that will be taken into account, the variations produced in energy production caused by the same changes should be also taken into account. That helps assessing if the change is positive or negative for the project economy. For instance, if the project developer decides to connect 20 turbines to a feeder instead of 10, some costs on cables could be saved. However, this very change could potentially increase the electrical losses in these connections or cause more probability of unavailability due to failures. If the losses are worth more than the saving in cables, this choice will be a bad one. To make this kind of assessments the simulation approach is required to calculate production and losses.

6.5. System boundaries

The time boundaries of the cost assessment studied in this project are the life cycle of offshore wind power plants. In addition, limits are required to be defined in terms of the components that are included and the ones that are left out of the scope. The system OWPP defined for this project includes the turbines, collection grid, integration system (substation platforms located offshore), transmission systems to shore, regulation and control of the plant and all the costs dedicated to the project development. The scope excludes the interface between the power plant and the national grid (substations, buried lines and aerial lines). Even if these items might be an important cost required to be afford by the project.
developer, the inclusion of these costs in the models must be carried out in future research and improvements of the models defined in this report.

Figure 6.7 OWPP system boundaries for this project.
7. Economy of wind power projects

7.1. Levelized cost of energy

Levelized cost of energy is a metric used to evaluate the total cost of electric-generating projects relative to the unit of energy generated.

\[ LCOE = \frac{\text{Present value of total cost}}{\text{Lifetime energy production}} \]  

(7.1)

This value is expressed in a monetary value divided by an energetic unit (usually €/MWh or equivalently €cent/kWh).

One of the virtues of this measure is that it allows comparison between generating technologies of different nature. This comparison can be found in Figure 7.1, where one can see that offshore wind has a higher LCOE than all the other technologies with exception of solar technologies.

![Figure 7.1 LCOE of different electricity-generating technologies. Source: [14]](image)

Renewable energies present an advantage compared to non-renewable. It is the fact that its cost of fuel is zero, while in most non-renewable technologies the fuel represents a major part in the total costs. However, the energy production plays a role in the LCOE and renewables are in disadvantage at that level, because major renewable technologies suffer fluctuations in the production due to variable weather conditions. As a result of all that, renewable technologies need a decrease in capital and operation costs in order to get to be competitive in comparison to non-renewables.

In the case of offshore wind, it is particularly essential to reduce the costs to make it competitive. Nowadays, the advantages of installing the plants in the sea (homogenous
winds, large space available, less visual impact, etc) cannot be taken advantage of due to its high costs of installation and maintenance. Reducing costs by improving the current technology could reduce the LCOE and make offshore wind one of the best choices for electricity production in terms of environment and economy.

7.2. State support to wind power and types of tariffs

For some years, the state members of the European Union have been giving some incentives for the generation of renewable energies, specially offering producers the possibility of having special tariffs. These special policies reduced the risk of investing in wind projects, but for the last few years they are being passed out in many of the UE member states [15].

One of the most popular policies is the feed-in tariff (FIT) that guarantees a fixed income per unit of electricity sold to the grid. During year 2012, 76% of the EU’s wind installed capacity was financed with FIT [15].

Other policies are mandatory quotas of wind energy in the energetic mix, giving producers green certificates or making projects based on tenders. These type of polices represented 17% of the EU’s wind installed capacity at 2012 [15].

Table 7.1 shows some countries within the EU that had a special policy to support wind power at 2012.

Table 7.1 Support policies to wind power in the EU (2012). Source: [15]

<table>
<thead>
<tr>
<th>Policy</th>
<th>EU member states</th>
</tr>
</thead>
<tbody>
<tr>
<td>FIT</td>
<td>Austria, Bulgaria, Cyprus, Czech Republic, Spain, France, Greece, Hungary, Croatia, Ireland, Italy, Lithuania, Luxembourg, Portugal</td>
</tr>
<tr>
<td>FIT premium</td>
<td>Germany, Denmark, Estonia, Spain, Finland, Latvia, Slovenia, Slovakia, United Kingdom</td>
</tr>
<tr>
<td>Green certificates</td>
<td>Belgium, Poland, Romania, Sweden, United Kingdom</td>
</tr>
<tr>
<td>Tenders</td>
<td>Italy, Latvia, Portugal</td>
</tr>
<tr>
<td>None</td>
<td>Malta</td>
</tr>
</tbody>
</table>

Even if some countries have cancelled these support policies to wind power, there are still other advantages available in most countries for renewable energy projects such as loans, grants or tax reliefs [15].
PART II

Development of the tool
8. Model of the offshore wind power plant

This chapter explains entirely the model used to calculate the LCOE, including the sources of information and the treatment of data.

8.1. Power factors in the electric grids

The power factor is the proportion of reactive power to active power that is present in a point of an electric circuit. This power factor is mathematically calculated as the cosine of the phase difference between voltage and current in the line. Consequently, the power factor can take numeric values between 0 and 1.

The grids used in offshore wind power plants are designed to work with low values of reactive power in order to reduce the electrical losses as much as possible. In the collection grid, the turbines regulation allow to control the reactive power, while in the transmission lines shunt reactors are installed to regulate the power in the lines.

Nevertheless, having zero reactive power in the grids is not possible. Somehow, the effect of this phenomenon had to be represented in the model of the plant, both to take into account the energetic effects and the cost dedicated to mitigate these effects.

Analysis carried out in [16] were made for values of PF ranged between 0,85 and 0,99, meaning that any value in this range was a possible case of good regulation of a wind power plant.

In order to take into account the reactive power, a power factor (PF) has been included in the model, both in the collection grid and in the transmission lines. This power factor is used to calculate the electric losses in both grids and for the choice of the baseline cable characteristics.

The value of the power factor cannot be calculated for a generic case, as it will depend on the design of the plant and also in the point of operation, meaning that the value will change over time. In order to dimensioning the cables, the worst case scenario has been chosen, meaning that PF=0,85 is used. However, in order to calculate the losses, the worst case scenario was suited, because it will underestimate the performance of the plant. A prudent value of PF=0,9 has been chosen, representing the design effort to minimize the reactive power, but taking into account that a little amount (in that case 10%) could always be present.

8.2. Plant model

8.2.1. Layout

The location of the turbines in the space will be defined either as a matrix rectangle (a certain number of turbines located in straight rows and columns, uniformly separated) or by coordinates (for any other type of distribution).

8.2.1.1. Layout definition by matrix rectangle
If the layout is defined as a rectangle, the main inputs will be the number of turbines, the number of rows and the separation of the turbines in the two dimensions of the plant. The rows are defined in the direction perpendicular to the prevailing wind, which means that a wind stream flowing in this prevailing direction will pass through as many lines of turbines as defined by the number of rows (see Figure 8.1).

When the number of turbines can be divided by the number of rows giving an integer as a result, the layout is a square with the same number of turbines in each row. However, when the two numbers are not divisible, the layout is no longer squared. In that case, the maximum number of columns with a turbine in each row not exceeding the number of turbines is calculated. Then, the remnant turbines are allocated in an additional column. One example of this type of layout is shown in Figure 8.2.

The separations in the prevailing wind direction (Spw) and in the direction perpendicular to the prevailing wind (Sperp) are defined in a certain number of rotor diameters and traduced to meters. Then, for each turbine in the layout an index is given and its coordinates are calculated. This process is done starting by assigning to turbine number one the origin of coordinates and increasing index by rows while adding increments of Sperp \([\text{m}]\) to the \(x\) coordinate of the turbine. Once a row is completed, the following is started by the next turbine index and decreasing the \(y\) coordinate by Spw \([\text{m}]\). An examble of a layout with 9 turbines located in 3 rows is shown in Figure 8.3.
8.2.1.2. Layout definition by coordinates

When a rectangle layout does not fit the requirements of a certain OWPP, the layout can be defined by giving to each turbine (indexed from 1 to \( N_{\text{wt}} \)) its specific pair of Cartesian coordinates \((x_i, y_i)\). An example is shown in Figure 8.4.

![Figure 8.4 Example of layout defined by coordinates. Source: self-elaboration.](image)

8.2.1.3. Connection point

In order to define the collection grid, a common connection point shall be defined by its coordinates \((x_{cp}, y_{cp})\). This point will determine the position of the offshore substation in the case that there is one in the plant. If there is no substation, the connection point will only be a reference point to connect all the turbines or feeders composing the grid.

8.2.2. Collection grid model

The procedure described in this section is a simple algorithm based on connecting each turbine to the nearest one. The algorithm does not optimize the connections length, however the results for rectangular layouts are quite consistent (the connections are made in straight
lines and the major part of the connections are as short as possible). In addition, the time of computing is quite short, which makes it a good choice for the tool code.

8.2.2.1. Layout distance matrix

Given a certain number of turbines (Nwt) and the position coordinates of each turbine, a matrix of distances between turbines can be calculated. The matrix, noted D, will be squared with dimension Nwt. Each component, $d_{ij}$, will be the distance between two turbines i and j.

$$d_{ij} = \sqrt{(x_j - x_i)^2 + (y_j - y_i)^2} \quad (8.1)$$

$$D = \begin{pmatrix} 0 & d_{1,2} & \cdots & d_{1,N_{wt}} \\ d_{2,1} & 0 & \cdots & d_{2,N_{wt}} \\ \vdots & \vdots & \ddots & \vdots \\ d_{N_{wt},1} & d_{N_{wt},2} & \cdots & 0 \end{pmatrix} \quad (8.2)$$

8.2.2.2. Connection matrix

Given a certain number of turbines (Nwt) and the number of feeders to distribute the turbines in (Nfeeders), the connections between turbines shall be determined. In order to do that, an iterative process is followed. In the case that the plant is connected in a star scheme there is no need to do this process; each turbine is directly connected to the common connection point.

First of all the number of turbines included in each feeder is calculated. That is done by an iterative process that adds one turbine at a time, each one in a different feeder, until the total number of turbines is reached.

The second step will consist in making a list of the turbines available for connection (at the beginning of the process all the turbines are available). Each turbine is identified by an index ranged between 1 and $N_{wt}$.

The connection matrix is a squared matrix of size $N_{wt}$ in which each component $c_{ij}$ takes the value 1 if the turbines i and j are connected to each other and 0 otherwise.

$$c_{ij} = \begin{cases} 
1 & \text{if turbines i and j are connected} \\
0 & \text{otherwise} 
\end{cases} \quad (8.3)$$

$$C = (c_{ij}) \quad (8.4)$$

For each turbine the starting turbine is selected by the minimum index among the available ones. The starting turbine is deleted from the available turbines list. This turbine is connected to the nearest turbine, calculated by minimum of the corresponding row in the distance matrix (D). In that step there are two restrictions: one turbine can be connected neither to itself nor to any unavailable turbine.
When the connection is done, it is included in the connection matrix, the connected turbine is deleted from the available list and the previous step is repeated. Each turbine is connected to the nearest one up to finishing the feeder.

To start a new feeder, a new starting turbine is calculated and the process repeated.

8.2.2.3. Connections to the connection point

The last turbine of each feeder is connected to the common connection point defined in section 8.2.1.3. In the case that the turbines are connected in a ring schema the first turbine of each feeder is connected to the connection point too, closing the loop. These connections are not done in a straight line, but with two segments corresponding to the projection of the distance between the turbine and the connection point in the x and y directions.

In the case of a star schema, every turbine is directly connected to the connection point.
8.2.2.4. Total cable length

Given the distance matrix $D$ and the connection matrix $C$ (both dimension $n \times n$), the total distance of cable used to connect turbines ($L_{tc}$) is calculated by product of the matrix components. The result of this operation will be expressed in meters.

$$L_{tc} = \frac{1}{2} \sum c_{ij} \cdot d_{ij} \quad \forall i, j \in [1, n]$$

(8.5)

The distance of the connections between one turbine and the CP is calculated in the connection algorithm each time than one of these connections are made saving the total length in the variable $L_{cp}$. The total length is then $L_{cs}$.

$$L_{cs} = L_{tc} + L_{cp}$$

(8.6)
8.2.2.5. **Average cable length of connecting sections**

For some further calculations, like the electric losses, the average length of cable between turbines is calculated, by dividing the total length of the grid by the number of connections. The total number of connections being $N_c$.

$$L_{CS} = \frac{L_{cs}}{N_c} \quad (8.7)$$

8.2.2.6. **Grid characteristics**

The collection grid model includes characteristics such as nominal voltage, cable sections and number of switchgears. It is possible to define up to three different cable sections by giving the % of the total length that corresponds to each section.

8.2.3. **Substation model**

The model for the substation is quite simple, including the number of platforms, the number of transformers, the transformer rated power and the number of switchgears both in the MV side and in the HV side.

8.2.4. **Transmission system model**

The model for the transmission grid includes the number of lines, the nominal voltage, the cable section area and current rating and the length of cables.

8.3. **Wind model**

As the model has to be implemented in form of software tool, almost every calculation has been settled for discrete operations. For these reason the wind modelled for different directions and also the wind speed has been divided in several discrete values. This procedure allows introducing probability in the model. The probability of having a certain wind speed when the wind is blowing in a certain direction will affect only the performance of the turbine during a certain time share of the total life time of the turbine.

8.3.1. **Discretization of space**

In this model the space will be divided in several wind directions (WD), depending on the information available:

- 1 WD: if there is no data about time shares between directions
- 4 WD: separated 90° (N, E, S, W)
- 8 WD: separated 45° (N, NE, E, SE, S, SW, W, NW)
- 12 WD: separated 30° (N, N-NE, E-NE, E, E-SE, S-SE, S, S-SW, W-SW, W, W-NW, N-NW)

For each wind direction, the time share corresponding to each direction will be required. Also, the wind speed distribution will be defined separately for each wind direction.
8.3.2. Discretization of wind speed

The most usual wind speeds are in the range from 0 to 25 m/s (90 km/h). The wind speeds exceeding that value happens in very few occasions (storms, whirlwinds,…) and are not statistically significant. In addition the useful speeds for wind electricity generation are usually in the range between 3 and 25 m/s.

The default cut-in and cut-out speeds for the turbines have been chosen to be 3 m/s and 25 m/s.

The speeds between 0 and 25 m/s have been divided into 26 wind speed divisions separated by 1 m/s under the form shown in Eq. (8.8)

\[ v = \{v_j\} = \{0, 1, 2, \ldots, 24, 25\} \]

(8.8)

8.3.3. Calculation of wind distributions

The scale factor for each direction is calculated using the approximation from Eq. (4.18), rewritten in Eq. (8.9). The mean wind speed of the direction \( v_i \) and the shape factor of the direction \( k_i \) are used.

\[ A_i = \frac{\bar{v}_i}{\left(0.568 + \frac{0.434}{k_i}\right)^{1/k_i}} \]

(8.9)

The wind distribution is calculated for each direction \( i \) and for each speed \( j \) by means of Eq. (8.10).

\[ h_i(v_j) = \frac{k_i}{A_i} \left(\frac{v_j}{A_i}\right)^{k_i-1} \exp\left(-\left(\frac{v_j}{A_i}\right)^{k_i}\right) \]

(8.10)

8.4. Wake effect calculation

The calculation of the wake effect impact implies a considerable difficulty: the decrease of speed for a certain turbine is affected by wind blowing direction, wind speed distributions and relative position of all the other turbines in the power plant. Because the combination of these three factors an accurate calculation must be made by iterative calculation starting by the turbines located upstream and finishing by the turbines located downstream. As the concepts upstream and downstream depend on the wind direction, the complexity of the geometry to solve the problem is considerably increased.

In addition, each turbine can be affected by several other turbines’ shadows either totally of partially. That fact makes the required algorithm even more complicated.

Previous experiences in calculating the wake effect in a random layout of turbines was made in [1]. The author of that work realized that, in one hand, the development of the algorithm and the implementation under informatics code take a lot of time and effort and in the other hand, the resulting calculation program consumed considerable time and resources.
At present, some research is ongoing at IREC in order to develop an optimized algorithm that could calculate the impact of the wake effect in a random layout.

Taking into account the former reasons and considering the limited time fixed for the finishing of this project, it was decided not to include a wake effect calculation model during the development of this project. The first version of the developed tool will not include the impact of wake effect. Nevertheless, wake effect might be included in the tool in the future.

### 8.5. CAPEX calculation

#### 8.5.1. CAPEX calculation model

In order to take into account the particular characteristics of different wind farms, it was compulsory to find costing models that allow to estimate the costs depending on variables, such as turbine rated power, power plant power, sea depth, distance to shore, and so on and so forth. One way to have this kind of costing models was to extrapolate from data related to finished or on-going projects. However, it would be desirable to have considerable amount of information from a large number of projects in order to build a reliable model.

Considering that the available information was little, usually not complete and it corresponded to too few projects, it was decided to look for costing models already published by authors that had more information sources. In [17], the authors give equations to calculate the cost for the major components of CAPEX for offshore wind projects, extracted from several sources and verified with real project data. This information has served as the basis for the modelling of the capital costs. Nevertheless, some modifications, hypothesis and additional features have been added.

The particular calculation of each component involved in the CAPEX model is explained in the following sections of this report.

#### 8.5.1.1. Turbine cost

In [17], an equation is given for the calculation of the turbine cost depending on the rated power of the machine. This equation is stated to be valid for turbines rated from 2 to 5 MW, or at least verified for these cases. Equation (8.11) shows the calculation, where $c_{WT}$ is the cost of the wind turbine in k€/turbine (at 2009 year’s value) and $P_{WT}$ is the rated power of the turbine in MW.

$$c_{WT} = 2,95 \cdot 10^3 \cdot \ln(P_{WT}) - 375,2$$  \hspace{1cm} (8.11)

The previous cost $c_{WT}$ corresponds to manufacturing and supply of a fully-equipped turbine, which means that takes into account the structure (including tower), the mechanical parts, the electric systems (i.e. generator and transformer) and any auxiliary systems. The equation does not include transportation and installation on site.

In order to update the prices to monetary value at 2014, the inflation ratio stated in section 3.1.4 is included in equation (8.12), where $C_{WT}$ is the cost of fully-equipped wind turbine in k€/turbine (at 2014 year’s value) and $P_{WT}$ is the rated power of the turbine in MW.
\[ C_{WT} = 1,1 \cdot 2,95 \cdot 10^3 \cdot \ln(P_{WT}) - 375,2 \] (8.12)

8.5.1.2. Foundation cost

8.5.1.2.1 Monopile type foundation cost

The author of [17] gives different approximations to calculate the cost of monopile type foundations. However, in the same publication states that the approximation that best fits real costs is given by Equation (8.13). This equation gives the value of the cost of the foundations in k€/turbine (at 2009 year’s value) as a function of wind turbine rated power \( P_{WT} \) [MW], the depth of the sea at the installation point \( D \) [m], the height of the turbine hub \( h \) [m] and the diameter of the rotor \( d \) [m].

\[ c_{MF} = 320 P_{WT} \cdot \left( 1 + 0,02(D - 8) \right) \cdot \left( 1 + 0,8 \cdot 10^{-6} \cdot \left( h\left(\frac{d}{2}\right)^2 - 10^5 \right) \right) \] (8.13)

In order to update the cost to 2014 € value, the inflation corresponding inflation ratio is used, resulting in Equation (8.14) where \( C_{MF} \) is the cost of a monopile foundation in k€/turbine (at 2014 year’s value) and the other parameters the same than in (8.13).

\[ C_{MF} = 1,1 \cdot 320 P_{WT} \cdot \left( 1 + 0,02(D - 8) \right) \cdot \left( 1 + 0,8 \cdot 10^{-6} \cdot \left( h\left(\frac{d}{2}\right)^2 - 10^5 \right) \right) \] (8.14)

It is important to keep in mind that monopile foundations are used in relatively deep waters, but is considered inadequate for depths higher than 30 m because of cost and technical issues (according to [4], p. 47). In addition, the previous equations were defined using as a baseline 8 m deep monopiles. It can be assumed that Equation (8.14) can be used for monopile foundations only if \( 8 \leq D \leq 30 \).

