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Model for an evaluation of electricity production and economical affordability of a wind turbine in Ireland

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Preface

This thesis was prepared in the Environmental Research Institute (ERI), at the University College of Cork (UCC) under the supervision of Peter Deeney, during the Erasmus exchange program between the UCC and the University of Padua from January until June 2022. It is assumed that the reader has a basic knowledge of electricity production from wind energy source and economics in order to better understand the main topics covered.

Abstract

As one of the main goals of this decade is to limit global warming and all emissions related to human activities, the generation of energy through renewable energy sources (RES) plays a crucial role in creating a sustainable future. Regarding the production of electricity, the wind energy and therefore the wind turbines can clearly contribute to the generation of clean energy, leading to lower emissions and thus reducing the impact on the environment.

The aim of this thesis is to build a model to evaluate the electricity production and the economical affordability of a wind turbine, suitable for every site considered in which a database of wind speed is available. In particular this thesis analyses a site located in Cork County, Ireland.

Starting from an analysis of the windiness of the site, using the two-parameter Weibull distribution, which is defined by his two parameters, both derived from six different numerical methods. The best method is evaluated calculating the errors on the measurement and for the number of samples available for this study, the empirical method turns out to be the best way to obtain the parameters.
Having the wind distribution, in particular the velocity that carries the maximum energy, a selection of different wind turbine models can be done. In this thesis three different models are compared because the selected wind turbines have different power coefficient curves that suits differently the wind probability distribution, they have different range of wind in which they can operate and different value of the diameter. As a result, the Fuhrländer FL MD7 is the model that gives the most electricity production.

To evaluate the economical affordability of the investment economic tools are used, which are the Discounted Pay Back Period, the Net Present Value (NPV) of the wind turbine at the end of life of the turbine and the Levelized Cost of Electricity (LCOE).
In this thesis six different scenarios are evaluated in order to show how the variation of the electricity price, the investment costs and the Weighted Average Cost of Capital (WACC) affect the cash flow, and therefore the return of the investment.
The first two scenarios are considered the base scenarios, in which the investment costs, operating and maintenance costs and the electricity price are the average obtained from the literature. The first one, which does not consider the WACC, shows a return of the investment of 7.3 and a NPV of 3053929.25 € while the second, as it can be expected, gives a return of the investment of 10.6 years, a NPV of 912187 € and a LCOE of 5.17 €cent/kWh.
The second two scenarios vary on the electricity price. In the first one it is chosen a current price equal to 125 €/MWh which is an increase of more than 50% compared to the base scenario. The pay-back period is about 7.1 years, the NPV at the end of life is 1169486.85 € and the LCOE is the same as the base the case since the electricity price does not affect this parameter. The second scenario is a forecast of the electricity

price to the 2030 and therefore also the investment costs are a forecast. The scenario considers an electricity price of 60 €/MWh and at the same time a reduction of the investment cost to 847 € per each kW of power of turbine installed. The pay-back period is about 12.4 years, the NPV at the end of life is 198246.20 €. A further study considers an electricity price of 60 €/MWh but without a decrease on the investment costs and sees a non-return of the investment in the lifetime of the wind turbine.

The last two scenarios consider a variation of ± 10% on the WACC. In the scenario in which it decreases and equal to 5.4% the pay-back period is about 10.1 years, the NPV at the end of life is 1059697.03 and the LCOE is 5 €cent/kWh.

In the scenario in which it decreases and equal to 6.6% the pay-back period is about 11.2 years, the NPV at the end of life is 774947.47 and the LCOE is 5.35 €cent/kWh.

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First of all, I would like to thank Peter Deeney for his support and supervision during all the months I spent in Ireland. He encouraged me during the project with his passion. His daily support and his wide knowledge helped me to better deal with the investigations I carried out in my thesis.

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1 Introduction

Climate change has become a major concern of this century. The Paris Agreement sets forth efforts to limit the global temperature rise to "well below" 2 °C and ideally to limit warming to 1.5 °C in the present century, compared to pre-industrial levels. To realise the climate targets of the Paris Agreement, a profound transformation in the global energy landscape is essential. Such a transformation is possible with the rapid deployment of low-carbon technologies replacing conventional fossil fuel generation and uses. To set the world on a pathway towards meeting the aims of the Paris Agreement, energy-related CO_2 emissions would need to be reduced by around 3.5% per year from now until 2050, with continued reduction afterwards. The transition to increasingly electrified forms of transport and heat, when combined with increases in renewable power generation, would deliver around 60% of the energy-related CO_2 emissions reductions needed by 2050. If additional reductions from direct use of renewables are considered, the share increases to 75%. When adding energy efficiency, the share increases to over 90% of energy-related CO_2 emissions reductions needed to set the world on a pathway to meeting the Paris Agreement. The energy transformation would also boost gross domestic product (GDP) by 2.5% and total employment by 0.2% globally in 2050 (IRENA, 2019).

Based on the current EU environmental policies, which support and promote initiatives that generate energy from renewable sources, there is a large increase in the construction of the wind power plants. Construction of new wind power is also connected with the requirements of energy security and lower dependences on imported fossil fuels. For these reasons, wind energy plays an important role in the energy system and is an alternative to conventional energy plants (Wais, 2017).

Wind power has grown rapidly since 2000, driven by R&D, supportive policies and falling costs. Global installed wind generation capacity – both onshore and offshore – has increased by a factor of 98 in the past two decades, jumping from 7.5 GW in 1997 to some 733 GW by 2018 according to IRENA's data. Onshore wind capacity grew from 178 GW in 2010 to 699 GW in 2020, while offshore wind has grown proportionately more, but from a lower base, from 3.1 GW in 2010 to 34.4 GW in 2020. Production of wind power increased by a factor of 5.2 between 2009 and 2019 to reach 1412 TWh (IRENA, 2022).

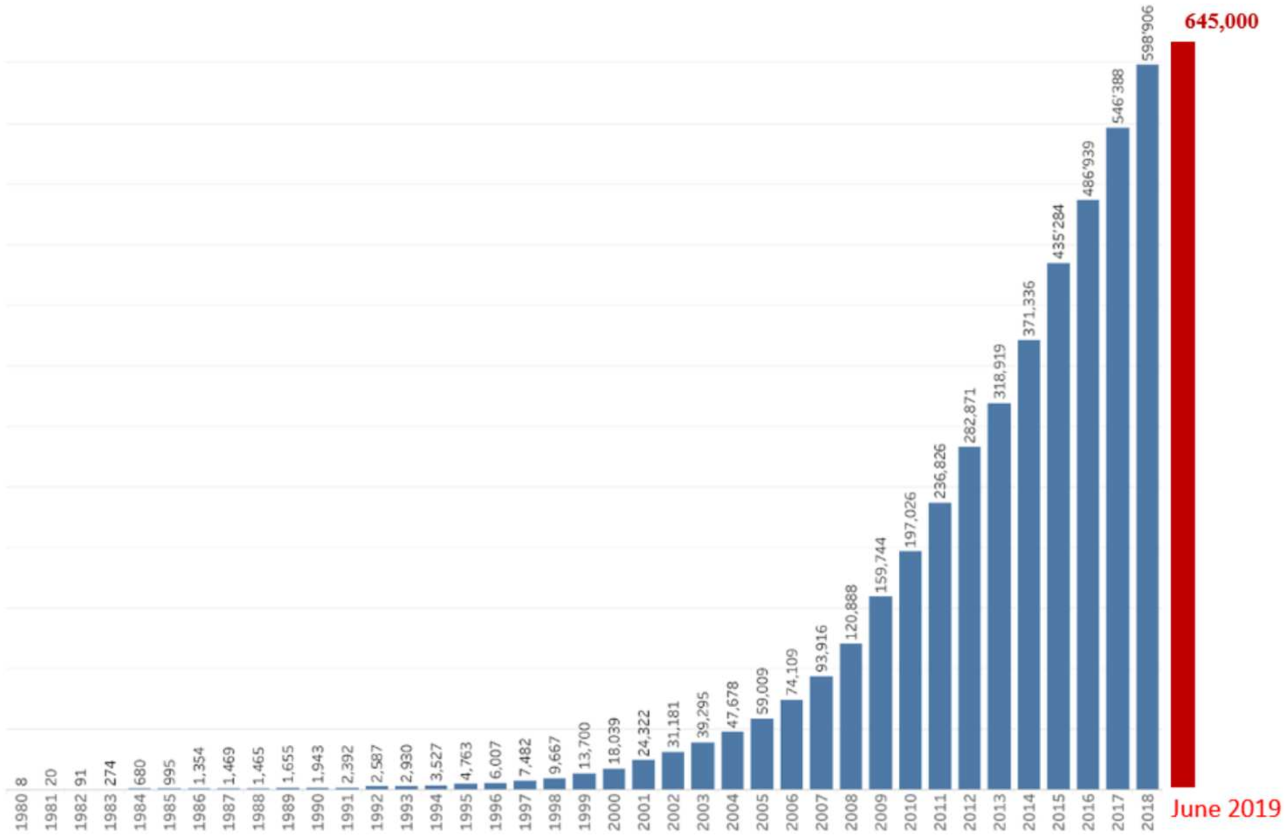

Figure 1 Global cumulative installed wind power capacity (Darwish & Al-Dabbagh, 2020)

Wind and solar energy will lead the way in the transformation of the global electricity sector. Wind power would supply more than one-third of total electricity demand by 2050 and is well aligned with energy transformation scenarios of various institutions, clearly highlighting the importance of scaling up the wind power generation share in order to decarbonise the energy system in the next three decades. This represents a nearly nine-fold rise in the wind power share in the total generation mix by 2050 compared to 2016 levels. However, in the context of total installed capacity by 2050, much larger capacity expansion would be needed for solar PV (8 519 GW) as compared to wind (6 044 GW) given the average lower capacity factors achieved by solar PV projects (IRENA, 2019).

Wind roadmap target is presented in Figure 5 which shows the wind regional wind electricity production to 2050 (TWh). It is clear that the Wind is expected to have the potential to provide 20% of global electricity production in 2050. In this respect the Global Wind Energy Council (GWEC), envisions 5.8 TW of wind by 2050. GWEC anticipated that China would remain the world’s largest market with 1789 GW of wind power by 2050, North America including the US, Canada and Mexico combining to have 919 GW and OECD Europe could have 703 GW of wind by 2050. In addition, Latin America predicted to generate (481 GW) and India (452 GW) (Darwish & Al-Dabbagh, 2020).

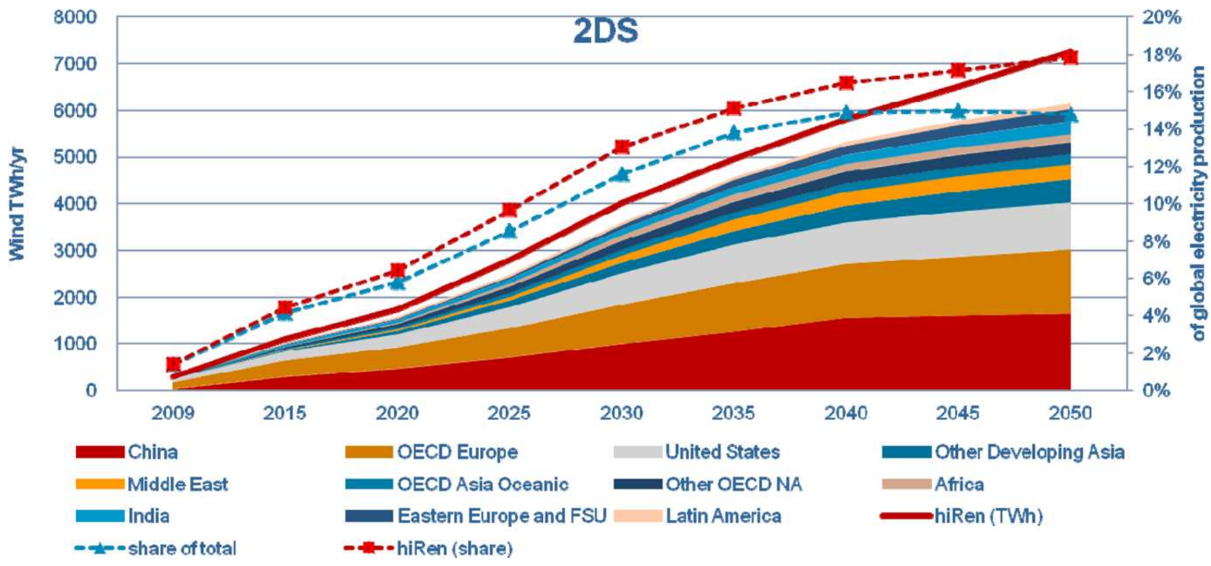

Figure 2 Wind power deployment to 2050 in the Roadmap vision (Darwish & Al-Dabbagh, 2020)

The combined installations of onshore and offshore wind capacity in Europe was the same as in 2018 but onshore was down. Table 2 shows the wind energy installed capacity by country in 2019, which shows a total of 4.9 GW (Darwish & Al-Dabbagh, 2020).

Onshore	**GW**
France	523
Sweden	459
Germany	287
Italy	286
Ukraine	262
Turkey	229
Greece	201
UK	187
Spain	148
Netherlands	83
Belgium	72
Portugal	57
Ireland	51
Russia	50
Bosnia and Herzegovina	36

Poland	17
Austria	16
Croatia	10
Denmark	6
Total	2979
Offshore	**GW**
UK	931
Denmark	374
Belgium	370
Germany	252
Total	1927

Table 1 Installed wind power in Europe 2019 (Darwish & Al-Dabbagh, 2020)

Over 20 years, Irish wind generation has grown from very low levels to become a major energy source. From a starting point of near zero in 2000, installed wind farm capacity in the Republic of Ireland (ROI) has grown to over 3.4 GW in 2018, and is expected to exceed 4.1 GW by 2020. To put this into context, the total installed generation capacity in ROI is around 11 GW today. Wind will contribute around 11 TWh of annual electricity generation by 2020 – this is equivalent to around 35% of total electricity consumption. This has transformed the Irish energy system, and has resulted in both additional costs and benefits to the Irish consumer, which this study seeks to quantify (Baringa, 2020).

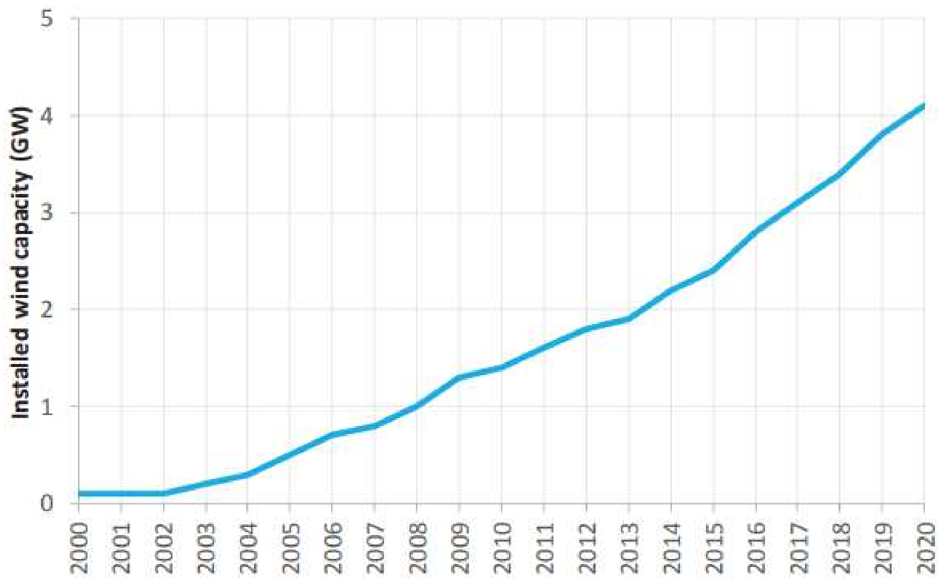

Figure 3 Irish wind installed capacity 2000-2020 (Baringa, 2020)

As the technology has improved and scaled up, costs have fallen and capacity factors have risen. Between 2010 and 2020, the global weighted-average levelized cost of electricity (LCOE) of onshore wind fell by 56%, from USD 0.089/kWh to USD 0.039/kWh (IRENA, 2022). In PICTURE is shown the LCOE trend over the years by country.

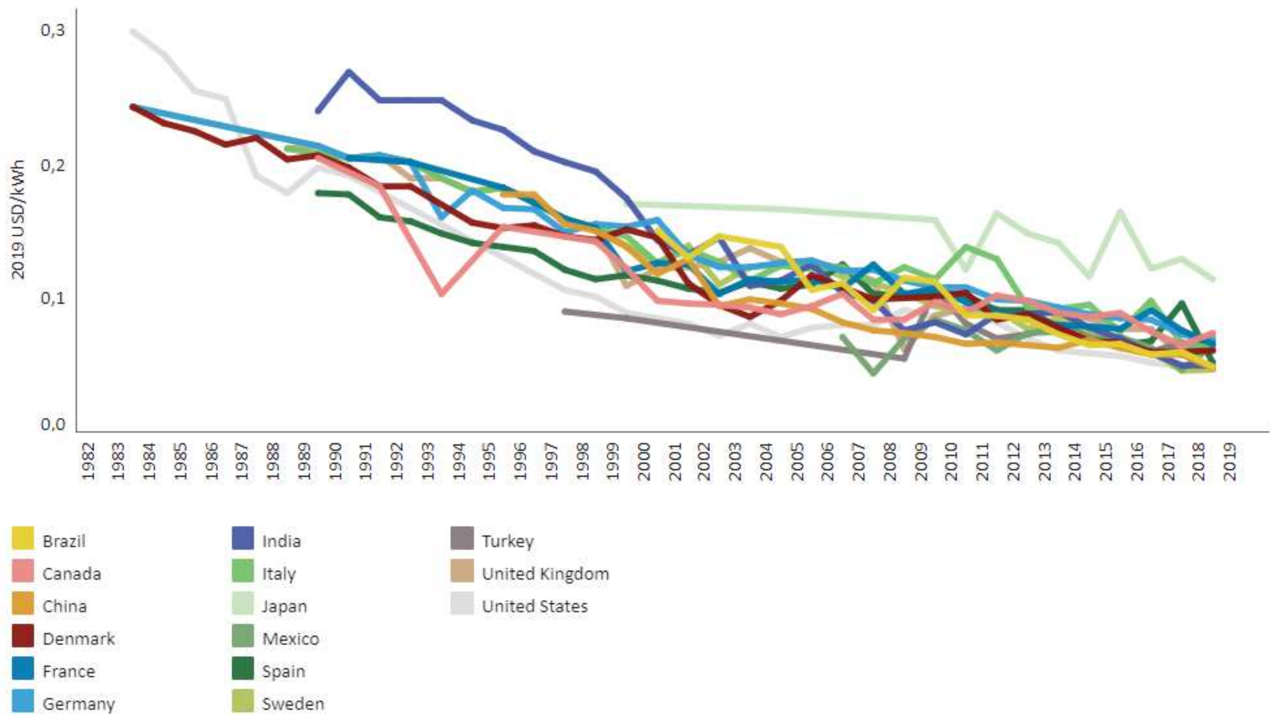

Figure 4 Weighted-average LCOE of newly commissioned onshore wind projects by country, 1984-2019 (IRENA, 2022)

1.1 State of the art of wind turbine

Wind turbines work on the principle of capturing the kinetic energy of the wind to transform it into rotational mechanical energy with the help of a rotor. The shaft in the wind turbine rotates due to the rotational movement of the rotor. This movement of the shaft can be then directly used to drive a generator or for heat production or for pumping water. Hence wind can be converted into heat energy, electrical energy, or mechanical energy using appropriate equipment. Power is a term used most commonly to describe the performance of any machine, it can be described as the energy extraction per unit of time (Zangenberg & Brøndsted, 2015)

A typical wind turbine design is made up of rotor blades, a drive shaft, a gear box, a speed shaft, a generator, and support cables and casing. The basic structure and major components of the HAWT are shown in FIGURE. Wind turbines can be horizontal-axis or vertical-axis turbine types. Two- or three-bladed turbines are usually used for electricity generation, whereas 20 or more blades are used for water pumping. Currently three-bladed wind turbines with horizontal-axis dominate the market.

Structural and mechanical designing of wind turbines are required according to the various parameters and conditions, including static loading, dynamic loading, fatigue loading, the minimum amount of wind required to start the equipment, transportation, commissioning, installation, and flexibility of loads. To capture the maximum wind power, a larger diameter of blades must be used. But it is not that easy to install large blades and big rotors as there must be a balance between the weight and structure of the wind turbine. Also, it depends upon the surrounding conditions. The rotor design is very significant as the rotor and its blades directly affect the efficiency of the turbine; soft designing techniques are used for this purpose. Turbine blades are carefully designed to reduce the weight and increase the efficiency of the wind turbine. Towers' design is of extreme importance as they must bear overall structure along with wind and climate variations. Fatigue cracks due to excessive vibrations are a major reason for the turbine towers to collapse, but there are very few cases of it. However, it did happen in Scotland when two towers collapsed in early 2008, the associated loss was expected to be in millions of dollars. Highways must also be in good condition to handle the transportation requirements of wind turbines (Zangenberg & Brøndsted, 2015).

