POLITECNICO DI TORINO

Master of science in Engineering and Management

Financial modeling to support decisions in offshore wind power projects

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Abstract

Wind power plays an important role in European low carbon's energy transition. Offshore wind investments have reached a reasonable maturity over the past decade with more than 90 wind farms in operation in the European countries. The advantages of wind power are many resulting in a considerable growth demand for this technology. This thesis is the result of an intensive collaboration with RINA S.p.A, company sited in Genoa (Italy).

An innovative and accurate Discounted Cash Flow Financial Model for Offshore wind power projects is verified and developed, with the objective to facilitate the evaluation and the decision-making process in Offshore wind projects for possible investors.

This thesis is a result of a deep analysis of the entire value chain of the wind power. The initial section of the work is a focus on the state of art analysis documenting the general investment trends in the market, the emerging evolutions in the different countries and the presentation of important index to predict the possible actual and future interest in the technology. After a brief and non-technical explanation of how a wind turbine works is developed an environmental and risks assessment for an offshore wind power project. After that, in chapter two is performed the literature review regarding Offshore financial model to analyze what is available in the literature regarding this topic, the chapter finishes with a theoretical sub-chapter regarding the financial and non-financial methods to evaluate the profitability of an investment.

The final section is dedicated to the case study that is analyzed in depth along the five typical phases of an energy project here mentioned: Development and Consenting, Production and Acquisition, Installation and Commissioning, Operation and maintenance and Decommissioning and Disposal. To each of this phase are linked different costs, these costs are estimated using the most recent equations available in the literature.

After having set a series of financial hypothesis, investments returns are calculated with a detailed assessment that takes in consideration the technical parameters of the problem. First, a deterministic model is developed, based on a realistic case study of an Offshore wind farm in UK, follows a sensitivity analysis to test how input parameters influence the model output. The sensitivity analysis highlights that the model outputs are extremely sensitive to the initial capital expenditure, as well as to some financial parameters and revenue parameters. In addition, all the main critical issues faced during the assessment of an Offshore project are evaluated and explained.

Methodology

Aim

This thesis has two objectives, the first one is to provide a general overview of the wind power technology to have a broad understanding of the technology and of its competitiveness. This overview focuses, firstly, on the overall investment done in the technology and on its evolution over time, then on a detail analysis of useful indicators to possibly predict the future interest in the technology. To conclude the overview, studies on the main cost drivers in offshore wind power project, a risk analysis and a study on the environmental impacts are performed. The second objective is to design a mathematical model to represent the financial performance of an Offshore wind power project. When an Offshore wind farm wants to be realized many financial analyses must be performed. These analyses can include studies on how much money is to be raised, the mixture of securities that must be adopted, the projected financial return, the possible risks related to the project etc. To define and therefore have a broad picture of the project a financial model is required.

This thesis develops such a tool by performing a financial feasibility study using the Discounted Cash Flow approach. The financial model integrates all the essential things strictly related to wind power to develop a financial model more accurate as possible and more user friendly as possible. First, a deterministic approach is developed, and outputs are determined by the parameter values and initial conditions. Then, a sensitivity analysis on the main critical variables that can affect the final financial result is performed to see how they could affect these final financial parameters. This work develops, verifies and validates such a tool on a suitable case study based in United Kingdom.

Introduction

Energy outlook

BP provides annually a report in which analyses and try to predict the trend in the consumption of energy in the future.

According to [1] the world GDP will double by 2040, this increase will mainly due to a fast economic increase of the emerging markets. This increase will obviously provide an increase in the global energy demand, that due to accelerating gains in energy efficiency will only increase around one third over the next 25 years. China, India and other emerging countries placed in Asia will account for around two-thirds of the growth in energy consumption. Renewable energy, as energy source, will be the one with the highest percentage growth, renewable source will account for 40% of the increase of primary energy as figure 1 represents.

In the forecasted scenario carbon emissions from energy production usage will increase by 10% by 2040. This rate is far slower considering what we have seen in the past 25 years, when carbon emission increased 55%. However, the projected increase in the carbon emissions is higher than the declined that was agreed among the nations in the Paris agreement. Therefore, this highlights the need for a more decisive change regarding carbon emissions. The left picture in figure 1 shows how energy sources will change for energy production in the future according to [1] and on the right is highlighted the evolution considering three scenarios about the carbon emission always accordingly to [1].

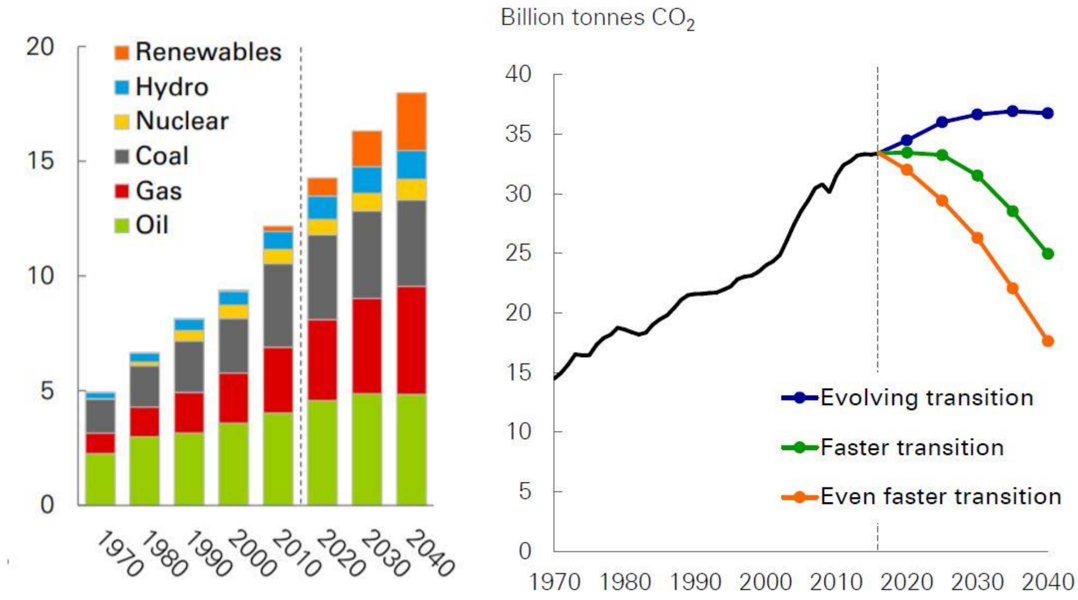

Figure 1: Energy transition by sources and carbon emissions considering three scenarios; source [1]

Investments trends in renewable energy

Investments in renewable energy are increasing and have reached USD 330 billion in 2015 and USD 263 billion in 2016 [2]. An important milestone was achieved by the investment in renewable in 2015, in fact from 2015 renewable power technologies for the first time attracted more finance than non-renewable power technologies, a trend that is still continuing from 2015 [3]

While annual investments declined in 2016 as figure 1 shows, the additional capacity installed in 2016 was even higher compared to the one installed in 2015 as it is described in figure 2. Figure 2 considers just the solar and the wind power (both offshore and onshore) because they account for about the 90% of new renewable investment and 80% of new renewable capacity installed.