8.5.1.2.2 Gravity base type foundation cost

Concerning gravity type foundations, no model has been found to calculate the cost. However, as far as this type of foundation is used in waters of very low depths, we can assume that water depth is not an important factor for this type of foundation. For example, an offshore park having average depth of 6 m will have turbines at depths from 4 to 8 m (as it is the case at Middelgrunden plant in Copenhagen), however for technical reasons all the foundations will be made equal, independently of the specific installation depth of each one. It can be assumed that the cost will be the same for 4 m, 6 m or 8 m depth.

The average cost of these gravity foundations for Middelgrunden plant was of 647 k€/turbine, but this cost includes manufacturing, transport and installation on site [18]. If assuming that the manufacturing cost is 50% of the total cost (which is coherent with our model for installation costs – see section 8.5.1.6), the cost of gravity foundations is 323,5 k€/turbine at 2000 year’s value.

It is expected that turbine size will have an impact on gravity foundation size, and consequently in the cost. One cannot simply expect a direct or linear relation between turbine rated power or tower height or rotor diameter and the size of the foundations thought kinetics of the whole structure (including vibration modes) must play a role on foundation
dimensioning. However, we can assume that the cost of the gravity foundation is in its largest part due to materials cost, particularly concrete. Knowing that, the baseline cost is given for 1800 t of dry concrete [18], one can correct the cost by multiplying by the ratio between the real weight of concrete and the baseline weight.

In addition the cost of gravity foundations must be reported to 2014 year’s value using the inflation ratio between 2000 and 2014.

The result of using the baseline cost for gravity foundations, updated to 2014 and corrected by the weight of the structure is given in Equation (8.15), where $C_{GF}$ is the cost of gravity foundation in k€/turbine at 2014 value and $W_{GF}$ is the weight of dry concrete of the gravity foundation in tones. This correction is not automatically applied in the model used in the tool, but the information could be used to correct the cost by the user.

$$C_{GF} = 1,31 \cdot 323,5 \cdot \frac{W_{GF}}{1800} \quad (8.15)$$

Even if sea depth is not a parameter of Equation (8.15), it applies only when the sea depth is $4 \text{ m} \leq D \leq 8 \text{ m}$. For more than 8 m other type of foundation should be used and less than 4 m is not contemplated because the concept offshore will lose sense.

### 8.5.1.2.3 Cost of other type of foundations

The research carried out during the development of this project gave not enough data to build a model for foundations different than monopiles and gravity bases. Further research shall give the possibility to include models for assessing costs of tripiles, jackets and floating structures or any new concept that could arise in the future.

### 8.5.1.2.4 Total cost of foundations

It has been assumed that only one type of foundation will be installed in the power plants to evaluate. In that case the expression of the total cost of foundations can be written as a function of the number of turbines in the power plant as in Eq. (8.16), knowing that only one of the costs adding to the sum will be different of zero.

$$C_F = N_{WT} \cdot (C_{MF} + C_{GF}) \quad (8.16)$$

### 8.5.1.3. Collection system cost

In [17], equations for calculate the cost of the integration system are given based on the contribution of the two main components of the system, which are switchgears and MVAC submarine cables.

For switchgears, the equation given in [17] is Eq. (8.17), where $c_{SG}$ is the cost of a switchgear in k€ at 2009 year’s value, and $V_{N,C}$ is the nominal voltage of the collection grid. This equation is expected to be reliable only for medium voltage grids, usually around 33kV.

$$c_{SG} = 40,543 + 0,76 \cdot V_{N,C} \quad (8.17)$$
Concerning the MVAC submarine cables, the estimation given by the author in [17] is stated in Eq. (8.18), where \( c_{CC} \) is the cost of collection cable in \( k\€/km \) (money at 2009's value) and \( S_{CC} \) is the section area of the cable in \( mm^2 \).

\[
c_{CC} = 0.4818 \cdot S_{CC} + 99,153 \quad (8.18)
\]

In order to update the prices to 2014's value, the previous equations are modified to get Eq. (8.19) for the cost of each switchgear \( C_{SG} \) and Eq. (8.20) for the cost of each km of MVAC cable \( C_{CC} \).

\[
C_{SG} = 1.1 \cdot (40,543 + 0.76 \cdot V_{N,C}) \quad (8.19)
\]

\[
C_{CC} = 1.1 \cdot (0.4818 \cdot S_{CC} + 99,153) \quad (8.20)
\]

The collection grid could be composed of cables of different section area at different parts of the grid. This way the cost and performance of the grid is optimized. In some parks there are at least two different types of cable, one for connecting arrays of turbines and another wider to connect each array to the offshore substation. Higher levels of optimization have been studied but are not so common in industrial applications.

In order to simplify the model, in this project grid optimization is not taken into account because it is not the main purpose of the project. Collection grid will be assumed to be entirely made of a single type of cable. The user of the model can choose to calculate cable using the section area corresponding to the largest length or to interpolate between the different sections area to be installed in the grid.

The error committed by simplifying the collection grid has been evaluated with a realistic example of a large wind park. Taking as a reference a 504 MW wind farm (Greater Gabbard – UK), with a total length of 173 km of collection grid cable, the costs have been calculated for two different scenarios:

1) Assuming that 150 km are made up by 500 mm\(^2\) section cable and 23 km are made up by 1200 mm\(^2\) section cable. The total cost of cable is 73,2 M\€.
2) Simplifying the model and assuming that the whole 173 km are made up by 500 mm\(^2\) section cable. The total cost is 64,7 M\€.

Looking at the examples, it is expected a difference of 8,5 M\€, representing 12% less than the hypothetically real case. However, this amount represents only 0,45% of the total CAPEX estimated for a 500 MW wind park (according to [4]). Considering that the larger the park, the larger the error could be, it shall be assumed that the simplification of the grid should not impact the calculation of the CAPEX with an error higher than 0,45%.

The general expression for the cost of the collection system is given in Eq. (8.21), where \( C_{SG} [k\€] \) is the cost of each switchgear from Eq. (8.19), \( N_{SG} \) is the number of switchgears in the system, \( C_{CC} [k\€/km] \) is the cost of MVAC submarine cable from Eq. (8.20) and \( L_{CG} \) is the total length of cable in the collection grid.

\[
C_{CS} = C_{SG} \cdot N_{SG} + C_{CC} \cdot L_{CG} \quad (8.21)
\]
8.5.1.4. Integration system cost

The cost for the integration system is estimated in [17] by evaluating the contribution of the main components of an offshore substation. These components are MV/HV transformers, MV switchgears, substation platform (including structure, facilities, and so forth) and auxiliary diesel generators.

For the evaluation of the cost of transformers, the author in [17] found two different approximations depending on the rated power of the transformer. The equations for these approximations are Eq. (8.22) to Eq. (8.24), where \( c_{TR} \) is the cost of one transformer in \( k\)€ at 2009’s value and \( A_{TR} \) the transformer rated power in MVA.

\[
\begin{align*}
  c_{TR}(\text{option A}) &= -153,05 + 131,1 \cdot A_{TR}^{0.4473} \quad (8.22) \\
  c_{TR}(\text{option B}) &= 42,688 \cdot A_{TR}^{0.7513} \quad (8.23) \\
  c_{TR}(\text{option C}) &= 9,8 \cdot A_{TR} \quad (8.24)
\end{align*}
\]

Option A is stated to be reliable for transformers with power less than 150 MVA, while option B is stated to be reliable for powers between 50 and 800 MVA. Option C does not have a restriction in the variable \( A_{TR} \) but is reliable as far as the HV stage of the transformer has a voltage less than 165 kV. If the three options for calculating the cost are plotted (Figure 8.7), one can realize that option C is a good approximation for powers up to 400 MVA.

![Figure 8.7 Comparison of costs of MV/HV transformers. Source: self-elaboration from [17]](image)

The research on real projects made during the development of this project has shown that the installed transformers in European projects have rated powers from 75 to 280 MVA. In addition, high voltage stages are in the range between 132 and 155 kV (with the exception of 3 projects having higher HV tension over 26 projects of the sample). One can conclude that, the calculation using option C will be accurate for almost every case, based on the above mentioned facts.

The expression chosen for the transformer cost calculation, based on Eq. (8.24) and updating the result to money value at year 2014, is stated in Eq. (8.25), where \( C_{TR} \) is the cost of one transformer in \( k\)€ and \( A_{TR} \) is the rated power of the transformer in MVA.
\[ C_{TR} = 1,1 \cdot 9,8 \cdot A_{TR} \] (8.25)

The substation platform cost is evaluated in [17] depending on the wind power plant rated power, as it is shown in Eq. (8.26), where \( c_{SSP} \) is the cost of substation platforms in k€ at 2009’s value, \( N_{WT} \) is the number of wind turbines and \( P_{WT} \) is the rated power of each wind turbine.

\[ c_{SSP} = 2534 + 88,7 \cdot N_{WT} \cdot P_{WT} \] (8.26)

The update of Eq. (8.26) to 2014’s euro value results in Eq. (8.27), where \( C_{SSP} \) is the cost of substation platforms required for the power plant in k€ at 2014’s value and the other parameters the same than in Eq. (8.26).

\[ C_{SSP} = 1,1 \cdot (2534 + 88,7 \cdot N_{WT} \cdot P_{WT}) \] (8.27)

The switchgears included in the substation are taken into account in [17] as an important contributor to the integration system’s cost. The author of [17] gives different treatment to medium voltage and to high voltage switchgears. For MV switchgears an equation dependent on the grid rated voltage is given, while for HV switchgears values are given for the main voltages used in industry (for 150 kV a GIS switchgear costs 950 k€(2009) and for 230 kV the cost is 1300 k€(2009). An extrapolation of the values given in [17] is represented in Figure 8.8, where considerable difference is noted between the cost for medium and high voltages.

![Figure 8.8 Costs of MV and HV switchgears. Source: self-elaboration from [17]](image)

Regarding the considerations stated above, a different cost model is taken for MV switchgears and for HV switchgears. The equation for MV is directly extracted from [17], and is stated in Eq. (8.28), where \( c_{MVSG} \) is the cost of a MV switchgear in 2009’s k€. The equation for HV is extrapolated from data available in [17], and is stated in Eq. (8.29), where \( c_{HVSG} \) is the cost of a HV switchgear in 2009’s k€. The term \( V_n \) appearing in both equations is the grid nominal voltage in kV. However, the MV equation is only to be used for medium voltages, typically around 33 kV, while the HV equation is to be used in high voltages. Nevertheless, the reliability of the HV equation could only be assured for 150 and 230 kV.

\[ c_{MVSG} = 40,543 + 0,76 \cdot V_n \] (8.28)
\[ c_{HVSG} = 293.75 + 4.375 \cdot V_n \quad (8.29) \]

The update of the previous equations to 2014’s monetary value results in Eq. (8.30) and Eq. (8.31), where \( c_{MVSG} \) is the cost of a MV switchgear and \( c_{HVSG} \) the cost of a HV switchgear, both in k€ at 2014’s value. The term \( V_n \) is the grid nominal voltage in kV.

\[ c_{MVSG} = 1.1 \cdot (40,543 + 0.76 \cdot V_n) \quad (8.30) \]

\[ c_{HVSG} = 1.1 \cdot (293.75 + 4.375 \cdot V_n) \quad (8.31) \]

The cost of auxiliary diesel generators are also modeled in [17] by means of Eq. (8.32) where \( c_{DG} \) is the cost of diesel generators for a whole power plant in k€ at 2009’s value, \( N_{WT} \) is the number of wind turbines and \( P_{WT} \) is the rated power of each wind turbine.

\[ c_{DG} = 21,242 + 2,069 \cdot N_{WT} \cdot P_{WT} \quad (8.32) \]

The update of Eq. (8.32) results in Eq. (8.33) where \( c_{DG} \) is the cost of the diesel generators required for the back-up of the power plant in k€ at 2014’s value.

\[ c_{DG} = 1.1 \cdot (21,242 + 2,069 \cdot N_{WT} \cdot P_{WT}) \quad (8.33) \]

The total cost of the integration system in k€ at 2014’s value is given by the parameter \( C_{IS} \) of Eq. (8.34). The meaning of the other parameters is the following: \( C_{TR} \) [k€] is the cost of each transformer given by Eq. (8.25), \( N_{TR} \) is the number of transformers in the wind power plant, \( C_{SSP} \) [k€] is the total cost dedicated to transformer platforms for the wind power plant (including foundations, structure, facilities, accommodations and so forth) given by Eq. (8.27), \( C_{MVSG} \) [k€] and \( C_{HVSG} \) [k€] are respectively the costs of each MV and HV switchgear, given by Eq. (8.30) and Eq. (8.31), and \( N_{MVSG} \) and \( N_{HVSG} \) the number of MV and HV switchgears installed in the system. Finally, \( C_{DG} \) [k€] is the total cost of diesel generators required for the wind power plant back-up, given by Eq. (8.33).

\[ C_{IS} = C_{TR} \cdot N_{TR} + C_{SSP} + C_{MVSG} \cdot N_{MVSG} + C_{HVSG} \cdot N_{HVSG} + C_{DG} \quad (8.34) \]

### 8.5.1.5. Transmission system cost

The cost of the transmission system will strongly depend on the type of export voltage used in the wind power plant. The most commonly used are MVAC and HVAC.

For MVAC, the transmission system could be considered as an extension of the collection grid and Eq. (8.20) could be used to evaluate the cost of cables. Even if special protection is given to the export cable, that will impact the installation cost, not the manufacturing cost. That equation is rewritten in Eq. (8.35) renaming the parameters. Then, \( C_{TC(MVAC)} \) is the cost of MVAC transmission cables in k€/km (money at 2014’s value) and \( S_{TC(MVAC)} \) the section of these cables in mm².

\[ C_{TC(MVAC)} = 1.1 \cdot (0.4818 \cdot S_{TC(MVAC)} + 99.153) \quad (8.35) \]
For HVAC, the author of [17] gives an equation based on three parameters (Eq. (8.58)). The parameters are given for the voltages of 132 and 230 kV (Table 8.1). It was assumed that other ratings should be calculated by linear interpolation between these values (see Figure 8.9).

\[ c_{TC(HVAC)} = \alpha + \beta e^{(\gamma I_n/10^5)} \]  
(8.36)

<table>
<thead>
<tr>
<th>Voltage [kV]</th>
<th>( \alpha ) [k€/km]</th>
<th>( \beta ) [k€/km]</th>
<th>( \gamma ) [A⁻¹]</th>
</tr>
</thead>
<tbody>
<tr>
<td>132</td>
<td>249.72</td>
<td>26.48</td>
<td>379.5</td>
</tr>
<tr>
<td>230</td>
<td>403.02</td>
<td>13.94</td>
<td>462.1</td>
</tr>
</tbody>
</table>

The interpolation between the values given in [17], allows calculating the cost coefficients by means of three functions of the rated voltage of the transmission cables. These functions are stated from Eq. (8.59) to Eq. (8.61).

\[ \alpha = 1,5643 \cdot V_{N,T} + 43,234 \]  
(8.37)

\[ \beta = -0,128 \cdot V_{N,T} + 43,371 \]  
(8.38)

\[ \gamma = 0,8429 \cdot V_{N,T} + 268,24 \]  
(8.39)

By updating the cost equation to 2014’s values the resulting expression is Eq. (8.64), where \( c_{TC(HVAC)} \) is the cost of HVAC submarine cable in k€/km at 2014’s value and \( \alpha, \beta \) and \( \gamma \) are the cost coefficients calculated by means of Eq. (8.59) to Eq. (8.61). Finally the parameter \( I_n \) is the cable ampacity in A. If the ampacity is not known, there is a procedure to roughly estimate it explained in section A.6.
The total cost of the transmission system will depend on the number of lines and its length. Eq. (8.41) and Eq. (8.42) give the total cost in k€ of the transmission system at 2014’s value, for MVAC and HVAC types respectively. The parameter $N_{TL}$ is the number of lines and $L_{TL}$ [km] is the length of the lines.

$$C_{TS(MVAC)} = N_{TL} \cdot L_{TL} \cdot C_{TC(MVAC)}$$ (8.41)

$$C_{TS(HVAC)} = N_{TL} \cdot L_{TL} \cdot C_{TC(HVAC)}$$ (8.42)

### 8.5.1.6. Construction and installation cost

The construction or installation cost will be calculated based on four items: the construction cost of foundations, the installation cost of turbines, the installation cost of collection submarine cables and the installation cost of transmission lines.

Based on data from [17], the construction cost of the foundations can be estimated by 50% of the manufacturing cost of the foundations themselves. This estimation is mainly based on information about monopile foundations. Due to lack of data on other types of foundations and being this cost an important contributor to the CAPEX, the 50% approximation has been adopted as the general estimation for all type of foundations evaluated with this model. The expression for this cost is Eq. (8.43).

$$C_{FC} = 0.5 \cdot C_{F}$$ (8.43)

The installation cost of the turbines is estimated in [17] by the 10% of the cost of manufacturing the turbines. The expression to calculate it will be Eq. (8.44), where $C_{WT}$ is the cost of manufacturing each turbine and $N_{WT}$ is the number of wind turbines in the power plant.

$$C_{WTI} = 0.1 \cdot C_{WT} \cdot N_{WT}$$ (8.44)

The cost of installation of the collection grid is in average of 365 k€/km at 2009’s value following the research in [17]. The updated (to year 2014) expression to calculate the collection system installation cost is given in Eq. (8.45), where $L_{CG}$ is the total length of cable in the collection grid in km.

$$C_{CSI} = 1.1 \cdot 365 \cdot L_{CG}$$ (8.45)

The cost of installation of the transmission lines is in average of 720 k€/km at 2009’s value following the research in [17]. The updated (to year 2014) expression to calculate the collection system installation cost is given in Eq. (8.46), where $L_{TL}$ is the length of cable in each line in km and $N_{TL}$ is the number of lines.

$$C_{TSI} = 1.1 \cdot 720 \cdot N_{TL} \cdot L_{TL}$$ (8.46)

The total construction and installation cost of the wind power plant is given by Eq. (8.47).
\[ C_{CI} = C_{FC} + C_{WTI} + C_{CSI} + C_{TSI} \] (8.47)

8.5.1.7. Regulation devices cost

The cost of components for grid regulation is mainly dedicated to shunt reactors, shunt capacitors and SVC systems (Static VAr Compensation). The cost of these grid regulation components is estimated to be 2/3 of the cost of the transformer of the same power [17].

\[ C_{GRC} = \frac{2}{3} \cdot C_{TR} \cdot N_{TR} \] (8.48)

The cost of monitoring and turbine control devices (SCADA) is expected to be of 75 \( k\€/turbine \) at 2009’s value after the research carried out in [17]. The updating to 2014’s value results in Eq. (8.49).

\[ C_{MCD} = 1,1 \cdot 75 \cdot N_{WT} \] (8.49)

The total cost of regulation devices will be calculated by means of Eq. (8.50).

\[ C_{RD} = C_{GRC} + C_{MCD} \] (8.50)

8.5.1.8. Project development cost

The research carried out in [17] gave as a result that the total development cost of an offshore wind power plant is approximatively of 46,8 \( k\€ \) per installed MW. The expression resulting of this information, after updating to 2014’s value of money, is Eq. (8.51), where \( C_{WPPD} \) is the total cost of the wind power plant development in \( k\€ \), \( N_{WT} \) is the number of wind turbines and \( P_{WT} \) is the rated power of the wind turbines in MW.

\[ C_{WPPD} = 1,1 \cdot 46,8 \cdot N_{WT} \cdot P_{WT} \] (8.51)

8.5.1.9. Insurance and contingency

There is no specific method to calculate the cost dedicated to insurance or contingency based on characteristics of the power plant found in literature during the research dedicated to this project. However, some estimations have been found to calculate this items as a certain % of the total CAPEX of projects.