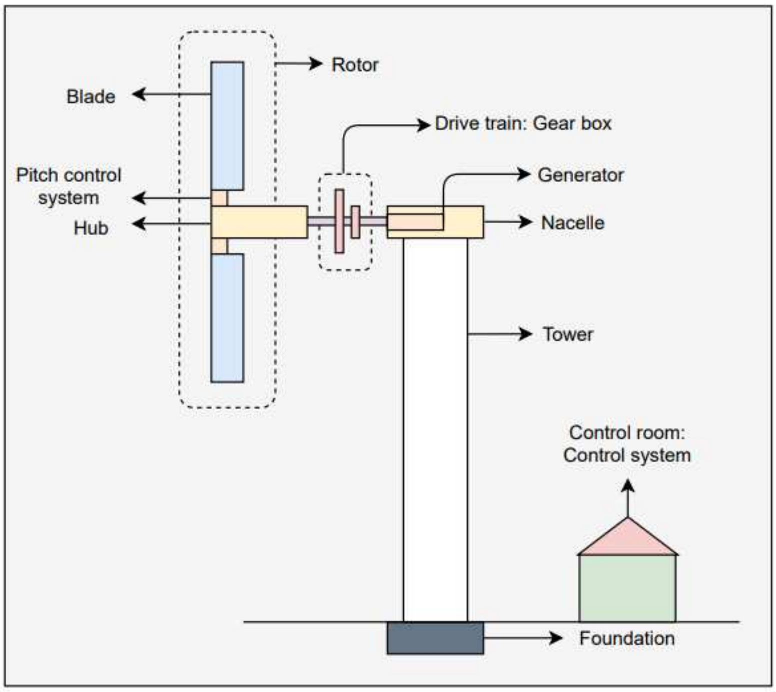

Figure 5 Basic structure and major components of the horizontal axis WT (HAWT) (Sawant et al., 2021)

The coefficient of performance (also called the maximum power coefficient Cp) expresses the ratio of the actual wind turbine power output (provided by turbine manufacturers) to the available wind power. The coefficient CP is related to the electro-mechanical efficiency of the wind turbine, which can be achieved at the optimal value of tip speed ratio. The tip speed ratio represents the ratio between the speed at the tip of the blade and the speed of the wind. FIGURE shows the power coefficient variation with tip speed ratio for various wind turbines. It is seen that there is a nonlinear relationship between CP and tip speed ratio. In addition, slow wind turbines have a relatively smaller CP value than fast wind turbines. However, the starting torques of fast wind turbines are lower than those of slow wind turbines (Zangenberg & Brøndsted, 2015).

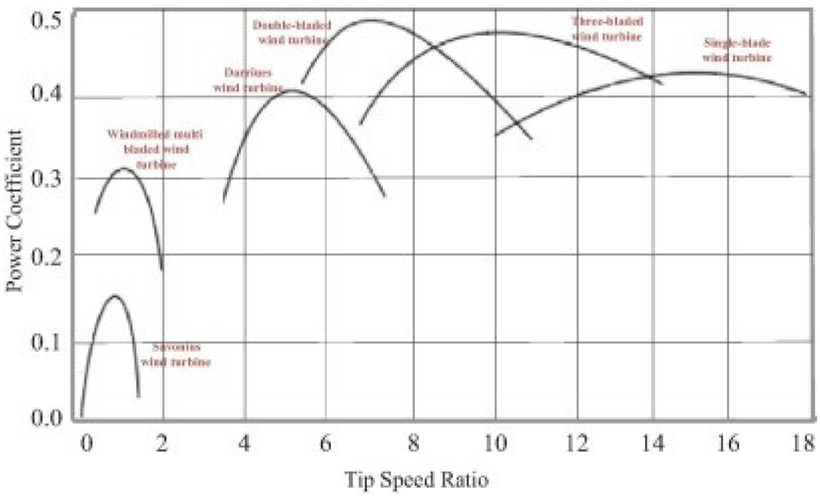

Figure 6 Power coefficient (CP) variation with tip speed ratio for several wind (Zangenberg & Brøndsted, 2015)

From the Betz theory, the maximum power that can be extracted from wind energy via a wind turbine is 16/27 (=0.593) of the kinetic energy of the wind at the turbine. Thus, the maximum value of CP is 16/27. CP values for advanced manufactured wind turbines are about 70%–80% of the Betz value (Zangenberg & Brøndsted, 2015).

As the contribution of wind power in the energy market is growing, there is a requirement of maintaining a constant output electrical frequency to have regulated supply like conventional generating units for stable operation. The current grid in European countries like UK and Ireland considers the primary frequency control strategy. They require wind turbine not to draw maximum power from wind and instead to operate wind turbines to ramp up or down the output in the event of frequency fluctuation, while German grid just reduces the power injection in wind turbines in the case of excess frequency. The two methods of reloading wind turbines, viz. pitching and an overspeeding, best fit in achieving non-optimal working point concerning power extraction from the wind. The current schemes are best suited for low as well as high wind speed, but still, further research is required considering the additional stresses on the system components.

In recent years, power systems have been becoming more dynamic with the integration of wind power, and it demands modification in the conventional control algorithms. A small amount of inertia is offered by the renewable energy power plants connected to the grids through the power electronics interface. As the inertia depends on the total rotating masses connected to the grid, the advanced power system needs spinning reserves for compensation of inertia to maintain system stability.

WTs are normally connected to the main power grid to utilize the available wind energy to the maximum level but provide less or no inertia as they are electromagnetically decoupled from the remaining power system, unlike traditional synchronous generators, which work in synchronization to grids. Inertia control is helpful against the power imbalance in odd events like generator failure, or load connection, and hence provides a system with higher stability. Such odd events also result in the fluctuation in the frequency; thus, inertia control is of utmost importance (Sawant et al., 2021).

An efficient and economical wind turbine system is desirable for the wind farm owner, and it can be realized with advanced control techniques. The widespread application of power from renewable fuel wind demands further technological development in the control methods for improvement in the design. It is discussed various WT control strategies in the literature that involve WT generator torque control and Maximum Power Point Tracking (MPPT) strategies, pitch control, and grid integration control so that researchers can consider it as starting point for further study. To maximize power production, generator torque control sets specific rotor speed, and for this, different MPPT strategies are utilized (Sawant et al., 2021).

1.2 Aim and structure of the project

This thesis aims to analyse the windiness of a site located in Ireland to evaluate the electricity production from a wind turbine. Finally, an economical study is made to evaluate the affordability of the investment in different scenarios, which involve a change in the electricity price, interest rate and investment costs.

In chapter 2 is discussed the Weibull distribution model for the analysis of the windiness of the site and the model for the calculation of the electricity production starting from the wind speed data.

In chapter 3 is presented the site chosen for this work and a selection of the wind turbine which is more suitable for the case of study.

In chapter 4 is reported the data for what concern all the economical evaluation. Firstly, the costs involved on the plant are selected giving the most recent values and the most suitable for the site. The cost involved are the investment and the operating and maintenance costs, obtained starting from a failure analysis of the components. Secondly, the Irish electricity market and the electricity selling tariff is discussed to calculate the income from the selling of the electricity produced by the turbine. Finally, the interest rate and some economical index, used for the comparison between the several scenarios, are reported.

In chapter 5 the results are shown. In particular the results of the model applied to the wind turbine on the specific site and the cash flow of every scenario with their own index are reported.

Lastly, a summary of the main findings from the study re reported in chapter 6.

2 Electricity Generation

In this section is reported all the physical equations needed for the calculation of the production of electricity from the wind turbine.

Starting from the wind speed data, an analysis of the windiness of the site is made using the Weibull distribution. Indeed, the performance of the wind turbines and the estimated wind energy at specified locations depends on the selection of wind speed distribution models. Based on the analysis, it is reported in the literature that the two parameter Weibull distribution, a widely used model in the wind energy industry, may not be sufficient in all the cases to specify the wind energy distribution and in estimating the available wind power. It was also observed that using the third parameter (location parameter), the three-parameter Weibull distribution model (which takes into consideration the frequency of null winds), found suitable in cases where there are high-frequency null wind speeds in selecting the site for wind turbine plant (Sawant et al., 2021).

2.1 Wind power

To evaluate the electricity generation the availability of the wind power in a specific site must be selected. In general, the available power from the wind is given by the following equation:

$$P_{AVAIL_v} = P_v = \frac{1}{2}\dot{m}v^2 = \frac{1}{2}\rho Q v^2 = \frac{1}{2}\rho A_R v^3 \tag{2. 1}$$

Where:

- $\dot{m}$ is the mass low rate of the wind flow (kg/s)
- v is the velocity of the wind (m/s)
- ρ is the density of the air (kg/m^3)
- A_R is the section of the wind turbine (m^2)
- Q is the air flow rate (m^3/s)

The corrected monthly air density $\bar{\rho}$ (kg/m^3) must be calculated to have a more accurate calculation of the power available at the specific site (Ahmed Shata & Hanitsch, 2006) and it is calculated as follow:

$$\bar{\rho} = \frac{\bar{P}}{R_d \bar{T}} \tag{2. 2}$$

Where:

- $\bar{P}$ is the monthly average air pressure (N/m^2)

- $\bar{T}$ is the monthly average air temperature (K)
- R_d is the gas constant for dry air (R_d = 287 J/kg K)

Instead of using the standard air density (ρ = 1.225 kg/m^3).

Considering a specific site, therefore with a variable wind speed during the year, the two parameter Weibull distribution can be used, with good approximation, for the evaluation of the probability distribution of the wind speed, since the frequency of null velocity is insignificant for the site considered (Wais, 2017).

2.2 Two-parameter Weibull distribution

Wind speed frequency distribution is an important statistical tool in predicting the wind energy output at a particular location. The Weibull distribution function is found to represent the variable nature of wind speed better than other distributions in most of the locations worldwide. The Weibull function is a two-parameter function, namely, shape parameter, k and scale parameter, c, and it is represented by the following equation (Baseer et al., 2017):

$$p(v) = \left(\frac{k}{c}\right)\left(\frac{v}{c}\right)^{k-1} e^{-\left(\frac{v}{c}\right)^k} \tag{2. 3}$$

Where $v > 0$ is the wind speed, $k > 0$ and $c > 0$.
k and c are calculated with the methods presented in section 2.3.

To calculate the available power from the wind distribution the following equations can be used:

$$P_{AVAIL} = \int_0^\infty P_v \cdot p(v)\, dv \tag{2. 4}$$

$$P_{AVAIL_{2P}} = \frac{1}{2}\rho A_R \cdot \left(\frac{k}{c}\right) \cdot \left(\frac{1}{c}\right)^{k-1} \int_0^\infty v^3 \cdot (v)^{k-1} e^{-\left(\frac{v}{c}\right)^k}\, dv \tag{2. 5}$$

Finally, the available power of the wind during the year is calculated:

$$E_{AVAIL_{2P}} = P_{AVAIL_{2P}} \cdot t_{YEAR} \tag{2. 6}$$

Where $t_{YEAR} = 8760$ hours in a year.

The Weibull cumulative distribution function is given as:

$$F(v) = 1 - e^{-\left(\frac{v}{c}\right)^k} \tag{2. 7}$$

Other specific velocities can be calculated in order to evaluate the proper size of the wind turbines for a specific site (Ozay & Celiktas, 2016).

Formula for mean wind speed is given as:

$$v_m = c\Gamma\left(1 + \frac{1}{k}\right) \quad (2.8)$$

Weibull parameters can be used to calculate the most probable wind speed and the wind speed that carries the most available energy. The formulas are given as:

$$V_{MP} = c\left[\frac{k-1}{k}\right]^{\frac{1}{k}} \quad (2.9)$$

$$V_{MaxE} = c\left[\frac{k+2}{k}\right]^{\frac{1}{k}} \quad (2.10)$$

The velocities are useful for the choice of the nominal wind speed of the wind turbine and therefore the wind turbine itself from the catalogue.

2.3 Methods to estimate Weibull parameters

Six kinds of numerical methods available in literature for estimating Weibull parameters are briefly shown below:

1. *Moment method* (Chang, 2011)

Moment method is based on the numerical iteration of the following two equations while the mean ($\bar{v}$) and standard deviation (σ) of wind speeds are available:

$$\bar{v} = c\Gamma\left(1 + \frac{1}{k}\right) \quad (2.11)$$

$$\sigma = c\left[\Gamma\left(1 + \frac{2}{k}\right) - \Gamma^2\left(1 + \frac{1}{k}\right)\right]^{1/2} \quad (2.12)$$

Where:

$$\bar{v} = \frac{1}{n}\sum_{i=1}^{n} v_i \tag{2. 13}$$

$$\sigma = \left[\frac{1}{n-1}\sum_{i=1}^{n}(v_i - \bar{v})^2\right]^{1/2} \tag{2. 14}$$

Where $\Gamma()$ is the Gamma function expressed by:

$$\Gamma(x) = \int_0^{\infty} t^{x-1}\exp(-t)\ dt \tag{2. 15}$$

2. *Empirical method* (Chang, 2011)

The empirical method has a practical and straightforward solution requiring only the average wind speed, v, and the standard deviation of the wind speed data, σ. Weibull parameters are estimated as

$$k = \left(\frac{\sigma}{\bar{v}}\right)^{-1.086} \tag{2. 16}$$

$$c = \frac{\bar{v}}{\Gamma\left(1+\frac{1}{k}\right)} \tag{2. 17}$$

3. *Graphical method* (Chang, 2011)

$$ln\{-ln[1 - F(v)]\} = kln(v) - kln(c) \tag{2. 18}$$

Plotting $ln(v)$ against ln $ln\{-ln[1 - F(v)]\}$, the slope of the straight line fitted best to data pairs is the shape parameter; the scale parameter is then obtained by the intercept with y-ordinate.

It is found that the empirical method provides more accurate prediction of average wind speed and power density than the graphical method (Chang, 2011).

4. *Maximum likelihood method* (Baseer et al., 2017)

Maximum likelihood method was suggested by Stevens and Smulders. This method requires extensive iterative calculations. Shape and scale parameters of Weibull distribution are estimated by these two equations

$$k = \left[\frac{\sum_{i=1}^{n} v_i^k \ln(v_i)}{\sum_{i=1}^{n} v_i^k} - \frac{\sum_{i=1}^{n} \ln(v_i)}{n}\right]^{-1} \tag{2. 19}$$

$$c = \left(\frac{1}{n}\sum_{i=1}^{n} v_i^k\right)^{1/k} \tag{2. 20}$$

A simple estimating procedure instead of the previous one has been developed. In this procedure, the parameter k is estimated by the formula (Ahmed Shata & Hanitsch, 2006):

$$[k] = \frac{\pi}{\sqrt{6}}\left[\frac{n(n-1)}{n\left(\sum_{i=1}^{n} \ln^2(v_i)\right) - \left(\sum_{i=1}^{n} \ln(v_i)\right)^2}\right]^{0.5} \tag{2. 21}$$

5. *Modified maximum likelihood method* (Chang, 2011)

If wind speed data in frequency distribution format are available, the modified maximum likelihood method can be considered.

$$k = \left[\frac{\sum_{i=1}^{n} v_i^k \ln(v_i) f(v_i)}{\sum_{i=1}^{n} v_i^k f(v_i)} - \frac{\sum_{i=1}^{n} \ln(v_i) f(v_i)}{f(v \geq 0)}\right]^{-1} \tag{2. 22}$$

$$c = \left[\frac{1}{f(v \geq 0)} \sum_{i=1}^{n} v_i^k \ln(v_i)\right]^{1/k} \tag{2. 23}$$

Where v_i is the wind speed central to bin i, n the number of bins. $f(v_i)$ the frequency for wind speed ranging within bin i, and $f(v \geq 0)$ is the probability for wind speed equal to or exceeding zero.

6. *Energy pattern factor method* (Chang, 2011)

For a given wind speed data, the energy pattern factor is defined as:

$$E_{pf} = \frac{\overline{v^3}}{\bar{v}^3} = \frac{\left(\frac{1}{n}\sum_{i=1}^{n} v_i^3\right)}{\left(\frac{1}{n}\sum_{i=1}^{n} \bar{v}_i\right)^2} \tag{2. 24}$$

Where $\overline{v^3}$ is the mean of wind speed cubes.

$$k = 1 + \frac{3.69}{E_{pf}^2} \tag{2. 25}$$

$$c = \frac{\bar{v}}{\Gamma\left(1+\frac{1}{k}\right)} \tag{2. 26}$$

To analyse the efficiency of the aforementioned Weibull parameter estimation methods, the following tests were conducted: Coefficient of determination, R^2, is the square of correlation between the frequencies of Weibull to that of actual observations. The coefficient of determination is computed according to the following equation:

$$R^2 = \frac{\sum_{i=1}^{N}(y_i - z_i)^2 - \sum_{i=1}^{N}(y_i - x_i)^2}{\sum_{i=1}^{N}(y_i - z_i)^2} \tag{2. 27}$$

The root mean square error, RMSE is the measure of the residuals of frequency of Weibull and actual observations

$$RMSE = \sqrt{\left[\frac{1}{N}\sum_{i=1}^{N}(y_i - x_i)^2\right]} \tag{2. 28}$$

The mean bias error, MBE and mean bias absolute error, MAE are a measure of how closely frequency of Weibull match the actual observations

$$MBE = \frac{1}{N}\sum_{i=1}^{N}(y_i - x_i) \tag{2. 29}$$

$$MBA = \frac{1}{N}\sum_{i=1}^{N}|y_i - x_i| \tag{2. 30}$$

Where: N is the number is observations, y_i is the frequency of observation, x_i is the frequency of Weibull and z_i is the mean wind speed.

2.3.1 Concluding remarks about parameter estimation methods

In simulation tests, the maximum likelihood and modified maximum likelihood methods present better performance than other methods while the number of random variables is small. The six methods' accuracy enhances obviously when data numbers become larger for all of simulation combinations. In analyses of actual wind data obtained from different climatic situations, it is found that the six methods are applicable if wind speed fits well with theoretical Weibull function. But if not, the maximum likelihood method is recommended since it has generally the smaller errors, followed by the modified maximum likelihood and moment methods. The graphical method gets the worst performance (Chang, 2011).

2.4 Output power generation

To find the power output from selected wind turbine, the number of hours the wind speed remained in different wind speed bins is determined at the turbine hub height. Then using the power curve data of the selected wind machine, the power output is calculated (Baseer et al., 2017).

To evaluate the output wind power (OWP) generated by a wind turbine the power coefficient of the turbine must be considered as well as the mechanical and electrical performances.

The output efficiency of the WT Ƞ is proportional to v^{-3} between inlet and nominal speed $V_{in} < V < V_{nom}$ maximum in the range $V_{nom} < V < V_{out}$, and null otherwise. The piecewise continuous curve used to describe the OWP is given as follows (Khelifi & Ferroudji, 2021):

$$P_G(V) = \begin{cases} 0 & if\ V<V_{in}\ or\ V>V_{out} \\ \frac{1}{2}\eta\rho\pi R^2 V^3 & if\ V_{in}<V<V_{nom} \\ P_{nom} & if\ V_{nom}<V<V_{out} \end{cases} \tag{2. 31}$$

The OWP factor $\eta = C_p \eta_{Tr} \eta_G$ measures the product of aerodynamics, drivetrain, and generator factors C_p, η_{Tr}, η_G respectively. The maximum value of C_p is 59.25% according to Betz's theory, but in practice, this value is less than 45%. This factor varies with wind-specific speed, solidity, chord, and attack angle. The factor η_{Tr} is generally determined by the losses in the gearbox, typically this factor is equal to $\eta_{Tr} = 91\% - 95\%$ at full load. The electrical factor covers losses in generator and electrical circuits, and it is equal to $\eta_G = 97\% - 98\%$ for induction generator at full load.
Optimal design of the WT requires closing the output wind power curve (OWPC) cubical output line curve, regardless technical and economic considerations (Khelifi & Ferroudji, 2021).

To calculate the wind speeds at a certain height starting from data at different heights the following equation can be used (Laban et al., 2019):

$$V_y = V_{10}\left(\frac{Z_y}{Z_{10}}\right)^{\alpha} \tag{2. 32}$$

Where:

- V_y is the mean velocity at the height Z_y that need to be calculated
- V_{10} is the mean velocity at the height Z_{10} that is already available

- α is the wind shear exponent of the region which depends on the roughness of the terrain

The shear coefficient can be calculated as follow:

$$\alpha = \frac{\ln(V_{20}) - \ln(V_{10})}{\ln(Z_{20}) - \ln(Z_{10})} \tag{2. 33}$$

Where V_{20} is the mean velocity at the height Z_{20} that is already available.

3 Wind Data and selection of the wind turbine

3.1 Site analysis

Wind data is collected from many sources as metrological authority and over the internet. Wind speeds can be collected for many sites for different period of times. Meteorologists generally conclude that it takes at least 5 years of wind data to determine a reliable average and variance of the wind speed. Some researchers claim that shorter period of time may be acceptable for designing renewable energy system with acceptable confidence. It is better to have a small interval between each reading of the wind speed data. Thirty minutes are recommended interval between each two points of data, but this may not be available for all sites under study because some of these sites have one-hour interval (Eltamaly, 2013).

The wind data used for the evaluation of the output power production are taken from a wind atlas made by SEAI[1] (Sustainable Energy Authority of Ireland). SEAI’s Wind Atlas is a digital map of Ireland’s wind energy resources. It provides detailed information on wind speeds, current windfarms and other important information which are used in assessing the suitability of wind resources in specific areas. In Figure 7 SEAI’s Wind Atlas of Irish's windfarmsit can be seen how the wind map and all the current windfarms are shown.

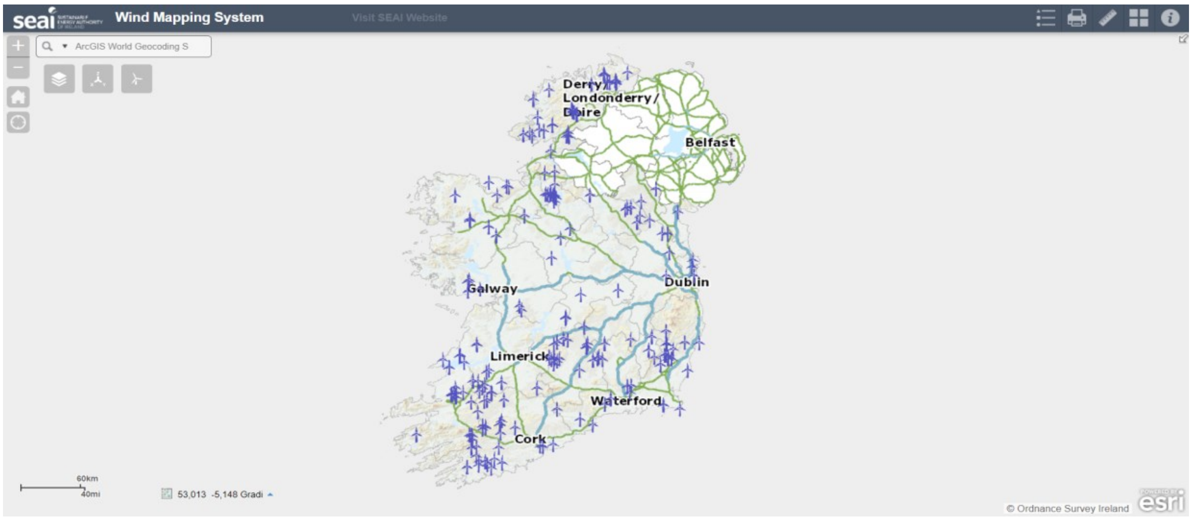

Figure 7 SEAI’s Wind Atlas of Irish's windfarms

As it is shown in Figure 8 Wind speed database for different heights The Wind Data Extract tool allows users to view either the hourly value of the wind speed or the wind direction. The information is provided for a

[1] SEAI (Sustainable Energy Authority of Ireland) is SEAI is Ireland's national sustainable energy authority. They work with householders, businesses, communities and government to create a cleaner energy future.

given height (20, 30 and 50 meters are available) for any specific point in the country. The information is based on 2006 data.