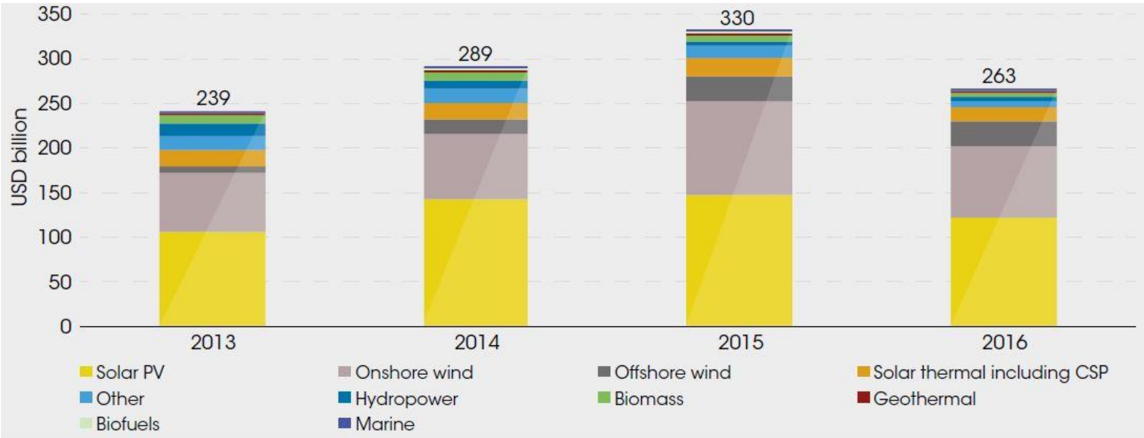

Figure 2: Renewable energy annual investment by technology type; source: [3]

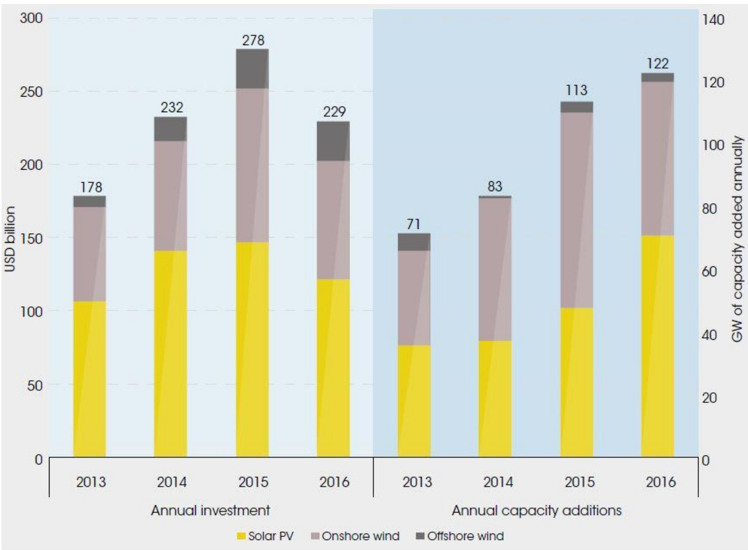

Figure 3: Solar PV and wind power annual investment and capacity additions, source: [3]

According to [3], the decrease in investment in renewable between 2015 and 2016 is because of two reasons. Lower technologies cost is the driver of the first reason, as each dollar of investment financed more capacity compared to 2015. The second one is due to a reduction in the volume of megawatts financed. A high percentage of this trend was caused by China, where, to enjoy feed-in tariff reductions, projects were finalized ahead of schedule. Also in Japan, Germany and UK feed in tariff played an important role and affected the investment between 2015 and 2016.

Looking on the long run, according to [4], 40% of the growth in power generation will be due to renewable, that are the fastest growing fuel source.

This enormous increase will bring the share of global power of renewables nearly 20% by 2035(in 2016 it accounted for 7%). The European union is still the first continent for renewable penetration. According to [4], EU will be able to double its renewable penetration reaching 40% by 2035.

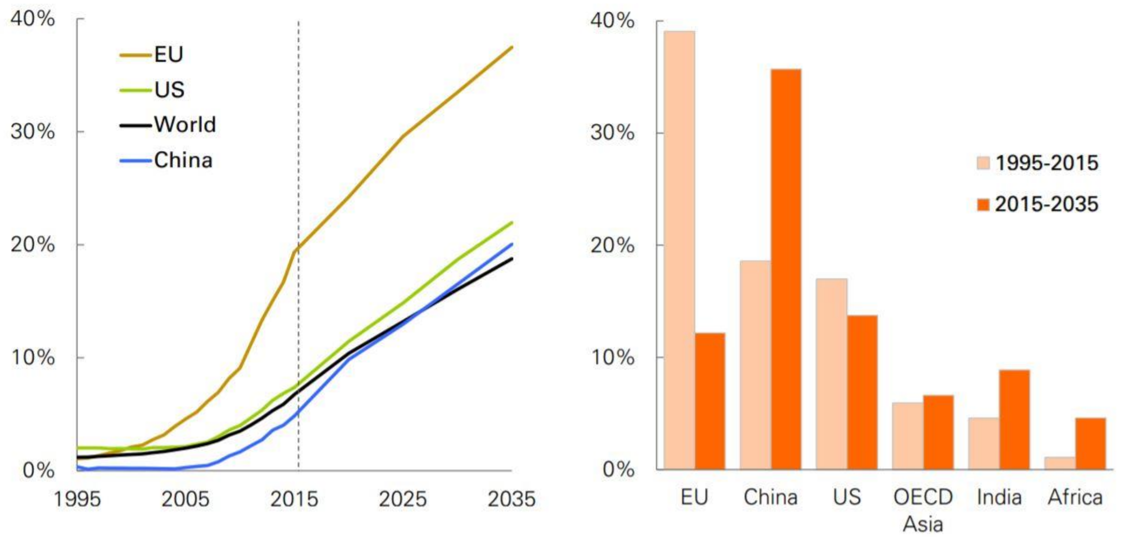

Figure 4: Renewables shares of power generation; source [4]

An increase in competitiveness of both solar and wind power is the main reason of this strong increase in renewables that will be under our eyes in the following years. According to [4], the cost of the main component of the solar power, the photovoltaic module, will continue falling in the next years but this cost will have a declined share of the total installed solar costs in the near future. In opposition, wind power costs are assumed to fall materially. Therefore, there is an extremely urgency to improve the performance of the wind turbines in harvesting the wind. The finance and investment landscape developed by [3] is shown in figure 5. The figure shows global renewable energy finance flows along the life cycle in 2015 and 2016, taking in consideration the full range of sources, instruments, regions and technologies, as well as distinctions between public and private finance sources. Values are averages of the data for the two years in USD billion. Direct public investment has typically constituted a small share of total renewable energy finance, fluctuating between 12% and 16% in 2013-2015, and dipping to 8% in 2016. The bulk of renewable energy investment – more than 90% in 2016 – is financed from private sources. The East Asia-Pacific region had the highest levels of private finance, averaging USD 101 billion annually in 2015-2016, followed by Western Europe, which averaged USD 55 billion during the same timeframe. Overall, private renewable energy investment stayed predominantly (93%) within the country of origin; by contrast, public investment saw a much more balanced split of public investment between in-country financing and international financing. Project developers contributed 40% of private finance each year, mostly concentrated in China, Japan, the UK and the US. Commercial financial institutions accounted for 23% of investment of such private finance in 2014-2016, hitting a high of USD 69 billion in 2015.