Data from [19] states that, for offshore wind projects, insurance can be about 2% of the total CAPEX, while contingency may be around 8% of the total CAPEX. Assuming these values as a baseline for the model, the costs of insurance and contingency can be calculated by resolution of Eq. (8.52), where CAPEX’ is the sum of all the items composing the CAPEX except the 10% dedicated to insurance and contingency.

\[ C_{I&C} = \frac{10}{100} \cdot (CAPEX' + C_{I&C}) \] (8.52)
8.5.2. Additional hypothesis for CAPEX

8.5.2.1. Breakdown of turbine capital costs

The previous model allows the calculation of the cost for a whole turbine but not the cost of each one of the sub-components forming the turbine. In some cases these prices could be needed, e.g. in order to estimate the replacement cost of some sub-components. In order to calculate these costs, a cost breakdown has been estimated.

Taking as a baseline the information from [4], a preliminary breakdown can be made. This breakdown is summarized in Table 8.2. However, the cost of the turbine is given independently of the components costs and the costs of the components (e.g. rotor and nacelle) are given independently of the cost of their sub-components. For these reason the sums of the costs of sub-components are not equal to the cost of the components (there is information missing) and the breakdown in % is not fully coherent.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine</td>
<td>6000</td>
<td>7420.21</td>
<td>100%</td>
</tr>
<tr>
<td>Rotor</td>
<td>1500</td>
<td>1855.05</td>
<td>25.6%</td>
</tr>
<tr>
<td>Blades</td>
<td>1050</td>
<td>1298.54</td>
<td>17.5%</td>
</tr>
<tr>
<td>Hub casting</td>
<td>80</td>
<td>98.84</td>
<td>1.4%</td>
</tr>
<tr>
<td>Blade bearings</td>
<td>150</td>
<td>185.51</td>
<td>2.5%</td>
</tr>
<tr>
<td>Pitch system</td>
<td>150</td>
<td>185.51</td>
<td>2.5%</td>
</tr>
<tr>
<td>Spinner</td>
<td>30</td>
<td>37.10</td>
<td>0.5%</td>
</tr>
<tr>
<td>Aux. systems</td>
<td>10</td>
<td>12.37</td>
<td>0.2%</td>
</tr>
<tr>
<td>Fabricated components</td>
<td>0</td>
<td>0.00</td>
<td>0.0%</td>
</tr>
<tr>
<td>Fasteners</td>
<td>5</td>
<td>6.18</td>
<td>0.1%</td>
</tr>
<tr>
<td>Nacelle</td>
<td>2500</td>
<td>3091.76</td>
<td>41.7%</td>
</tr>
<tr>
<td>Bedplate</td>
<td>120</td>
<td>148.40</td>
<td>2.0%</td>
</tr>
<tr>
<td>Main bearing</td>
<td>80</td>
<td>98.94</td>
<td>1.3%</td>
</tr>
<tr>
<td>Main shaft</td>
<td>100</td>
<td>123.67</td>
<td>1.7%</td>
</tr>
<tr>
<td>Gearbox</td>
<td>1000</td>
<td>1236.70</td>
<td>16.7%</td>
</tr>
<tr>
<td>Generator</td>
<td>250</td>
<td>309.18</td>
<td>4.2%</td>
</tr>
<tr>
<td>Power take-off</td>
<td>400</td>
<td>494.68</td>
<td>6.7%</td>
</tr>
<tr>
<td>Control system</td>
<td>70</td>
<td>86.57</td>
<td>1.2%</td>
</tr>
<tr>
<td>Yaw system</td>
<td>100</td>
<td>123.67</td>
<td>1.7%</td>
</tr>
<tr>
<td>Yaw bearing</td>
<td>50</td>
<td>61.84</td>
<td>0.8%</td>
</tr>
<tr>
<td>Aux. systems</td>
<td>0</td>
<td>0.00</td>
<td>0.0%</td>
</tr>
<tr>
<td>Cover</td>
<td>90</td>
<td>111.30</td>
<td>1.5%</td>
</tr>
<tr>
<td>Small components</td>
<td>0</td>
<td>0.00</td>
<td>0.0%</td>
</tr>
<tr>
<td>Fasteners</td>
<td>5</td>
<td>6.18</td>
<td>0.1%</td>
</tr>
<tr>
<td>Condition monitoring system</td>
<td>20</td>
<td>24.73</td>
<td>0.3%</td>
</tr>
</tbody>
</table>

In order to complete the breakdown with coherence, some additional hypotheses have been made:

- The difference between rotor’s cost and its sub-components sum of costs will be assigned to fabricated components. This represents 0.4% of the turbine’s cost, so this is the maximum possible error made.
• The difference between the nacelle’s cost and its sub-components sum of costs will be assigned to auxiliary systems. This represents 3.6% of the turbine’s cost, so this is the maximum possible error made.

• The difference between the turbine’s cost and its components sum of costs will be assigned to a new item called “miscellaneous”. This represents 16.7% of the turbine’s cost, so it was necessary to take into account.

• The cost of power take-off has been divided between converter and transformer. The cost of transformer has been estimated by means of Eq. (8.25) by assuming a rated power of 10 MVA for a 5 MW turbine (to take into account a conservative estimation of reactive power).

The final breakdown after using these hypotheses is summarized in Table 8.3. The original data was given for a 5 MW wind turbine. It has been assumed that the breakdown will serve for any turbine with independence of its rated power.

Table 8.3 Turbine costs breakdown. Source: self-elaboration from [4]

<table>
<thead>
<tr>
<th>Component</th>
<th>k€ (2014)</th>
<th>Breakdown (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine</td>
<td>740,212</td>
<td>100%</td>
</tr>
<tr>
<td>Rotor</td>
<td>3855,083</td>
<td>25.0%</td>
</tr>
<tr>
<td>Blades</td>
<td>1298,54</td>
<td>17.5%</td>
</tr>
<tr>
<td>Hub casing</td>
<td>98,94</td>
<td>1.3%</td>
</tr>
<tr>
<td>Blade bearings</td>
<td>185,51</td>
<td>2.5%</td>
</tr>
<tr>
<td>Pitch system</td>
<td>185,51</td>
<td>2.5%</td>
</tr>
<tr>
<td>Spinner</td>
<td>37,10</td>
<td>0.5%</td>
</tr>
<tr>
<td>Aux. systems</td>
<td>123,37</td>
<td>0.2%</td>
</tr>
<tr>
<td>Fabricated components</td>
<td>30,92</td>
<td>0.4%</td>
</tr>
<tr>
<td>Fasteners</td>
<td>6,18</td>
<td>0.1%</td>
</tr>
<tr>
<td>Nacelle</td>
<td>3091,75</td>
<td>41.7%</td>
</tr>
<tr>
<td>Bedplate</td>
<td>148,40</td>
<td>2.0%</td>
</tr>
<tr>
<td>Main bearing</td>
<td>98,94</td>
<td>1.3%</td>
</tr>
<tr>
<td>Main shaft</td>
<td>123,07</td>
<td>1.7%</td>
</tr>
<tr>
<td>Gearbox</td>
<td>1236,70</td>
<td>16.7%</td>
</tr>
<tr>
<td>Generator</td>
<td>309,18</td>
<td>4.2%</td>
</tr>
<tr>
<td>Converters</td>
<td>387,09</td>
<td>5.2%</td>
</tr>
<tr>
<td>LV/MV Transformer</td>
<td>107,59</td>
<td>1.5%</td>
</tr>
<tr>
<td>Control system</td>
<td>86,57</td>
<td>1.2%</td>
</tr>
<tr>
<td>Yaw system</td>
<td>123,67</td>
<td>1.7%</td>
</tr>
<tr>
<td>Yaw bearing</td>
<td>61,84</td>
<td>0.8%</td>
</tr>
<tr>
<td>Aux. systems</td>
<td>265,89</td>
<td>3.6%</td>
</tr>
<tr>
<td>Cover</td>
<td>111,80</td>
<td>1.5%</td>
</tr>
<tr>
<td>Small components</td>
<td>0,03</td>
<td>0.0%</td>
</tr>
<tr>
<td>Fasteners</td>
<td>6,18</td>
<td>0.1%</td>
</tr>
<tr>
<td>Condition monitoring system</td>
<td>24,73</td>
<td>0.3%</td>
</tr>
<tr>
<td>Tower</td>
<td>1236,70</td>
<td>16.7%</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>1236,70</td>
<td>16.7%</td>
</tr>
</tbody>
</table>
8.6. OPEX calculation

8.6.1. Cost of predictive maintenance calculation model

This model is based in the assumption that a series of operations are made in the plant during a period of a year and calculating the cost of workforce, transport and material required to do this operations.

This model includes the fixed costs required to do the planned operations of maintenance, but also includes fixed costs related to the unplanned maintenance. For instance, the workforce cost and the vessels cost are only included in the planned maintenance budget, while the same workforce and vessels are used in the unplanned maintenance operations.

The total cost of planned maintenance for a period of a year will be the sum of the three concepts stated above.

\[ C_{PM} = C_{\text{transport}} + C_{\text{workforce}} + C_{\text{material}} \]  

8.6.1.1. Transport cost

The cost of each travel to make a maintenance operation is calculated using the distance between the plant and the shore and the price of fuel (see Eq. (8.52)). The baseline fuel cost of the model is 5 €/km.

\[ C_{\text{travel}} = 2 \cdot D_{\text{shore}} \cdot P_{\text{fuel}} \]  

The annual cost of transport is calculated by the cost of travel multiplied by the number of operations over a year, formed by the inspections in wind turbines and the inspections in grid (see Eq. (8.56)).

\[ C_{\text{transport}} = C_{\text{travel}} \cdot (N_{\text{inspectionsWT}} + N_{\text{inspectionsGrid}}) \]

8.6.1.2. Workforce cost

The annual cost of workforce is calculated with the average workers’ gross salary and the number of workers required to operate the plant. The baseline number of workers is fixed to 1 worker for each 5 MW of installed power [4], while the baseline salary to 35000 €/year.

\[ C_{\text{workforce}} = \text{Salary} \cdot N_{\text{workers}} \]

8.6.1.3. Material cost

The material cost is the budget dedicated to rent or purchase the vessels for access the offshore site.

The average cost of a vessel is around 20 M€ [4]. The amortization cost over a period of 20 years will be 100000 €/year. The baseline annual cost of one vessel is then fixed to 100000 €/year.

The number of vessels required to operate the plant has been fixed to 1 vessel every 100 MW of installed power [4].
\[ C_{\text{material}} = C_{\text{vessel}} \cdot N_{\text{vessels}} \] (8.57)

8.6.2. Cost of corrective maintenance calculation model

The corrective maintenance cannot be modeled by deterministic methods due to its unpredictable nature. However, an estimation of its occurrence can be made by means of probabilistic methods. In this section, a method to estimate the expected failure is explained for the wind power plant main components that are more liable to break down.

The components that break down more often and with more impact in terms of cost and unavailability are the wind turbines, mainly due to rotor and drive train failures but also due to failures of the power converter. Other components that can generate a great impact on cost are cables, due to the high cost required to find the failure in a submarine environment and replace the damaged section. In addition, substation transformers shall be taken into account due to their high cost in case of replacement. Data on reliability for all these components can be found on Table 8.4.

Table 8.4 Failure rates and MTTR of wind power plant components. Source: [1]

<table>
<thead>
<tr>
<th>Component</th>
<th>Failure rate ([\text{year}^{-1}] [\text{km}^{-1} \cdot \text{year}^{-1}])</th>
<th>MTTR ([\text{h}])</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine</td>
<td>1</td>
<td>144</td>
</tr>
<tr>
<td>Power converter</td>
<td>0.27</td>
<td>120</td>
</tr>
<tr>
<td>LV/MV transformer</td>
<td>0.007712</td>
<td>144</td>
</tr>
<tr>
<td>Submarine cable*</td>
<td>0.00021</td>
<td>144</td>
</tr>
<tr>
<td>MV/HV transformer</td>
<td>0.006</td>
<td>144</td>
</tr>
</tbody>
</table>

Whenever a component fails, two different operations could be required: either reparation or a replacement. The cost of reparation will be the probabilistically estimated cost of displace workforce to search for the problem and solve it. The cost of replacement will be the probabilistically estimated cost of material needed to replace a broken component.

8.6.2.1. Number of failures

The average number of failures over a year is given by the failure rate \(\lambda\) of each component (Table 8.4). However, the treatment of each component is different in relation to the maintenance strategy. The failures of some components would unleash an operation of repair, while others would demand an immediate replacement of the component. In the first case, the origin of the failure will be of minor importance for the estimation of the cost, while in the second case, it would be an important data.

8.6.2.1.1 Failures on turbines

A turbine failure can be produced by the failure of the drive train or the converter or the transformer. The failure rate of the whole wind turbine will be the sum of the components failure rates. According to Table 8.4, the result is 1.277712 year\(^{-1}\), as shown in Eq. (8.58), where \(\lambda_{\text{WT}}\) is the failure rate of the whole wind turbine, \(\lambda_{\text{TDT}}\) is the failure rate of the drive...
train, \( \lambda_{TPC} \) is the failure rate of the turbine power converter and \( \lambda_{TTR} \) is the failure rate of the turbine transformer.

\[
\lambda_{WT} = \lambda_{TDT} + \lambda_{TPC} + \lambda_{TTR} = 1,277712 \quad (8.58)
\]

### 8.6.2.1.2 Failures on collection grid

The failure rate for submarine cables is given in failures per year and kilometer (Table 8.4). In order to estimate the number of failures, the length of cable in the grid is required. However, the collection grid is formed by cable sections connecting different components (mainly turbines and substations) and when a failure occurs only the affected section will be replaced. For these reasons, the failure rate has been calculated for each cable section assuming an average length equal for all the sections.

The procedure to estimate the failure rate of a collection cable section is given by Eq. (8.59), where \( \lambda_{CCS} \) [year\(^{-1}\)] is the failure rate of a section, \( \lambda_{SC} \) is the submarine cable failure rate per km given in Table 8.4 and \( \overline{L_{CS}} \) is the average length of a section in km. That last parameter will depend on the wind park layout and is calculated by means of Eq. (8.7).

\[
\lambda_{CCS} = \lambda_{SC} \cdot \overline{L_{CS}} = 0,00021 \cdot \overline{L_{CS}} \quad (8.59)
\]

### 8.6.2.1.3 Failures on substation

The failures on substations are assumed to be due exclusively to failures on transformers. The failure rate of a MV/HV transformer is given in Table 8.4. In the mathematical model will be defined by means of Eq. (8.60). The units of the failure rate are year\(^{-1}\).

\[
\lambda_{TR} = 0,006 \quad (8.60)
\]

### 8.6.2.1.4 Failures on transmission grid

The failure on a transmission line is determined based on the failure rate of submarine cable for the whole length of the line, because all the line gets inoperative in case of failure.

\[
\lambda_{TL} = \lambda_{SC} \cdot L_{TL} = 0,00021 \cdot L_{TL} \quad (8.61)
\]

### 8.6.2.2. Reparation cost

The repairing cost included in the model includes only the transport cost to site required to do the operation. The calculation of the transport cost is the same that in the planned maintenance (section 8.6.1.1). The cost of workforce and materials such as vessels are included in the planned maintenance budget and not in the unplanned to avoid duplicities. The cost of material dedicated to replace components is included in the replacement cost.

\[
AC_{\text{reparation}} = (\lambda_{WT} + \lambda_{CCS} + \lambda_{TR} + \lambda_{TL}) \cdot C_{\text{transport}} \quad (8.62)
\]
8.6.2.3. Replacement cost

The replacement cost is easier to estimate because is directly connected to the purchasing cost of the component. The cost dedicated to transport required to make the replacement operation is taken into account in the reparation cost.

The total annual cost of replacements is the sum of annual costs dedicated to wind turbines replacement, collection cable sections replacement, transformers replacement and transmission lines replacement.

\[ AC_{\text{replacement}} = AC_{\text{WTR}} + AC_{\text{CCR}} + AC_{\text{TRR}} + AC_{\text{TLR}} \]  

(8.63)

8.6.2.3.1 Replacement cost of wind turbine components

When a failure is produced in a component of a wind turbine, the design of these machines allows the operator to easily replace only the affected component without remove the other equipment of the turbine.

As the failure of the turbine could be caused by the failure of one of some of its components, the cost of replacement shall be distributed depending on the probability of failure of each one of the components

\[ C_{\text{WTR}} = \frac{\lambda_{\text{TDT}}}{\lambda_{\text{WT}}} \cdot C_{\text{DTR}} + \frac{\lambda_{\text{TPC}}}{\lambda_{\text{WT}}} \cdot C_{\text{PCR}} + \frac{\lambda_{\text{TTR}}}{\lambda_{\text{WT}}} \cdot C_{\text{TTR}} \]  

(8.64)

In order to calculate the costs of replacement of the three components, the most obvious method is to use the purchase price of the component. However, when the failure is produced in the drive train the component to replace can be any one of the drive train or rotor components, from the blades to the generator. Conservative approaches say that the cost of all the replacements needed in turbines is equivalent in cost to replace one gearbox over every two turbines during the whole life of the turbine (i.e. 20 years) [20]. As the drive train is expected to fail every \( 1/\lambda_{\text{TDT}} \) years, and the cost over 20 years shall be 1/2 of the cost of the turbine gearbox, then the cost per failure is calculated using Eq. (8.65). In that expression \( C_{\text{DTR}} \) \([k€, 2014]\) is the average expected cost of replacement for every failure in the drive train, \( \lambda_{\text{TDT}} \) \([\text{year}^{-1}]\) is the failure rate of the drive train, and \( C_{\text{GB}} \) is the cost of a gearbox in \( k€ \) at 2014’s value.

\[ C_{\text{DTR}} = \frac{1}{20} \cdot \frac{1}{\lambda_{\text{TDT}}} \cdot \frac{1}{2} \cdot C_{\text{GB}} \]  

(8.65)

The cost of replacement of the power converter and the LV/MV transformer will be directly the purchase price of the converter and the transformer (see Eq. (8.66) and Eq. (8.67)).

\[ C_{\text{PCR}} = C_{\text{PC}} \]  

(8.66)

\[ C_{\text{TTR}} = C_{\text{TT}} \]  

(8.67)

The previous equations could seem useless, however the values of \( C_{\text{GB}} \), \( C_{\text{PC}} \) and \( C_{\text{TT}} \) will be just estimated as a percentage of the total turbine cost and for the numerical
implementation of the model it was considered interesting to differentiate between the cost of purchasing of the components and the cost of replacing them, even if in the default case their values are the same. The estimations for the previous purchasing costs are the following: the gearbox represents 16.7% of the cost of a turbine while power converter represents 5.2% and the transformer represents 1.5% (see section 8.5.2.1). The calculation of these parameters is done by means of equations (8.68) to (8.70).

\[
C_{GB} = 0.167 \cdot C_{WT} \quad (8.68)
\]

\[
C_{PC} = 0.052 \cdot C_{WT} \quad (8.69)
\]

\[
C_{TT} = 0.015 \cdot C_{WT} \quad (8.70)
\]

The annual cost of replacement in turbines will be determined by multiplying the cost of each replacement operation and the failure rate of the turbine.

\[
AC_{WTR} = \lambda_{WT} \cdot C_{WTR} \quad (8.71)
\]

\subsection{8.6.2.3.2 Replacement cost of submarine collection cables sections}

The annual cost of replacing cable sections is based on the cable section failure rate and the manufacturing cost of the sections. The cost of a section is based in the cost per km and the average length of a section.

\[
AC_{CCR} = \lambda_{CCS} \cdot C_{CC} \cdot \bar{L}_{CS} \quad (8.72)
\]

\subsection{8.6.2.3.3 Replacement cost of transformers in substations}

The annual cost of replacing transformers is based on the failure rate of transformers and the manufacturing cost a transformer.

\[
AC_{TRR} = \lambda_{TR} \cdot C_{TR} \quad (8.73)
\]

\subsection{8.6.2.3.4 Replacement cost of transmission lines}

The annual cost of replacing transmission cables is based in the failure rate of the cables and the manufacturing cost of a line. The cost of the line is calculated by division of the total cost of the transmission system by the number of lines.

\[
AC_{TLR} = \lambda_{TL} \cdot C_{TL} \quad (8.74)
\]

\[
C_{TL} = C_{TS} / N_{TL} \quad (8.75)
\]

\subsection{8.6.2.4 Total cost of corrective maintenance}

The total cost of corrective maintenance is the sum of the annual cost of reparations and the annual cost of replacements.

\[
AC_{TRR} = AC_{reparation} + AC_{replacement} \quad (8.76)
\]
8.7. Production calculation

8.7.1. Calculation of power output

The power is calculated for every wind speed division distinguishing between speeds out the cut-in/cut-out ranges and speeds in the range. In Eq. (8.77) to Eq. (8.79) the term $P(v_j)$ is the extractable power in MW for a certain speed division $v_j$ in m/s. The term $\eta_{WT}$ takes into account the turbine’s efficiency (defined by the ratio between the power extracted from the wind and the electrical power feed in the grid).

$$P(v_j) = 0 \text{ if } v_j \leq 3$$ (8.77)

$$P(v_j) = \frac{1}{2} \rho A v_j^3 C_p \cdot 10^{-6} \cdot \eta_{WT} \text{ if } 3 \leq v_j \leq 25$$ (8.78)

$$P(v_j) = 0 \text{ if } v_j \geq 25$$ (8.79)

The last case ($v_j \geq 25$) is not really used because $v_j$ will only take values between 0 and 25, as it is explained in the section 8.3.2.