For this study only the values of the wind speed are considered, at the heights of 20 and 50 meters, in order to calculate the roughness coefficient of the site and consequently calculate the right values of wind speed at hub's height of the wind turbine using the equations reported in chapter 2.4.

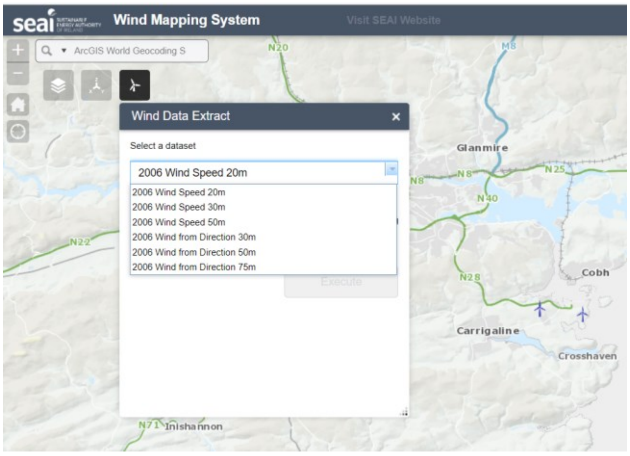

Figure 8 Wind speed database for different heights

The wind farm chosen for this analysis is located in Ringaskiddy, Cork County (Ireland) and only one wind turbine is considered.

3.1.1 How climate change will affect wind speed in Ireland

The wind energy potential of the Irish climate has been well documented. However, climate change may alter the wind patterns in the future; a reduction in speeds may reduce the commercial returns or pose problems for the continuity of supply; an increase in the frequency of severe winds (e.g., gale/storm gusts) may similarly impact on supply continuity. Conversely, an increase in the mean wind speed may have a positive effect on the available power supply (Akay et al., 2013).

It is highly uncertain how winter storm tracks over the North Atlantic Ocean may change under climate change this century. Following the general consensus in the literature to date, the average wind changes over the North Atlantic by the end of the century are small and negative and less than the high natural interannual variability of the region. Natural variability is large and dominant and is projected to remain so for the century to come. A recent study shows that mean wind speed at 10 m height will decrease this century up to 3% over the North Atlantic Ocean for all seasons under moderate and high-end scenarios of climate change. This study was based on global climate model projections for the period 2070 - 2099 compared with 1980 - 2009. The study also shows that wind extremes and storminess over the North Atlantic Ocean will also decrease: the 5% strongest winds (the so-called 95th percentile of all wind speeds) will decrease by up to 15%. Wind climate changes over the North Atlantic Ocean not necessarily reflect future changes in wind climate over Ireland, however: the projected decreases in the frequency and intensity of windstorms crossing Ireland are not statistically significant.

Wind speeds could be about 10% stronger in winter on average by mid-century (measured at a height of 60-metres), but about 15% lighter in summer. Wind speed is another very uncertain variable, however (ClimateChangePost, 2022).

Nolan (Akay et al., 2013) reported a study of the changing of wind speed in four different scenarios (explained in the paper):

- ECHAM5 A1B
- ECHAM5 A2
- ECHAM5 B1
- ECHAM4 B2

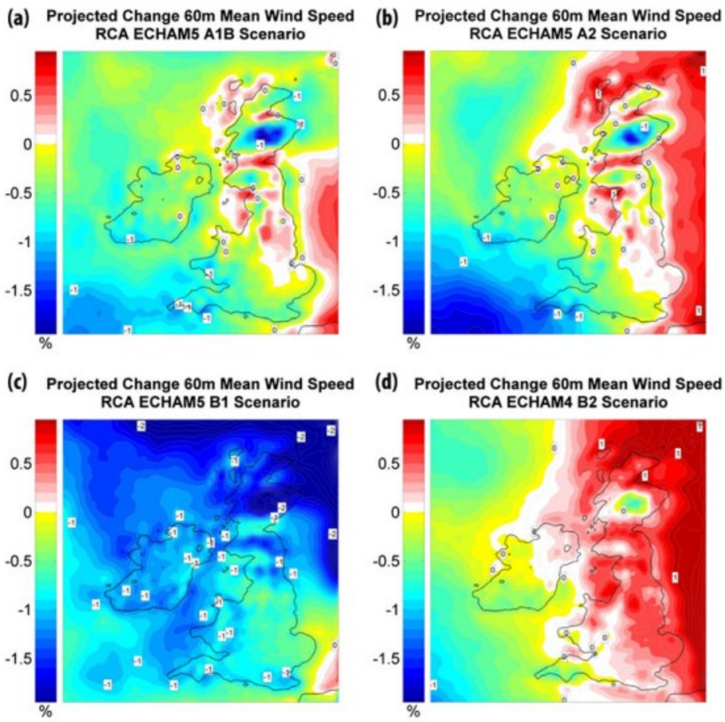

Figure 9 The predicted percentage change of the annual 60 m mean wind speed for the four climate scenario simulations: (a) RCA ECHAM5 A1B, (b) RCA ECHAM5 A2, (c) RCA ECHAM5 B1 and (d) RCA ECHAM4 B2. In each case, the future period 2021-2060 is compared with the control period 1961-2000 (Akay et al., 2013)

Figure 9 shows the projected percentage change of the 60 m mean wind speed for the four scenario simulations. It is noted that all four scenario simulations show no substantial increase or decrease in mean wind speed over Ireland. In order to investigate the effects of climate change on the energy content of the wind, the projected change in the 60 m mean cubed wind speed were calculated. Again, small changes (-2 to

2%) were observed in the energy content of the wind for the four GHG scenario simulations (figure not presented). However, when stratified per season, we do see substantial changes in the mean wind speed, particularly for the winter and summer months. The projections show an expected increase in the winter mean wind speed over Ireland ranging from 1% for the ECHAM5 B1 simulation to 3.5% for the ECHAM5 A1B simulation (not presented). The projected change in the energy content of the wind for the winter months ranges from an increase of 2–4% for the ECHAM5 B1 simulation to an increase of 8–11% for the ECHAM5 A1B simulation FIGURE (Akay et al., 2013).

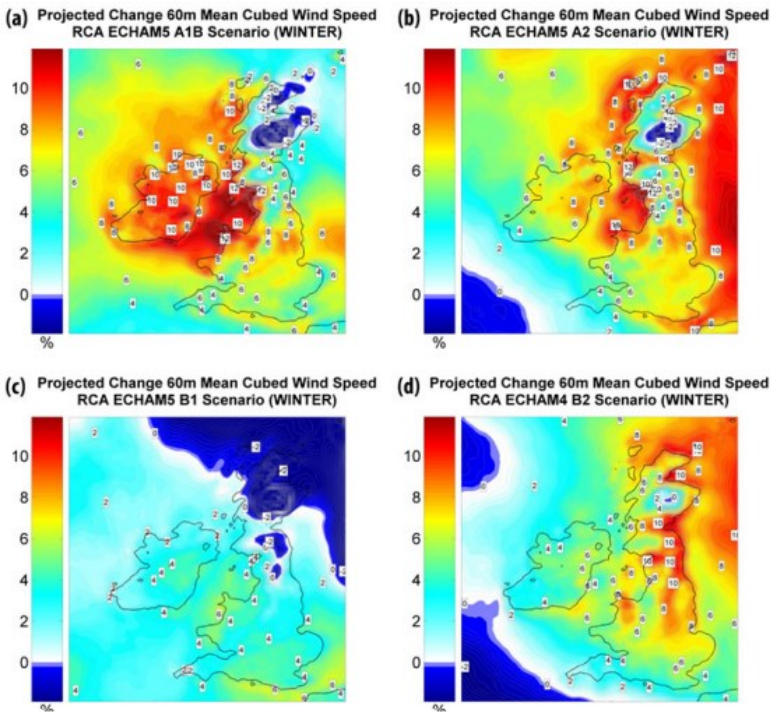

Figure 10 The projected percentage change of the 99th percentile 60 m wind speed for the four climate scenario simulations: (a) RCA ECHAM5 A1B, (b) RCA ECHAM5 A2, (c) RCA ECHAM5 B1 and (d) RCA ECHAM4 B2. In each case, the future period 2021–2060 is compared with the control period 1961–2000 (Akay et al., 2013)

The projections show an expected decrease in the summer mean wind speed over Ireland ranging from 2–3% for the ECHAM5 A2 simulation to 4–5% for the ECHAM4 B2 simulation (not presented). The projected change in the energy content of the wind for the summer months ranges from a decrease of 4–10% for the ECHAM5 A2 simulation to a decrease of 14–16% for the ECHAM4 B2 simulation (Akay et al., 2013).

3.2 Typical Wind Farm Power Output

Performance data for market available wind turbines are introduced, such as rated power, hub height, diameter of swept area, cut-in speed, rated speed, cut-out speed, price of wind turbine, and efficiency of the mechanical and electrical system.

To evaluate the most suitable turbine for the site under consideration, a comparison of three different models is made as a function of the power coefficient curves and the characteristics of the turbines.
The simulation is made with the same site windiness and hub height of the aerogenerator, and since the turbine sizes are equal to each other (same investment and failure costs) the turbine that turns out to have the maximum electricity production is the one that is best suited.

Fuhrländer FL MD7

For this purpose, has been chosen the wind turbine Fuhrländer FL MD 77 of the size of 1.5 MW which present the following characteristics:

Power	
Rated power	1.5 MW
Cut-in wind speed	3.0 m/s
Rated wind speed	11.1 m/s
Cut-out wind speed	20 m/s
Survival wind speed	50.1 m/s
Rotor	
Diameter	77 m
Swept area	4657 m^2
Number of blades	3
Rotor speed max	17.3 rpm
Tipspeed	70 m/s
Power density	322.1 W/m^2
Gear box	
Type	spur/planetary
Stages	3
Ratio	1:104
Generator	

Type	Double Fed Asyn
Speed, max	1800 rpm
Voltage	690 V
Grid connection	IGBT
Grid Frequency	50 Hz
Tower	
Hub height	100 m

Table 2 Datasheet of Fuhrländer FL MD 77

In order to evaluate the actual output power of the wind turbine the power coefficient of the turbine, for each value of wind speed, must be considered. In the Figure 11 Power curve of Fuhrländer FL MD 77 the power curve and the power coefficient curve are shown.

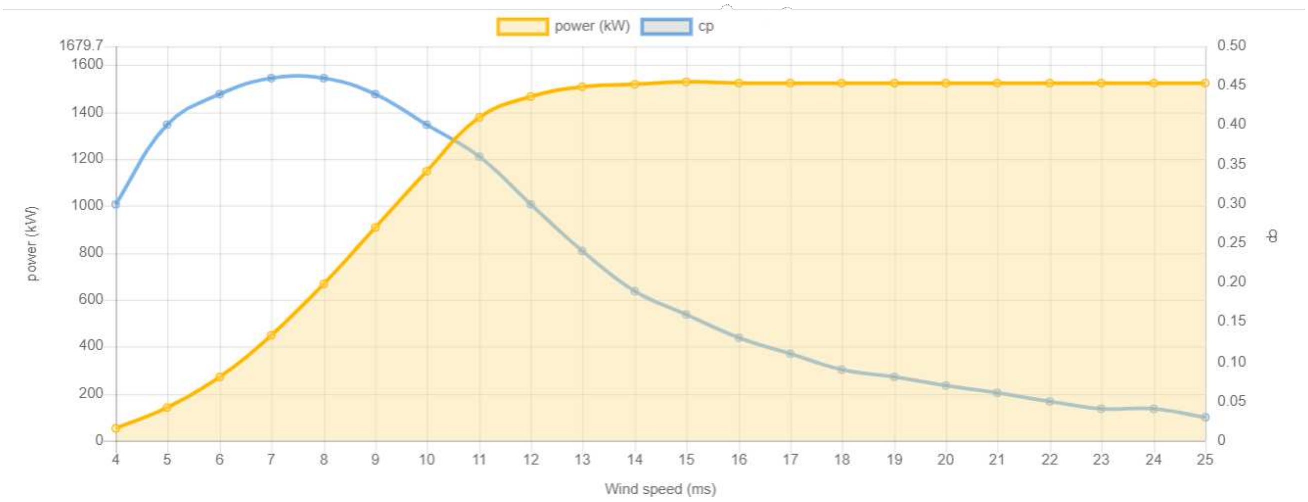

Figure 11 Power curve of Fuhrländer FL MD 77

Südwind S-70

The second turbine is selected for this study because it has the peak of the power coefficient curve closer to the velocity of maximum energy compared to the first wind turbine, increasing the production for wind speeds around this velocity.

Power	
Rated power	1.5 MW
Cut-in wind speed	3.0 m/s
Rated wind speed	13 m/s
Cut-out wind speed	25 m/s
Survival wind speed	59.5 m/s
Rotor	
Diameter	70 m
Swept area	3848 m^2
Number of blades	3
Rotor speed max	19 rpm
Tipspeed	70 m/s
Power density	389.8 W/m^2
Gear box	
Type	planetary / helical
Stages	3
Ratio	1:94
Generator	
Type	double fed induction
Speed, max	1800 rpm
Voltage	690 V
Grid connection	IGBT
Grid Frequency	50/60 Hz
Tower	
Hub height	98 m

Table 3 Datasheet of Südwind S-70

Another advantage that shows this model is that the cut-in velocity is lower, and the cut-out velocity is higher, increasing the bin velocity in which the wind turbine works, taking advantage of a wider speed range.

The hub height is two meters lower in this case but for the simulation it is considered a height of 100 m.

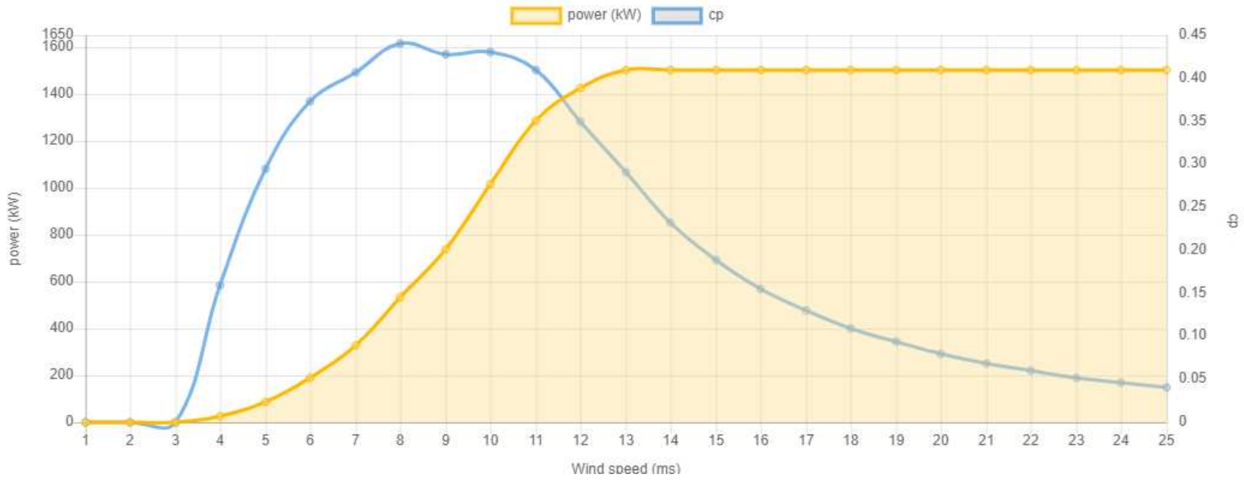

Figure 12 Power curve of Südwind S-70

Südwind S-77

Power	
Rated power	1.5 MW
Cut-in wind speed	3.0 m/s
Rated wind speed	11.1 m/s
Cut-out wind speed	25 m/s
Survival wind speed	56.3 m/s
Rotor	
Diameter	77 m
Swept area	4657 m^2
Number of blades	3
Rotor speed max	17.3 rpm
Tipspeed	70 m/s
Power density	322.1 W/m^2
Gear box	
Type	spur/planetary
Stages	3
Ratio	1:104
Generator	

Type	Double Fed Asyn
Speed, max	1800 rpm
Voltage	690 V
Grid connection	IGBT
Grid Frequency	50 Hz
Tower	
Hub height	100 m

Table 4 Datasheet of Südwind S-77

Similarly, to the previous model the third one shows a peak of the power coefficient curve closer to the velocity of maximum energy and has a wider wind speed range. Moreover, it can be noticed that the power coefficient curve is flatter compared to the others thus giving a higher average efficiency of the turbine.

On the other side the maximum value of the power coefficient is lower than the first case.

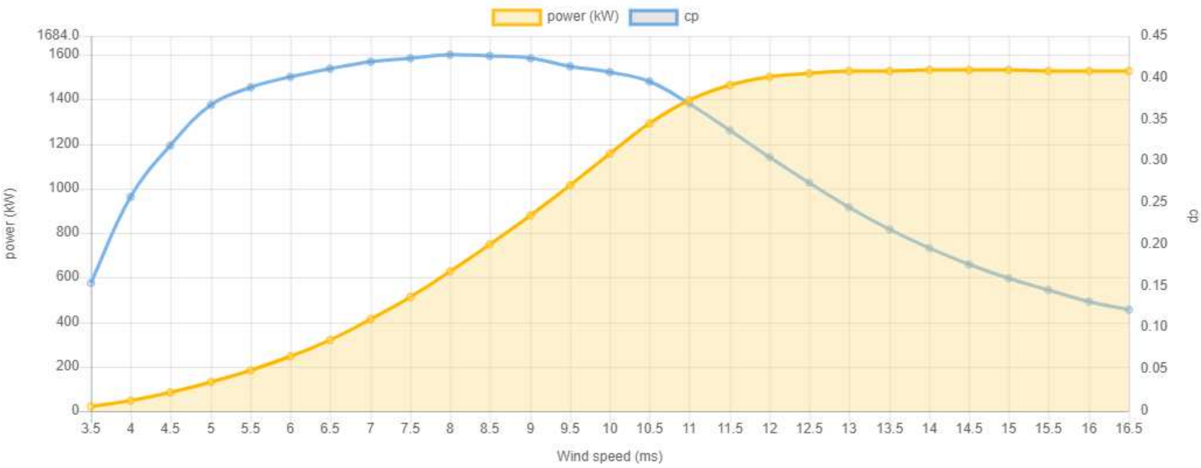

Figure 13 Power curve of Südwind S-77

In Figure 14 Power curve of the three wind turbine modelsis shown the trend of the power output of the three turbines. It is already possible to see that the second model has a lower wind power coefficient, and it is markedly detached from the others. The third case seems to be the best option from this point of view, but the lower value of the maximum point of the power coefficient may give a lower energy production.

Figure 14 Power curve of the three wind turbine models

4 Economic evaluation

4.1 Failure Rates

The failure rates of the WTs now installed, have almost continually declined in the first operational years. This is true for the older turbines under 500 kW and for the 500/600 kW class. However, the group of mega-watt WTs show a significantly higher failure rate, which also declines by increasing age. But, including now more and more mega-watt WT models of the newest generation, the failure rate in the first year of operation is being reduced (Hahn et al., 2007).

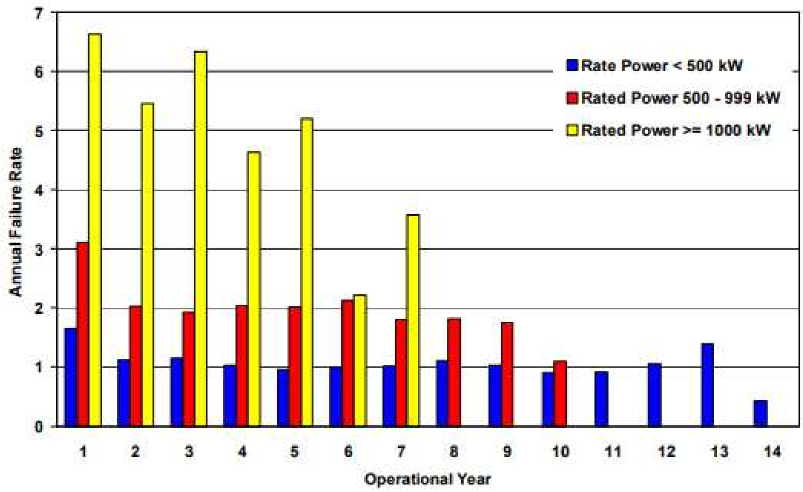

Figure 15 Frequency of 'failure rate' with increasing operational age (Hahn et al., 2007)

According to extensive research and investigations, power electronics is one of the most fragile parts in the wind turbine system. On the other hand, power semiconductor, capacitor, and DCB (disconnecting circuit breaker) are the most reliability-problematic components in a power electronics converter. The main cause of wear-out failure in these components is thermal cycling at the contacting boundary of two different materials (Ma et al., 2015).

According to different data from the literature and from wind farms, average failure rates of generic 2–3 MW wind turbine sub-systems are presented in Figure 16 Failure distribution per sub-system (Tazi et al., 2017), where it can be seen that only 20% of the sub-systems (control, electric and converter sub-systems) cause more than 50% of the total failures of the wind turbine system. Indeed, control, electrical and converter sub-systems fail frequently during operation (Tazi et al., 2017).