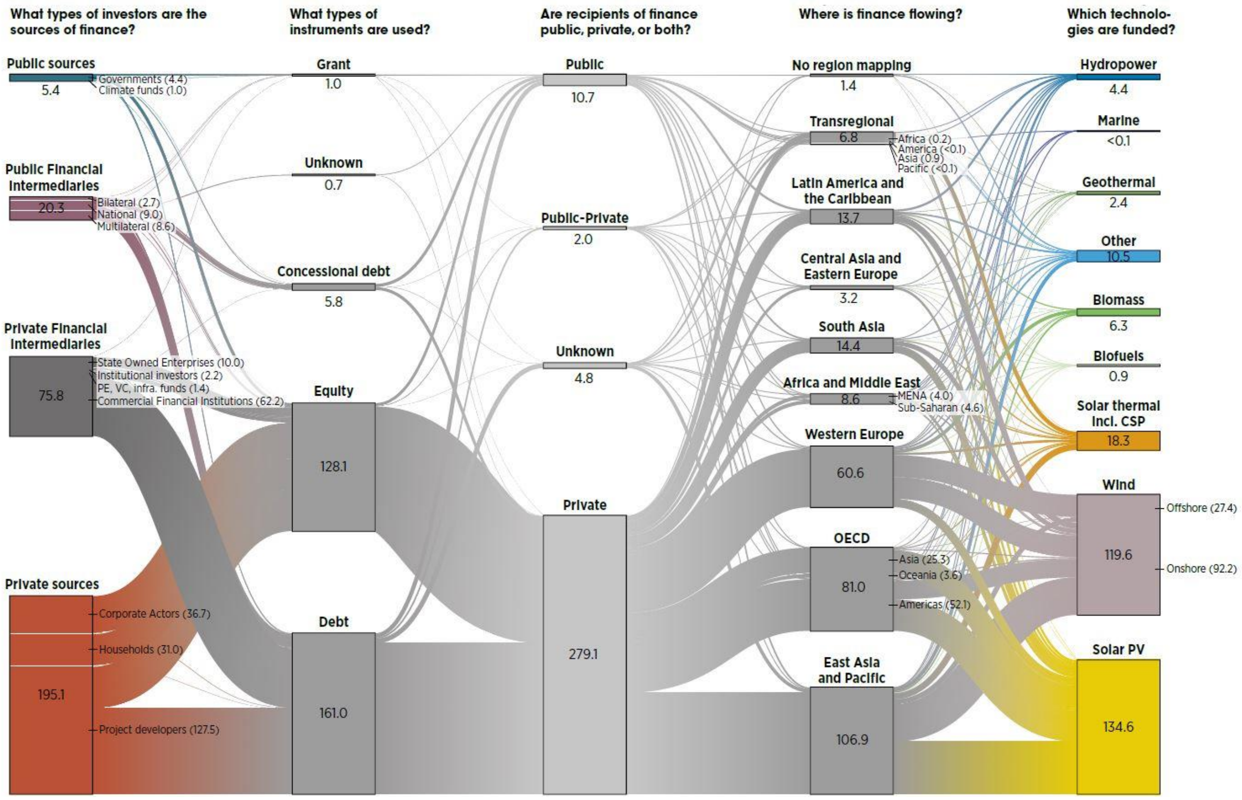

Figure 5: Global landscape of renewable energy finance 2015/2016; source: [3]

By the end of 2016, 147 countries had renewable energy support policies in place. While feed-in tariffs/premiums continue to be implemented, falling costs and grid integration issues have driven an increase in the use of auction mechanisms.
Investment in solar and wind (onshore and offshore) accounted for, on average, 90% of total private finance between 2013 and 2016. This reflects the maturity of solar and wind power technologies.

Wind power as an emerging trend

A growing number of countries are receiving the benefits of the wind power. In 2017, approximately 12% of EU annual electricity consumption was covered by wind energy. At least 8 EU countries overpassed the threshold of 12%, among these countries there is the Denmark that met 44% of its annual electricity consumption with wind power. The wind power global capacity is increasing year by year as figure 5 shows. Costa Rica, Nicaragua and Uruguay are among the 13 countries that met 10% or more of their annual electricity consumption with wind power. Globally, wind power provides an estimated 5.6% of total electricity generation.[5]

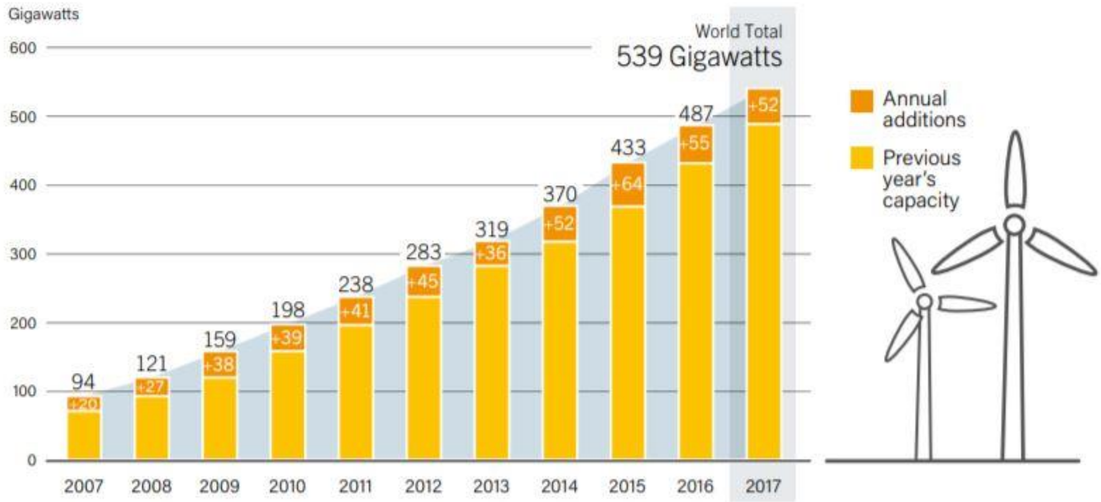

Figure 6: Wind Power Global capacity and additions; source: [5]

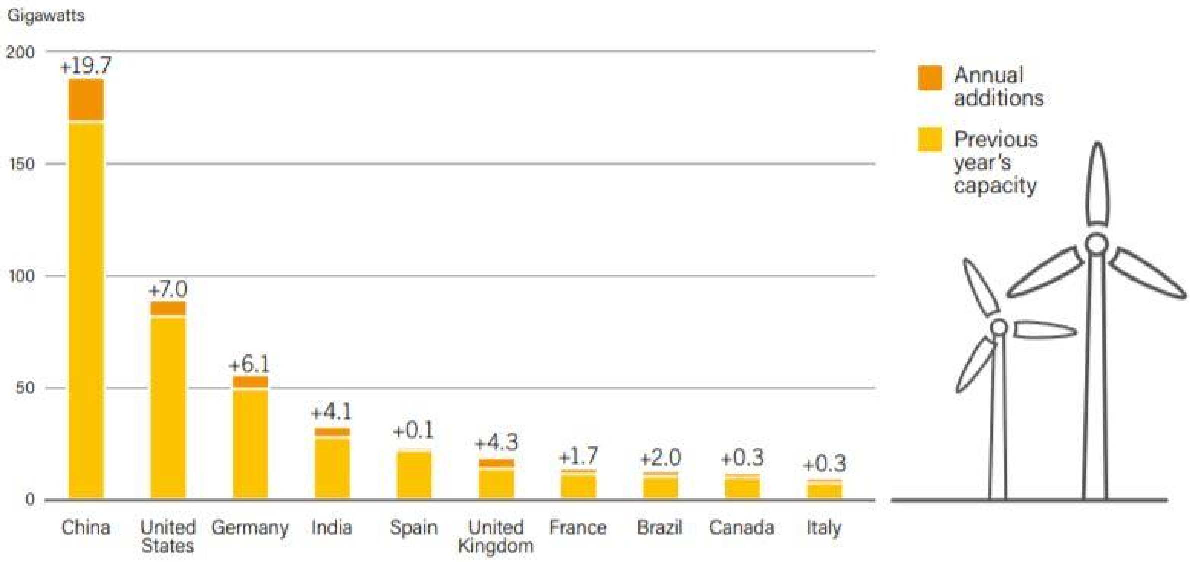

Figure 7: Wind Power capacity and additions, Top 10 countries; source: [5]

In 2017, for the ninth consecutive year Asia was the biggest market representing about 50% of added capacity, second was Europe with about 30% of the total added capacity, the rest was 14% for North America and almost 6% for Latin America and Caribbean.

Chapter 1: State of the art – Wind power in depth analysis

1.1 Main manufacturers

Since this type of technology is improving technologically quite quickly and is becoming more and more profitable, competition among the manufacturers in the industry is increasing, competitors are looking for ways to reduce costs and to contribute to the consolidation of this industry.