The default values for the other terms in the equations are $\rho = 1.2 \text{ kg/m}^3$ for the air density assuming normal conditions and $C_p = 0.5$ assuming that the turbines are constantly well regulated to give the maximum output. The swept area ($A$) is calculated by means of the rotor diameter (see Eq. (8.80)).

$$A = \frac{\pi \cdot d^2}{4}$$ (8.80)

The power output is limited by the turbine’s rated power. When the value of extractable power ($P(v_j)$) is higher than the turbine’s rated power, the power output shall be fixed to that value

$$P_{out}(v_j) = P(v_j) \text{ if } P(v_j) < P_{WT}$$ (8.81)

$$P_{out}(v_j) = P_{WT} \text{ if } P(v_j) \geq P_{WT}$$ (8.82)

In the conditions stated below, a diagram of power output must look like the one in Figure 8.10, where the bars are the output power by wind speed divisions, the polynomic line is the extractable power and the flat horizontal line the turbine’s rated power.
8.7.2. Calculation of energy yield

Getting back to Eq. (4.22) but slightly changing the nomenclature, one gets Eq. (8.83), where $E_{WT}$ is the energy output of an specific wind turbine, $T$ the period of time expressed in hours/year (usually $T = 8760 \text{ h/year}$), $n_i$ the number of wind directions considered, $t_i$ the time share of each direction, $n_j$ the number of wind divisions (in this case $n_j = 26$), $h_i(v_j)$ the probability of a certain speed $v_j$ following the Weibull distribution corresponding to the direction $i$ and $P_{out}(v_j)$ the power output for the speed $v_j$ expressed in MW. The value of energy results in MWh/year.

$$E_{WT} = T \cdot \sum_{i=1}^{n_i} t_i \cdot \sum_{j=1}^{n_j} h_i(v_j) \cdot P_{out}(v_j) \quad (8.83)$$

The annual energy yield [MWh/year] of the whole power plant is simply calculated by Eq. (8.84) when no difference is made between the turbines.

$$E_{OWPP} = E_{WT} \cdot N_{WT} \quad (8.84)$$

In the case that every turbine is differentiated, for example if wake effect is taken into account, Eq. (8.84) must be substituted by Eq. (8.85) to calculate the annual energy yield.

$$E_{OWPP}^* = \sum_{k=1}^{N_{WT}} E_{WT,k} \quad (8.85)$$

The total energy yield of the plant over the whole life cycle (20 years) is 20 times the annual yield, as the wind model is assumed to be equal for every year.

$$E_{20years} = 20 E_{OWPP} \quad (8.86)$$
8.7.3. Calculation of average energy production

This value is important in order to estimate the losses due to unavailability of a turbine. Eq. (8.87) allows calculating the average production of a single turbine during an hour of operation. The units of AEP would be \( \text{MWh/h} \) (note that this is not simply noted \( \text{MW} \) because it shall be understood that it is energy produced per hour of operation, and using simply \( \text{MW} \) can create confusion with other parameters).

\[
\text{AEP} = \frac{E_{\text{WT}}}{T} \quad (8.87)
\]

8.7.4. Calculation of the production

The annual production of the plant is calculated by subtracting any energy losses to the energy yield. The PRODUCTION is expressed in \( \text{MWh/year} \).

\[
\text{PRODUCTION} = E_{\text{OWPP}} - E_{\text{losses}} \quad (8.88)
\]

Detailed procedure to calculate the losses is explained in section 8.8.

8.7.5. Calculation of load factor

In order to calculate the load factor of the power plant, the first step is to calculate the total full-load energy that can be produced. Over a period of a year the total energy that could be produced at full-load is given by Eq. (8.89), where \( E_{\text{OWPP}} \) is this energy in \( \text{MWh/year} \), \( P_{\text{WT}} \) is the rated power of the turbines[\( \text{MW} \)], \( N_{\text{WT}} \) the number of turbines in the plant and \( T = 8760 \text{ h/year} \).

\[
E_{\text{OWPP}} = P_{\text{WT}} \cdot N_{\text{WT}} \cdot T \quad (8.89)
\]

The load factor of the plant is calculated by division between the real output energy (PRODUCTION) and the full-load energy.

\[
\text{LF} = \frac{\text{PRODUCTION}}{E_{\text{OWPP}}} \quad (8.90)
\]

8.8. Losses calculation

The total losses are calculated by the sum of the losses due to unavailability plus the electric losses.

\[
E_{\text{losses}} = E_{\text{lost,\text{U}}} + E_{\text{lost,E}} \quad (8.91)
\]
8.8.1. Losses due to unavailability

Each turbine in a wind plant has two potential states: functioning (ON) or failing (OFF). The failing state can be due to failure in the turbine itself or any other component required for transmitting the electricity to the national grid (e.g., cables, transformers,). The failing state means that the energy that could be generated by the turbine is not reaching its destination.

In the example diagram on Figure 8.11, the energy potentially generated by turbine 1 can be failing to reach the grid because of failures in the turbine itself, or in one of the four cables on the grid, or in both transformers at the same time or in the transmission line.

The components connected in series sum his probability of failure, while the components connected in parallel multiply the probabilities, reducing the risk of failure.

\[ \lambda_{T1} \]

\[ \lambda_{C1} \quad \lambda_{C2} \quad \lambda_{C3} \quad \lambda_{C4} \quad \lambda_{TR1} \quad \lambda_{TR2} \quad \lambda_{TL} \]

Figure 8.11 Diagram of wind plant with failure rates of components. Source: self-elaboration

8.8.1.1. Hypotheses of the model

The model used for the calculation of the failures and the derived energy losses is based on the following hypotheses:

- The failure rate of a component is constant during the life cycle of the plant \[ \lambda(t) = \lambda \]
- All the components of a certain type (turbines, transformers) share the same failure rate.
- All the cables sections in the collection grid will be assumed of the same length (the average length of the sections will be used),
- The mean time to repair (MTTR) a failure will be the same for all failures, independently of the component failing.

The values of failure rates and MTTR used in the model are shown in Table 8.5 (originally extracted from [1]).
Table 8.5 Failure rates and MTTR of wind power plant components. Summarized from Table 8.4

<table>
<thead>
<tr>
<th>Component</th>
<th>Failure rate [year⁻¹][km⁻¹·year⁻¹]</th>
<th>MTTR [h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine</td>
<td>1.277712</td>
<td>144</td>
</tr>
<tr>
<td>Submarine cable*</td>
<td>0.00021</td>
<td>144</td>
</tr>
<tr>
<td>MV/HV transformer</td>
<td>0.006</td>
<td>144</td>
</tr>
</tbody>
</table>

All this failure rates are expressed in year⁻¹ which represents failures per year. In order to calculate the energy lost due to unavailability it will be necessary to take into account the time required to solve the failures and the average energy lost per time unit.

8.8.1.2. The reliability function

Based in the failure rates of the plant components, the probability that a certain component survives a certain period of time is calculated thanks to the reliability function (see Eq. (8.92)).

$$R(t) = e^{-\lambda(t)\cdot t}$$  \hspace{1cm} (8.92)

The distribution function is stated in Eq. (8.93).

$$F(t) = 1 - e^{-\lambda(t)\cdot t}$$  \hspace{1cm} (8.93)

As long as the failure rates are calculated for a year of operation, the previous equations will be simplified for the case $t = 1$ year. In addition, using the hypothesis that the failure rate is constant over time, the equations of reliability and distribution for a period of a year became Eq. (8.94) and Eq.(8.95).

$$R = e^{-\lambda}$$  \hspace{1cm} (8.94)

$$F = 1 - e^{-\lambda}$$  \hspace{1cm} (8.95)

8.8.1.3. Reliability in series and in parallel

When several ($n$) components are connected in series, a failure in any one of them entails the failure of the whole system. The reliability of connections in series can be calculated by means of Eq. (8.96), where $R_i$ is the reliability of each component. The reliability of the system is reduced by connecting components in series.

$$R_{\text{series}} = \prod_{i=1}^{n} R_i$$  \hspace{1cm} (8.96)

On the contrary, connecting components in parallel increases the reliability, because all the components in parallel must fail simultaneously in order to entail a failure of the system.
When components are connected in parallel the system reliability is calculated by means of Eq. (8.97).

\[ R_{\text{parallel}} = 1 - \prod_{i=1}^{n} (1 - R_i) \]  

(8.97)

### 8.8.1.4. Total reliability of a turbine

In order to assess if a turbine is failing in supplying energy to the national grid, all the components between the wind and the connection point shall be taken into account. For this project, the components considered have been turbines (including all the sub-components), cables in the collection grid, transformers in the substation and cables in the transmission system. The total reliability of a turbine will be calculated based on the reliability of these four systems.

For each wind turbine in the plant, the total reliability can be written as in Eq. (8.98), where \( R_i \) is the probability of the turbine not failing the energy supply (OFF state) during a year, \( R_{WTi} \) is the reliability of the wind turbine \( i \) (considering only the machine), \( R_{\text{grid}(Ti)} \) is the reliability of the whole collection grid connected to the turbine \( i \), \( R_{SS} \) is the reliability of the substation and \( R_{TS} \) is reliability of the transmission system. This equation results of applying the relation of components connected in series (see Eq. (8.96)).

\[ R_i = R_{WTi} \cdot R_{\text{grid}(Ti)} \cdot R_{SS} \cdot R_{TS} \]  

(8.98)

The previous equation is assuming that the substation and the transmission system are the same for every turbine in the plant. On the contrary, the reliability of the grid strongly depends on the connection of each turbine to the grid and shall be calculated independently for each wind turbine.

Each term of the equation requires an explanation. The reliability of wind turbine \( (R_{WTi}) \) is calculated using the turbine failure rate (see Table 8.5), as it is explained in 8.8.1.7. The reliability of substations, transmission system and collection grid is calculated using the failure rates of cables and transformers, depending on which type of connection is used (see sections 8.8.1.7 to 8.8.1.10 for further explanation).

### 8.8.1.5. Total failure rate of a turbine

Knowing the total reliability of a turbine, its total failure rate can be calculated by means of the relation of these two parameters. Reordering Eq. (8.94)

\[ \lambda_i = -\ln(R_i) \]  

(8.99)

This \( \lambda_i \) indicates the total number of times that the turbine \( i \) will be in the OFF state over a period of one year, whatever the cause of the failure.
8.8.1.6. Energy lost due to failures

The energy lost due to failing states is calculated using Eq. (8.100), where $E_{\text{lost}(Ti)}$ is the energy lost due to unavailability by the turbine $i$ in MWh/year, $\lambda_i$ is the total failure rate of the turbine in year$^{-1}$, $AEP$ is the average energy production explained in section 8.7.3 expressed in MWh/h and $MTTR$ is the mean time to repair of failures in hours.

$$E_{\text{lost}(Ti)} = \lambda_i \cdot AEP \cdot MTTR \quad (8.100)$$

The MTTR is extracted from [1], and summarized in Table 8.5. In that case the time is 144 hours for any kind of failure. If different values were to be used, an average value should be used.

The total energy lost in the power plant ($E_{\text{lost},U}$) due to unavailability is the sum of the energy lost by every single turbine (Eq. (8.97)). Energy is still expressed in MWh/year.

$$E_{\text{lost},U} = \sum_{i=1}^{N_{WT}} E_{\text{lost}(Ti)} \quad (8.101)$$

8.8.1.7. Reliability of the turbine (only the machine)

The expression to calculate the reliability of a transmission line is Eq. (8.104), where $\lambda_{WT}$ is the failure rate of a single turbine.

$$R_{WT} = e^{-\lambda_{WT}} \quad (8.102)$$

The failure rate of a turbine is extracted from Table 8.5 (and was previously explained in section 8.6.2.1.1).

$$\lambda_{WT} = 1,277712 \quad (8.103)$$

8.8.1.8. Reliability of transmission lines

The possible failure of the transmission system will depend on the number of independent lines connected in parallel. As the failure of the whole system will ultimately depend on the simultaneous failure of all the lines at the same time, including redundant lines, the probability of failure is considerably reduced.

The expression to calculate the reliability of a transmission line is Eq. (8.104), where $\lambda_{TL}$ is the failure rate of a single line.

$$R_{TL} = e^{-\lambda_{TL}} \quad (8.104)$$

For $n_{TL}$ lines in parallel and using the relation of connections in parallel (Eq. (8.97)), the reliability of the whole transmission system ($R_{TS}$) is calculated by means of Eq. (8.105) using the failure rate of a single line.
The failure rate of each line is calculated using the specific failure rate of submarine cables from Table 8.5 and the length of the lines (this was previously explained in section 8.6.2.1.4.)

\[
\lambda_{TL} = 0,00021 \cdot L_{TL} \quad (8.106)
\]

8.8.1.9. Reliability of substations

Transformers are connected in parallel precisely to avoid the substation failing due to a failure in one transformer. The reliability of a single transformer is calculated based on its failure rate as it is shown in Eq. (8.107).

\[
R_{TR} = e^{-\lambda_{TR}} \quad (8.107)
\]

The reliability of the whole substation \(R_{SS}\) will strongly depend in the number of transformers connected in parallel. The expression to calculate this failure rate is Eq. (8.108), where \(\lambda_{TR}\) is the failure rate of each transformer and \(n_{TR}\) the number of transformers in parallel.

\[
R_{SS} = 1 - \prod_{i=1}^{n_{TR}} (1 - e^{-\lambda_{TR}}) = 1 - (1 - e^{-\lambda_{TR}})^{n_{TR}} \quad (8.108)
\]

The failure rate of each transformer is extracted from Table 8.5 (this was previously explained in section 8.6.2.1.3)

\[
\lambda_{TR} = 0,006 \quad (8.109)
\]

8.8.1.10. Failure rates on collection grid

The failure in the feeder grid connected to a turbine will depend on the type of connection used in the feeder. Three cases have been chosen to be included in the model: Radial, ring and star connections.

In any of these cases, the reliability is finally calculated by means of the reliability of a single collection cable section.

\[
R_{CCS} = e^{-\lambda_{CCS}} \quad (8.110)
\]

This reliability is calculated from the failure rate of a collection cable section as in Eq. (8.111) (this was previously explained in section 8.6.2.1.4).

\[
\lambda_{CCS} = 0,00021 \cdot L_{CS} \quad (8.111)
\]
8.8.1.10.1 Case 1: Radial connections

When the feeders are connected with a radial scheme, the energy generated in each turbine has a single way to reach the substation platform. All the cable sections between the turbine and the substation must be working to avoid a failure on the grid.

![Diagram of feeder with radial connection](image)

Figure 8.12 Diagram of feeder with radial connection. Source: self-elaboration

Taking Figure 8.12 as a reference, one can see that the turbine $T_1$ is only affected by the possible failure of cable $C_1$, but turbine $k$ is affected by cables $C_1$ to $C_k$. On single failure among these $k$ components connected in series is enough to produce the general failure, then the general expression for the reliability of the grid for a certain turbine $k$ is given in Eq. (8.112).

$$R_{grid(Tk)}^{Radial} = \prod_{i=1}^{k} R_{CCS} = R_{CCS}^k \quad (8.112)$$

8.8.1.10.2 Case 2: Ring connections

When the feeders are connected in a ring scheme, the energy produced in one turbine has to possible ways of reaching the substation, reducing the risk of failure.

![Diagram of feeder with ring connection](image)

Figure 8.13 Diagram of feeder with ring connection. Source: self-elaboration

Taking Figure 8.13 as a reference, one can see that the turbine $T_1$ is only affected by the possible failure of cable $C_1$ in the right side and by cables $C_2$ to $C_{n+1}$ in the left side. For
turbine $k$, there are $k$ cables in the right side and $n+1-k$ cables on the left side. Two simultaneous failures are required in that case to make the turbine be unavailable, one in the left (upstream) and one in the right (downstream); in that case we can see it as two different paths connected in parallel. The reliability of the grid for the turbine $k$ (see Eq. (8.113))

$$R_{grid(T_k)}^{Ring} = 1 - \left(1 - R_{grid(T_k)}^{Upstream}\right) \cdot \left(1 - R_{grid(T_k)}^{Downstream}\right) \quad (8.113)$$

The reliability of the paths upstream and downstream can be calculated using the reliability of the radial grid, for the number of cables at each side.

$$R_{grid(T_k)}^{Upstream} = \prod_{i=1}^{k} R_{CCS} = R_{CCS}^k \quad (8.114)$$

$$R_{grid(T_k)}^{Downstream} = \prod_{i=k+1}^{n+1} R_{CCS} = R_{CCS}^{(n-k+1)} \quad (8.115)$$

Then, the reliability of the grid for thee turbine $k$ connected in ring is given by Eq. (8.116).

$$R_{grid(T_k)}^{Ring} = 1 - \left(1 - R_{CCS}^k\right) \cdot \left(1 - R_{CCS}^{(n-k+1)}\right) \quad (8.116)$$

### 8.8.1.10.3 Case 3: Star connections

When the feeders are connected in star scheme, each turbine has its own independent cable for connection to the substation.

$$T_k$$

![Figure 8.14 Diagram of feeder with star connection. Source: self-elaboration](image)

Taking Figure 8.14 as a reference, the reliability of the turbine $k$ due to the grid is simply the cable section reliability (Eq.(8.117)).

$$R_{grid(T_k)}^{Star} = R_{CCS} \quad (8.117)$$
8.8.2. Electric losses

The electric losses are calculated in this model by approximation of the electric grids efficiency at full load. The target is to get an approximation of the maximum losses in % of electric generation and apply this % to the annual energy produced by the plant.

The power losses due to intensity of current are calculated by the $I^2R$ formula, while the losses due to voltage are calculated as $U \omega C \tan \delta$ for voltages higher than 100 kV, following the indications of the manufacturer [21].

In the collection grid, the current shall be calculated for each cable section. Figure 8.15 shows that, assigning index to the turbines in a feeder from 1 to n and equally for the cable sections, each cable section is loaded with the power of a different number of turbines. In the figure, cable $C_1$ is loaded with power $P_{T1}$, cable $C_2$ is loaded with power $P_{T1} + P_{T2}$ and so on.