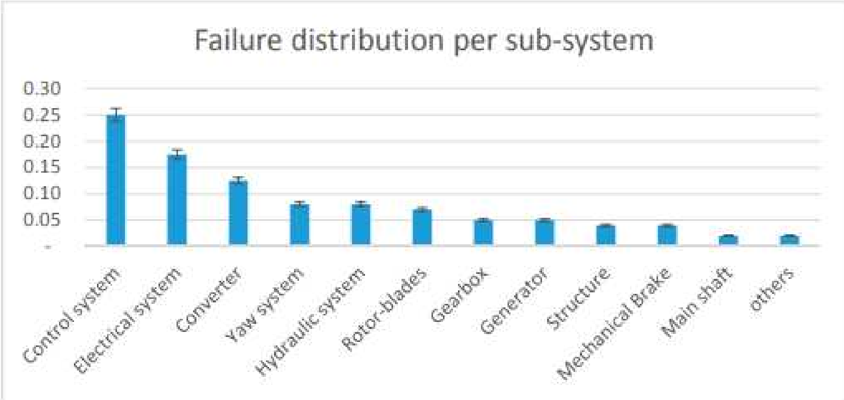

Figure 16 Failure distribution per sub-system (Tazi et al., 2017)

Electrical and control systems cumulate the most failures in a wind turbine, which is in line with Figure 16 Failure distribution per sub-system (Tazi et al., 2017). However, sub-systems such as gearbox causes an important downtime if failures occur. This is also explained by the complexity of maintenance of this sub-system.

Structure failure supposes a complete failure of the structure (Tower/foundations/nacelle), this component rarely fails in a holistic way (annual average failure rate: 0.09). Thus, it will not be considered for reliability and criticality analysis. Thus, the components that generate high expenses are Gearbox and Rotor-blade sub-system (Tazi et al., 2017).

4.1.1 Gearbox failure

Several authors have also estimated gearbox failure rates from their knowledge and industrial experience as 0.097, 0.09, and 0.155 (in failures/turbine/year). From these studies one can infer that the gearbox failure rate in an onshore wind turbines application varies from 0.05 to 0.15 failures/turbine/year (Bhardwaj et al., 2019).

As it can be seen from Figure 17 Average annual replacement rate of gearboxes (Tazi et al., 2017)the average failure rate during 10 operational years can be estimated at 5%, peaked in years 4, 5 and 8 (Tazi et al., 2017).

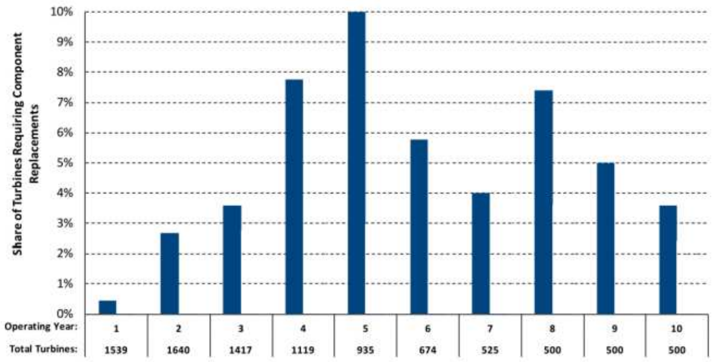

Figure 17 Average annual replacement rate of gearboxes (Tazi et al., 2017)

Besides, gearbox replacement costs are very high, a cost of € 445,000 to € 628,000 is needed for the replacement of a 2–3 MW wind turbine gearbox. An average expected failure cost of this critical sub-system is around 493,000 €, it also causes the highest loss of production cost (Tazi et al., 2017).

4.1.2 Rotor-Blades Sub-System

In the figures is reported a study on the average blade replacements during 10 operational years over more than 1000 wind turbines. Figure 18 (a) Average annual probabilities for blade replacements dependent on the operational—the black curve is a fitted Weibull curve; (b) failure rate of blades over 20 years represents this study, where it can be noticed a 1% to 3% of the surveilled wind turbines require blade replacement, with spikes in the 1st and 5th year (Tazi et al., 2017).

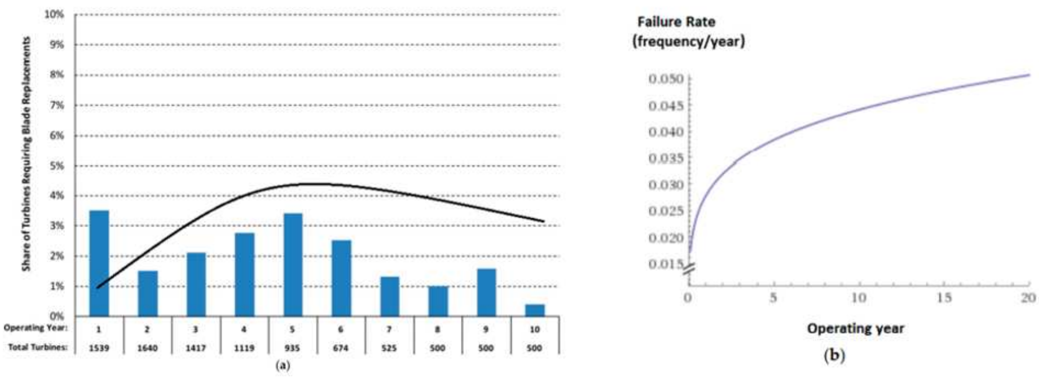

Figure 18 (a) Average annual probabilities for blade replacements dependent on the operational—the black curve is a fitted Weibull curve; (b) failure rate of blades over 20 years

It is pointed out that blade replacements in the 1st and 2nd years are typically the result of manufacturing defects or damage occurring during the construction process. Besides, he calculates about 2% of wind turbines blade replacements per year (over 10 operational years), (Tazi et al., 2017).

4.1.3 Failure costs

The criticality of each sub-system is calculated as the total expected failure costs times the corresponding failure rate. Expected failure cost can be estimated using the following Equation (Tazi et al., 2017):

$$Expeted\ failure\ cost\ = \textstyle\sum_{n_{components}} p_n c_n + Loss\ of\ production\ cost \tag{4. 1}$$

$$Loss\ of\ production\ cost\ = Expected\ production\ during\ downtime\ \times$$

$$Capacity\ factor\ \times Selling\ tariff \tag{4. 2}$$

$$Component\ criticality\ =\ Expected\ failure\ cost\ \times Failure\ rate \tag{4. 3}$$

Where "p_n" and "c_n" are the probability and the cost associated to a particular failure occurring in component "n", respectively. The loss of production cost ($Capacity\ factor\ \times Selling\ tariff$ *(4. 2)*) considers the energy supposed to be generated during the downtime of wind turbine components (Tazi et al., 2017).

In the following table are presented the average data regarding the failure of each subsystem of a wind turbine.

Sub-System	Failure rate (N/year)	Annual Reliability	Average Replacement Cost (€) (Including Crane + Labor)	Average Downtime per Hours
Structure	0.09	0.913	682,386.00	97.00
Gearbox	0.1	0.904	528,253.33	260.50
Rotor-blades	0.17	0.843	305,873.33	146.53
Main shaft	0.05	0.951	199,170.00	181.77
Generator	0.1	0.904	189,908.00	126.13
Yaw system	0.18	0.835	199,990.00	67.93
Converter	0.24	0.786	81,272.00	90.00
Electrical system	0.55	0.576	33,980.00	72.93
Control system	0.41	0.663	28,388.00	55.20
Hydraulic system	0.23	0.794	23,300.00	41.47
Mechanical Brake	0.13	0.878	8,560.00	65.60
Others	0.11	0.895	5,000.00	105.60

Table 5 Data used to calculate the expected failure costs generated in a 2–3 MW wind turbine system (Tazi et al., 2017)

4.2 Capital costs

Currently, onshore wind is one of the most competitive sources of new power generation capacity. Globally, the total installed costs of onshore wind fell by an average of 22% between 2010 and 2018, and declined by 6% in 2018 compared to 2017 (IRENA, 2019).

The cost of onshore wind farms will continue to fall. Historically, the installed costs of onshore wind power have declined by 7% every time global installed capacity has doubled. By 2025, the total installed costs of onshore wind farms could decline by around 12% (IRENA, 2016).

Michael Taylor at IRENA[2] has summarised its latest studies that show how the cost of renewables are set to continue declining dramatically through to 2030. Going forward, the weighted average cost of electricity in the G20 countries from offshore wind could fall by almost 50% by 2030 from 2019 levels, onshore wind by around 45% (Taylor, 2020).

The installed cost of a wind power project is dominated by the upfront capital cost (often referred to as CAPEX) for the wind turbines (including towers and installation) and this can be as much as 84% of the total installed cost. Similarly, to other renewable technologies, the high upfront costs of wind power can be a barrier to their uptake, despite the fact there is no fuel price risk once the wind farm is built. The capital costs of a wind power project can be broken down into the following major categories (Sector, 2012):

- The turbine cost: including blades, tower and transformer
- Civil works: including construction costs for site preparation and the foundations for the towers
- Grid connection costs: This can include transformers and substations, as well as the connection to the local distribution or transmission network. Grid connection costs (including the electrical work, electricity lines and the connection point) are typically 11% to 14% of the total capital cost of onshore wind farms
- Other capital costs: these can include the construction of buildings, control systems, project consultancy costs, etc.

[2] The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international cooperation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy.

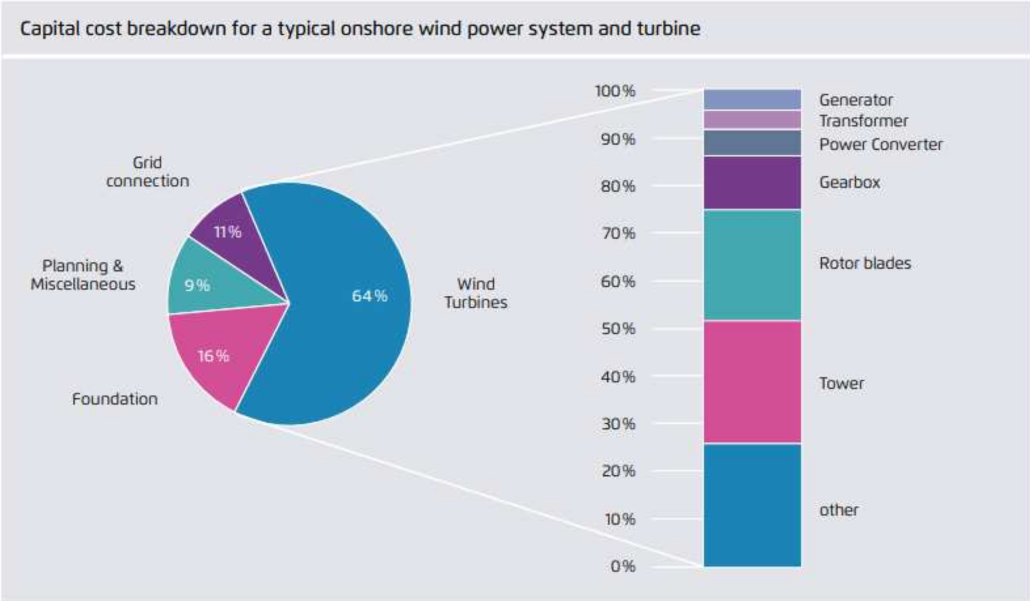

Figure 19 capital cost breakdown for a typical onshore wind power system and turbine (Sector, 2012)

	Cost share (%)
Wind turbine	65 – 84
Grid connection	9 – 14
Construction	4 – 16
Other capital cost	4 - 10

Table 6 capital cost breakdown for typical onshore wind power systems in developed countries (Sector, 2012)

Globally, the weighted average investment cost of onshore wind declined from USD 4 766/kW in 1983 to USD 1 623/kW in 2014, a reduction of two-thirds. This makes onshore wind a significant investment class, with cumulative investment of USD 647 billion over the period 1983 to 2014. Preliminary data for 2015 suggest costs continued to fall, with a global weighted average of USD 1 560/kW (IRENA, 2016).

The installed cost of wind power projects in 2012 was in the range of USD 1 700/kW to USD 2 150/kW for onshore wind farms in developed countries (Sector, 2012). In the Table 7 is reported the trend of onshore wind power system installed cost 2010 USD /kW of Ireland between 2002 and 2010.

Onshore wind power system installed cost 2010 USD/kW								
	2003	2004	2005	2006	2007	2008	2009	2010
Ireland	1034	973	-	-	2883	2533	2268	2419

Table 7 Onshore wind power system installed cost in Ireland (Sector, 2012)

The international energy agency (IEA) in its annual report in 2015 reported the values of installed cost of Ireland.

In Ireland wind turbine prices in 2015 continued to favour buyers and averaged 850 EUR/kW (925 USD/kW) for medium to large projects and 950 EUR/kW (1,034 USD/kW) for small projects less than 10 MW. Total wind farm capital expenditure costs averaged 1,600 EUR/kW (1,741 USD/kW) for larger projects in 2015 and 1,700 EUR/MW (1,850 USD/MW) for projects smaller than 10 MW, the small increase on 2014 costs primarily due to increasing grid connection costs. The above costs do not include legal and financing fees which might add 150 EUR/kW (163 USD/kW) for large projects and 200 EUR/kW (218 USD/kW) for smaller projects. The effects of rising costs were somewhat offset by low interest rates, which served to sustain an attractive rate of return for wind farm investors (IEA Wind, 2016).

Improvements in technology and manufacturing processes, regional manufacturing facilities and competitive supply chains are all putting downward pressure on turbine prices. In 2018, with the exception of China and India, average turbine prices were between USD 790 and USD 900/kW depending on their size, down from between USD 910 and USD 1 050/kW in 2017. For onshore wind farms installed in 2018, the country-specific average total installed costs were around USD 1 170/ kW in China, 1 200/ kW in India, USD 1 660/kW in the US, USD 1 820/ kW in Brazil, USD 1 830/kW in Germany, USD 1 870/ kW in France and USD 2 030/kW in the UK (IRENA, 2019).

In the Figure 20 is shown the value of onshore wind power system installed cost 2018 USD/kW of every considered country in 2010 and 2018.

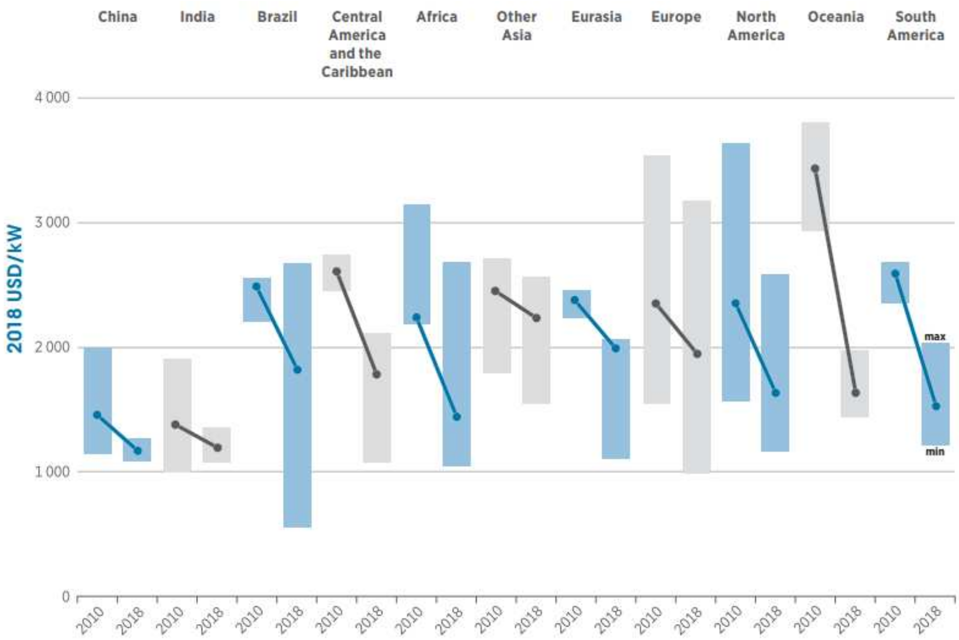

Figure 20 Total Installed cost ranges and weighted averages for onshore wind projects by country (IRENA, 2019)

The international Renewable Energy Agency (IRENA) reported that for onshore wind farms installed in 2018, the country specific average total installed costs were around USD 1 170/kW in China, USD 1 200/kW in India, USD 1 660/kW in the United States, USD 1 820/kW in Brazil, USD 1 830/kW in Germany, USD 1 870/kW in France and USD 2 030/kW in the United Kingdom.

In Figure 21 is shown the trend of onshore wind power system installed cost 2018 USD /kW of every considered country in the period between the 80s/90s and 2018.

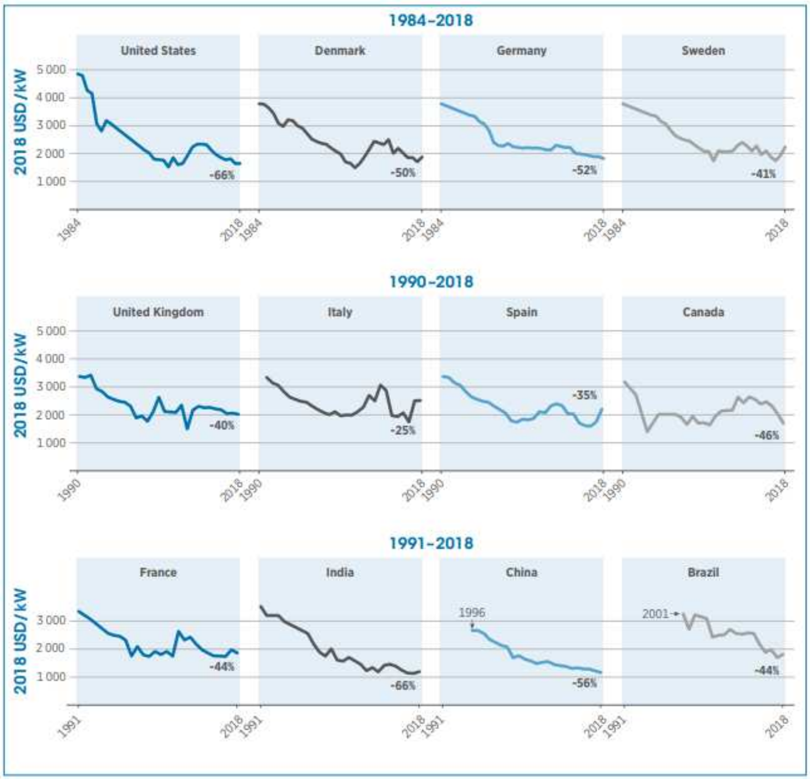

Figure 21 Onshore wind weighted average installed costs in 12 countries (IRENA, 2019)

The total installed cost is expected to drop further in the next three decades, reaching an average range of USD 800 to 1 350/kW by 2030 and USD 650 to 1 000/kW by 2050 compared to current average levels of USD 1 497/kW in 2018 (IRENA, 2019).

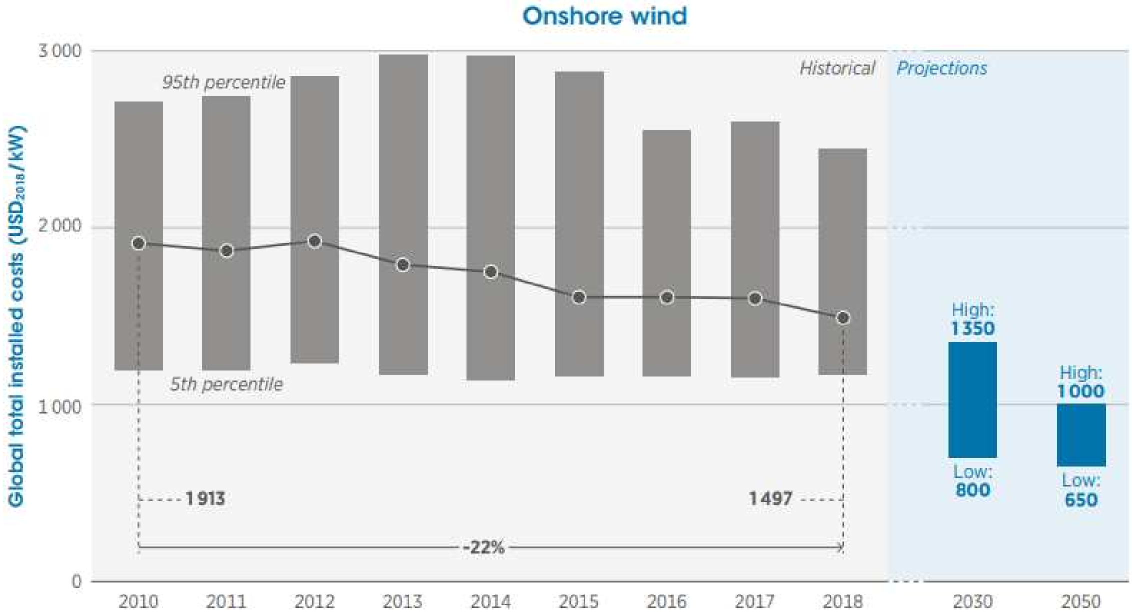

Figure 22 Total installed cost of onshore wind projects has fallen rapidly and is expected to decline (IRENA, 2019)

The costs in the figure represent the total capital costs of a wind power plant assigned to four main categories: wind turbine cost (rotor blades, gearbox, generator, power converter, nacelle, tower and transformer), civil works (construction works for site preparation and foundations for tower), grid connection costs (transformers, substations and connection to the local distribution or transmission network) and planning and project costs (development cost and fees, licenses, financial closing costs, feasibility and development studies, legal fees, owners' insurance, debt service reserve and construction management).