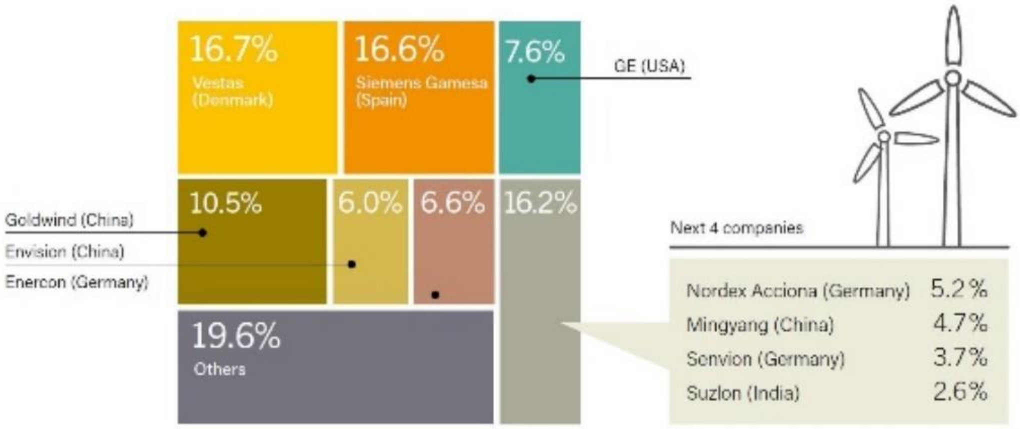

Figure 8: Market share of Top 10 producers of turbine, 2017, source:[5]

The competition is increasing and so the top 10 manufacturers increased their market share at the expense of smaller manufacturers (nearly 80%, up from 75% in 2016).
Thank you to the global presence Vestas (Denmark) is maintaining its position as the largest supplier of wind turbines. Siemens Gamesa, company created by the merge between two giants Siemens and Gamesa follows Vestas closely with 16.6% of market share. China's Goldwind accounts for 10.5% of market share, it mainly focuses on domestic project that represent about 90% of new projects.
GE, the main US manufacturer is fourth, followed by Germany's Enercon, which had a record year thanks to a strong domestic market. The huge increase of Goldwind and Envision in the Chinese market made drop the volumes of the other Chinese manufacturers.
China, EU, India and the United States are mainly the countries in which the wind turbine is manufactured, instead, the manufacturing of the components such as the blades take place in locations closer to the supply market. The main manufacturers listed above are opening new

offices/ manufacturing plants to be closer to the emerging markets, as companies seek to reduce cost of transport and look for new source of revenue.
Here some examples of how main producers are trying to address and localize in different countries in order to reduce transportation costs of components:

- European turbine makers: Vestas, Nordex and Senvion invested in India, which is having a rapid growth
- The third blade factory was opened by Siemens Gamesa in India and it launched the first Africa's first blade factory in Morocco
- A new blade manufacturing plant has been built by LM Windpower (Denmark; part of GE) in Turkey to supply the rapidly growing market there, and opened its fourth blade factory in northeastern China

These are only three of the many examples of companies that are tending to localize closer to the new emerging markets.

1.2 The Capacity factor and its evolution overtime for both onshore and offshore

Before analyzing how a wind turbine works it is good to have in mind what the capacity factor and the Levelized Cost Of energy (LCOE) are.

The capacity factor is defined on Wikipedia as "The ratio of an actual electrical energy output over a given period of time to the maximum possible electrical energy output over that period". The capacity factor is an important parameter to take into account when making forecasts of the future energy that the wind power will produce. A higher capacity factor will provide, considering the other factors equal, a higher produced energy compared to a smaller capacity factor.
Wind quality and technology used are therefore two factors that heavily affect the capacity factors. In the recent years we have assisted to an improvement in the turbine technologies and thank you to these improvements, there has been a consistent trend towards higher capacity factors globally, but with significant variations by market. These improvements are mainly driven by a growth in the average hub height, turbine rating and rotor diameters of installed turbines, but also by more efficient material and more quality resource. In 2017, the global weighted average capacity factor for onshore wind increased from around 20% in 1983 to around 29% [6]. For new offshore commissioned plant the average capacity factor, always

mentioned in [6], reached around 42%. Therefore, based on the above sentence, the capacity factor for offshore wind power is a higher compared to onshore. This is due to mainly two reasons, the first one is the location; usually offshore turbines are set in windier places, the second one is about the dimension of the turbine that are bigger for offshore than for onshore. A graphical representation of the data above mentioned is given by figure 9.

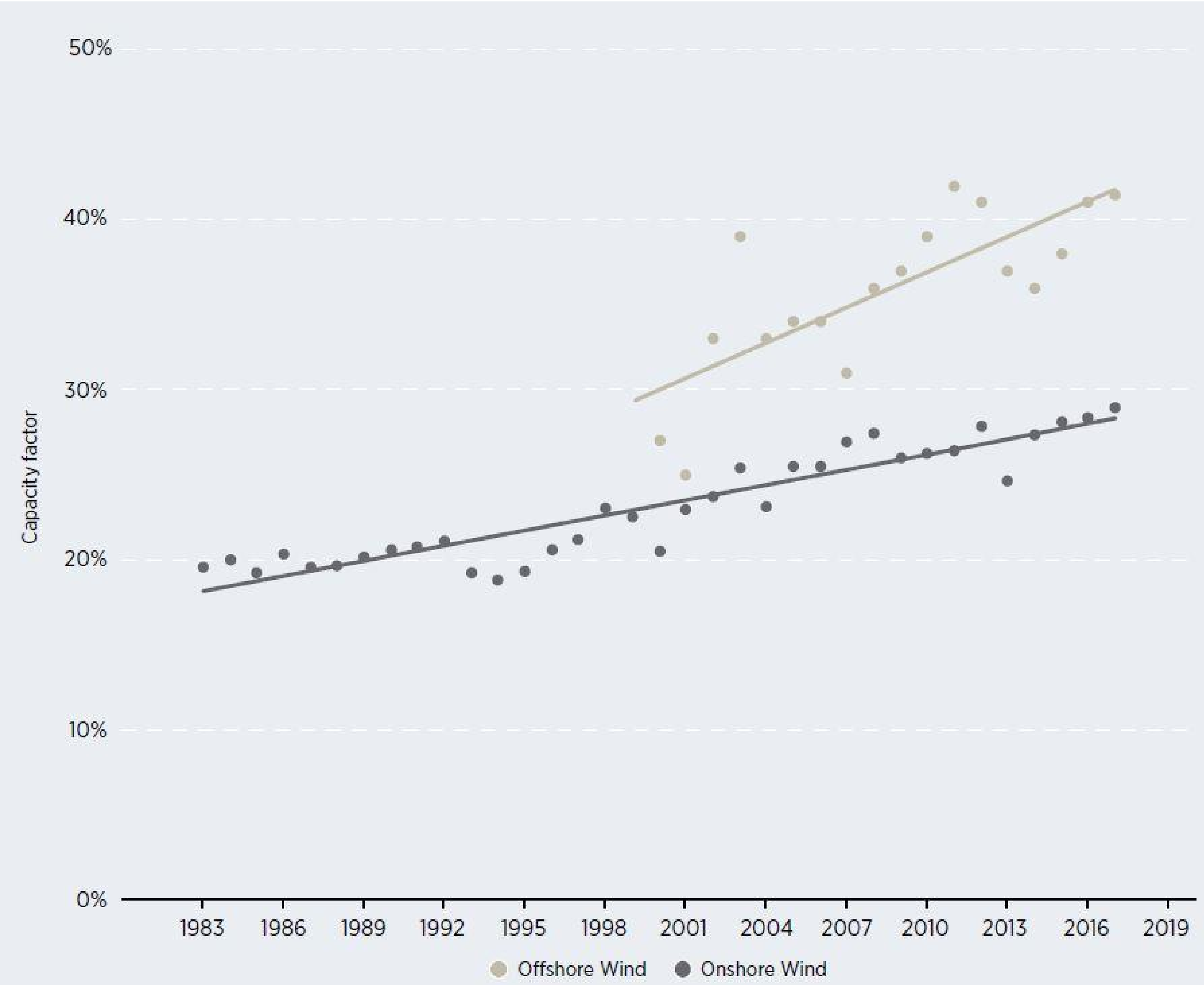

Figure 9: Evolution of the capacity factors over time for both onshore and offshore wind power; source: [6]

1.3 The Levelized cost of energy (LCOE) of wind power

The levelized cost of energy or LCOE is similar to the concept of breakeven point. The LCOE is a measurement that allow to calculate how much money must be made per unit of electricity (kWh, MWh etc.) to recoup the lifetime costs of the project. The CAPEX, the maintenance costs, the cost of fuel for the system (if any), the OPEX, the discount rate and the Capacity factor are factors that are all taken in considerations when calculating the LCOE. There are many potential trade-offs to be considered when developing an LCOE modelling approach. The formula used for calculating the LCOE of renewable energy technologies is provided by [3] and is :

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{Mel}{(1+i)^t}}$$

Where I_0 stands for initial investment, Mel for the electricity produced in the year t, A_t for total annual cost in the year t, i for the real interest rate %, n the years of lifetime and t the current year.