![Diagram of power in a feeder](source)

Figure 8.15 Diagram of power in a feeder. Source: self-elaboration.

In case of full load, each turbine is generating its rated power. The current in each section is also affected by the power factor that depends of the operation point of the grid. Considering the worst case scenario, a power factor of 0.85 is used (see section 8.1). The current in each section $i$ is calculated by means of Eq. (8.118), where $P_i$ is the power load of the cable section [MW], $U$ is the grid voltage [kV] and $I_i$ the current [A].

$$I_i = \frac{P_i}{\sqrt{3} \cdot U \cdot PF} \cdot 10^3$$  \hspace{1cm} (8.118)

The power lost in the collection grid is then calculated by means of Eq. (8.119), where $N_{cs}$ is the number of cable sections in the grid, $R_i$ is the cable resistance and $L_{ccs}$ is the average length of cable sections.

$$P_{lost,CG} = \sum_{i=1}^{N_{cs}} I_i^2 \cdot R_i \cdot L_{ccs}$$  \hspace{1cm} (8.119)

The current in each cable $j$ of the transmission system is calculated at full load using the rated power of the power plant divided by the number of transmission lines (see Eq. (8.130)).
The power lost in the transmission grid is then calculated by means of Eq. (8.131). The first term refers to losses due to current, where $N_{TL}$ is the number of cable sections in the grid, $R_j$ is the cable resistance and $L_{TL}$ is the length of transmission cables. The second term refers to losses due to voltage, where $C_j$ is the cable capacity, $\omega$ is the angular frequency of the grid, in that case $2\pi 50$, and $\tan \delta$ is the dielectric power loss factor of the cable. Following instructions from a manufacturer, dielectric power loss factor for XLPE is $3.5 \times 10^{-4}$ in the worst case [21]. This is the value used in the model for $\tan \delta$.

$$P_{\text{lost,}TG} = \sum_{j=1}^{N_{TL}} I_j^2 \cdot R_j \cdot L_{TL} + \sum_{j=1}^{N_{TL}} U_j^2 \cdot \omega \cdot C_j \cdot L_{TL} \cdot \tan \delta$$  

(8.121)

The cables database included values of resistance at 20°C, however the losses calculation should be done with resistance at the operating temperature. Indications from the manufacturer gave 90°C as the reference temperature [21]. The change of resistance depending on the temperature is calculated by means of Eq. (8.122), according to [22].

$$R_2 = R_1 \left[ 1 + \alpha \left( T_2 - T_1 \right) \right]$$  

(8.122)

In case of need to calculate the resistance of a generic cable based on its section, Eq. (8.123) can be used with the conductor resistivity. For Copper, $\rho$ at 20°C is 0.01724 $\Omega \text{mm}^2/\text{m}$ and $\alpha$ is 0.00393 [22].

$$R = \frac{\rho}{A}$$  

(8.123)

In order to estimate the energy lost in the plant, the efficiency of the grids are calculated by means of Eq. (8.134) and (8.135).

$$\eta_{CG} = \frac{P_{\text{OWPP}} - P_{\text{lost,CG}}}{P_{\text{OWPP}}}$$  

(8.124)

$$\eta_{TG} = \frac{P_{\text{OWPP}} - P_{\text{lost,TG}}}{P_{\text{OWPP}}}$$  

(8.125)

For the integration system, the efficiency of a transformer is estimated to 0.98. In case that there is no substation in the plant that value is set to 1.

The energy lost due to electric losses is calculated using these efficiencies. The input energy is the energy yield of the plant minus the losses due to unavailability. Eq. (8.126) to Eq. (8.129) are used to calculate the losses in each system and the total electric losses.

$$E_{\text{lost,CG}} = (E_{\text{OWPP}} - E_{\text{lost,}U}) (1 - \eta_{CG})$$  

(8.126)
\[ E_{\text{lost,TR}} = (E_{\text{OWPP}} - E_{\text{lost,U}}) \eta_{CG} (1 - \eta_{TR}) \quad (8.127) \]

\[ E_{\text{lost,TG}} = (E_{\text{OWPP}} - E_{\text{lost,U}}) \eta_{CG} \eta_{TR} (1 - \eta_{TG}) \quad (8.128) \]

\[ E_{\text{lost,E}} = E_{\text{lost,CG}} + E_{\text{lost,TR}} + E_{\text{lost,TG}} \quad (8.129) \]

### 8.9. LCOE Calculation

The levelized cost of energy is the updated total cost of the project dedicated to produce every unit of electrical energy.

\[ LCOE = \frac{\text{Present value of total cost}}{\text{Lifetime energy production}} \quad (8.130) \]

Based on the data from [23], the LCOE can be calculated as the Life Cycle Cost (LCC) divided by the Lifetime Energy Production (LEP).

\[ LCOE = \frac{LCC}{LEP} \quad (8.131) \]

The LCC is the Net Present Value of both capital costs (CC) and operation and maintenance cost (OMC).

\[ LCC = NPV(CC + OMC) = NPV(CC) + NPV(OMC) \quad (8.132) \]

In order to traduce this formulation to the parameters previously used in this report (CAPEX, OPEX, DECEX and PRODUCTION), some assumptions have to be made.

The first assumption is that the Net Present Value of capital costs will simply be the CAPEX plus the NPV of decommissioning costs. That can be made as far as the CAPEX is calculated at the value of the year previous to start the operation (t=0) and all the investment is done during this year, while the DECEX is expensed the year before finishing the operation (t=LT+1). The term \( r \) is the discount rate used to calculate the present value.

\[ NPV(CC) = CAPEX + \frac{DECEX}{(1 + r)^{LT+1}} \quad (8.133) \]

The second assumption is that the operation cost are expended between t=1 and t=LT and the cost value is similar for every year of operation, only modified by the inflation rate. The NPV of OMC will be the NPV of OPEX (calculated as annual cost) updated by inflation plus the NPV of any interest generated by loans plus other possible costs.

\[ NPV(OMC) = \sum_{t=1}^{LT} \frac{OPEX \cdot (1 + IR)^t}{(1 + r)^t} + \sum_{t=1}^{LT} \frac{LOAN \cdot (1 + LI)^t}{(1 + r)^t} + \text{Other Costs} \quad (8.134) \]
The term *Other Costs* has been included in order to take account any cost of operation not included previously in the model, for example the cost of land rental. This is intentional, because some kind of costs are too particular to specific projects, but not applicable to all the OWPP. This *Other Costs* can be constant over time or variable, so this term has to be calculated as a NPV to time $t=0$.

The LEP is the annual energy production (previously noted PRODUCTION) multiplied by the lifetime of the plant (LT). The usual value is $LT = 20$ years, though other values of lifetime could be used in this model, it is recommended not to use values higher than 20 years, as long as the impact of doing this is not contemplated in the models to calculate the cost of maintenance or estimating the failures on the plant.

$$LEP = LT \cdot PRODUCTION \quad (8.135)$$

### 8.9.1. Inputs for the LCOE model

**8.9.1.1. Discount rate**

The discount rate is used to calculate the net present value of future investments. The value of the discount rate depends on several factors, but in case of lack of information for an electricity generation project a discount rate of 10% must fit well [23]. The default value in the model is then set to 10%.

**8.9.1.2. Inflation**

Annual inflation is used to update the operating costs over the life years of the plant. The baseline calculation cost is made with an inflation rate of 3%.

**8.9.1.3. Loans**

The loan is included in the model as a % of the capital costs. This represents the portion of the capital costs that will be paid back with interests to the investors. The baseline case is that 100% of the CAPEX is financed by this method.

The loan payment is allocated in equally amounts over all the years of the life time, with the corresponding interest.

**8.9.1.4. Interest rate on loans**

The annual interest rate of loans is the proportion of the loan that is payed as interests. In the baseline calculation model it is set to 5%.

**8.9.1.5. Other costs**

The term other cost is included to allow the user correct the final calculation of the LCOE with any cost that might not be reflected in other parts of the model but it is known by the project designer.

The default value of this term is set to zero.
9. Cost assessment tool for Offshore Wind Power Plants

This chapter describes the tool as it has been designed and programmed.

9.1. Description of the tool

The product of the work carried out in this project is the entitled ‘Cost Assessment tool for Offshore Wind Power Plants’, which is a software dedicated to the calculation of the LCOE of Offshore Wind Power Plants. The tool is organized in blocks or windows that are shown sequentially to ask for inputs and calculate results. Each block is dedicated to the definition of a part of the plant or the calculation of a concept.

Figure 9.1 shows the blocks that conform the tool. The first six blocks are purely dedicated to the introduction of data for the definition of the power plant, while the following five might ask for some data but their main purpose is to do the calculations and show results. The last block includes a command that saves the main results of the simulation in a file.

![Figure 9.1 Diagram of parts of the ‘Cost Assessment Tool for OWPP’. Source: self-elaboration.](image)

This tool has been programed using Matlab programming language, but the final file of results is an MS Excel file. From the functional point of view, each block allows the introduction of data, process the data and save the important variables in files. Other blocks are able to access these files to search for information.

The tool is based in the models presented in chapter 0 of this report. The definition part is based in the ‘Plant model’ and the ‘Wind model’, as well as in the ‘Dimensioning’ explained in section 0. The calculation part is based in the ‘Cost model’ (that includes CAPEX calculation and OPEX calculation), in the ‘Energetic model’ (that includes energy yield calculation and losses calculation) and in the ‘Economic model’ (which is dedicated to the calculation of the LCOE). Figure 9.2 shows the overall procedure of use.
The tool is designed to cover any lack of information that the final user might have, because it gives default data in every block. Nevertheless, the tool is designed with flexibility, as it allows the user to introduce the data manually and to modify the default values given by the tool.

This tool has been designed to be as much detailed as possible, meaning that all the simulations are specifically done for the defined power plant, taking into account all the characteristics defined by the user.

Last, but not least, an important effort has been put in the accuracy of the results. The case studies that can be found in section 10 of this report have been simulated using the tool in order to evaluate the level of accuracy of the results of the tool.

9.2. Scope of the tool

The tool has been designed for the simulation of offshore wind power plants that use AC in their grids. The plants can include offshore substations or not.

The tool offers a baseline dimensioning that is based in assumptions and rough calculations. This data is useful for pre-design stages of projects and serves to calculate approximate LCOE. For detailed engineering stages, the user should introduce the data manually to have a more accurate result.

All the data related to costs given by the tool is based on a cost model resulting from research and it is accurate enough for any stage of project development.

9.3. User’s guide

A copy of the user’s guide can be found in Annex D of this report. A digital copy is included with the tool.
10. Case studies for tool validation

The model has been tested and compared to the reference data presented below. In order to do this, two simulations have been done for two different types of OWPP and comparison is made to equivalent data. This chapter summarizes this validation process.

10.1. Reference data for CAPEX

In order to validate the results concerning CAPEX given by the calculation model used to program the tool, some sources have been selected for comparison. These sources give information about capital costs of European projects. This selected sources and the used information are explained in the following paragraphs.

A publication from Kic InnoEnergy [3] summarizes the expected CAPEX of European projects based on data from real projects developed in the United Kingdom, reporting costs to end 2013 value of money. This document gives data for four scenarios of 500 MW parks depending on turbines rated power, sea depth and distance to shore. The values for CAPEX are shown in Table 10.1. The four scenarios studied are 4 MW turbines in sites type A or type B and 8 MW turbines also in sites type A or type B. Sites type A are located at 40 km from construction port in waters of 25 m of average depth, while sites type B are located at 125 km from port with 35 m of average water depth.

<table>
<thead>
<tr>
<th>[k€/MW]</th>
<th>Scenario:</th>
<th>4MW - A</th>
<th>4MW - B</th>
<th>8MW - A</th>
<th>8MW - B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Development</td>
<td>101</td>
<td>108</td>
<td>90</td>
<td>95</td>
<td></td>
</tr>
<tr>
<td>Turbine</td>
<td>1279</td>
<td>1279</td>
<td>1498</td>
<td>1498</td>
<td></td>
</tr>
<tr>
<td>Support structure</td>
<td>677</td>
<td>861</td>
<td>689</td>
<td>722</td>
<td></td>
</tr>
<tr>
<td>Array electrical</td>
<td>98</td>
<td>99</td>
<td>89</td>
<td>91</td>
<td></td>
</tr>
<tr>
<td>Construction</td>
<td>543</td>
<td>645</td>
<td>320</td>
<td>496</td>
<td></td>
</tr>
<tr>
<td>CAPEX</td>
<td>2698</td>
<td>2992</td>
<td>2686</td>
<td>2902</td>
<td></td>
</tr>
</tbody>
</table>

Following the data from Table 10.1 the values of CAPEX for the studied projects are between 2686 and 2992 k€/MW (it is assumed that this values are valid for January 2014). These values include all the capital expenditures of turbines, foundations (monopile type, except jacket type for the scenario 8 MW – site type B), collection system (33kV AC), project development, transportation and construction of the previous mentioned components.

Another trustworthy source with complete information was found in a document from The Crown State [4], with average costs of all the OWPP components for a typical 500 MW plant. In that case the CAPEX was around 3753 k€/MW at 2014’s value (original data was in £ from 2010). There is a considerable difference regarding the values found in [3], however the information in [4] is four years older and the deviation could be due to the fast growth of the wind industry causing costs decreasing or maybe to higher production costs in the UK in comparison to the EU average. Even if the different sources do not completely agree, both were kept for comparison.
In addition to general data, it was particularly interesting to gather information on specific projects in order to verify the accuracy of our own models by comparison to real data. With this purpose the wind farm of Middelgrunden was analyzed thanks to the information from [18].

The Middelgrunden wind farm is a 40 MW power plant located in front of the port of Copenhagen, at only 3,5 km from the port. It is composed of 20 turbines rated 2 MW each, with hub height of 64 m and diameter of rotor 76 m, constructed in water depths between 4 and 8 m with gravity concrete foundations. The collection grid works at 33 kV as well as the transmission to shore. There is no integration system offshore. The CAPEX values are summarized in Table 10.2 (value of money at 2014 has been calculated using inflation between 2000 and 2014 of 1,31).

<table>
<thead>
<tr>
<th></th>
<th>[M€] (year 2000)</th>
<th>[k€/MW] (year 2000)</th>
<th>[k€/MW] (year 2014)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbines</td>
<td>26,68</td>
<td>667</td>
<td>874</td>
</tr>
<tr>
<td>Foundations</td>
<td>12,94</td>
<td>324</td>
<td>424</td>
</tr>
<tr>
<td>Grid connection</td>
<td>4,51</td>
<td>113</td>
<td>148</td>
</tr>
<tr>
<td>Design, advice, planning</td>
<td>2,98</td>
<td>75</td>
<td>98</td>
</tr>
<tr>
<td>Other costs</td>
<td>1,44</td>
<td>36</td>
<td>47</td>
</tr>
<tr>
<td>CAPEX</td>
<td>48,55</td>
<td>1214</td>
<td>1590</td>
</tr>
</tbody>
</table>

The difference between these values and the previously presented in Table 10.1 could be justified by the particularities of the Middelgrunden project: closeness to port, very low water depths, relatively small gravity foundations (only 1800 tones each) are features that could made the capital costs of this particular project lower than the average. Nevertheless, the data from this project could be later used to verify if the model is accurate for this type of project that one could describe as “small wind farm”.

The data from Middelgrunden does not include the transmission grid between the park and the port. For a matter of comparison, the cost of these components has been added to the CAPEX. This cost has been estimated to 2,9 M€, giving a total CAPEX for comparison of 1684 k€/MW.

The summary of reference data for CAPEX can be found in Table 10.3.

<table>
<thead>
<tr>
<th>Source</th>
<th>KIC</th>
<th>The Crown State</th>
<th>Middelgrunden</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPEX [k€/MW]</td>
<td>2686 to 2992</td>
<td>3753</td>
<td>1684</td>
</tr>
</tbody>
</table>
10.2. Reference data for OPEX

In order to validate the results concerning OPEX given by the calculation model used to program the tool, some sources have been selected for comparison. These sources give information about operation costs of European projects. This selected sources and the used information are explained in the following paragraphs.

A publication from Kic InnoEnergy [3] gives values of OPEX for European projects in different cases (the cases are explained in section 10.1). The values are summarized in Table 10.4.

Table 10.4 OPEX of different projects. Source: [3]

<table>
<thead>
<tr>
<th>[k€/MW/year]</th>
<th>Scenario:</th>
<th>4MW - A</th>
<th>4MW - B</th>
<th>8MW - A</th>
<th>8MW - B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned</td>
<td></td>
<td>31</td>
<td>37</td>
<td>23</td>
<td>28</td>
</tr>
<tr>
<td>Unplanned</td>
<td></td>
<td>65</td>
<td>78</td>
<td>48</td>
<td>57</td>
</tr>
<tr>
<td>OPEX</td>
<td></td>
<td>96</td>
<td>115</td>
<td>71</td>
<td>85</td>
</tr>
</tbody>
</table>

According to Kic the OPEX of offshore projects should take values between 71 and 115 k€/MW/year.

Another data publication by NREL [24] gives values of OPEX for wind projects (both offshore and onshore) for different countries. The values are summarized in Table 10.5.

Table 10.5 OPEX of wind projects (offshore + onshore) by countries. Source: [24]

<table>
<thead>
<tr>
<th>O&amp;M</th>
<th>[€/MWh]</th>
<th>[k€/MW/year]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>12,5</td>
<td>43,8 (*)</td>
</tr>
<tr>
<td>Germany</td>
<td>54,9</td>
<td></td>
</tr>
<tr>
<td>Ireland</td>
<td>54,0</td>
<td></td>
</tr>
<tr>
<td>Norway</td>
<td>19,6</td>
<td>60,1 (*)</td>
</tr>
<tr>
<td>USA</td>
<td>63,0</td>
<td></td>
</tr>
</tbody>
</table>

(*) Calculated for a load factor of 40%.

According to NREL, the OPEX should be in the range between 44 and 63 k€/MW/year, which is lower than the data by Kic. This is due to the fact that these values are average of countries that includes onshore wind. The maintenance cost of offshore projects is higher than the cost for onshore projects.

The summary of reference data for CAPEX can be found in Table 10.6.

Table 10.6 Summary of reference data for OPEX. Source: [3], [24].

<table>
<thead>
<tr>
<th>Source</th>
<th>KIC</th>
<th>NREL (includes onshore)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPEX [k€/MW/year]</td>
<td>71 to 115</td>
<td>44 to 63</td>
</tr>
</tbody>
</table>
10.3. Reference data for LCOE

In order to validate the results concerning LCOE given by the calculation model used to program the tool, some sources have been selected for comparison. These sources give information about LCOE of real projects.

Data from Kic [3] gives a reference value for the LCOE of offshore wind electricity in the order of 10 €cents/kWh.

Data from the Transparent Cost Database from NREL [14] gives a range between 8,9 and 18,7 €cent/kWh.

The summary of reference data for LCOE can be found in Table 10.7.

<table>
<thead>
<tr>
<th>Source</th>
<th>KIC</th>
<th>NREL (includes onshore)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPEX [€cent/kWh]</td>
<td>10</td>
<td>8,9 to 18,7</td>
</tr>
</tbody>
</table>

10.4. Description of the case studies for tool validation

The first simulation corresponded to a 500 MW OWPP with offshore substation and HVAC connection to shore. The main hypotheses made were the following:

- 100 turbines of 5 MW each
- Rotor diameter (D) = 126 m
- Hub height = 95 m
- Sea depth = 15 m
- Distance from shore = 30 km
- Monopole foundations
- Turbines layout: 10x10 matrix, separated of 7 D x 4 D
- Collection grid at 33 kV, radial connections
- 2 transformers of 315 MVA
- 2 transmission lines at 220 kV
- Wind mean speed 8 m/s, k=3,5 for a load factor around 40%
- Wind mean speed 7,2 m/s, k=3,5 for a load factor around 30%

In order to test a smaller plant with no substation, a second simulation was made trying to reproduce the Middelgrunden wind park (40 MW). The main assumptions were the following:

- 20 turbines of 2 MW
- Rotor diameter (D) = 76 m
- Hub height = 64 m
- Sea depth = 8 m
- Distance from shore = 3,5 km
- Gravity base foundations
- Turbines layout: single row, separated of 2,5 D
- Collection grid at 33 kV, radial connections
- Single transmission line at 33 kV
- Insurance and contingency are set to zero cost (as in the reference data)
- Wind mean speed 8 m/s, k=3,5 for a load factor around 40%
- Wind mean speed 7,2 m/s, k=3,5 for a load factor around 30%
- Insurance and contingency are not included in CAPEX but as other costs in the LCOE (9838k€)

10.5. Results

Figure 10.1 shows the results of calculated CAPEX of both simulations compared to reference data.