4.3 Electricity Prices

4.3.1 Trading in the Electricity Market in Ireland

The SEM operated as an All-Island mandatory pool spot market for Northern Ireland and the Republic of Ireland from 1 November 2007 to 30 September 2018. A new market design, the Integrated Single Electricity Market (I-SEM), went live on Monday 1 October 2018, having been delayed from 23 May 2018. This more closely integrates the Irish electricity spot market with the GB and continental markets, as well as replacing the previous administered mechanism for capacity payments with a new auction-based capacity market (Baringa, 2020).

In Ireland electricity is bought and sold on the Integrated Single Electricity Market (I-SEM) bringing the Irish electricity market in line with the rest of Europe. In I-SEM auctions takes place daily where generators compete to supply electricity in hourly blocks.
I-SEM is really made up of three different markets. There are two 'ex ante' markets – called the Day Ahead and the Intraday – which means electricity is bought and sold before the market closes. And there is a third, called the Balancing Market, which takes place after trading has ceased (Wind Energy Ireland, 2019).

The price at which generators supply electricity to the Irish wholesale electricity market is the biggest cost in the final price of electricity. The resulting wholesale price is about 55-60% of the cost of electricity for most customers. Wholesale electricity prices in Ireland are sensitive to the price of gas from which we get up to half of our electricity in Ireland (46% in 2014).
The second biggest element of the price of our electricity is the cost of the electricity transmission and distribution system which is about 30% of the electricity price for most customers.
The remainder of the price is made up of supplier charges, government taxes and levies that relate to security of supply and renewable energy (Ireland 2050, n.d.).

- Electricity generation is what it costs to produce the electricity, including energy input, operating costs, overhead costs and profit for the generation company
- Transmission and distribution include what it costs to provide the wires and operate the system that transports electricity to homes and businesses across the country
- Supplier charges are to cover the cost of metering and billing

For small businesses, generation (60%) plus transmission and distribution (29%) of electricity make up almost 90% of the price of electricity, as illustrated below (Table 8).

COST COMPONENT	% COST	DETERMINED BY
Electricity generation	60	Wholesale market
Transmission and distribution	29	Regulated assets
Supplier charges	5	Retail market
PSO	5	Energy policy
Taxes	0.5	Fiscal policy

Table 8 Breakdown of the electricity price (Ireland 2050, n.d.)

The new market has experienced a considerable amount of negative prices. Negative prices are an interesting phenomenon. These occur when market prices clear at a value less than zero, meaning generators are willing to pay for their power to be consumed.
Large generators incur a cost when they reduce their generation below a certain point. It can, depending on the market, be cheaper for them to sell their electricity at a loss and keep going than it is to power down only to power up later. This creates a situation where the market price is less than zero.
Interestingly, approximately 4 per cent of all half hour periods were negative. Note that negative prices are often seen in power markets across Northern Europe. It is an economic signal that there is a significant over-supply in the market (Wind Energy Ireland, 2019).

4.3.2 Historical electricity price

In the period between 2008 and 2013 power prices increased to an average 61 €/MWh, up from around 40 €/MWh in the previous years. This was driven by higher commodity prices and, up to 2010, strong electricity demand. Higher prices narrow the premium paid to wind farms under the Renewable Energy Feed-in Tariff (REFIT) and Alternative Energy Requirement (AER) schemes, resulting in low wind support costs. In addition, amid high fuel and carbon prices, zero-marginal cost wind generation provides a downward force on power prices, significantly reducing wholesale costs (Baringa, 2020).

In the period between 2014 and 2017 lower commodity prices drove down the power price to an average of 49 €/MWh. This had the effect of increasing the subsidy payments under the REFIT scheme and reducing the wholesale cost savings potential of wind generation. Increasing levels of wind generation also drive-up constraint costs (Baringa, 2020).

In Figure 23 is shown the trend of the average electricity systema marginal price compared to gas price as reported in the annual report of 2019 by EirGrid group, who operates and develops the national high voltage electricity grid in Ireland (CITATION).

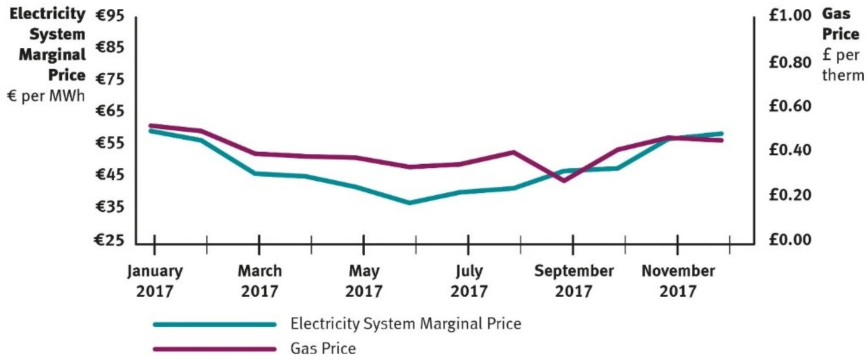

Figure 23 Average electricity system marginal price compared to gas price (SEAI)

From the figure it can be seen that the average price of electricity was around 46 €/MWh in 2017 in the period of time considered.

Figure 24 illustrates the average half hourly price in each market since the 1 October 2018. The morning and evening demand peaks correlate with higher prices on average as can be seen in the two peaks at 9am and 6:30pm (Wind Energy Ireland, 2019).

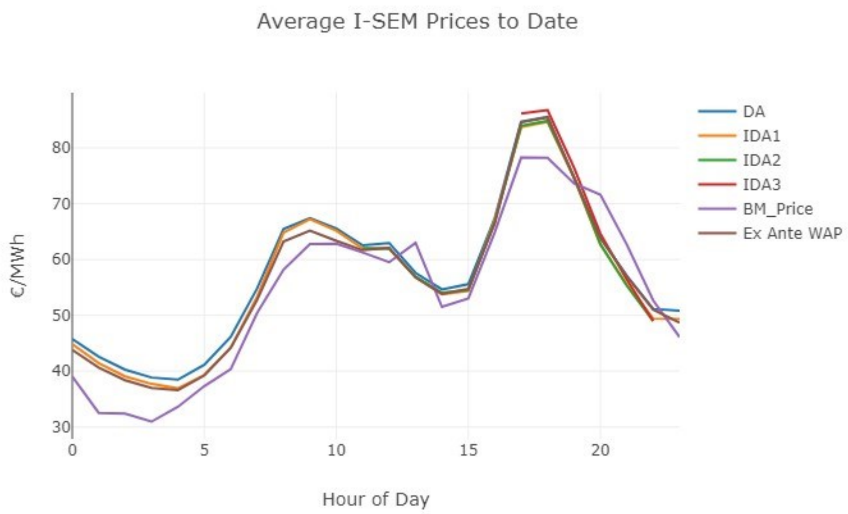

Figure 24 Average I-SEM Prices to Date (Wind Energy Ireland, 2019)

On 24 January (2019), the Balancing Market Price even went as high as €3,774/MWh, when the average wholesale price for electricity in Ireland is around €60. This meant that generators which under-delivered i.e. which were "short" during that trading period were forced to buy back at €3,774 for each MW they were short. This volatility and price uncertainty presents a balancing risk for market participants. The trend is shown in Figure 25.

Figure 25 All market prices to date – Ex Ante WAP (Weighted Average Price) (Wind Energy Ireland, 2019)

The government body Sustainable Energy Authority of Ireland (SEAI) who promote and assist the development of sustainable energy reported the average electricity price to business consumer, which is shown in Figure 26.

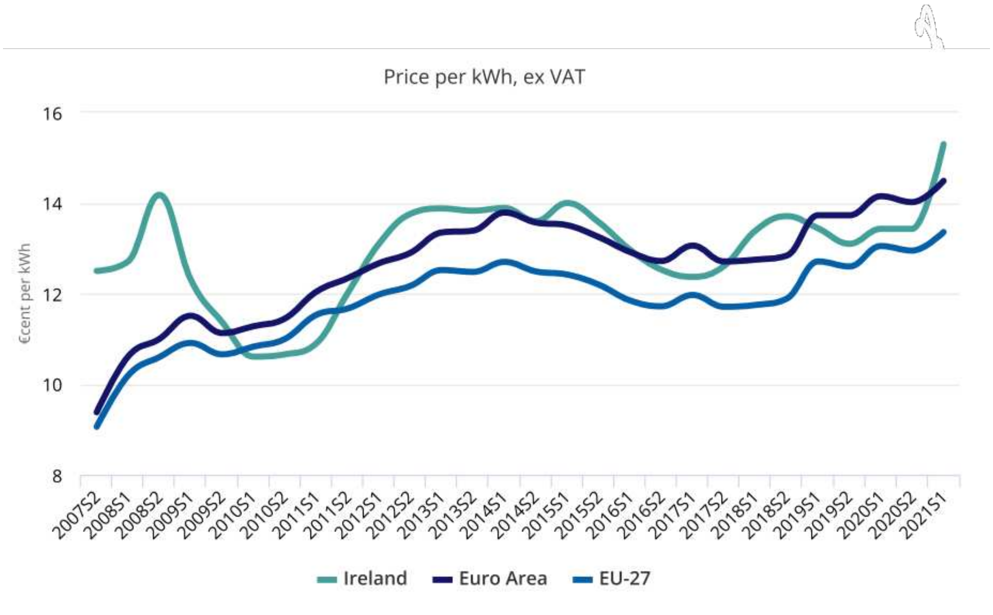

Figure 26 Price of electricity per kWh ex VAT (SEAI)

The weighted average price of electricity to business consumers in Ireland has been above the European average since the second half of 2011 and has fluctuated above and below the Euro Area since the end of 2016. The latest data available, for the January to June 2021 period, show the weighted average price in Ireland grew by 13.9% and was 14.5% and 5.6% above the EU and Euro Area average respectively (SEAI, n.d.).

As reported in the previous section (trading in the electricity market) the percentage of the electricity generation (wholesale market) of the total cost for the business consumer is around 60%.

In Table 9 are reported the average cost value for each time interval considered and the relative share of electricity generation.

Ireland	Average electricity price to business (Euro cent/kWh)	Electricity generation (60%)
Average (ALL)	12.97	7.78
Average (2010-2021)	13.16	7.90
Average (2012-2021)	13.47	8.08
Average (2014-2021)	13.42	8.05
Average (2016-2021)	13.30	7.98
Average (2018-2021)	13.69	8.21
Average (2020-2021)	14.05	8.43

Table 9 Average electricity prices in different time interval in Ireland (SEAI)

4.3.3 Current electricity price

Soaring gas and coal prices were the main driver for the rapid rise in wholesale electricity prices in many countries in 2021. Our price index for major wholesale electricity markets of major advanced economies almost doubled compared with 2020 (up 64% from the 2016-2020 average).

Wholesale prices in the fourth quarter of 2021 in France, Germany, Spain and the United Kingdom were three to more than four times higher than the fourth quarter 2016-2020 average. This was mainly caused by the steep rise in gas prices, alongside .

The Nordic region also saw a surge, wholesale prices rising in the fourth quarter of 2021 almost three times compared with the fourth quarter average of 2016-2020, and over seven times higher than the same period in 2020. However, average prices of EUR 96/MWh in the fourth quarter of 2021 were only about half as high as in Western Europe (OECD, 2022).

In Figure 27 is shown the quarterly average wholesale prices for selected regions, 2016-2021.

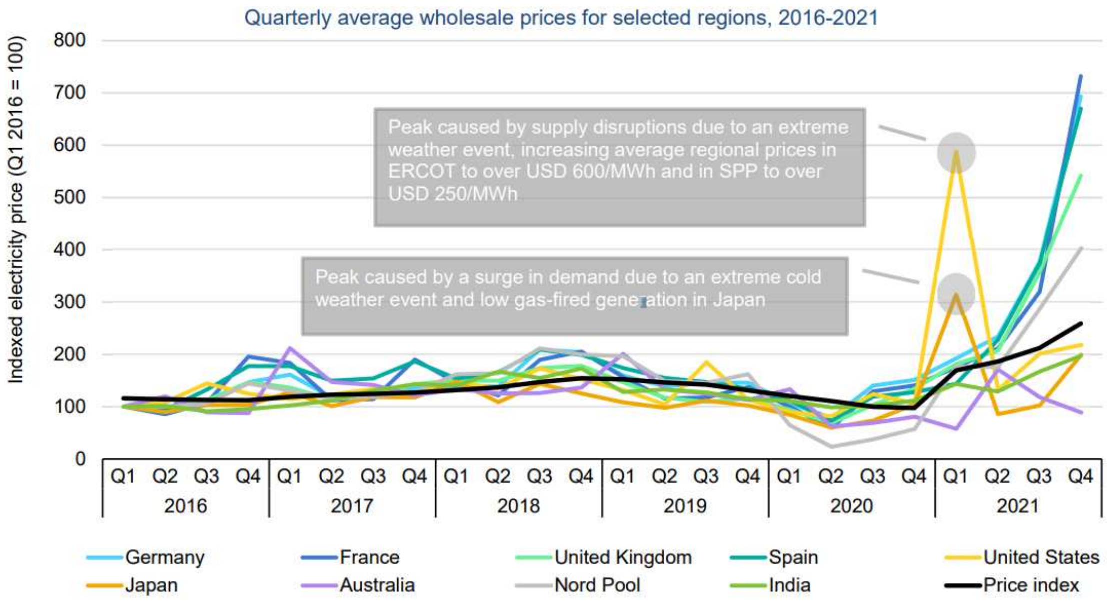

Figure 27 Quarterly average wholesale prices for selected regions, 2016-2021 (OECD, 2022)

2020 was a landmark year for energy prices in Ireland. The onset of the Covid-19 pandemic resulted in record low energy demand, which in turn saw unprecedented low wholesale power prices. Flogas Enterprise reported that the wholesale power price for 2020 averaged at €37.46/MWh. This is 25% lower than in 2019 (€50.26/MWh), which was in turn 21% lower than 2018. In addition to Covid-19, the significant growth in wind penetration helped to push down wholesale energy prices, as record-breaking levels of wind energy were present in the system (Flogas Enterprises, n.d.).

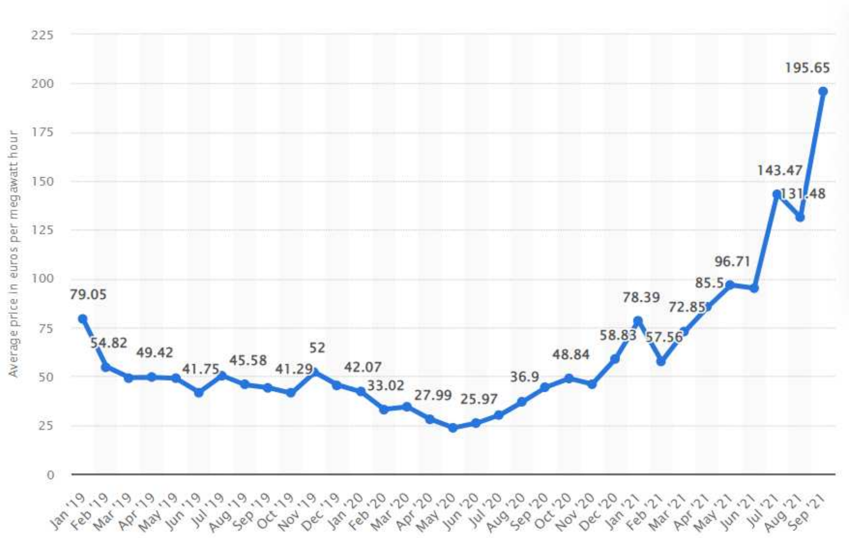

Figure 28 average monthly electricity wholesale price in Ireland from January 2019 to September 2021 (Statista, 2022)

In September 2021, the average wholesale electricity price in Ireland surpassed 195 euros per megawatt hour, the highest figure reported in the period under consideration. This was a month-over-month increase of nearly 49 percent. In comparison to the same month of the previous year, prices rose by over 150 euros per megawatt hour. In 2021, electricity prices in the European Union (EU) have soared, the combination of a myriad of factors, including increased heating demand due to cold winters, a rise in natural gas and coal prices, and a drop in wind power generation due to lack of wind (Statista, 2022).

4.3.4 Electricity price forecast

Afman (Afman, Maarten Hers, Sebastiaan Scholten, 2017) published a study in which they made an electricity price forecast based on forecasts of installed renewable energy capacity of Germany and Netherlands, for two different scenario: lower prices scenarios and higher prices scenarios.

The National energy outlook (NEO) expects a development of installed capacities for wind and solar in the Netherlands, going from 7 GW wind and 6 GW solar PV in 2020 to 11 GW wind and 17 GW solar PV in 2030. Therefore, they decided to simulate an additional 2030 'high-RES' scenario with more progressive renewable energy supply capacities: 20 GW wind offshore, 8 GW wind onshore, 20 GW solar PV. For Germany, they use the prognosis from (Netzentwicklungsplan, 2016) for all years.

FIGURE shows the year-average price of electricity, where only the 10, 20, 30, 40 or 50% cheapest hours of the year have been included in the average. Two things stand out. First of all, especially the 10-20% cheapest hours (900-1,800 hours of the year) show a declining trend over time. We expect that progression in renewables infeed is the primary reason for this. The second thing that stands out is that the 'high-RES' scenario (28 GW wind and 20 GW solar) is really low during even 50% of the hours of the year – this reflects that in this scenario, the demand is way too little to accommodate excesses of RES (Afman, Maarten Hers, Sebastiaan Scholten, 2017).

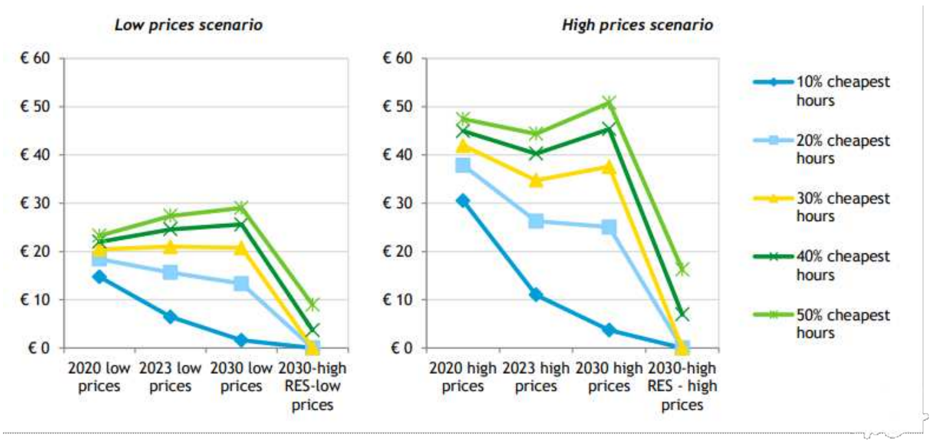

Figure 29 Average price during the X% cheapest hours of the year (Afman, Maarten Hers, Sebastiaan Scholten, 2017)

Figure 30 is similar to Figure 29, but instead of low prices, this figure reflects the most expensive hours of the year. In this figure, we see all lines rising as time progresses, so the prices rise, essentially driven by scenario fuel and CO2 prices. One thing is interesting to note, and that is that the prices in the 2030 'high-RES' scenario are higher than the prices in the 2030 regular scenario. This cannot be due to fuel or CO2 prices, which are unchanged compared to the regular 2030 scenario. Therefore, we conclude that this is purely driven by flexibility constraints of the generating park, requiring the use of more expensive generating units. This leads to more price volatility. An insight such as this can only be generated from market simulation with a market model that captures flexibility constraints of thermal units (Afman, Maarten Hers, Sebastiaan Scholten, 2017).

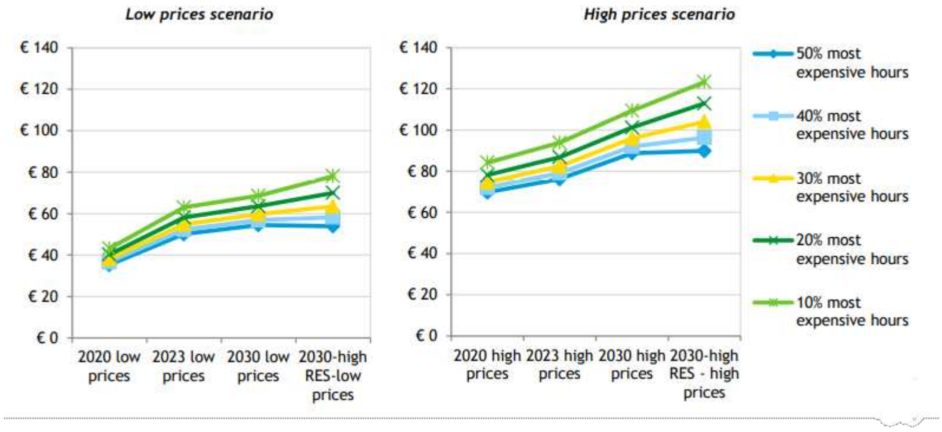

Figure 30 Average price during the X% most expensive hours of the year (Afman, Maarten Hers, Sebastiaan Scholten, 2017)

In Table 10 are shown the average values of electricity prices in every year considered for each scenario.

	Low prices scenario				High prices scenario			
	2020 low prices	**2023 low prices**	**2030 low prices**	**2030 high RES-low prices**	**2020 high prices**	**2023 high prices**	**2030 high prices**	**2030 high RES-high prices**
Average price €/MWh	29.3	38.8	41.8	31.4	58.6	60.3	69.8	53.0

Table 10 Simulation results for the scenarios (Afman, Maarten Hers, Sebastiaan Scholten, 2017)

Aurora Energy Research (Beer, 2021) published a study in which they made an electricity price forecast based on six countries in Europe.

This study compares two scenarios, one “Pessimistic Scenario” where EU Governments fail to overcome existing barriers to renewables deployment while slowing down coal exits and a “Target Scenario” where these barriers are removed, and renewables generation shares reach a level which is aligned with the

European Commission's Renewables Directive for 2030 and the results of the Commission's Impact Assessment of the effects of the European Green Deal. This scenario allows unprofitable coal capacity to retire in the 2020s, i.e. earlier than current government plans.

They find that slowed renewables deployment under a Pessimistic Scenario would drive significant increases in both carbon and wholesale electricity prices. This would result in higher costs for industry and consumers and could threaten the competitiveness of European Industry (Beer, 2021).