By knowing the LCOE and so by knowing the cost per kWh generated for our project we can decide if our project is competitive and if it can be profitable in the future. Figure 10 shows the global average levelized cost of electricity of onshore wind, 1983-2017 [6]. The global weighted average LCOE declined from USD 0.40/kWh in 1983 to USD 0.06/kWh and even less in 2017, an 85% decline.

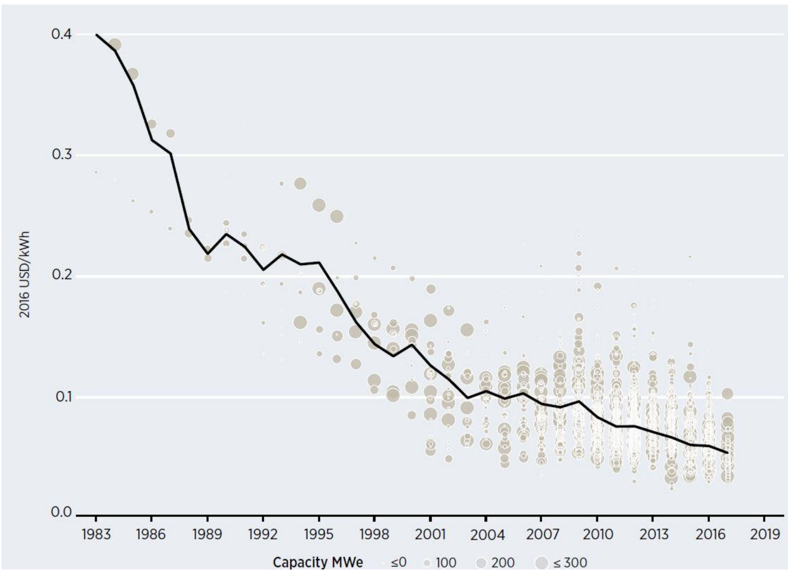

Figure 10: Evolution of the LCOE for onshore wind power; source: [6]

During the 2016, China, India, Brazil, Eurasia and North America had the best LCOE, it varied from USD 0.06 to USD 0.07/kWh. In these countries and regions is present more than half of global cumulative installed capacity.

From 2010-2016, as figure 11 represents, the global weighted average LCOE of offshore wind decreased from USD 0.17 to USD 0.14/kWh, despite total installed costs having increased by 8% during this period. This has been made possible by improved technology that has allowed higher capacity factors that have more than offset the increase in installed costs observed in this period. The higher value of LCOE compared with onshore wind is due to the higher costs of installations that obviously offshore wind requires.

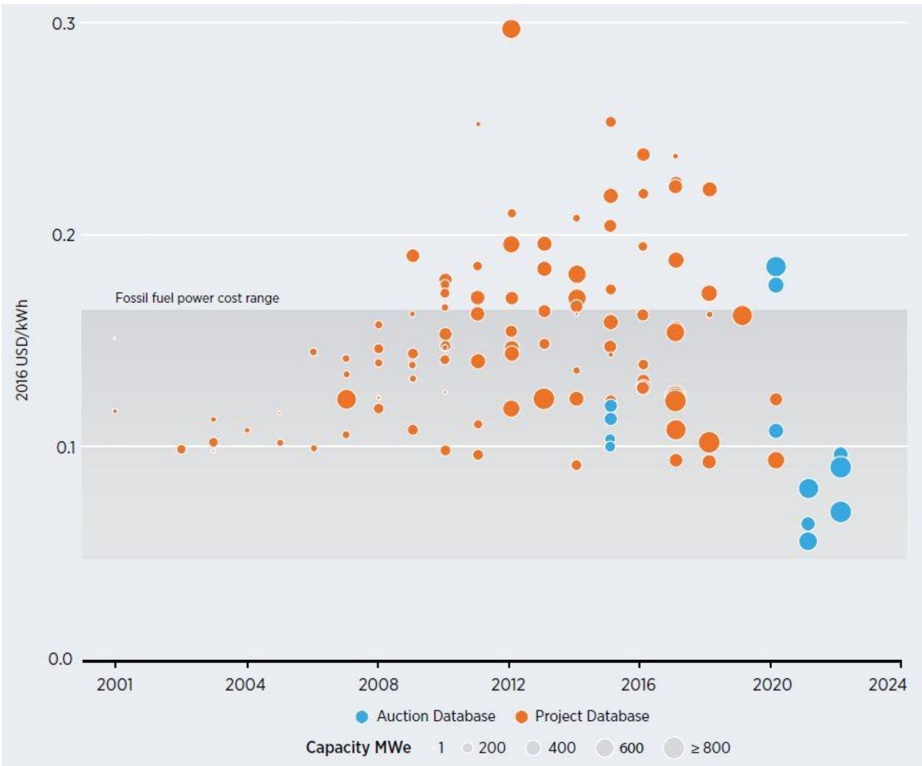

Figure 11: Evolution of the LCOE for offshore wind; source: [6]

An important and recent analysis, dated November 2018, developed by the financial advisor Lazard [7] announced that the LCOE for wind power source is the most affordable one comparing both renewable and conventional sources. Here an extract of how, according to Lazard renewable energy can play an important role in the future: “We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including environmental and social consequences of various conventional generation technologies, RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase and government subsidies in certain regions”

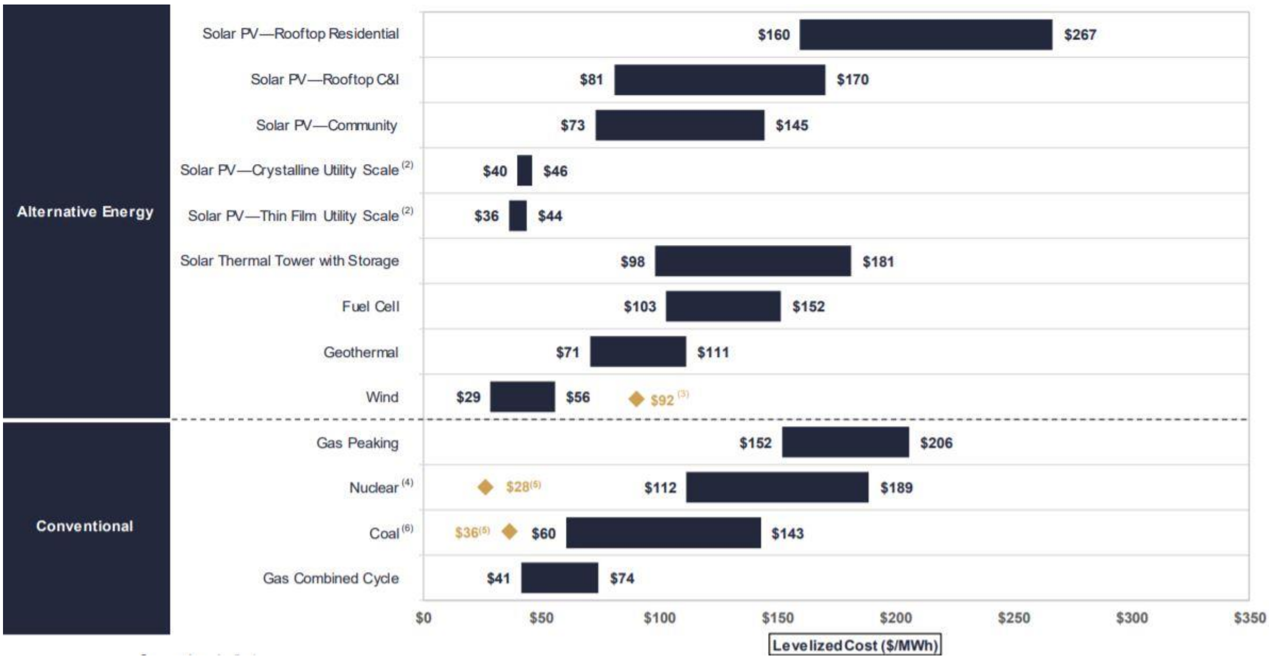

Figure 12: The levelized cost of energy for alternative and conventional source of energy: source: [7]