The simulation 1 gives a total value of CAPEX that agrees with the data from Kic. The calculated value is in the range of the reference data, with an error of 2,7% in relation to the average value. The deviation to the data by The Crown State is higher (26,9%), however these reference data is older. In any case, the order of magnitude of the calculation model seems to be right for the CAPEX. The level of accuracy might depend on particularities of each project to simulate.

The simulation 2 should be compared to the original data from Middelgrunden power plant. The total value of CAPEX calculated by the tool fits very well the real value of CAPEX (with an error of only 3,1%).

The breakdown of the CAPEX total value has been analyzed too. The results are shown in Figure 10.2 and in Table 10.8. The share of the main components look similar for the simulations and the reference data, with only some deviations.
In that case, the simulation 1 agrees with data from The Crown state better than with data from KIC. The values for turbines, structures and installation fit very well this source, while the electrical infrastructure looks a little bit over dimensioned. The deviations in comparison to KIC data are bigger, especially for turbines and structures, however this source gives a share of only 3% of the CAPEX to the electric infrastructure, which seems very low for such an important part of the plant.

The simulation 2 fits well the breakdown of CAPEX deduced from the reference data from the Middelgrunden power plant. The only remarkable difference is that the electrical infrastructure costed more in reality than the calculated value. That might be caused by the fact that this plant was made in a moment of low development of the market with few previous experiences. The Middelgunden plant had to serve as a demonstration, and some costs could have been higher than it would be nowadays, with a more developed wind industry.

![CAPEX breakdown comparison](image)

**Figure 10.2 Comparison of CAPEX breakdown. Source: self-elaboration.**

In any case, deviations in the breakdown of CAPEX do not cause an error on the LCOE as far as the total CAPEX is accurate. This analysis serves as an indicator that further research is required to get to accurately calculate every item in the breakdown.

**Table 10.8 CAPEX breakdown values for comparison. Source: self-elaboration**

<table>
<thead>
<tr>
<th></th>
<th>KIC data</th>
<th>The Crown State (500MW)</th>
<th>Simulation (500MW)</th>
<th>Middelgrunden (40MW)</th>
<th>Simulation (40MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine</td>
<td>49%</td>
<td>39,5%</td>
<td>39,3%</td>
<td>46,7%</td>
<td>53,9%</td>
</tr>
<tr>
<td>Development</td>
<td>3%</td>
<td>4,0%</td>
<td>2,1%</td>
<td>5,8%</td>
<td>3,0%</td>
</tr>
<tr>
<td>Structures</td>
<td>26%</td>
<td>19,8%</td>
<td>19,9%</td>
<td>12,6%</td>
<td>12,3%</td>
</tr>
<tr>
<td>Elect. Infrast.</td>
<td>3%</td>
<td>11,7%</td>
<td>17,2%</td>
<td>11,9%</td>
<td>5,8%</td>
</tr>
<tr>
<td>AT&amp;I</td>
<td>18%</td>
<td>25,0%</td>
<td>20,5%</td>
<td>20,3%</td>
<td>22,6%</td>
</tr>
<tr>
<td>Other</td>
<td>0%</td>
<td>0,0%</td>
<td>1,0%</td>
<td>2,8%</td>
<td>2,4%</td>
</tr>
</tbody>
</table>

In any case, deviations in the breakdown of CAPEX do not cause an error on the LCOE as far as the total CAPEX is accurate. This analysis serves as an indicator that further research is required to get to accurately calculate every item in the breakdown.

Figure 10.3 shows the values of calculated OPEX in both simulations compared to reference data.
As the reference data only included specific cost to installed power, the same value has been calculated for the simulations. Both simulations gave similar results: 72 and 71 k€/MW/year. These values agree to the reference data from Kic. The reference data from NREL is a little bit lower, because it includes onshore projects.

The calculated values of the LCOE have been 7,78 €cent/kWh for the simulation 1 and 5,8 €cent/kWh for the simulation 2. These values calculated by the tool were calculated for a load factor of the power plants of 40%, which is an optimistic scenario.

In order to consider a more pessimistic scenario, new simulations have been done, reducing the wind speed in order to target a load factor of 30%. In that case, the LCOE has resulted 10,1 €cent/kWh for the simulation 1 and 7,2 €cent/kWh for the simulation 2.

The reference data gave values between 8,9 and 18,7 €cent/kWh. For the simulation 1, the pessimistic scenario fits the expected range, while the optimistic is less than two cents lower. The simulation 2 is lower in both cases, however that was expected due to the characteristics of the project (closeness to shore, small electric grid, low water depth, etc).

The order of magnitude of the results seems correct in comparison to the reference data.
PART III

Exploitation and environmental impact
11. Exploitation of the project

11.1. Exploitable products

The main result of this project that can be object of commercialization is the *Economic Assessment Tool for Offshore Wind Power Plants*. This tool is suitable for pre design stages and economic analysis of wind projects for companies and research centers.

The tool, as it has been developed and presented in this report, is a basic version and lacks some features that could make it more valuable for customers. For that reason, this exploitation plan will consider further investment in the improvement of the tool in order to get a new version with better performance and more options. This new version will be called from now on the *Premium version* of the tool. Different payment fees will be considered for the use of the tool depending on the version purchased.

This *Premium version* is expected to include the following features:

- Loading of data from external files (.xls)
- Introduction of layout by coordinates
- HVDC transmission
- Additional foundation structures
- Wake effect
- Optimization of electric grid
- Extended cables database

The *Premium version* should make easier the dissemination and sales of the tool.

Before selling, the program shall be transformed into self-standing executable file. That will avoid the requirement of installing Matlab to run it and will also protect the code from being accessed and manipulated.

11.2. Dissemination strategy

The basic version of the tool will be used by IREC for some projects in the near future. That will give a good opportunity to show the tool to project partners, including research institutions and industrial companies. If there is enough interest on the tool, the possibility of developing the Premium version will be considered.

Once the first potential customers are found, the tool shall be disseminated through other channels such as specialized journals, fairs and wind associations. Another way to give added value to the tool is to use it for economic analysis of related work at IREC that could be published under form of papers, thesis and so forth.

Actually, this dissemination work has already started with the presentation of this project that took place at IREC’s premises in June 2015 in the context of the starting meeting of EERA research team on *Component and system cost of wind energy*. 
11.3. Economic analysis

For the economic analysis, two versions of the tool are considered. The basic version considers the costs of all the work realized up to present. The premium version considers the same costs plus additional investment.

Four cases of exploitation strategy are considered and economic indicators have been calculated for each case. These indicators are used to evaluate the potential benefits and risks of each case.

11.3.1. Economic indicators of the project

The economic analysis has been made by calculation of the Net Present Value (NPV) and the Internal Rate of Return (IRR) of the investment with the previously stated assumptions. For the NPV, the discount rate used to take into account time value of money and risk has been 15% ($r = 0.015$).

The formulae used are the following.

$$NPV = \sum_{t=1}^{5} \frac{Cash \ Flow_t}{(1 + r)^t} - Investment$$

$$IRR = r \text{ if } NPV(r) = 0$$

The pay-back date of the investment is also an important indicator to consider. The investment is payed-back when the accumulated NPV of the project is positive.

11.3.2. Costs of development

This is the list of assumptions made for the cost analysis:

- The basic version of the tool has been developed in 181 days, with an average work load of 5 h/day.
- The basic version of the tool has required 905 hours-person of work (research + programming). The premium version is assumed to require additional 905 hours-person.
- The average cost of labor is assumed to be 8 €/h. This corresponds to a worker in internship (student or recently graduate).
- The transport to the workplace has been made using public transport. Considering two travels a day, a total of 362 travels has been made. The average cost of travel in Barcelona is 0.995 €/travel. The premium version is assumed to require two times the number of travels.
- The power required to run the laptop is calculated using the following data: the laptop consumes 92W at full load, during 905 hours gives a total of 83.26 kWh. The current cost of electricity is 0.14 €/kWh (only the consumption term can be directly applied to this project, so other costs are out of scope).
• The laptop and software have not been exclusively dedicated to this project. We assume an amortization cost of 300 €/year that includes hardware and software. The tool will spend these materials during a year (for both versions of the tool).

The following table summarizes the costs of each version based on the assumptions stated previously.

| Table 11.1 Cost of development of the tool. Source: self-elaboration. |
|-----------------------------|-----------------------------|-----------------------------|
| **LABOR**                  | Basic  | Premium  |
| Hours                      | 905    | 1810 h    |
| Cost per hour              | 8      | 8 €/h     |
| Cost of labor              | 7240   | 14480 €    |
| **TRANSPORT**              |        |            |
| Travels                    | 362    | 724 travels |
| Cost per travel            | 0,995  | 0,995 €/travel |
| Cost of transport          | 360,19 | 720,38 €    |
| **MATERIALS**              |        |            |
| Electricity                | 83,26 kWh | 166,52 kWh |
| Cost of electricity        | 0,14   | 0,14 €/kWh |
| Laptop + software          | 300    | 300 €      |
| Cost of materials          | 311,66 | 323,31 €    |
| **TOTAL**                  | 7911,85 € | 15523,69 € |

11.3.3. Case analysis

Four exploitation strategies have been considered as calculation cases, each with its own assumptions. All the cases have been calculated for five years, considering that the offshore wind market could suffer major changes in longer terms.

In all the cases, the starting investment corresponds to the cost of development of the tool, in either of its two versions.

11.3.3.1. Analysis of case I: Selling the basic version of the tool

The list of assumptions for this case is the following:

• The exploitation would be carried out among other activities in an existing company.
• The basic version of the tool is expected to be sold for 12000 € to research institutions or small consultancy companies.
• Every license allows the use of the software without limit of time and includes support and updates during a year. The annual budget dedicated to giving this service is 3000 €/year.
• The expected sales are 1 license per year during years 1 and 2 and then 2 licenses per year during years 3 to 5.
Table 11.2 shows the calculation and results for this case of analysis.

### Table 11.2 Calculation for economic analysis. Case I. Source: self-elaboration

<table>
<thead>
<tr>
<th></th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>NPV</th>
<th>IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year</td>
<td>7911.85</td>
<td>3000</td>
<td>3000</td>
<td>3000</td>
<td>3000</td>
<td>3000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales</td>
<td>0</td>
<td>12000</td>
<td>12000</td>
<td>24000</td>
<td>24000</td>
<td>24000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash flow</td>
<td>-7911.85</td>
<td>9000</td>
<td>9000</td>
<td>21000</td>
<td>21000</td>
<td>21000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV</td>
<td>0.00</td>
<td>8866.99507</td>
<td>8733.55574</td>
<td>20082.0369</td>
<td>19783.8688</td>
<td>19493.4668</td>
<td>69053.10</td>
<td></td>
</tr>
<tr>
<td>Accumulated</td>
<td>-7911.85</td>
<td>955.15</td>
<td>9691.10</td>
<td>29773.76</td>
<td>49559.63</td>
<td>65051.10</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Using this strategy the NPV of the project is higher than 69000 €, which means that potential benefit is very high compared to the initial investment. The high value of IRR indicates that any discount rate under that value will still give positive results, meaning that this investment is low risk if the income targets can be accomplished. In that case of exploitation, the payback would be reached the first year of exploitation.

### 11.3.3.2 Analysis of case II: Selling the premium version of the tool

The list of assumptions for this case is the following:

- The exploitation would be carried out among other activities in an existing company.
- The *premium version* of the tool is expected to be sold for 50000 € to wind power leader companies (this represents less than 1% of the budget dedicated to engineering in a 200 MW project).
- Every license allows the use of the software for three years and includes support and updates during the three years. The annual budget dedicated to giving this service is 3000 €/year.
- The expected sales are 3 licenses, one each year during years 1, 2 and 3. The cost of services is included in years 4 and 5.

Table 11.3 shows the calculation and results for this case of analysis.

### Table 11.3 Calculation for economic analysis. Case II. Source: self-elaboration

<table>
<thead>
<tr>
<th></th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>NPV</th>
<th>IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year</td>
<td>15523.89</td>
<td>3000</td>
<td>3000</td>
<td>3000</td>
<td>3000</td>
<td>3000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales</td>
<td>0</td>
<td>50000</td>
<td>50000</td>
<td>50000</td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash flow</td>
<td>-15523.89</td>
<td>47000</td>
<td>47000</td>
<td>47000</td>
<td>-3000</td>
<td>-3000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV</td>
<td>0.00</td>
<td>46305.4187</td>
<td>45621.1022</td>
<td>44548.6987</td>
<td>-2826.5529</td>
<td>-2784.7809</td>
<td>115738.39</td>
<td>29%</td>
</tr>
<tr>
<td>Accumulated</td>
<td>-15523.89</td>
<td>30781.73</td>
<td>74462.83</td>
<td>121349.73</td>
<td>116523.17</td>
<td>115738.39</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Using this strategy the NPV of the project is higher than 115000 €, which means that potential benefit is higher than in case I. However, investment is higher too. The high value of IRR indicates that this investment is low risk if the income targets can be accomplished, however failing in founding customers could put the project finance in a bad position. If all goes as planned, the pay-back would be reached the first year of exploitation.
11.3.3.3. Analysis of case III: Creating an start-up company and making studies

The list of assumptions for this case is the following:

- A company would be created for the exploitation, consisting in a freelance engineer that offers economic studies as consultancy services.
- The *premium version* of the tool would be required. Each study will be paid 10000 €.
- The cost of the company is expected to be 5000 €/year, divided into 3000 €/year for freelance license fee and 2000 €/year for other costs (material, electricity, web page, etc.).
- The cost of workforce is expected to be 32000 €/year, divided into 30000 €/year in concept of salary for the worker and 2000 €/year for the state health contribution.
- The expected sales are 2 studies in year 1, 3 studies in year 2 and 4 studies in years 3 to 5 each.

Table 11.4 shows the calculation and results for this case of analysis.

<table>
<thead>
<tr>
<th>START-UP</th>
<th>CASE III</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year</td>
<td>0</td>
</tr>
<tr>
<td>Investment</td>
<td>15523.69</td>
</tr>
<tr>
<td>Sales</td>
<td>0</td>
</tr>
<tr>
<td>Cash flow</td>
<td>-15523.69</td>
</tr>
<tr>
<td>NPV</td>
<td>0.00</td>
</tr>
<tr>
<td>Accumulated</td>
<td>-15523.69</td>
</tr>
</tbody>
</table>

Using this strategy the NPV of the project is negative, meaning that 30500 € could potentially be lost. The negative value of IRR indicates that this investment is not worth using any discount rate. The only way to get profit with this strategy is either to reduce costs or increase sales. Pay-back is not possible if those measures are not applied.

11.3.3.4. Analysis of case IV: Mixed strategy

The list of assumptions for this case is the following:

- A company would be created for the exploitation, consisting in a freelance engineer that offers economic studies as consultancy services and also sells licenses for both versions of the tool and gives support to customers.
- The *premium version* of the tool would be required. The costs of studies and tool licenses are the same than in cases I, II and III.
- The cost of the company and workforce are expected to be the same than in case III.
- The sales are expected to be 2 studies and 1 *basic* version in year 1, 3 studies and 1 *basic* license in year 2, 2 studies plus 1 *basic* license plus 1 *premium* license in year 3, and 3 studies plus 1 *basic* license both in years 4 and 5.
Table 11.5 shows the calculation and results for this case of analysis.

Table 11.5 Calculation for economic analysis. Case IV. Source: self-elaboration

<table>
<thead>
<tr>
<th>Year</th>
<th>Investment (€)</th>
<th>Sales (basic)</th>
<th>Sales (premium)</th>
<th>Sales (studies)</th>
<th>Cash flow</th>
<th>NPV (€)</th>
<th>IRR (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>15523.69</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-15523.69</td>
<td>-4926.10347</td>
<td>36790.00</td>
</tr>
<tr>
<td>1</td>
<td>37000.00</td>
<td>12000.00</td>
<td>0</td>
<td>0</td>
<td>37000.00</td>
<td>45034.2647</td>
<td>45%</td>
</tr>
<tr>
<td>2</td>
<td>37000.00</td>
<td>12000.00</td>
<td>0</td>
<td>0</td>
<td>37000.00</td>
<td>45034.2647</td>
<td>45%</td>
</tr>
<tr>
<td>3</td>
<td>37000.00</td>
<td>12000.00</td>
<td>0</td>
<td>0</td>
<td>37000.00</td>
<td>45034.2647</td>
<td>45%</td>
</tr>
<tr>
<td>4</td>
<td>37000.00</td>
<td>12000.00</td>
<td>0</td>
<td>0</td>
<td>37000.00</td>
<td>45034.2647</td>
<td>45%</td>
</tr>
<tr>
<td>5</td>
<td>37000.00</td>
<td>12000.00</td>
<td>0</td>
<td>0</td>
<td>37000.00</td>
<td>45034.2647</td>
<td>45%</td>
</tr>
</tbody>
</table>

Using this strategy the NPV of the project is higher than 36000 €, which means that potential benefit can be earned. The 45 % value of IRR indicates that this investment could still be worth with discount rates higher than the calculation basis. The investment risk is moderate, given that potential benefit is not much higher than the original investment and that the sales objectives could not be completely achieved. If the income targets can be accomplished, then the pay-back would be reached the third year of exploitation.

11.3.4. Conclusions of the analysis

Table 11.6 summarizes the results of the analysis for every case.

Table 11.6 Summary of results from the economic analysis. Source: self-elaboration

<table>
<thead>
<tr>
<th>CASE</th>
<th>Strategy</th>
<th>Investment (€)</th>
<th>NPV (€)</th>
<th>IRR (%)</th>
<th>Pay-back year</th>
</tr>
</thead>
<tbody>
<tr>
<td>CASE I</td>
<td>BASIC</td>
<td>7911.85</td>
<td>69053.10</td>
<td>137%</td>
<td>1st</td>
</tr>
<tr>
<td>CASE II</td>
<td>PREMIUM</td>
<td>15523.69</td>
<td>115738.39</td>
<td>298%</td>
<td>1st</td>
</tr>
<tr>
<td>CASE III</td>
<td>START-UP</td>
<td>15523.69</td>
<td>-30586.81</td>
<td>&lt;0</td>
<td>Never</td>
</tr>
<tr>
<td>CASE IV</td>
<td>MIXED</td>
<td>15523.69</td>
<td>36790.00</td>
<td>45%</td>
<td>3rd</td>
</tr>
</tbody>
</table>

Two lectures shall be made up from the previously presented economic analysis, one from the point of view of IREC and another from the point of view of an entrepreneur.

From the point of view of IREC, case I showed that potential benefit could be achieved by selling the basic version of the tool with very low investment and low risk. Doing further investment to develop the premium version could give higher benefits. In fact, increasing the investment by 50%, the NPV of the project increases by 67%. The risk of this second case relies in the fact that the sales price of the premium version has been set for large companies that can afford this kind of expense. The success of this strategy relies in the capacity to find three customers willing to pay this amount of money.