- EUA prices would be almost 80% higher in 2030 than under a scenario where governments meet the renewables share outlined in the Commission's Impact Assessment Report and implied by the Commission's renewables targets under its Renewables Directive.
- Wholesale electricity prices would be 44% higher on average in 2030 between both Scenarios and across a list of six focus countries (Poland, Germany, Italy, Romania, Bulgaria, and Greece), which increasingly replace coal with new natural gas generation, thereby increasing the EU's import dependence.

Overcoming current barriers to renewables deployment, while allowing unprofitable coal and lignite plants to retire earlier than outlined under government plans would ensure stable to falling electricity and carbon prices that maintain the competitiveness of European industry. A more direct switch from coal to renewables would reduce the EU power sector's dependence on natural gas imports and limit its exposure to commodity price volatility. Avoiding overinvestments into natural gas capacity is of particular relevance in light of the IEA's Net Zero conclusion that the power sector in all OECD countries should be decarbonised by 2035 and for all other countries until 2040 (Beer, 2021).

- EUA prices would fall below levels observed during the Fall 2021 natural gas supply shortage while renewables increasingly replace coal, limiting the need for natural gas as transition fuel.
- Wholesale electricity prices and natural gas generation in six focus countries would stagnate or fall until 2030 compared to historically observed levels.

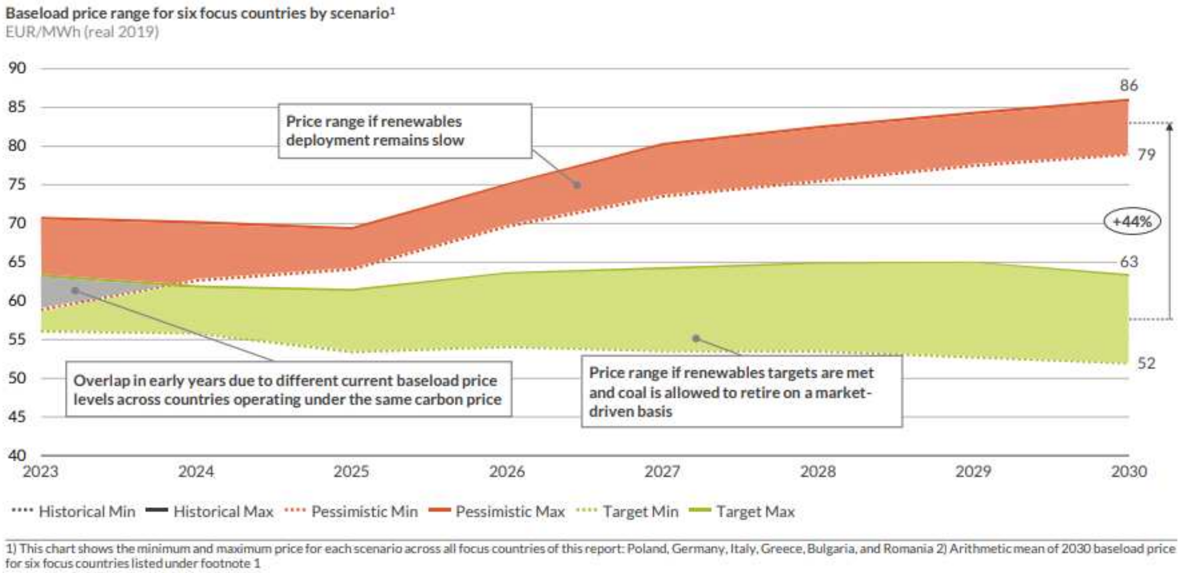

Figure 31 Quarterly average wholesale prices for selected regions, 2016-2021 (Beer, 2021)

Figure 31 shows that higher renewables capacities as well as the lower carbon price result in significantly lower wholesale power prices across European markets ensuring affordable wholesale electricity prices for European industry and other consumers.

4.3.5 Influence of wind power on the price of electricity

Wind farms use wind forecasts to predict their generation volumes for the Day Ahead Market and will establish positions based on those, altering their ex-ante position in the Intraday Market when they receive new wind forecasts closer to the trading period.

Considering the risk, a good wind forecast is crucial for trading wind energy. Wind is a price taker in the Balancing Market. This is because wind energy – because it doesn't need to pay for fuel like coal or gas and has the benefit of the support scheme – bids into the market with a price of zero. This drives downward pressure on the price of wholesale electricity prices (Wind Energy Ireland, 2019).

Wind farms, once constructed, are inexpensive to run as wind generation has a low marginal cost. Wind generation therefore displaces higher cost electricity sources such as gas plants or imports. This dynamic means wind reduces power prices across the entire electricity market, which also lowers end costs for all consumers (Baringa, 2020).

Generation from wind units is prioritized over other generation sources – fossil fuels for example. So, in times of high generation and low demand, when the System Operator (SO) might need to turn generators down or off to prevent overgeneration and grid pressures, wind will be turned down/off only after non-priority units have been (Wind Energy Ireland, 2019).

Figure 32 shows the simulated impact of wind generation on the wholesale power price: actual power prices are significantly lower than power prices simulated under a 'no wind' scenario, The effect increases as wind generation grows – for example, we estimate that in 2018, wind helped to reduce power prices by over 20% (Baringa, 2020).

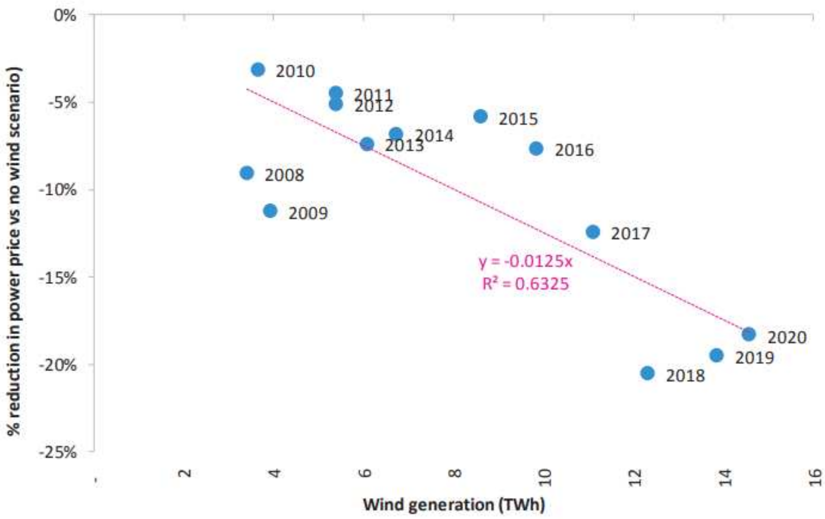

Figure 32 Wind generation and wholesale price reduction vs 'no wind' scenario (Baringa, 2020)

In a Baringa publication (Baringa, 2020) they have analysed the impact of wind generation on SEM and I-SEM wholesale power prices in detail. As first step they simulated and reproduced historical power prices from 2008-2018 YTD. As a second step, we assume wind generation to be zero and rerun the market model to simulate power prices in a 'no wind' counterfactual. To maintain the same level of system security, they maintained a similar de-rated capacity margin by substituting wind for open cycle gas turbine (OCGT) plants. Under the I-SEM capacity market rules, wind receives a capacity credit of about 10% and OCGTs a capacity credit of about 92%. This means that 1 GW of wind is replaced by 109 MW (= 1 GW * (10% / 92%) of OCGTs. They calculated the savings as the difference in wholesale price (in €/MWh) between the two runs, multiplied by the overall GWh electricity demand in Ireland.

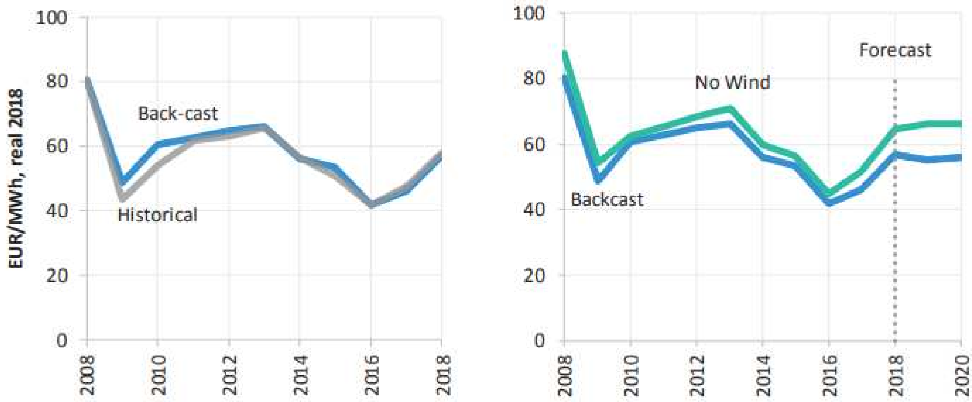

Figure 33 SEM historical and modelled SMP and SEM back-cast and 'No Wind' SMP (Baringa, 2020)

4.4 Borrowing Costs

The cost of capital constitutes a critical component in the investment decision making and the company's valuation process by investors. The cost of capital is considered as the expenses and interests to be paid in order to raise all necessary funds for the financing of potential investments and, thus, represents the internal rate of return that makes equal the current stock price to the present value of the expected future cash flow. In this context, it represents the opportunity cost or, equivalently, the specific rate of return that a capital supplier requires as compensation for investing capital (Angelopoulos et al., 2016).

4.4.1 weighted average cost of capital

The weighted average cost of capital (WACC) is utilized in order to measure the mean cost of capital of investments. In general, the total capital of a company or a project may consist of both debt and equity capital. The WACC is the summation of the cost of every capital element multiplied by its proportional share. The following mathematical formula presents the WACC indicator:

$$WACC = \frac{E}{E+D} \cdot CoE + \frac{D}{E+D} \cdot CoD \cdot (1 - CTR) \qquad (4.\ 4)$$

Where:

- WACC: weighted average cost of capital
- CoE: cost of equity
- E: market value of equity
- CoD: cost of debt
- D: market value of debt
- CTR: corporate tax rate

AURES[3] in its report presented data on relevant financing variables of concrete RE projects in Europe. In particular, the variables asked were the Weighted Average Cost of Capital (WACC), its components Cost of Debt and Cost of Equity (CoD and CoE)

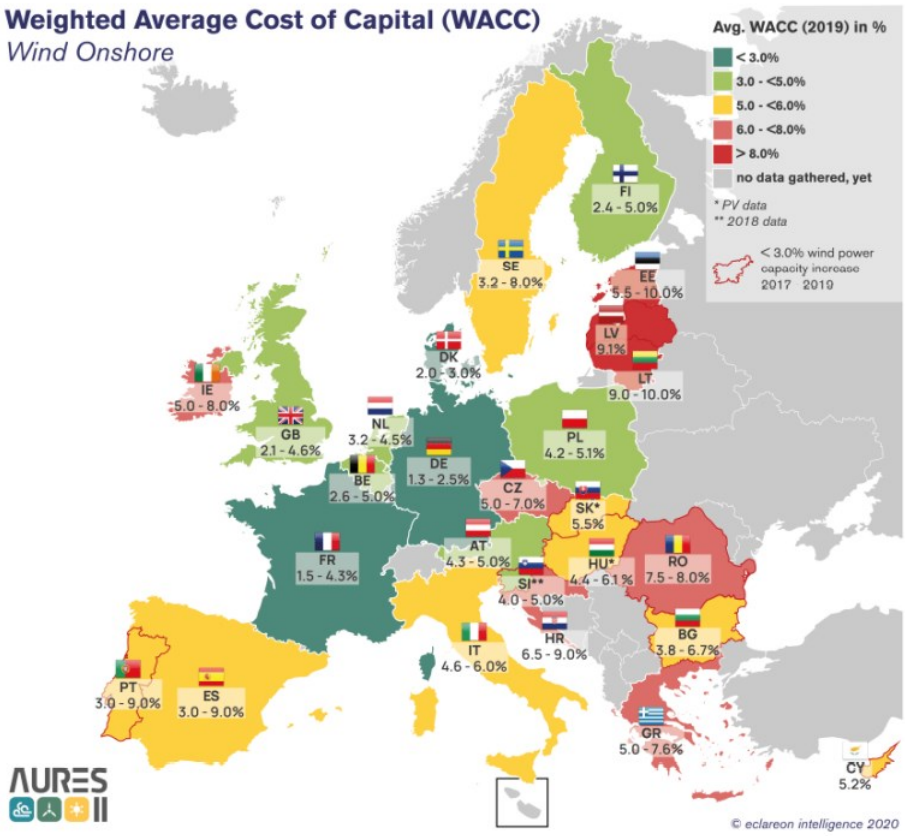

Figure 34 Overview on WACC for wind onshore (2019) (Roth et al., 2021)

Secondly, according to interviewed experts, Ireland presents a higher-than-expected WACC, i.e., ranging from 5.0% to 8.0%. A plausible reason is the absence of support schemes for wind onshore projects during the period under analysis (2017-2019). Support schemes, such as Feed-in Tariff or Feed-in Premium, can reduce the exposure to market prices of wind onshore projects, which in turn means lower risks and consequently lower WACC. They are also fundamental for the debt financing conditions of RES projects, since they define the project´s cash flows (Roth et al., 2021).

[3] AURES - Auctions for Renewable Energy Support - is a coordination and support action financed by the European Commission under the Horizon 2020 program to improve the implementation of renewable energy policies in EU Member States.

4.4.2 Cost of debt

Cost of debt is the total amount of interest paid by a firm or an entity in order to borrow capital. The debt providers generally require higher returns for financing more risky investments or companies, which, mostly, results in higher values of the cost of debt. The cost of debt can be quantified by summing a risk-free rate and a risk premium so as to incorporate the perceived risks (Angelopoulos et al., 2016).

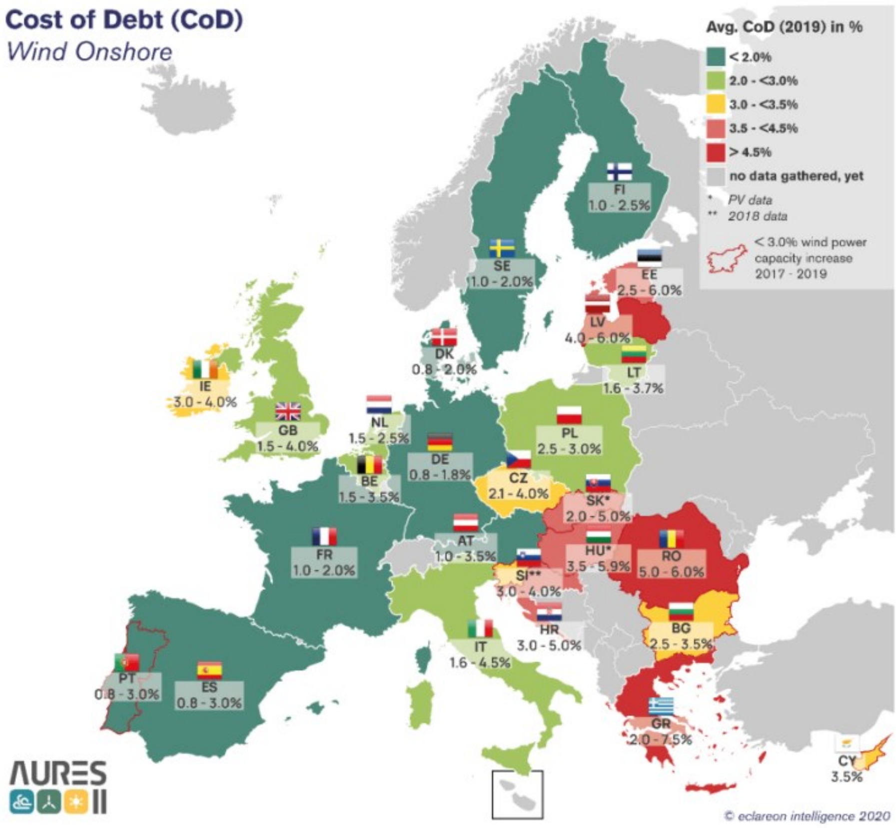

Figure 35 Cost of Debt for onshore wind projects (Average 2019) (Roth et al., 2021)

4.4.3 Cost of equity

The cost of equity illustrates the minimum required rate of return that equity investors expect from their investments. It also constitutes an adequate index for quantifying the level of risk of specific investment alternatives. In particular, greater values of the cost of equity reflect a higher level of risk and, thus, investment decisions differ, as they depend on the different risk perception of several investors (Angelopoulos et al., 2016).

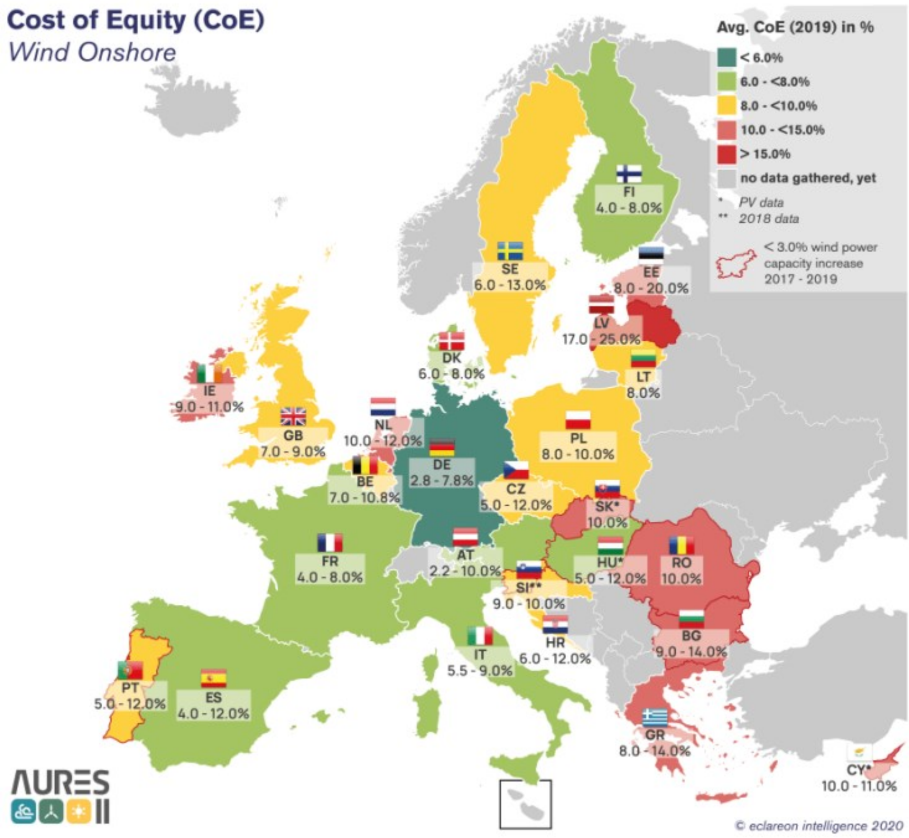

Figure 36 Cost of Equity for onshore wind projects (2019) (Roth et al., 2021)

4.4.4 Debt-to-equity ratio

Capital structure refers to the amount of debt and equity that a company or a project is using for its funding. The shares of debt and equity capital depend on the level of the average debt-to-equity ratio for the relevant sector and on the firm's strategy (Angelopoulos et al., 2016).

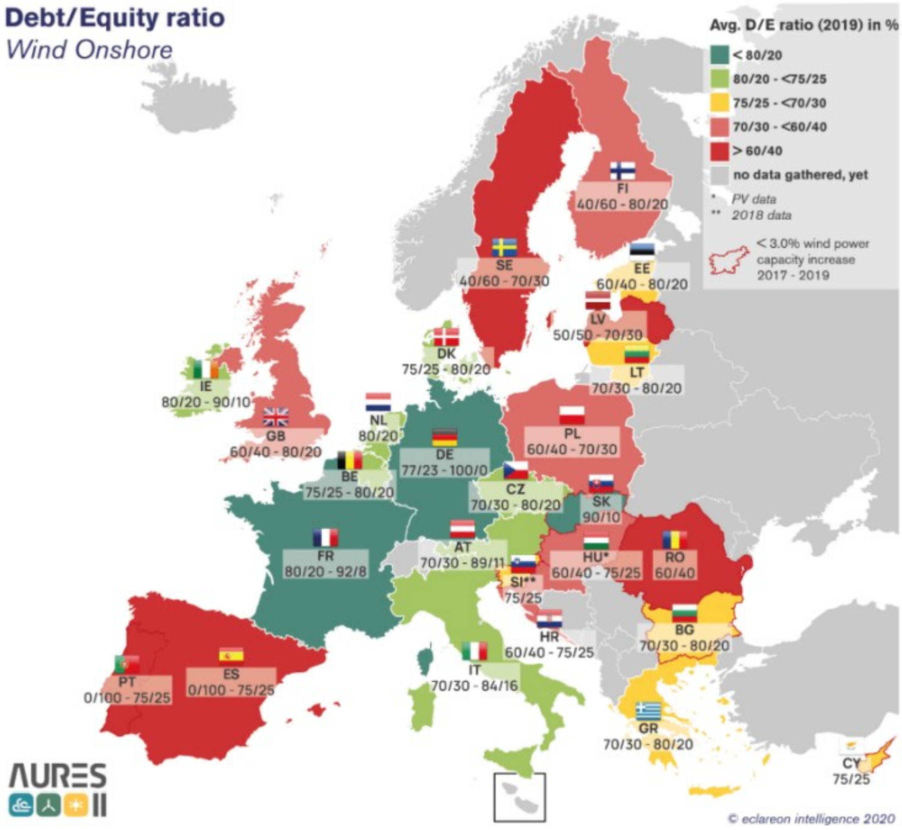

Figure 37 Debt to equity ratio 2019 for onshore wind projects (Roth et al., 2021)

Countries like Italy, Greece, Ireland, Czech Republic, Estonia, and the Netherlands, experienced a more pronounced shift to larger debt shares. Most in this group present also a significant wind power development, which in addition to the better finance conditions such as lower interest rates, may explain the increased capacity to leverage debt (Roth et al., 2021).