As can been easily seen from figure 10, the wind power that consider both onshore and offshore wind power has got the lowest value for LCOE. This means that to generate a hypothetical MWh are required from 29 dollars to 56 dollars, it is therefore the cheapest way to produce energy according to Lazard. This is a super important result that should even more place the wind power in the spotlight.

1.4 How a wind turbine works and new emerging evolutions for the foundations for offshore wind farm

The basic principle for the exploitation of wind energy is apparently simple: the wind force causes the movement of the blades; these blades are connected with a rotor hub that forces them to perform a rotary motion around the axis of the axle. The rotor hub is connected to a series of devices (brakes, gearbox etc.) which transmit the motion to an electric generator; that is in charge of converting mechanical energy into electrical energy.

The electrical energy generated in this way is first treated in a series of devices (groups power factor correction, capacitor banks, elevator transformers, etc.) which make this energy produced compatible with the transport network to which it will be connected thank you to a special cable. These wind-powered machines can be divided into two groups, vertical axis wind turbines and horizontal.

1.4.1 Vertical axis wind turbines

The rotor rotates with an axis perpendicular to the direction of the wind, while the blades are moving in the direction of the rotor. It is not necessary to orient them according to the wind direction. The small number of moving parts in the structure compared to the horizontal one gives to these wind turbines a high resistance to strong wind and high turbulence conditions. However, the efficiency of these kind of turbine result to be lower compared to the horizontal one.

1.4.2 Horizontal axis generators

The rotor hub axis is parallel to the wind direction and the rotor hub rotates on a plane perpendicular to the wind direction. The high speeds of rotation that are achieved with this system allow to reach high power coefficient. This system is able to operate even at low wind speeds. In order to guarantee a constant and high efficiency the wind direction has to be aligned with the rotor axis; for this purpose, systems of mechanical or aerodynamic adjustment must be used.

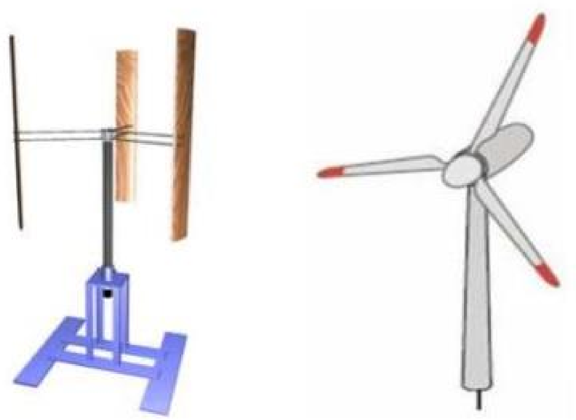

Figure 13: Example of vertical and horizontal wind turbines; source:[8]

All wind turbines with horizontal axis, beyond the sizes (micro, mini or large) and of the models, have many fundamental and common components as [8] mentions :

- **Rotor**: this is the assembly part formed by the rotor blades, the rotor hub, the rotor bearing etc. Two-bladed rotors are the cheapest one and run at higher speeds than three-bladed ones but tend to vibrate more and to be noisier. There are also rotors with only one blade, balanced by a counterweight, which turn even faster than the two and three blades, but they are the worst in terms of energy consumption. For big turbines and in particular for offshore wind energy generation the best option result to be the three-bladed rotors.

- **Braking system**: It is essential for controlling the power of the wind turbine and to stop the rotor in case of excessive wind speed

- **Tower**: The tower supports the nacelle and the rotor. The objective of the tower is to limitate the oscillations and vibrations caused by wind. It must be anchored to the ground or seabed with reinforced foundations

- **Gearbox**: It is necessary to transform the slow rotation of the blades into a faster rotation that can make the electricity generator works

- **Generator**: It transforms the mechanical energy of the rotation of the blades into electricity

- **Control system**: It is used to manage the operation of the wind turbine and automatically activate the safety device that locks the operation of the wind turbine in the event of a malfunction or of overload due to excessive wind speed

- **Nacelle**: It is located at the top of the tower in which are located all the above components with the exception of the rotor blades and rotor hub. The nacelle can rotate 180° around the vertical axis to provide a constant alignment between the rotor axis and the direction of the wind to maximize the efficiency of the wind turbine

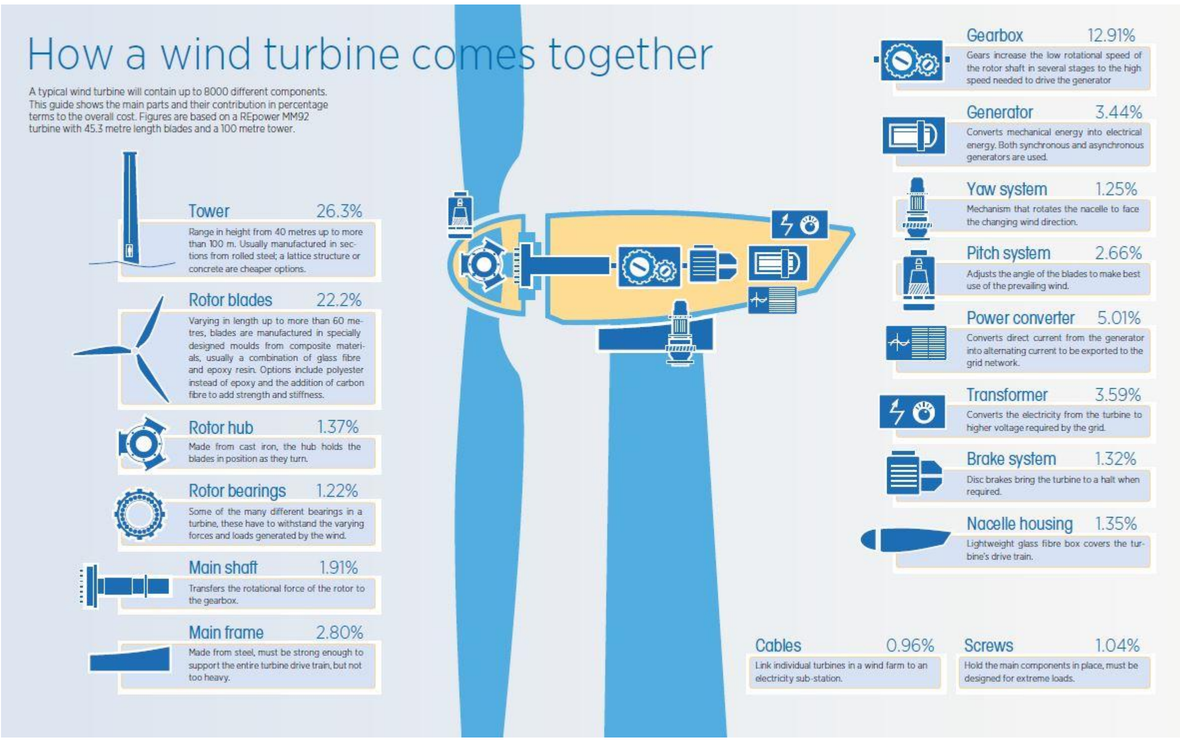

Figure 14: Main components in a wind turbine and their contribution in percentage terms to the overall cost of the turbine; source: [9]

A detail component analysis is provided by figure 14 in which also the costs in percentage terms to the overall cost of the turbine is taken in consideration for each component.