From the point of view of an entrepreneur, starting a consultancy company to develop studies for customers does not seem a profitable business strategy, unless the capacity to find customers is much higher than the assumed for the analysis of case III. The risk of this investment for a single person seems too high. Nevertheless, the diversification of the business, meaning that this company could make studies and sell the software, could make a chance of profitable business. The potential benefit of this strategy is very low compared to the investment, however a modest annual salary for the entrepreneur was counted as a fixed cost. That means that, even if potential benefit is not enough to attract external
investors, if the entrepreneur can afford this investment he will find a way of making a living in addition to the benefits. The major risk of this strategy is that failing in finding customers, especially to sell the premium tool, could quickly create losses in the company finances. These losses could be difficult to afford for a company that relies in a single person.
12. Environmental impact of the project

The main object of the project has been the tool. All the environmental impact generated during the realization of the project has been dedicated to the development of this tool.

Only two concepts are considered as environmental impact of this project, the energy consumed for the development of the work and the energy consumed for the transport of the workforce. These are the impact caused exclusively by this project and no other cause.

Other concepts has been left out of the scope because they are not completely dedicated to the project. For instance, the impact of manufacturing the laptop might not be applied to this project, as far as it was not purchased specifically with this purpose. Other concepts such as the lights or air conditioning at the research center will not be counted, as many other people were using them at the same time.

The energy used during the project has been of 83,26 kWh (it was calculated in the economic analysis). The carbon dioxide emission to apply is 0,425 kg CO\(_2\)/kWh (data from the International Energy Agency for the Spanish electric mix, for years between 2011 and 2016). This makes a total amount of 35,39 kg of CO\(_2\).

The energy used for transportation corresponds to the 362 travels made by subway train. Each travel covered 15 km with some carbon dioxide emissions of 44,51 gCO\(_2\)/km/passenger [25]. The total emissions are 241,69 kg of CO\(_2\).

The total impact of the project is the emission of 277,08 kg of CO\(_2\).
Conclusions

The main objective of the project was to develop a tool capable of calculating LCOE of OWPP with different configurations. This objective has been accomplished and the resulting tool gives the user flexibility to accurately define the OWPP and allows the calculation of the LCOE with the defined parameters.

The objective of the first part was to gather knowledge on wind technology and economics for energy-generating projects assessment. All the useful information found during this research project has been included in this report and will be available to be used in future work in this field.

The objective of the second part was to build a calculation model and develop the tool. This has been done and the result will be used in future projects at IREC to assess economy of wind projects. In addition, the resulting tool has been tested with satisfactory results. Nevertheless, there is still margin for improvements especially in technical aspects of the tool.

The third part aimed to evaluate the project economically and environmentally. This has been done and the conclusion is that the tool has potential commercial interest but the level of risk depends on the targeted exploitation strategy. Concerning the environmental impact of the project, it has proven to be very low.

As a general conclusion of the work carried out, a main idea stands out: the offshore wind industry has still potential to grow, but many improvements are still needed to make it competitive. Particularly, reducing the LCOE is essential and that could be done by reducing manufacturing and logistic costs as well as improving current technology to increase efficiency and reliability. Finding ways to exploit deeper waters at low cost would allow the expansion of offshore wind among all the coastal countries that are not currently interested in this technology. For all these reasons, research in all the fields related to wind power is still necessary. Potential energetic, environmental and social benefits are at stake.
Acknowledgements

During the realization of this project I received some priceless help from IREC staff members to whom I would like to address my personal thanks. Especially to Gabriela Benveniste for her constant interest and supervision and to Dr. Oriol Gomis for his counseling. Also to Dr. Mikel de Prada and Dr. José Luis Domínguez for their knowledge and bibliography transfer every time I asked them. Finally thanks to Dr. Cristina Corchero for helping me to solve the probability of failure problem.

Special thanks must be addressed to my parents, Paco and Isabel, for giving me all the support and funds that have allowed me to follow my engineering studies. They also taught me to appreciate the value of perseverance and hard work.
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Annex A. Dimensioning of OWPP

The dimensioning of the power plant as well as the dimensioning of each one of its components shall be a matter of design to carry out by experts during the development phase of an offshore wind power project. However, as the final objective of this project is the implementation of a tool for modelling OWPP, it was considered necessary to establish a simplified procedure for the dimensioning of the plant based on the minimum variables possible. This way, a reliable estimation of number of components, power ratings, distribution of components and so forth can be quickly done in case that the final user of the tool do not have all the data.

The following sub-sections give guidelines for dimensioning and establish a simple process to calculate default values related to the power plant components.

A.1 Power rating

The active power installed in a wind power plant should be determined according to the objectives of the developer but also in compliance with the national grid needs, limitations, regulations and so forth.

Typically, offshore wind laboratories have been rated a few MW, small plants for demonstrations and industrial development of the technology have been rated from 10 to 100 MW and large plants are powered up to 600 MW.

At present, projects of 500 MW are considered as the standard size for future power plants [3], [4]. This size is competitive in comparison to other technologies, though it is the power of a medium-sized thermal plant or half the power of a thermal nuclear plant.

A.2 Number of turbines

Once the power rating of the plant is decided, the number of turbines shall be determined depending on the rated power of the turbines chosen to be installed. The power rating of wind turbines have been increasing continuously since the beginning of the development of the wind power industry (see Figure 12.1). This tendency is justified because the higher the power rating of each machine, the lower are the specific costs (the cost per installed MW). Even if the turbine cost increases with size, if less units are required, the cost of foundations, electric connections, transport, installation and maintenance are reduced.
The size of turbines installed offshore are larger than the ones used onshore, thanks to cheaper land use, less visual impact issues, less noise damping requirements, and so forth. At present turbines installed offshore are usually rated 3 to 6 MW. Forecasts expect to have 8 MW turbines in the short term (before 2020) [3].

In order to choose a turbine it is wise to pick up the larger among the available sizes. That determines the rated power ($P_{WT}$). The number of turbines is calculated by simple division of the wind power plant rated power by the turbine rated power rounding to the higher nearest integer number (Eq. (12.1)).

$$N_{WT} = \min\{n \in \mathbb{Z} | n \geq \frac{P_{WP}}{P_{WT}}\}$$  \hspace{0.5cm} (12.1)

### A.3 Turbine efficiency

Some of the power extracted from the wind does not reach the collection grid due to mechanical and electrical losses in the turbine’s drive train, generator, transformer, converters or cables. In this study, the turbine efficiency ($\eta_{WT}$) is defined as the ratio between the mechanical power extracted from the wind and the electric power feed in the grid.

For matters of dimensioning, the default value used in the models will be $\eta_{WT} = 0.9$.

### A.4 Plant layout

The arrangement of the wind turbines depends on many factors, such as seabed conditions, water depth or even aesthetical factors (if the wind park is seen from ashore as it was the case in Copenhagen’s harbor [18]). Nevertheless, if these conditions allow it, the most common arrangement is in a rectangular array.

The orientation of the turbines array depends on the prevailing wind direction of the site (i.e. the direction in which the wind will potentially supply more power to the turbines, taking
into account both the probability distribution of directions and the probability distribution of wind speed).

The separation of the turbines in the prevailing wind direction is set to reduce wake effect. The standard value for this separation is 7 times the rotor diameter [26].

The separation of the turbines in the direction perpendicular to the prevailing wind does not need to be as high as in the prevailing wind direction, because the slower winds expected in this direction should create less aerodynamic shadow. The standard value for the separation in this direction is 4 times the rotor diameter [26].

Increasing the separation between turbines will increase expenses in collection grid cables and installation as well as electrical losses in the grid that could not be compensate by reduction of the wake effect. Consequently, the configuration 4Dx7D was established as a reference for this project.

![Figure 12.2 Reference turbine array. Source: self-elaboration](image)

**A.5 Number of turbine feeders**

The number of feeders is a matter of design. It shall be defined to minimize the cables lengths but with certain limitations of power to transmit, depending on the characteristics of the cables.

For a simple dimensioning, taking into consideration that the turbines layout will be a rectangle, the number of feeders will be equal to the number of rows in the layout, meaning that each row of turbines will be a separate feeder.

**A.6 Transmission cables characteristics for HVAC lines and required number of lines**

The transmission lines are dimensioned in order to transmit all the energy generated by the power plant at full load conditions. In addition, extra rating must be added to consider the reactive power generated in the line.

In order to make an accurate dimensioning of cables for the export lines, it is recommended to acquire the manufacturer's technical sheets and follow his instructions for the dimensioning. Nevertheless, some simplified method is required to estimate the cable parameters for the model in development on this project. This simplified model will prove useful to make a quick estimation whenever the real cable data is not available.
This dimensioning procedure is based on the data available in Annex A, and concerns only 3-core submarine cables made of Copper with XLPE insulation. In addition, only three operating voltages are available: 132, 220 and 275 kV.

The calculation shall start by estimating the maximum current solicitation in the line, which will depend on the power to export. By default, the starting number of lines shall be one ($N_{TL} = 1$). Eq. (12.2) shows the maximum current solicitation ($I_{\text{max}}$) for the OWPP power rating ($P_{\text{OWPP}}$) and the voltage of the lines ($U$). In addition, a power factor is included to take into account reactive power. For this dimensioning, the worst case scenario is applied, meaning $PF = 0.85$ (see section 8.1).

$$I_{\text{max}} = \frac{P_{\text{OWPP}}}{N_{TL}} \cdot \sqrt{3} \cdot U \cdot PF \cdot 10^3$$  \hspace{2cm} (12.2)

Then, one searches on the database (Annex B - Table 1) the minimum ampacity ($I_{TC}$) higher than the solicitation maximum current and chooses the corresponding cable section ($S_{TC}$). If there is no cable capable of giving enough performance, then the number of lines shall be increased by one, meaning that one additional cable is connected in parallel, and the process repeated.

Once the cable section is selected, the corresponding electric characteristics (resistance at 20°C, capacitance and inductance) can be determined by means of Annex B - Table 2, for the three values of voltage included in the database.

The safety factor of the cables can be calculated as the ratio between the ampacity and the maximum solicitation.

$$SF = \frac{I_{TC}}{I_{\text{max}}}$$  \hspace{2cm} (12.3)

If redundancy of lines is wished to be included, the number of lines can be doubled. This is done to reduce the risk of failure of the transmission system.

### A.7 Transmission cables characteristics for MVAC lines

The dimensioning of cables for the transmission lines in MVAC is similar to the procedure explained for HVAC, only using the cables database for 33 kV. In order to choose the cross section Annex B - Table 3 shall be used and to know the electric characteristics of the cables Annex B - Table 4 shall be used.

### A.8 Collection cables characteristics

The dimensioning of collection cables will be based on 3-core cables made of Copper with XPLE insulation for operation at 33 kV. The cables data can be found on Annex A.

The procedure for the dimensioning shall start by determining the active power required to flow within a feeder. This value will depend on the number of turbines in the feeder and also in the type of connection.
For turbines connected in a star scheme, the maximum power solicitation in the cable is simply the maximum power output of the turbine. For turbines connected in a radial or ring schema the maximum power solicitation is the sum of maximum output powers of all the turbines.

Given a feeder with $N_{WT,feeder}$ turbines, the maximum active power solicitation will be $P_{\text{max,feeder}}$, as it is shown in Eq. (12.4).

$$P_{\text{max,feeder}} = P_{WT} \cdot N_{WT,feeder} \quad (12.4)$$

The maximum current solicitation ($I_{\text{max,feeder}}$) is determined by Eq. (12.5), with $U=33$ kV and the power factor of the worst case scenario ($PF=0.85$).

$$I_{\text{max,feeder}} = \frac{P_{\text{max,feeder}}}{\sqrt{3} \cdot U \cdot PF} \cdot 10^3 \quad (12.5)$$

Then, one searches on the database (Annex B - Table 3) the minimum ampacity ($I_{TC}$) higher than the solicitation maximum current and chooses the corresponding cable section ($S_{TC}$). If there is no cable capable of giving enough performance, then the number of feeders shall be increased by one (except for star scheme connections), reducing the active power in the feeder, and the process repeated.

Once the cable section is selected, the corresponding electric characteristics (resistance at 20°C, capacitance and inductance) can be determined by means of Annex B - Table 4.

The safety factor of the cables can be calculated as the ratio between the ampacity and the maximum solicitation.

$$SF = \frac{I_{TC}}{I_{\text{max}}} \quad (12.6)$$

### A.9 Length of transmission lines

The length of the transmission lines will depend on the distance between the offshore platforms and the connection point onshore. This distance shall be specific for each power plant, and trying to make a general law is difficult and shall be source of error. However, for a matter of gross dimensioning, in case of lack of specific data, a study has been carried out with data on the projects presented in Annex B.

The representation of transmission lines length vs. distance to shore of several projects show a linear tendency, which means that the cable lengths tends to be a certain proportion higher than the straight line distance between the power plant and the coastline (see Figure 12.3).
In order to make an estimation of required cable lengths for a certain project, Eq. (12.7) shall be used, where $L_{TL}$ is the length of the transmission lines in km and $D_{\text{shore}}$, the distance between the plant and the coastline, also in km.

$$L_{TL} = 1.19 \cdot D_{\text{shore}} + 2.89 \quad (12.7)$$

A.10 Number of transformers

The usual arrangement in wind parks is to have two transformers in parallel connected to one or more transmission lines also in parallel (see Figure 12.4 for an example of substation for a 500 MW OWPP. This simple architecture is enough for wind power plants of low power rating (up to 500 MW) [26].
one or more transformers in parallel a transformer unit, an OWPP with offshore substation and HVAC transmission to shore can be reduced to a certain number of transformer units \(N_{TU}\) connected in parallel to a certain number of transmission lines \(N_{TL}\). Each transformer unit represents a different offshore platform and is composed by a certain number of transformers in parallel \(n_{TR}\) and is feed by a certain number of turbine clusters \(n_{cl}\). This architecture is shown in Figure 12.5.

![Figure 12.5 Baseline architecture of substation for HVAC OWPP. Source: self-elaboration from [26]](image)

In case that the transmission to shore is made in HVDC, the architecture is similar to the HVAC with the difference that a current converter stage is required between the voltage stepping up stage and the transmission lines (see Figure 12.6). In that case only one converter and one single HVDC line is required for powers up to 1000 MW after the reference architecture found in [26].

![Figure 12.6 Baseline architecture of substation for HVDC OWPP. Source: self-elaboration from [12]](image)

In any case, the minimum number of transformers in a transformer unit is two, in order to ensure 50% redundancy in case of one transformer failing [26]. The baseline cases for default rough dimensioning are explained in the following sections.
A.10.1 Substation baseline case for HVAC OWPP

The power rating of the transformers will depend on the total power installed in the plant. Figure 12.7 shows a certain relation between the installed power in the plant and the power ratings of the installed transformers. This plot is extracted from a study carried out with data on the projects presented in Annex B. Using this data to calculate the power to install in the substation will be a source of error, because there is not enough data to establish a strong relation and the few data available gives a considerable lack of accuracy. Nevertheless, only for a matter of rough dimensioning it is acceptable to use this approach, given that the error committed will be in the side of security (over-dimensioning), as it will be demonstrated with the following example.

Assuming a 500 MW plant, the schema shown in Figure 12.4 [26], includes two transformers of 250 MVA. Using the trend line of Figure 12.7, the total power of transformers shall be around 630 MVA, which means two transformers of 315 MVA. In fact, if one draws a line of unitary gradient, meaning transformer power = turbines power, (red line in the figure), one can see that all the projects in the study are over the line. As a conclusion, this approach is conservative for all cases, compared to the baseline installations given in [26].

![Figure 12.7 Transformer total power vs. plant rated power. Source: self-elaboration from Annex B.](image)

A simple way to estimate the power required in the substations is to fix as a baseline that only one platform will be installed and 2 transformers will be used for plants rated up to 500 MW. Then, one can estimate the required power of each one using the trend line shown in Figure 12.7.

\[ A_{TR} = 0.5 \cdot (1.1644 \cdot P_{WP} + 47.551) \text{ if } P_{WP} \leq 500 \text{MW} \quad (12.8) \]

\[ N_{TR} = 2 \quad (12.9) \]
For powers higher than 500 MW, as we cannot ensure that bigger transformers may exist or be easily available at a fair price, the baseline number of transformers will be set to 4. This approach can be considered acceptable for plants up to 1000 MW.

\[
A_{TR} = 0.25 \cdot (1.1644 \cdot \text{P}_{WP} + 47.551) \text{ if } \text{P}_{WP} > 500 \text{MW} \quad (12.10)
\]

\[
N_{TR} = 4 \quad (12.11)
\]

A.10.2 Substation baseline case for HVDC OWPP

Because of lack of data on costs and technology, the HVDC transmission has been left out of the scope of the first version of the tool. For this reason, the baseline dimensioning procedure has not been developed at present, waiting for the gathering of more data that could help in building a better model.

A.11 Number of switchgears

The switchgears will be counted in substations and in the collection grid.

A.11.1 Switchgears in the substations

Based on the schema in Figure 12.4, each transformer has at least 3 switchgears in the medium voltage side and at least 1 in the high voltage side. In addition, each transmission line requires its own high voltage switchgear.

\[
N_{MVSG} = 3 \cdot N_{TR} \quad (12.12)
\]

\[
N_{HVSG} = N_{TR} + N_{TL} \quad (12.13)
\]

A.11.2 Switchgears in the collection grid

In order to disconnect a turbine from the grid, two switchgears are required, one upstream and one downstream. However, these switchgears are included in the turbine for a matter of cost calculation. Consequently, they will not be counted in the number of switchgears in the grid.

As a baseline, each feeder shall require its own switchgear in the interface with the substation (if there is one substation). As a default value, 1 switchgear per feeder \((k = 1)\) will be counted, or 2 per feeder in case of turbines connected in a ring scheme \((k = 2)\).

\[
N_{SG} = k \cdot N_{\text{feeders}} \quad (12.14)
\]
Annex B. Submarine cables database

This annex summarizes the information gathered in the submarine cables database included within the tool. All the information concerns 3-core submarine cables made of Copper with cross-linked polyethylene insulation (XLPE). The information is sourced from a technical user’s guide of the manufacturer ABB [27].

B.1 High voltage submarine cables

The following table is used to determine cable sections for a certain required current rating for HVAC submarine cables.

**Annex B - Table 1 Sections and current rating of HVAC submarine Cu cables (XLPE 3-core) for 100 to 300 kV. Source: [27]**

<table>
<thead>
<tr>
<th>Section [mm²]</th>
<th>Ampacity [A]</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>530</td>
</tr>
<tr>
<td>400</td>
<td>590</td>
</tr>
<tr>
<td>500</td>
<td>655</td>
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<tr>
<td>630</td>
<td>715</td>
</tr>
<tr>
<td>800</td>
<td>775</td>
</tr>
<tr>
<td>1000</td>
<td>825</td>
</tr>
</tbody>
</table>

The following table serves to determine electrical characteristics of cables depending on their cross section and operation voltage.

**Annex B - Table 2 Electrical characteristics of HVAC submarine Cu cable (XLPE 3-core). Source: [27]**

<table>
<thead>
<tr>
<th>Voltage</th>
<th>132 kV</th>
<th>220 kV</th>
<th>275 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Section [mm²]</td>
<td>R(20°) [Ω/km]</td>
<td>L [mH/km]</td>
<td>C [μF/km]</td>
</tr>
<tr>
<td>300</td>
<td>0,0575</td>
<td>0,42</td>
<td>0,16</td>
</tr>
<tr>
<td>400</td>
<td>0,0431</td>
<td>0,4</td>
<td>0,18</td>
</tr>
<tr>
<td>500</td>
<td>0,0345</td>
<td>0,38</td>
<td>0,20</td>
</tr>
<tr>
<td>630</td>
<td>0,0274</td>
<td>0,37</td>
<td>0,21</td>
</tr>
<tr>
<td>800</td>
<td>0,0216</td>
<td>0,36</td>
<td>0,23</td>
</tr>
<tr>
<td>1000</td>
<td>0,0172</td>
<td>0,35</td>
<td>0,25</td>
</tr>
</tbody>
</table>
B.2 Medium voltage submarine cables

The following table is used to determine cable sections for a certain required current rating for MV submarine cables.