4.5 Economic evaluation

The NPV in the i-th year is calculated using the net cash flows, discount rate, and the initial investment cost of the system as (Kong et al., 2019):

$$NPV(i) = \sum_{t=1}^{i} \frac{C_n(t)}{(1+r)^t} - I_0 \tag{4. 5}$$

Where r is the discount rate, I_0 is an initial investment cost of the turbine and $C_n(t)$ is the net cash flows are calculated by using the annual cash inflows and cash outflows as follow:

$$C_n(t) = C_i(t) - C_o(t) \tag{4. 6}$$

$C_i(t)$ is the net cash inflows and $C_o(t)$ is the net cash outflows at the t-th year. The annual cash inflows are composed of the profits. The annual cash outflows include the annual Operation and Maintenance (O&M) cost of the system.

The DTU LCOE model is a simple approach to cost calculation, mainly developed for the assessment of the cost impact of new technologies. The first component of cost is the capital expenditure (CAPEX). Other elements of the cost model are development costs (DEVEX), abandonment (decommission) costs (ABEX), and the operational expenditure (OPEX) representing the operation and maintenance cost. The power production (annual energy production [AEP]) is calculated from an assumed turbine capacity factor, which in the model can be assumed to decline annually due to wear. The cost of energy is levelized, that is, it calculated as the sum of discounted total costs C_d divided by discounted production P_d. The discounting is based on the financial investment decision date (FID), here year 0. Thus, the levelized cost of energy (LCOE) is calculated as (Chen et al., 2021):

$$LCOE = \frac{C_d}{P_d} \tag{4. 7}$$

Where:

$$C_d = \sum_{t=k}^{T} \frac{C(t)}{(1+W_n)^t} \tag{4. 8}$$

And

$$P_d = \sum_{t=k}^{T} \frac{AEP(t)}{(1+W_r)^t} \tag{4. 9}$$

$C(t)$ is the total cost of year t, that is, the sum of CAPEX, DEVEX, OPEX, and ABEX. AEP[t] is the annual energy production for year t. For CAPEX and DEVEX, the actual year can be offset a number of years relative to the FID. W_n and W_r are the nominal weighted average cost of capital (WACC) and the real weighted average cost of capital, respectively. The relation between these two are

$$W_r = \frac{1+W_n}{1+I} - 1 \tag{4. 10}$$

Where I is the inflation rate.

5 Results Cash Flow Model

In this section several cash flows are presented in order to evaluate the profitability of the wind farm considering changes in certain components of the financial model such as operating and maintenance costs, cost of electricity and the weighted average cost of capital (WACC). The variations of these cost components are made based on the base scenario presented in the next sections. To see how every component affects the profitability of the wind farm various cost scenarios are considered.
The financial parameters used for the comparison are the simple pay-back period, the discounted pay-back period, and the net present value (NPV) at the end of the life cycle of the wind turbine.

The different scenarios are as follows:

- Scenario 1: Base scenario without considering the wacc.
- Scenario 2: Base scenario considering the wacc.
- Scenario 3: Current electricity price scenario.
- Scenario 4: Electricity price forecast scenario
- Scenario 5: Decrease of the WACC scenario
- Scenario 6: Increase of the WACC scenario

In the next sections the results of every component of costs are presented.

5.1 *Electricity generation and r*evenue *g*enerated

The calculation of the electricity generated by the wind turbine is done starting from the evaluation of the probability wind distribution of the site, using the the two-parameter Weibull distribution. Since the wind speed values are not available for the height of the hub (100 m), they are calculated using $V_y = V_{10}\left(\frac{Z_y}{Z_{10}}\right)^{\alpha}$ *(2. 32*). The roughness coefficient of the site is obtained using Equation $\alpha = \frac{\ln(V_{20}) - \ln(V_{10})}{\ln(Z_{20}) - \ln(Z_{10})}$ *(2. 33*) considering the wind speed values at the height of 20 and 50 meters.

In TABLE are reported the results of the three methods used for the calculation of Weibull parameters and errors with respect to actual wind sampling. The empirical method and energy pattern method show very similar results, particularly the first one has lower errors although the difference with the second one is negligible. The maximum likelihood method is theoretically the most precise of the methods, but the number of samples is too low to give a correct result, indeed while the first two methods lead to the same Weibull distribution the likelihood method give a completely different curve. The curves are shown in Figure 38.

Parameter estimation method	k	s [m/s]	R^2	$RMSE$	MBE	MBA
Empirical method	1.9761	8.1530	0.9717	1.14601	-0.0001416	0.1567
Energy pattern method	1.9894	8.1542	0.9725	1.4397	-0.0001416	0.1546
Maximum likelihood method	0.2357	5.4781	-3.3274	18.0586	-0.0001416	1.0966

Table 11 Weibull parameters and their errors on the measurement

The first two methods give almost the same results and since the empirical method has the lowest errors, it is considered for the simulation.

The Weibull parameters and the characteristic of the site (windiness and rough coefficient) are reported in the Table 12 (all values refer to the height of 100 meters).

Mean velocity (m/s)	7.23
Standard deviation	3.86
Roughness coefficient	0.233
Shape factor	1.98
Scale factor (m/s)	8.15
Most probable wind speed (m/s)	5.71
Wind speed that carries the most energy (m/s)	11.61

Table 12 Results of the windiness site analysis

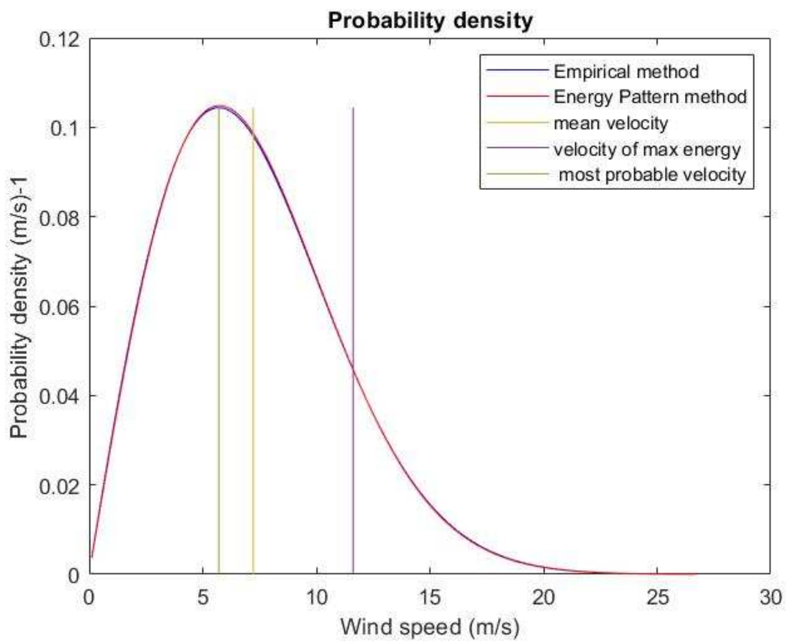

Figure 38 Probability density curves for each Weibull parameters methods

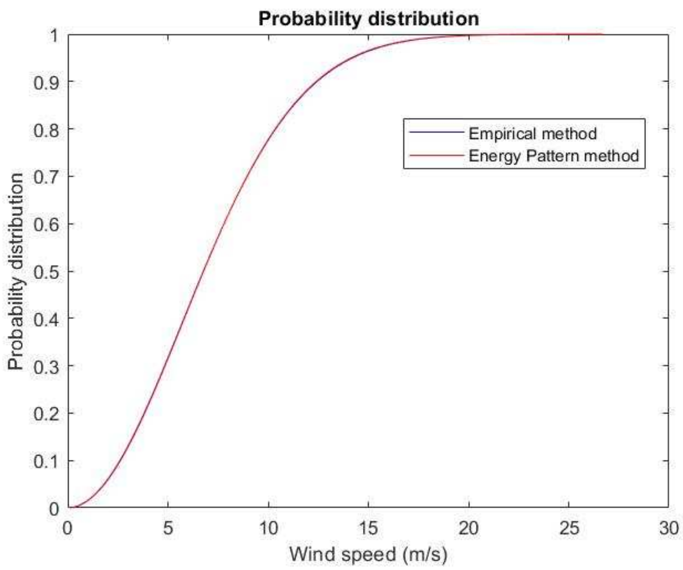

Figure 39 Probability distribution curves for each Weibull parameters methods

The results of the simulation show that the first model of wind turbine presented in Section 3.2 gives the most production of electricity as reported in Table 13.

Wind turbine model	Electricity produced [GWh/year]
Fuhrländer FL MD 77	4.416
Südwind S-70	3.889
Südwind S-77	4.213

Table 13 Electricity production for each wind turbine models

The calculation of the output power is made considering the conditions expressed by the Equation$P_G(V) = \begin{cases} 0 & if\ V<V_{in}\ or\ V>V_{out} \\ \frac{1}{2}\eta\rho\pi R^2V^3 & if\ V_{in}<V<V_{nom} \\ P_{nom} & if\ V_{nom}<V<V_{out} \end{cases}$ *(2. 31)* in which the power output is considered equal to zero when the wind speed is below the cut-in and over the cut-out velocity, equal to the power produced at a specific wind speed when the wind speed is between the cut-in and nominal velocity and equal to the nominal power when the wind speed is between the nominal and the cut-out velocity.

For the second one the value of the air density considered is equal to 1.225 kg/m^3 and the values of the power coefficient of the wind turbine are those reported in Figure 11.

The mechanical efficiency and electrical system efficiency considered are respectively 94% and 98%.

The results relating to the annual energy production are shown in Table 14.

Total energy produced (MWh)	4,416.5
Hour at rated operation	2,944.3
Capacity factor (%)	33.6

Table 14 Electricity of Fuhrländer FL MD 77 wind turbine model

The evaluation of the revenue generated is equal to electricity generated multiplied by the price of electricity on the wholesale electricity market. For the basic scenario the electricity price is considered based on the historical prices of the years before 2019. After the latter, the electricity market witnessed significant changes in energy prices due to the covid 19 pandemic and the political situation in Russia.

Electricity price (€/kWh)	82
Yearly revenue generated (€)	362154.9

Table 15 Electricity price and yearly revenue generated

5.2 Capital costs

The capital costs considered include turbines, unit transformer, crane, non-buoyant foundation, protection equipment, grid-code compliance devices and testing. The cost of the initial investment per kW of nominal power of the wind turbine is defined according to the most recent data reported in Section 4.2. In 2015, according to IEA, the cost of investment in Ireland is around 1900 €/kW (including financing fees) for power plant with nominal power lower than 10 MW. The latest values, reported by IRENA, refer to the year of 2018 and shows an average value of the capital cost in Europe of 1850 USD dollar/kW and considering a euro/dollar currency exchange in 2018 of 1 euro = 1.18 USD dollar the investment cost is equal to 1550 €/kW. The latter is used as a value of the capital cost per kW of rated power of the turbine in this study.

5.3 Failure costs

The failure costs of the wind turbine are calculated considering two components of cost: the replacement of the turbine's components and the loss of production due to the downtime of the wind turbine during the replacement of the wind turbine.
Both are calculated on an annual basis and for this purpose an annual failure rate of each component is considered, and for this study the failure rate values reported in Table 5 are chosen.

The total annual cost of replacement of the components, as reported in the first part of the Equation $Expeted\ failure\ cost\ = \sum_{n_{components}} p_n c_n + Loss\ of\ production\ cost$ *(4. 1)*, is the summation of the product between the failure rate and the cost of replacement of the single component. With regard to the last, the values reported in Table 5 are taken into consideration, nonetheless, they are referred to a 3 MW turbine size, therefore they are reduced by a 50%.

The annual cost of loss of production is the summation of the loss of production of each component which is calculated as reported in the $Capacity\ factor\ \times Selling\ tariff$ *(4. 2)* and multiplied by the annual failure rate. The downtown hours of every component used for this study are reported in Table 5 Data used to calculate the expected failure costs generated in a 2–3 MW wind turbine system (Tazi et al., 2017). The capacity factor and the electricity selling price used in the equation are equal to 0.336 and 82 €/MWh respectively.

The results relating to the failure costs are reported in Table 16.

Annual cost of replacement (€)	113,313.25
Annual cost of loss of production (€)	8223.5
Total annual failure costs (€)	121,536.75

Table 16 Annual operating and maintenance costs

5.4 Result of scenarios

5.4.1 Base scenario

Base scenario without WACC

The current scenario is based on the assumptions reported in the previous sections of the results and its purpose is to show the cost-effectiveness of installing this type of turbine in the specific site.

The Table 17 refers to the cash flow over 20 years of operation. In this simulation the WACC is not considered in order to evaluate the simple pay-back period, even though an interest rate has to be considered for investments that have required a money loan and for the time window considered (several years).

It should be pointed out that the calculation of simple payback period omits many factors that may have a significant effect on the system economic cost effectiveness. These include escalating fuel (in a hybrid power system) and loan costs, depreciation on capital costs, operation & maintenance costs (O&M), and variations in the value of delivered electricity. Some of these variables are attempted to be included in some author's calculations for a simple payback period. This method is the simplest method, and it takes short time to do the calculations and get the preliminary results and information.

Year	cash outflows			cash inflows	Cash flow
	inevstment	loss prod	failure cost		
0	-2325000				-2325000
1		-8223.5		362154.9	-1971068.6
2		-8223.5		362154.9	-1617137.2
3		-8223.5		362154.9	-1263205.8
4		-8223.5		362154.9	-909274.4
5		-8223.5		362154.9	-555343
6		-8223.5	-113313.25	362154.9	-314724.85
7		-8223.5	-113313.25	362154.9	-74106.7
8		-8223.5	-113313.25	362154.9	166511.45
9		-8223.5	-113313.25	362154.9	407129.6
10		-8223.5	-113313.25	362154.9	647747.75
11		-8223.5	-113313.25	362154.9	888365.9
12		-8223.5	-113313.25	362154.9	1128984.05

13	-8223.5	-113313.25	362154.9	1369602.2
14	-8223.5	-113313.25	362154.9	1610220.35
15	-8223.5	-113313.25	362154.9	1850838.5
16	-8223.5	-113313.25	362154.9	2091456.65
17	-8223.5	-113313.25	362154.9	2332074.8
18	-8223.5	-113313.25	362154.9	2572692.95
19	-8223.5	-113313.25	362154.9	2813311.1
20	-8223.5	-113313.25	362154.9	3053929.25

Table 17 Cash flow of base scenario without WACC

From the Table 17 it can be seen that for the first five years the costs associated to the failure of the components is equal to zero, due to the warranty issued by the manufacturer which is usually around five years for the wind turbines. For this reason, the first five years are the most profitable of the whole lifetime of the wind turbine.

For this scenario the payback period, as well as the simple payback period since it does not consider the interest rate, is just over seven years, indeed it can be seen a positive value of the NPV on the eighth year. Not considering the WACC this scenario is more optimistic than the following ones and it can’t also be considered realistic since it does not consider the change in the value of money over time and the interest rate in lending from banks and the equities. This scenario is presented for a comparison with the following scenarios to show how the WACC influences the cash flow.

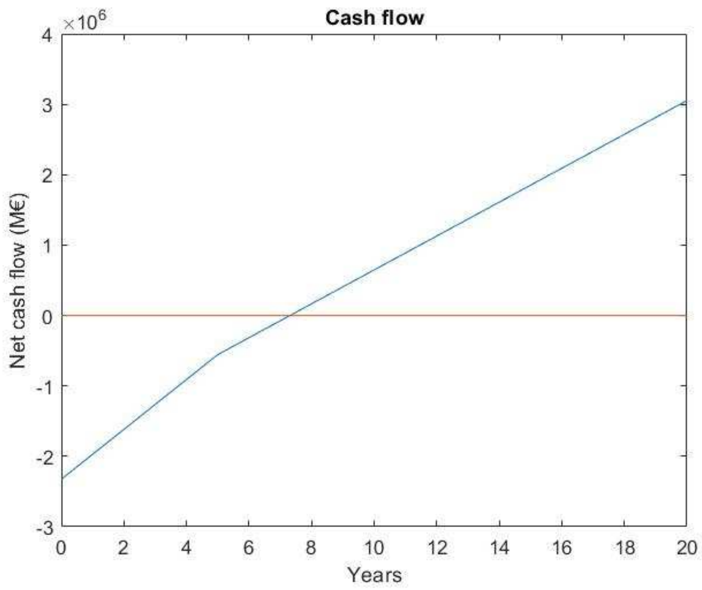

Figure 40 Cash flow trend of base scenario without WACC

Figure 40 shows the trend of the cash flow over the years. As mentioned above it can be seen that after five years there is a change in slope in the increase of the cash flow, due to the end of warranty and a consequent greater influence on operating and maintenance costs. Moreover, since the WACC is not considered the trend of the cash flow is linear over the years.

In this and subsequent scenarios it is not considered the influence of possible catastrophic events. Some of the weather conditions are taken into account in the failure rates of the several components of the wind turbine but further situation, more extreme, such as hurricanes or lightning which could causes severe damage or permanently destroy the turbine will lead to a drastic fall of the cash flow or in the worst situation a replacement of the turbine without a return on investment.

Pay-Back period (years)	7.3
NPV after 20 years (€)	3053929.25

Table 18 Results of the economical evaluation of base scenario without WACC

Base scenario with WACC

In the second version of the basic scenario the WACC is considered.

Year	Cash outflows			cash inflows	Cash flow
	inevstment	loss prod	failure cost		
0	-2325000				-2325000.00
1		-7758.02		341655.57	-1991102.45
2		-7318.89		322316.57	-1676104.77
3		-6904.61		304072.24	-1378937.14
4		-6513.78		286860.60	-1098590.32
5		-6145.08		270623.21	-834112.19
6		-5797.24	-79881.37	255304.91	-664485.89
7		-5469.10	-75359.78	240853.69	-504461.07
8		-5159.53	-71094.13	227220.46	-353494.27
9		-4867.48	-67069.94	214358.93	-211072.76
10		-4591.96	-63273.53	202225.40	-76712.84
11		-4332.04	-59692.01	190778.68	50041.80
12		-4086.83	-56313.21	179979.89	169621.65
13		-3855.50	-53125.67	169792.35	282432.83
14		-3637.26	-50118.56	160181.46	388858.47
15		-3431.38	-47281.66	151114.59	489260.01
16		-3237.15	-44605.34	142560.93	583978.46
17		-3053.92	-42080.51	134491.44	673335.47
18		-2881.05	-39698.59	126878.72	757634.55
19		-2717.97	-37451.50	119696.91	837161.98
20		-2564.13	-35331.61	112921.61	912187.85

Table 19 Cash flow of base scenario with WACC

As shown in the Table 19 the component of costs and the cash inflows are not constant over the years but decrease over time since the first year and this effect is more pronounced over the years. It can be noticed that after 20 years of operation the proceeds are worth a third of what they were in the first year. This affects the cash flow which increase more slowly than the case that does not consider the WACC, indeed, as highlighted in the table, the first year with a positive NPV is the eleventh, and not the eighth as in the previous case. Also, the NPV at the last year of operation is lower than one third of what it was on the case without the WACC, making the investment less attractive.

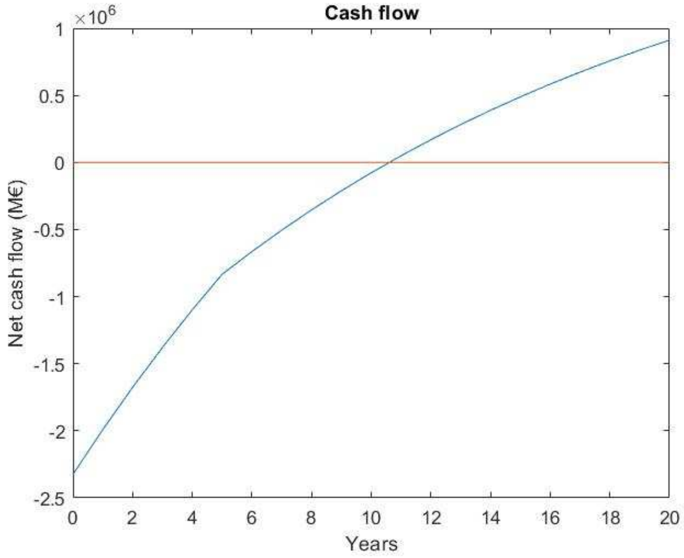

Figure 41 Cash flow trend of base scenario with WACC

Figure 41 shows the trend of the base scenario which, unlike the previous case, is influenced by the WACC causing a non-linear trend and with a smaller slope over the years.

Pay-Back period (years)	10.6
NVP after 20 years (€)	912187.85
LCOE (cent/kWh)	5.17

Table 20 Results of the economical evaluation of base scenario with WACC

5.4.2 Electricity cost scenario

The current scenarios are a variation of the previous one and differ only in the selling price of electricity, while initial investment and component failure costs remain the same as initial assumptions. Costs relating to loss of production, on the other hand, are influenced by the cost of electricity as it is proportional to it, if the cost of electricity is higher, the greater will be the costs related to production losses, since the hours of maintenance and the failure rates are the same.

Current electricity price scenario

The first scenario considers the cost of electricity on the wholesale market during the last semester of 2021. During that period, the cost of electricity varied significantly due to a rise in natural gas and coal prices, and a drop in wind power generation due to lack of wind. On the chapter on the cost of electricity, two values of the cost of electricity are reported, the first one reported by OECD refers to the fourth quarter of 2021 and is equal to EUR 96/MWh, the second one instead refers to the electricity price in the Irish wholesale market and is equal to 195 €/MWh. It is clear that the in this time frame the price of electricity is very variable and it is not possible to make price forecasts in the immediate future. In any case, to study how the current price of electricity affects the feasibility of the investment, an average price for 2021 is chosen equal to 125 €/MWh.