The foundation is an extremely important part in the development of wind turbines. It can account for 7-10% of onshore wind farm costs and 15% to 20% or more for offshore wind farms, as [10] mentions. The materials that mainly compose the foundations are cement and steel, the cost of the foundations therefore will be strongly influenced by these commodity prices. As said for offshore the foundations are an extremely important and expensive part of the project. Therefore, a deeper analysis is required. Many factors affect the foundation selection in each project. The main factors include water depth, seabed conditions, turbine loading, rotor and nacelle mass and rotor speed, corporate experience and supply chain capability. The most famous offshore foundations available today according to [11] are the bottom-fixed that can be categorized under 3 main groups:

- Monopiles are the simplest and still today the most used foundations. This foundation can be used up to 40 meters water deep. Monopile foundations are cylindrical steel piles that normally are driven tens of meters into the seabed. Usually, due to soil conditions the installation is assisted by internal drilling

- Gravity base foundations made from concrete. In this type of foundations, the stability of the wind power is provided by a mass that is placed on the seabed, this mass provides stability against wave, current and turbine loading. The material in which they are built is mainly reinforced concrete and they can have either a flat base or a conical design. This type of foundations is able to give more stiffness compared to the monopiles and it is becoming more cost effective when it is chosen to support large turbine in deep water.

- Space frame jacket and other steel space-frame structures. This foundation provides more stiffness compared to the monopiles. However, the production process is quite complex, usually it involves delivering pre-rolled and pre-cut tubular sections to the production facility, where they are assembled using manual welding. In some cases, tubular sections are connected using pre-manufactured nodes. There are also other options for the foundations, such as the tripods and the tripiles but today they are not considered to be cost effective due to the high presence of steel and due to a more challenging manufacturing process. Tripiles also require a more complex installation process.

A graphical representation of these different ways of bottom fixed foundations is available in figure 15.

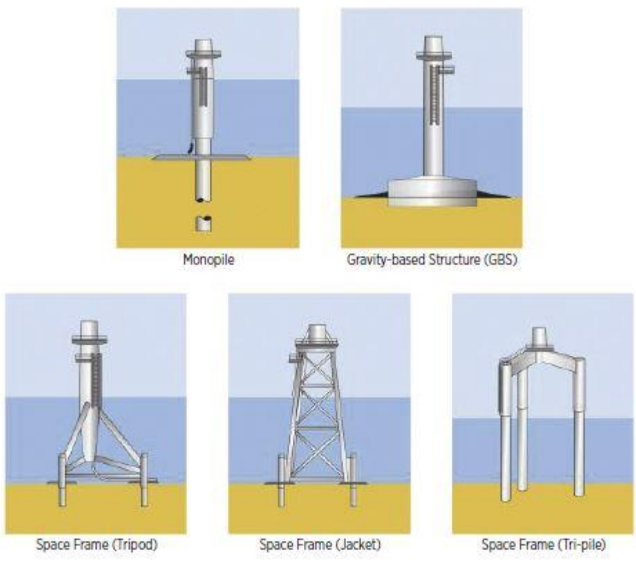

Figure 15: Different types of bottom fixed foundations available for offshore wind turbine; source: [11]

In recent years, as [12] mentions, have been developed also floating solutions for the foundations of offshore wind turbine. This kind of foundation has two big benefits:

- They allow access to deep-water sites. Since no proper foundations must be built they allow to reach deep water. In the countries that present a narrow continental shelf, floating foundation offer the only opportunity for large-scale offshore wind deployment.
- They ease turbine set-up. Also, in mid-depth conditions they can offer a low-cost solution since they have a high potential of standardization.

In addition, floating foundations provides a higher benefit for the environment since the installation of floating foundations is less environmental invasive compared to bottom-fixed one.

In figure 16 the different possibility for floating foundation are represented.

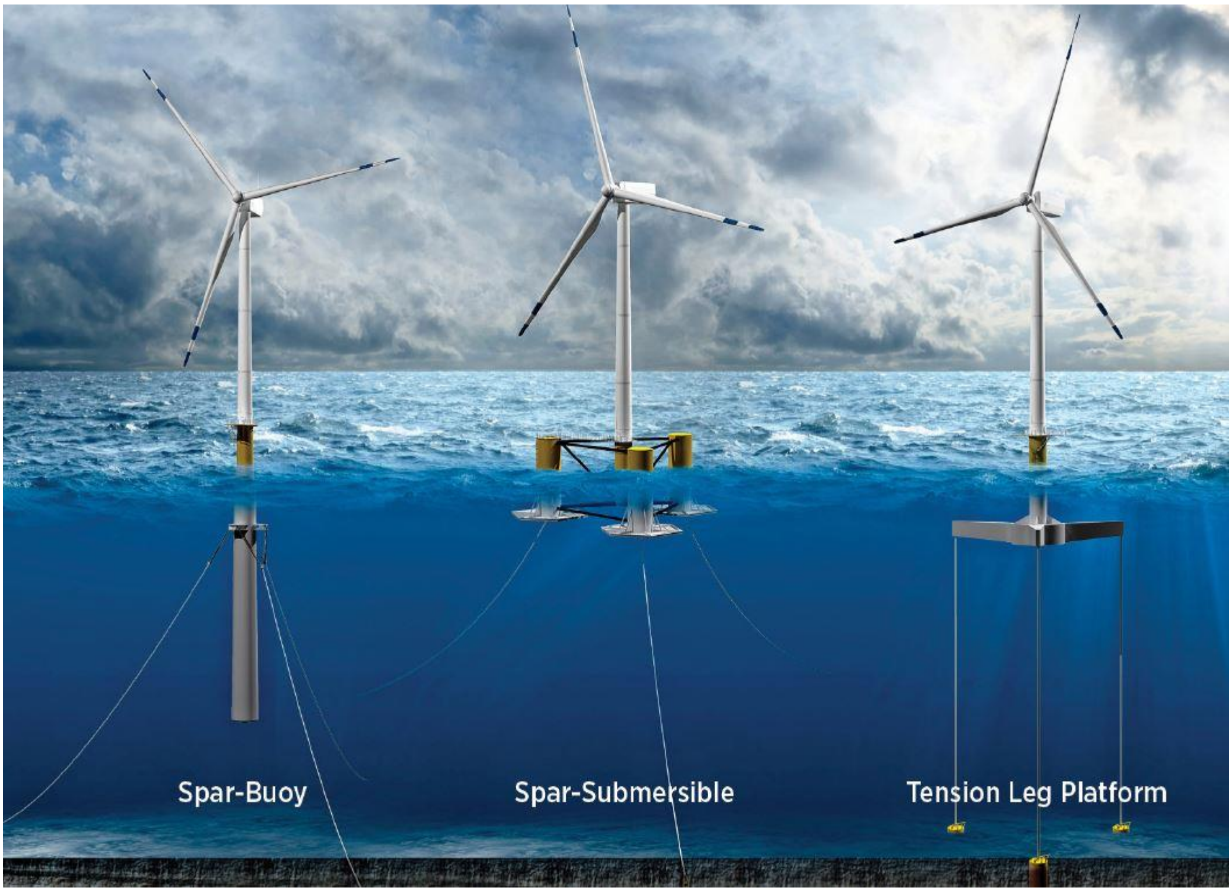

Figure 16: Different types of floating foundations available for offshore wind turbine; source: [12]

1.5 Risks when dealing with wind power project

Dealing with project is always an extremely difficult and complicated thing; risks are intrinsic in the development of the project and they can be found at different levels and at different steps of the development of the project. The literature currently does not provide a standardized classification of risks associated with renewable energy and wind power project. A good approach to identify the main risks of a wind power project is presented in the article [13] in which risks are categorized accordingly to the category they belong to. A graphical representation of the main risks in wind power is present in figure 17.