Annex B - Table 3 Sections and current rating of MVAC submarine Cu cables (XLPE 3-core) for 10 to 90 kV. Source: [27]

<table>
<thead>
<tr>
<th>Section [mm²]</th>
<th>Ampacity [A]</th>
</tr>
</thead>
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<tr>
<td>95</td>
<td>358</td>
</tr>
<tr>
<td>120</td>
<td>406</td>
</tr>
<tr>
<td>150</td>
<td>452</td>
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<tr>
<td>185</td>
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<tr>
<td>240</td>
<td>582</td>
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<tr>
<td>300</td>
<td>649</td>
</tr>
<tr>
<td>400</td>
<td>713</td>
</tr>
<tr>
<td>500</td>
<td>790</td>
</tr>
<tr>
<td>630</td>
<td>861</td>
</tr>
</tbody>
</table>

The following table serves to determine electrical characteristics of cables depending on their cross section for 33 kV.

Annex B - Table 4 Electrical characteristics of 33 kV submarine Cu cable (XLPE 3-core). Source: [27]

<table>
<thead>
<tr>
<th>Section [mm²]</th>
<th>R(20°) [Ω/km]</th>
<th>L [mH/km]</th>
<th>C [μF/km]</th>
</tr>
</thead>
<tbody>
<tr>
<td>95</td>
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<td>0.420</td>
<td>0.161</td>
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<tr>
<td>120</td>
<td>0.1967</td>
<td>0.401</td>
<td>0.176</td>
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<tr>
<td>150</td>
<td>0.1597</td>
<td>0.387</td>
<td>0.188</td>
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<tr>
<td>185</td>
<td>0.1281</td>
<td>0.374</td>
<td>0.203</td>
</tr>
<tr>
<td>240</td>
<td>0.0981</td>
<td>0.358</td>
<td>0.228</td>
</tr>
<tr>
<td>300</td>
<td>0.0790</td>
<td>0.344</td>
<td>0.244</td>
</tr>
<tr>
<td>400</td>
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<td>0.331</td>
<td>0.270</td>
</tr>
<tr>
<td>500</td>
<td>0.0505</td>
<td>0.315</td>
<td>0.300</td>
</tr>
<tr>
<td>630</td>
<td>0.0409</td>
<td>0.305</td>
<td>0.328</td>
</tr>
</tbody>
</table>
### Annex C. Projects database

The following tables summarize data from offshore wind power plants already installed or under construction in Europe. Source: self-elaboration from [10].

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
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<td>46</td>
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<td>Monopile</td>
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<td>3721</td>
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<td>27</td>
<td>18 - 28</td>
<td></td>
<td>Gravity</td>
<td></td>
<td>150</td>
<td>153</td>
<td>5100</td>
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<td>G-Power II</td>
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<td>30 x 5</td>
<td>27</td>
<td>12 - 24</td>
<td></td>
<td>Jackett</td>
<td>Offshore</td>
<td>150</td>
<td>312.6</td>
<td>4404</td>
</tr>
<tr>
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<td>18 x 6</td>
<td>26</td>
<td>12 - 26</td>
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<td>Offshore</td>
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<td>Offshore</td>
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<td>1738</td>
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<tr>
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<td>31.7</td>
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<td>-</td>
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<td>Offshore</td>
<td>155</td>
<td>2220</td>
<td>5707</td>
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</tr>
</tbody>
</table>

*The project names followed by * indicate that the wind park is under construction or operating partially.
The cost columns refer to CAPEX and are not updated. Each cost could be in EUR values at different years.
The author does not assure the accuracy of this data.
Annex D. Note on monetary update

The project presented in this report is mainly focused in calculating and evaluating costs or prices. Consequently, all the values, data and results are expressed in units of variable value along time, e. g. k€. In order to keep the coherence of the data, all the values are stated to correspond to a particular year (e. g. k€ 2009).

Whenever operations with different costs or comparisons are made, all the values are reported to the same year. In order to do that, an inflation indicator was taken into account. Rather than updating by the usually used Harmonized Index of Consumer Prices (HICP) it was preferable to use an indicator that fitted better the nature of the costs involved in the power generation projects. The indicator chosen was the Industrial Producer Price Index (PPI). This index was adequate to update costs regarding that wind power projects are capital-intensive, where the main costs are dedicated to manufacture and works. The PPI give the evolution of prices in industry while the HICP is focused on general prices for final consumers from a household point of view.

The inflation ratios between different years were calculated by quotient of the PPI of two different years. The PPI values used corresponded to the European Union (28 countries). All the costs used in comparisons were reported to 2014 year’s value using Eq. (12.15).

\[
\text{€}(2014) = \text{€}(t) \cdot \frac{\text{PPI}(2014)}{\text{PPI}(t)}
\]  

Figure 12.8 Statistics on PPI in EU(28) between 2000 and 2014. Source: Eurostat [28]

In addition, some currency changes have been necessary to harmonize data. Particularly, some of the sources of information gave the costs in pound sterling (£) instead of euros. In those cases, before time update, currency change has been calculated using the average exchange rate of the year of the original data. Then the inflation was applied to the converted values. By doing currency exchange first, it is assumed that the same inflation applies to the values, which is correct because all the data sources used in this project referred to member countries of the European Union.
The currency conversion was made by means of the Eq. (12.16), where $\varepsilon(t)$ is the value in EUR at year $t$ of the data source, $V(t)$ is the value in the original currency at year $t$, and $X(t)$ the exchange ratio between the original currency and EUR at year $t$.

$$
\varepsilon(t) = V(t) \cdot X(t)
$$

(12.16)

All the PPI and currency exchange ratios used in the project are summarized in Table 12.1.

<table>
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<th>Year</th>
<th>IPP</th>
<th>GBP to EUR</th>
<th>USD to EUR</th>
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<td>1.2332</td>
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<tr>
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<td>2005</td>
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<tr>
<td>2006</td>
<td>93.00</td>
<td>1.2411</td>
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<td>2007</td>
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<td>2008</td>
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<tr>
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<tr>
<td>2014</td>
<td>105.21</td>
<td>1.2411</td>
<td>1.3283</td>
</tr>
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</table>

In some cases, it was necessary to update an equation giving a cost as a result, in order to have the results at 2014 value. In those cases, the inflation ratio was calculated and included as a factor in the equation. The main ratios used were inflation between 2009 and 2014, which value according to the PPI method is 1.1, and between 2000 and 2014, which value is 1.31. For these reason, many of the equations given in the report regarding costs and later used in the programming of the LCOE tool, includes these 1.1 and 1.31 as factors.
Annex E. Cost Assessment Tool for OWPP - User’s guide

Software requirements

The Cost assessment tool for Offshore Wind Power Plants has been developed in Matlab 2012 and requires the software Matlab for its execution (previous versions of Matlab shall work).

The outputs of the tool are saved in an MS Excel file. It is recommended to have a copy of Excel installed when using the tool; otherwise an error will be produced when the tool tries to save the data. However, the tool can be used without this feature.

Previous considerations

The tool is designed to introduce data in a fixed sequence. Each block requires the introduction of a certain amount of data prior to jump to the next block. The program do not allow to jump to the next block without introducing all the data required, however going back to previous blocks is neither allowed. It is recommended to check carefully the introduced data before changing to the next block in order to avoid mistakes.

The program includes safety mechanisms to avoid mistakes such as introducing symbols instead of numbers or introducing inconsistent values (e.g. negative values for positive measures). Whenever that happens an error message is prompted to warn the user.

The program only accepts points to express decimals. If a comma is used an error message is prompted to warn the user.

About this version of the tool

This is the first version of the tool and may not include all the desirable features and options. Some of the simulation procedures are not optimized in terms of accuracy, however the time of calculation is short thanks to its simplicity.

This version of the tool includes options to simulate OWPP with AC transmission. The HVDC transmissions are out of the scope.

This version of the tool does not allow importing a file with the OWPP data, but it allows exporting a file to save the results.

The economic assessment modules of this tool have proven to be accurate when they have been compared to real projects.

Getting started

In order to launch the program the file ‘Main.m’ shall be executed. You may double click on the file or alternatively write ‘Main’ in the command window and press return.
(Note that the current folder must be set to the folder of the tool).

The *Title* section will be prompted. In order to launch the tool the button ‘Run tool’ shall be pressed.

Then, a menu will be prompted. In the top left corner there are two links. When pressed two different documents can be accessed: one includes general information about the tool and the other is linked to this user’s guide. The menu only has an available action for this version of the tool which is ‘Start definition of OWPP’; this button will launch the first *block* of the tool.
Block 1: Offshore wind power plant description

The first block is dedicated to introduce general data about the plant and to define the layout (the arrangement of the turbines in the space).

The top part of the screen requires the introduction of data. The button ‘Set default values’ gives fixed values for a typical 500 MW plant with HVAC transmission and turbines rated to 5 MW. These values can be changed prior to press the button ‘Save layout’ which will save this data too.

The type of OWPP includes a help button (marked ‘?’) to show the differences between types. This information is included later in this section of the guide.

The types of foundations included in this version of the tool are monopile and gravity base. In order to use other types of foundations you can select any of these and change the cost calculated in the CAPEX block by the cost of the foundation that you want to consider.

The lowest part of the screen is dedicated to the definition of the layout. In this version of the tool the layout can only be defined by generation of a matrix rectangle. This is made by defining the number of turbines, the number of rows and the separation of the turbines in the two directions of the plane. The separations are defined as multiples of the rotor diameter (use decimals is allowed).

![Offshore wind power plant description](image)

The button ‘Save layout’ will save all the data of the block. Any change introduced later will not be taken into account. When the ‘Save layout’ button is pressed an additional window appears to ask for the definition of a connection point; this step is required for the later definition of the grid. The button ‘Plot layout’ will take the saved data and plot the turbines in the screen. The distances in the plot are draw at scale.

The ‘Connection Point’ window gives you three possible positions for the CP: downwind, left side or right side. For each possibility an explicative image is prompted. It also requires
a distance expressed as a multiple of the rotor diameter. With this information the button 'Calculate coordinates' will calculate the coordinates of the CP in the plant reference. This coordinates can be modified prior to save the data with the ‘Save’ button.

The help button next to the type of OWPP selection panel shows a window with a description and a diagram of each type of plant considered. Only the types 1 and 2 are included in this version of the tool.
Block 2: Wind conditions

This block is dedicated to the definition of the wind conditions in the plant. The required data is the average speed of the wind and the shape factor of the Weibull distribution. The tool allows the introduction of different data for several directions (you can choose 1, 4, 8 or 12 different directions). In that case the data shall be introduced for each direction.

The left part of the screen is dedicated to the introduction of the data, while the right side shows plots and results.

The time share column indicates the % of time that the wind blows in each direction. The sum of these values must be 100%.

The mean wind speed column is required to calculate the Weibull distribution of each direction.

The shape factor $k$ can be defined for each direction independently or using one for all the direction by pressing the ‘Use a unique shape factor’ button. For offshore plants the values of $k$ shall take values between 3 and 4.

The ‘Generate default values’ button will randomly assign time shares, speeds and shape factors. The time shares are completely random but they sum 100%. The shape factors are random values between 3 and 4. The mean speeds are based on a Weibull distribution with mean speed 12 m/s and the previously calculated shape factors.

For an accurate calculation of the LCOE it is recommended not to use the default values for the wind conditions.

The ‘Save and plot results’ button will save the wind data and plot the Weibull distribution function of each direction. In addition the potential energy of each direction is calculated and plotted below. This potential energy indicates the energy that the wind can provide for
each unit of rotor area installed during a year. This calculation is made for an ideal turbine
(Betz’ law).

**Block 3: Transmission grid**

This block is dedicated to the definition of the transmission grid installed between the plant
and the shore.

The ‘Calculate default values’ button makes a dimensioning of the grid. This dimensioning
is based on the cables database included in the tool. For HVAC transmissions the tool gives
the possibility to choose among three levels of voltage for the dimensioning (132 kV, 220
kV or 275 kV). For plants with transmission in MVAC only 33 kV is available.

The tool makes a choice of cables among the available cables in the database considering
full load and a power factor of 0,85 (worst case scenario). It gives the characteristics of the
selected cables and the number of parallel lines required using these cables. The right part
of the screen indicates the maximum intensity of current that will load the cables in the
calculation scenario and the safety factor in comparison to the cables rated ampacity.

The length of cables is estimated based on the distance to shore.

Any change in the data must be introduced prior to press the ‘Save and continue’ button.
This button saves the data introduced and jumps to the next block.
**Block 4: Integration system**

This *block* is dedicated to the description of the integration system (usually called offshore substation).

The button ‘Generate default values’ makes a dimensioning of the minimum equipment required for the plant. The number of platforms is set to one by default. The number of transformers is set to two for plants up to 500 MW and to four for higher powers. The transformers power is calculated based on the plant rated power (considering a power factor of 0.85 to have the worst case scenario). The number of switchgears is set based on examples of real projects. The baseline dimensioning includes diesel generators for the plant back-up.

![Integration system diagram]

Note that if the type of plant selected in *block* 1 does not include a substation, all the values are set to zero and a warning message is prompted.

![Warning message]

The option to include HVDC transmission equipment is not available in this version of the tool.

After introducing the data or making changes to the dimensioning the button ‘Save data’ must be press to save the current values. Finally, the button 'Next' jumps to the next *block*. 
**Block 5: Collection grid**

This *block* is dedicated to the definition of the grid that connects all the turbines. The turbines are grouped in feeders or groups of turbines and each feeder is connected to the previously defined *Connection Point*.

First of all a type of connection must be chosen. Selecting ‘Radial’ one end of each feeder is connected to the CP, selecting ‘Ring’ both ends are connected and selecting ‘Star’ each turbine is individually connected to the CP.

After selecting the connection type you can press the ‘Set default values’ button for making an automatic dimensioning of the grid. This will set the number of feeders, cables section and number of switchgears based on the type of connection previously selected. The voltage level is always set to 33 kV.

The baseline dimensioning looks for a cable in the database that could be loaded with the whole power of a feeder. The case of calculation includes a power factor of 0.85 and the plant at full load to be in the worst case scenario. The number of feeders calculated is the minimum with which some cable in the database could stand the maximum load.

After the dimensioning, the user can introduce changes. For instance you can include different types of cables indicating which % of the grid is made with each cable. That feature could help to optimizing costs.

When all the data is introduced the button ‘Save data’ serves to save the current values. After that, the button ‘Plot grid’ must be pressed. A diagram of the grid will be prompted and the length of the grid is calculated.
In the diagram, red lines show the cables in the feeders and green lines show the cables that connect each feeder to the CP. A green circle indicates which turbine is connected to the CP.

The algorithm that makes the connections does not optimize distances in this version of the tool but saves calculation time and gives good approaches. The button ‘Next’ jumps to the next block.

**Block 6: Maintenance**

This block is dedicated to the definition of planned maintenance procedures.

The ‘Generate default values’ gives data for a common case. The values are based on research. Some values like the number of vessels and number of workers are dependent on the dimension of the power plant.

![Maintenance Block](image)

**Block 7: CAPEX**

This block is dedicated to the calculation of the CAPEX or capital costs of the project.

The left column of the screen contains specific costs related to components. When the button ‘Calculate default data’ is pressed all the costs are calculated and shown. These values correspond to the previously defined power plant and are based on research in the subject. Almost all the values are specified per unit or component (e.g. cost per turbine, cost per km of cable, etc). The user can make changes in those values at this stage.

The button ‘Calculate CAPEX’ translates the previous costs to total costs of the project per categories. At this stage a part of the budget is added to insurance and contingencies. The user can make changes at this stage too.

The ‘Save data’ button saves all the costs and calculates the total CAPEX (in absolute value and in cost per MW installed). It also gives the breakdown of the main systems and items in %.
The ‘Next’ button jumps to the next block.

**Block 8: OPEX**

This block is dedicated to calculate the costs of operation and maintenance of the plant.

The ‘Calculate OPEX’ button starts the calculation of the costs which are based on the previously defined power plant and on data from research.

The top part of the windows shows the cost of planned maintenance, based on the schedule and data defined before. The bottom part shows the cost of unplanned or corrective maintenance, based on failure rates of the plant components. The information below the value gives an approach of mean number of failures and mean cost of major repairs.
The button ‘Save data’ records the current values. Any changes in the costs should be made before using this command.

The button ‘Next’ jumps to the next block.

**Block 9: Energy yield**

This block is dedicated to the calculation of the energy yield or energetic production of the power plant.

The top left part of the window asks for the basic data to make the calculations. The ‘Set default values’ gives usual values as baseline assumptions. The power coefficient and the turbine efficiency are expected to be mean values representative of the turbine’s usual operation. The cut-in and cut-out speeds define the range of speeds that allows the turbine to be operating; these values are set by default at 3 and 25 m/s, but any value between 0 and 25 can be introduced.
The ‘Calculate energy yield’ button starts the calculation and shows the results. In the left part of the window the power curve of the turbines is shown. The right part is dedicated to the energy yield: the graph shows the energy production of each turbine and the total annual production of the plant is written below.

In this version of the tool all the turbines are treated identically, which means that the energy curve of each turbine will be identical.

The ‘Next’ button jumps to the next block.

**Block 10: Losses**

This block is dedicated to the calculation of the losses. Two types of losses are taken into account: unavailability losses and electric losses.

The left part of the window requires the introduction of data for the calculation. The ‘Calculate default values’ button gives an approach of each of the required values. For the availability losses, the mean time to repair failures (MTTR) is a fixed value based on research, while the average energy produced is calculated from the plant energy yield (this value is discounted as average because failures can be produced at any time of the year). For the electric efficiencies, the substation is given a fixed value while the two grids are estimated by calculation of power losses (IR²) at full load and with a power factor of 0.85. For the transmission grid, losses due to voltage are included when HV is used.
The ‘Calculate losses’ button saves the data and starts the calculation. The results are prompted both for the unavailability losses and for the electric losses. The losses are stated in annual value and in % of the energy yield.

The ‘Next’ button jumps to the next block.

**Block 11: LCOE**

This block is dedicated to the calculation of the Levelized Cost of Energy.

Some data is required to be introduced to do the calculation. The ‘Set default values’ gives values for a particular case of study.

The discount rate is the rate used to calculate Net Present Values of the costs, the inflation rate corresponds to annual inflation. The user has to define which % of the CAPEX has been financed through loans and the interest rate of the loans. The life time is the number of years that the plant will be operating. The ‘other costs’ is dedicated to include any additional cost that was not represented in the model; in case of use this feature you must write the total cost in NPV at year 0 in k€. Any cost of decommissioning can be included, as well as any benefit (in negative values).
The ‘Calculate LCOE’ button starts the calculation and prompts the results. The ‘Save results’ button makes a copy of the data in an MS Excel file and closes the program.

**Warning:** if you do not have the software MS Excel installed, Matlab can give you an error warning. In that case you should save manually the result of the LCOE and close the program using the X button rather than use the ‘Save results’ command.

The file ‘Template.xlsm’ included in the program folder is the base to save the simulation data. This file must not be removed from the folder or overwritten. When the program save the data the file ‘Template.xlsm’ is opened with the data of the simulation written. In order to save the data you should use the ‘Save as’ command of Excel and save it with a new name in the folder of your choice.
The Excel file includes a summary of the results in the sheet named ‘Outputs’.

You will also find a summary of the input data in the sheet named ‘Inputs’ and the turbines coordinates in the sheet named ‘Layout’.

Finally, the file includes a copy of the cables database in the sheet named ‘Cables database’.