Year	cash outflows			Cash inflows	Cash flow
	inevstment	loss prod	failure cost		
0	-2325000				-2325000.00
1		-14853.77		520813.68	-1847679.33
2		-14012.99		491333.66	-1422865.64
3		-13219.81		463522.32	-1044782.97
4		-12471.51		437285.21	-708290.73
5		-11765.58		412533.22	-408813.84
6		-11099.60	-79881.37	389182.28	-198593.69
7		-10471.32	-75359.78	367153.09	-11498.50
8		-9878.61	-71094.13	346370.84	155015.55
9		-9319.44	-67069.94	326764.95	303212.46
10		-8791.93	-63273.53	308268.82	435107.19
11		-8294.27	-59692.01	290819.64	552493.02
12		-7824.78	-56313.21	274358.15	656966.00

13	-7381.87	-53125.67	258828.44	749946.58
14	-6964.03	-50118.56	244177.78	832698.96
15	-6569.84	-47281.66	230356.39	906348.28
16	-6197.96	-44605.34	217317.35	971895.92
17	-5847.13	-42080.51	205016.37	1030233.08
18	-5516.16	-39698.59	193411.67	1082152.95
19	-5203.93	-37451.50	182463.84	1128361.45
20	-4909.37	-35331.61	172135.70	1169486.85

Table 21 Cash flow of current electricity scenario

As shown in Table 21, an increase on the selling tariff of the electricity produced by the wind turbine, as it might be expected, leads to a greater economic convenience of the investment compared to the base scenario with interest rate considered. The first year with a positive VAN is indeed the eighth, instead of the eleventh of the previous case and the value of the VAN in the last year of operation is almost 30% greater in the current scenario.

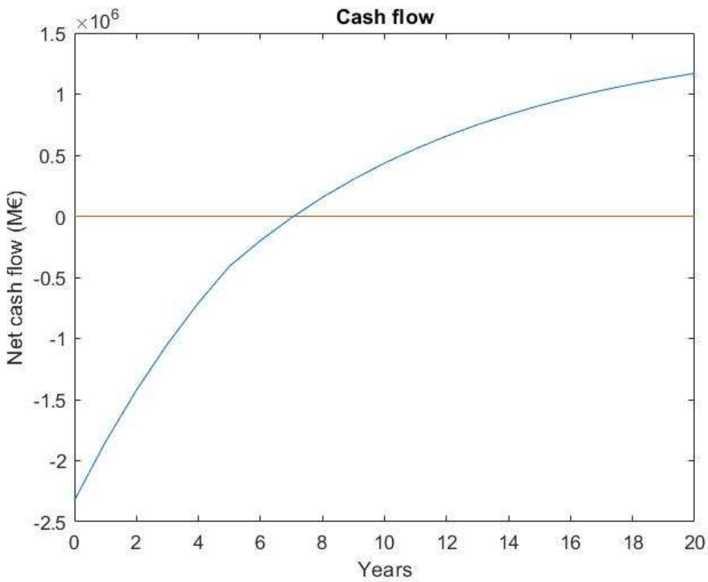

Figure 42 Cash flow trend of current electricity scenario

In conclusion, an increase in the sale price of electricity leads to an economic advantage, even if this increases not only the revenues but also the costs related to the stop of production. It must be taken into account that in this scenario the price of electricity has been defined in a temporal context of high volatility of its value, therefore the price considered could have an unreliable value for the near future, which could have a strong increase or return to pre-pandemic levels. This scenario is made to shows how the cost of electricity impact on the cash flow of the wind turbine, particularly, how it is affected by an increment of the price of more than the 50%.

Pay-Back period (years)	7.1
NVP after 20 years (€)	1169486.85
LCOE (cent/kWh)	5.17

Table 22 Results of the economical evaluation of current electricity scenario

Forecast electricity price scenario

The second variation of the electricity price scenario is a forecast of the electricity selling price to 2030. In the section it is discussed what the electricity selling price may be by analyzing different scenarios depending on the level of penetration of renewables in power generation. In accordance with environmental policies, it is reasonable to assume that renewable energy will make a greater contribution in 2030. Therefore, the sale price of electricity is set following these scenarios, all of which report values around 60 €/MWh. The selling price is reduced by 27% compared to the base scenario.

Similarly, a forecast to 2030 is also considered for capital costs. The price varies in a range between 800 and 1350 $\$_{2018}$/kW therefore an average value of 847 €/kW is considered for the simulation. The capital costs are reduced by 45% compared to the base scenario.

Year	**cash outflows**			**cash inflows**	**Cash flow**
	inevstment	**loss prod**	**failure cost**		
0	-1270500				-1270500
1		-5677.55		249990.57	-1040016.02
2		-5356.18		235840.16	-834886.10
3		-5053.00		222490.71	-652321.20
4		-4766.98		209896.90	-489839.09
5		-4497.15		198015.94	-345230.59
6		-4242.59	-79881.37	186807.49	-272842.75

7	-4002.45	-75359.78	176233.48	-208417.83
8	-3775.89	-71094.13	166258.00	-151079.89
9	-3562.16	-67069.94	156847.17	-100049.32
10	-3360.53	-63273.53	147969.03	-54632.29
11	-3170.31	-59692.01	139593.43	-14211.30
12	-2990.86	-56313.21	131691.91	21763.23
13	-2821.57	-53125.67	124237.65	53780.44
14	-2661.86	-50118.56	117205.33	82275.65
15	-2511.18	-47281.66	110571.07	107636.28
16	-2369.04	-44605.34	104312.33	130207.15
17	-2234.95	-42080.51	98407.86	150295.14
18	-2108.44	-39698.59	92837.60	168173.38
19	-1989.09	-37451.50	87582.64	184084.96
20	-1876.50	-35331.61	82625.13	198246.20

Table 23 Cash flow of forecast electricity scenario

The pay-back period in this case is around 12.4 years of operation. This is due to the reduction of the selling price of the electricity which it strongly affects the cash flow, even though the installation costs are considerably reduced and loss of production in monetary terms decrease due to the electricity price reduction.

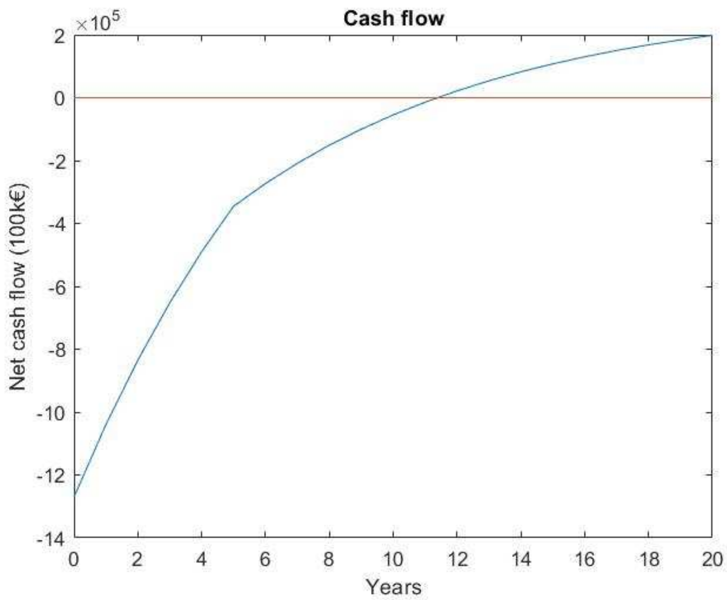

Figure 43 Cash flow trend of forecast electricity scenario

The levelized cost of electricity is lower compared to the previous cases due to the reduction of the initial investment costs and it is reduced by 33%.

Pay-Back period (years)	12.4
NVP after 20 years (€)	198246.20
LCOE (cent/kWh)	3.45

Table 24 Results of the economical evaluation of forecast electricity scenario

A third case, which is not reported, considers an electricity price of 60 €/MWh but without a decrease on the investment costs. This scenario shows a non-return of the investment over the period considered, indeed the NPV at the end of the life cycle is negative.

5.4.3 WACC variation scenarios

The current scenarios are a variation of the previous one and differ only in the weighted average cost of capital. As a result, maintenance costs, production losses, and revenues also vary, all being affected by the interest rate, while the initial investment cost is the same since it is done in the first year and therefore it is not affected by the wacc.

Decrease of the WACC

The first case of the WACC variation scenarios considers a decrease of the interest rate of 10% compared to the base scenario, therefore the WACC it is equal to 5.4%.

Year	cash outflows			Cash inflows	Cash flow
	inevstment	loss prod	failure cost		
0	-2325000				-2325000.00
1		-7802.18		343600.47	-1989201.71
2		-7402.45		325996.66	-1670607.50
3		-7023.20		309294.74	-1368335.96
4		-6663.37		293448.52	-1081550.82
5		-6321.99		278414.15	-809458.65
6		-5998.09	-82648.89	264150.05	-633955.58
7		-5690.79	-78414.51	250616.75	-467444.13
8		-5399.23	-74397.07	237776.80	-309463.62
9		-5122.61	-70585.45	225594.69	-159577.00
10		-4860.16	-66969.12	214036.71	-17369.57
11		-4611.16	-63538.06	203070.88	117552.09
12		-4374.91	-60282.79	192666.87	245561.25
13		-4150.77	-57194.30	182795.89	367012.06
14		-3938.11	-54264.04	173430.63	482240.54
15		-3736.35	-51483.91	164545.19	591565.48
16		-3544.92	-48846.22	156114.98	695289.32
17		-3363.31	-46343.66	148116.68	793699.04
18		-3190.99	-43969.32	140528.16	887066.90
19		-3027.51	-41716.62	133328.43	975651.20
20		-2872.40	-39579.33	126497.56	1059697.03

Table 25 Cash flow of decrease of the WACC scenario

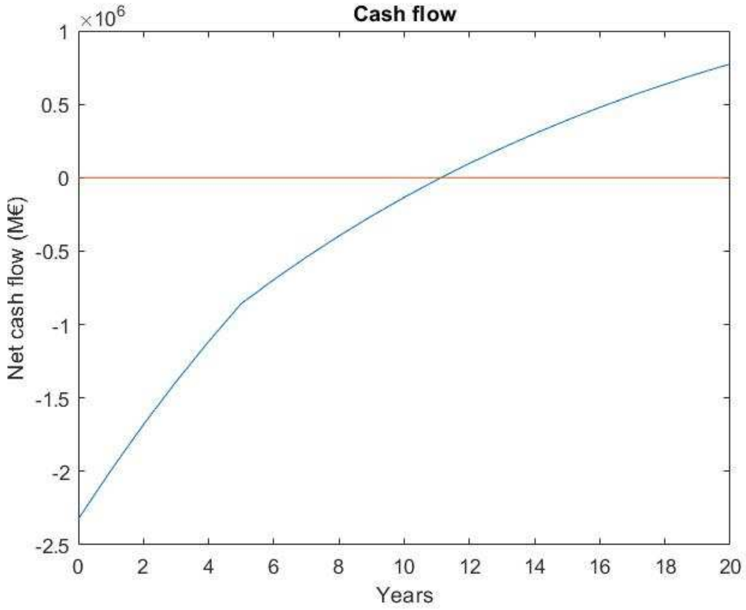

Figure 44 Cash flow trend of decrease of the WACC scenario

A change in the interest rate causes a change in both operating costs and revenues from the sale of electricity but overall, the cash flow does not change much compared to the base case. A 20% decrease in the interest rate would, for example, lead to a payback time of 9.6 years, which is not far from the 10.5 or so of the base case.

Pay-Back period (years)	10.1
NVP after 20 years (€)	1059697.03
LCOE (cent/kWh)	5.00

Table 26 Results of the economical evaluation of decrease of the WACC scenario

Increase of the WACC

The first case of the WACC variation scenarios considers an increase of the interest rate of 10% compared to the base scenario, therefore the WACC it is equal to 6.6%.

Year	**cash outflows**			**Cash inflows**	**Cash flow**
	inevstment	**loss prod**	**failure cost**		
0	-2325000				-2325000.00

1	-7714.35		339732.55	-1992981.80
2	-7236.73		318698.45	-1681520.08
3	-6788.68		298966.65	-1389342.10
4	-6368.36		280456.52	-1115253.94
5	-5974.08		263092.42	-858135.59
6	-5604.20	-77221.36	246803.40	-694157.75
7	-5257.22	-72440.30	231522.89	-540332.39
8	-4931.73	-67955.26	217188.45	-396030.92
9	-4626.39	-63747.90	203741.51	-260663.69
10	-4339.95	-59801.03	191127.12	-133677.55
11	-4071.25	-56098.53	179293.73	-14553.58
12	-3819.18	-52625.26	168193.00	97194.97
13	-3582.72	-49367.03	157779.55	202024.77
14	-3360.90	-46310.54	148010.83	300364.16
15	-3152.82	-43443.28	138846.93	392614.99
16	-2957.61	-40753.55	130250.41	479154.24
17	-2774.50	-38230.34	122186.12	560335.52
18	-2602.72	-35863.36	114621.13	636490.57
19	-2441.57	-33642.93	107524.51	707930.58
20	-2290.41	-31559.97	100867.27	774947.47

Table 27 Cash flow of increase of the WACC scenario

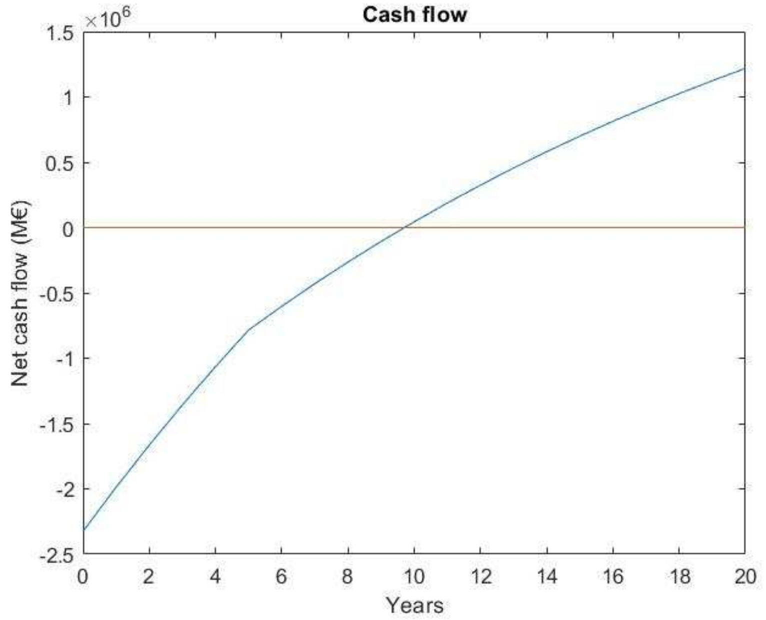

Figure 45 Cash flow trend of increase of the WACC scenario

Pay-Back period (years)	11.2
NVP after 20 years (€)	774947.47
LCOE (cent/kWh)	5.35

Table 28 Cash flow of increase of the WACC scenario

5.5 Comparison with actual data

The LCOE of onshore wind power plants in 2021, with specific plant costs ranging from 1400 to 2000 EUR/kW, are between 3.94 and 8.29 €cent/kWh.

The LCOE of onshore wind power plants are among the lowest of all technologies, together with PV utility-scale. From current LCOE between 3.94 and 8.29 €cent/kWh, costs will decrease in the long term to between 3.40 and 6.97 €cent/kWh (Kost et al., 2021).

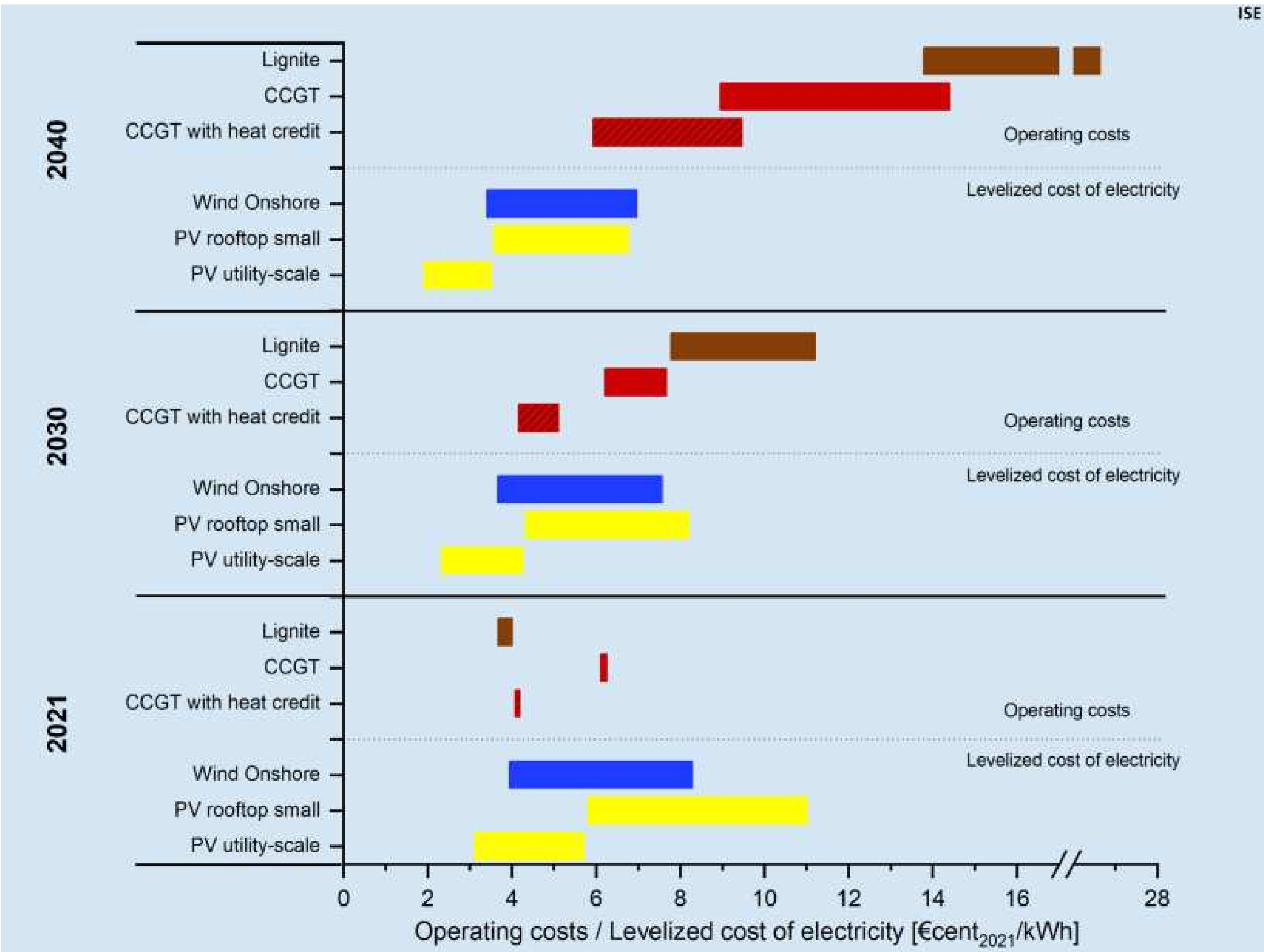

Figure 46 Comparison of LCOE of renewables with operating costs of existing conventional fossil-fuel power plants in 2021, 2030, and 2040 (Kost et al., 2021)

As shown in Figure 46 the LOCE of every scenario is in line as what is reported from the study. Also, for the electricity price forecast to 2030 the resulting cost of electricity is in the range of the forecast made by the study. Comparing the result with this data it can be argued that the investment of a wind turbine at the site under consideration could prove to be a worthwhile investment.

6 Conclusions

The use of wind power for power production, based on WTs, occupies a great part in the electricity market worldwide and has become increasingly attractive in many windy countries, nowadays. Worthy development and exploitation of wind energy might improve the renewable power generation capabilities, maximizing the specific energy produced, and contributing to electricity production at reasonable costs.

In this work a is presented a model to evaluate the possible production of a wind turbine located in Ireland starting from the data windiness of the site. Three wind turbines models of the same power size are compared using a model to evaluate the electricity production to find which one is more suitable for the site.

The *Fuhrländer FL MD 77* wind turbine model turns out to be the best option which gives an annual electricity production of 4,416 MWh considering electricity and mechanical efficiency. This result is from the model of analysis of the windiness of the site in which the empirical method is used for the Weibull distribution because it is the method which has the lowest errors on the actual wind speed data.

The capacity factor of the turbine is equal to 33.6% which is in line with what the IEA reported which is that the average capacity factor of wind farms in Ireland in 2020 was 30%, higher than in previous years.

Considering a selling price of the electricity on the Ireland wholesale market equal to 82 €/MWh gives a yearly revenue of 362154.9 €, value which on the several scenarios is varied only in those the price of electricity is varied. Again, for the base scenario the investment cost per kW of power of the turbine and the operating and maintenance costs are considered fixed and they are respectively 1550 €/kW and 121.536,75 (annually).

Another parameter is the weighted average cost of capital or interest rate which is equal to 6% for all the cases except for those scenarios in which the change in the interest rate is studied.

The results of each scenario are the following:

1. For the base scenario which considers the WACC the pay-back period of the investment is about 10.6 years, the net present value of the plant at the 20-th year of operation is equal to 912187.85 € and the levelized cost of electricity is 5.17 €cent/kWh.
2. For the electricity price scenarios, a current selling tariff and a forecast price are considered. In the first one it is chosen a price of 125 €/MWh which is an increase of more than 50% compared to the base scenario. The pay-back period is about 7.1 years, the NPV at the end of life is 1169486.85 € and the LCOE is the same as the base the case since the electricity price does not affect this parameter.

   The price forecast scenario considers an electricity price of 60 €/MWh and at the same time a reduction of the investment cost to 847 € per each kW of power of turbine installed. The pay-back period is about 12.4 years, the NPV at the end of life is 198246.20 €.

A further study considers an electricity price of 60 €/MWh but without a decrease on the investment costs and sees a non-return of the investment in the lifetime of the wind turbine.

3. For the WACC scenario a variation of the interest of ± 10% is considered. In the scenario in which it decreases and equal to 5.4% the pay-back period is about 10.1 years, the NPV at the end of life is 1059697.03 and the LCOE is 5 €cent/kWh.

   In the scenario in which it decreases and equal to 6.6% the pay-back period is about 11.2 years, the NPV at the end of life is 774947.47 and the LCOE is 5.35 €cent/kWh.

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