Risk	Subcategory
1. Strategic / business risks	Financing risks / insufficient expertise / insufficient public acceptance / complex approval processes / insufficient management know-how
2. Transport / construction / completion	Revenue loss due to start-up delay / damage or theft during transport or construction
3. Operation / maintenance	a) General operation and maintenance risks / damages / technological and innovation risk
	b) Revenue loss due to business interruption
	c) Damage due to natural hazards (severe weather)
	d) Damage due to serial losses
4. Liability / legal risk	Liabilities to third parties / law costs / contracting risk
5. Market / sales risks	a) Variability of revenue due to weather / resource risk
	b) Variability of revenue due to grid availability / curtailment risk
	c) Variability of revenue due to price volatility
6. Counterparty risk	a) Supplier of O&M services
	b) Counterparty risk Power Purchase Agreement (PPA)
7. Policy / regulatory risks	Policy support / Feed-in-Tariff (FiT) changes; uncertainty regarding regulation (e.g., Solvency II and Basel III)

Figure 17: Main risks in a wind power project; source: [13]

The categories 2,3,4,5 refer to the life-cycle phases of a typical wind power project. Therefore, this subdivision allows also to understand also at which stage a risk may appear.

Obviously, the impact and the relevance of the risks depends on the actual situation in the respective country and obviously risks may have different outcomes such as: Increasing costs of project, delay the duration of the project, decrease the quality of the infrastructure etc.

In general, offshore wind power is more complex and so more subject to risks compared to the better-established onshore power. This complexity implies a more sophisticated risk analysis and usually more expensive insurance solutions. Below follows a detail analysis of the different risks to take into account when starting a wind power project.

1.5.1 Strategic and business risks

This first category includes strategic and business risks such as for instance the lack of cooperation partners to share technical expertise, financing access, insufficient access to capital, diversification of risks and an eventual missing exploitation of economies of scale to reduce costs. In addition to the risks above mentioned this category takes into account the resistance by the general public in regard to renewable energy and the possible missing know-how of the management of the project. Complex and long approval procedures are especially relevant for offshore wind parks.

1.5.2 Transport, construction, and completion risks

This part focuses on the risks that may appear on the initial part of the project, this part is considered as the riskiest phase of the whole project. The kind of risks that are taken into account in this category are for example the loss of revenue due to start-up delays, the risk of damage during transportation or construction, which, due to the high capital intensity of these projects can become very costly if something wrong happens.

The transport and the construction are much riskier in case of an offshore project as the processes are more complex. Also grid connection for offshore project is more subject to risk compared to onshore project.

1.5.3 Operation and maintenance risks

During the operation and maintenance phases various risks may arise. These risks can be divided in three categories that are explained below.

- General operation and maintenance risks → physical assets may be damaged due to accident, wear, tear and possible unplanned situations (for example due to unavailable resources or replacements, which can cause considerable delays). Also design flaws and component failure are risks that must be considered.

- Natural hazards → they represent a risk for both onshore and offshore project. This risk is especially relevant for offshore wind where strong winds, waves and tides can cause damage. In addition, ice can occur and affect the wind turbine functionality

- Another important risk associated with operation and maintenance is the serial loss that can be particularly grave especially for offshore wind parks due to the cost-intensive nature of repair and replacement operations at the sea

1.5.4 Liability and legal risks

Legal and liability to third parties are another risk that is associated with wind power project. This category includes also damages to the environment and the relative liability that arise from the damage. Usually there are insurances that cover this type of liability

1.5.5 Market and Sales risks

This category takes in consideration the financial risks that may arise due to the power prices fluctuations and the inability to sell electricity due to regional grid oversupply (curtailment risk).

- Variability of revenue due to weather/resource risk → As already mentioned the revenues of a wind turbine vary considerably due to the different wind speeds. In US, the wind speed has a variability of 15-20% considering a horizon of a year (the variability of solar is only 5%).
  Usually onshore wind turbine has a higher inter-year variation than offshore wind turbine. As debt has to be paid regularly, a minimum debt service coverage ratio is needed.

- Variability of revenue due to grid availability / curtailment risk → The revenues are affected by the grid availability and thus curtailment risk. The curtailment risk consists of not being able to sell the power produced, this of course lead to a loss in revenues in countries in which no fixed support schemes are present. Curtailment risk is defined as an excess generation of wind energy in combination with insufficient network capacities, for example, transmission and/or distribution congestion and insufficient regional demand.

Markets without support schemes are directly exposed to market risks, as sales fully depend on energy prices. In case in which a power purchase agreement is not set the fluctuations and/or a fall in energy prices can imply a considerable revenue risk if output is sold at a lower price than the reference value. As a risk transfer mechanism, energy derivatives can be purchased, but the electricity price behavior may change in the case of an increasing share of renewable energy

1.5.6 Counterparty risks

A) Supplier of O&M services → To be sure that the contract, the guarantees and the warranties proceed according to the plan is extremely important the financial stability of the supplier of operation and maintenance (O&M). This is also an issue for offshore wind parks that have experienced numerous contractor insolvencies in the past.

B) Counterparty risk power purchase agreement (PPA)→ If the project owner decides to sign a power purchase agreement a counterparty risk should be taken into account.

1.5.7 Political, policy and regulatory risks

This category takes in consideration risks that are related with political changes. It includes for instance changes in governmental priorities, modified or abandoned renewable energy support schemes (e.g., feed-in-tariffs)

1.6 Environmental impacts of wind power projects

Wind turbines, in contrast with the conventional fossil fuels and nuclear power, do not pollute the atmosphere with greenhouse gases and do not create any problems for future generations with radioactive waste. However, the impacts on human life and on the environment are not zero. According to [14] to build a truly sustainable society, the environmental impacts and the impact on human life of wind power should be further studied and analyzed.

Usually, onshore wind farms are built in piece of land that has already been impacted by land clearing. Therefore, the impacts on vegetation and ground destruction are minimal compared with coal mines [15]. Another advantage is that if wind farms are decommissioned, the landscape can be returned to its previous condition.

The impacts of this technology on the environment can be listed under three main categories [15] : Ecological, Visual and Noise impact. These three categories are analyzed in the next paragraphs considering both offshore and onshore scenarios.

1.6.1 Ecological impact

The impacts on the ecology side can varied according to the location, season, species, ecosystem type and other factors. Wind turbines can cause through collision fatalities of birds and bats, usually the most hit part are the turbine blades. Not all the birds and bats are the same, they differ in their vulnerability of collision. Another effect that this technology has on animals is related with the construction of the foundations. In fact, for onshore wind project this construction affects and alter ecosystem structure through soil disruption and vegetation disruption while offshore foundations cause seabed alteration. Alteration of vegetation due to the installation of the foundations represents the most significant potential change and loss of habitat for some species.

1.6.2 Visual impact

Another critical factor is the visual impact. The visual impact is present for both onshore and offshore wind turbine. For visual impact is meant the visual impact of the turbines (size, height, number, material and color), of the access and site tracks but also of the substation buildings, of the compound and of the grid. As already said wind farms are not permanent; therefore, after the decommissioning phase the landscape can return to its original condition. Many turbine manufactures have identified, thank you to the help of designers, a design to minimize the potential visual impact of the turbines.

1.6.3 Noise impact

Noise from wind developments has been one of the most studied environmental impacts of this technology. Noise, compared to landscape and visual impacts, can be measured and predicted easily. Since the turbine has some moving parts it generates noise during operation. This noise arises from mainly two sources:

1. the noise generated by the gearbox and generator
2. The noise generated by the interaction of the turbine blades with the wind.

The second noise is more critical compared to the first one. Its low frequency may cause annoyance in people's lives. An example is a study made by Pedersen that has tested the relationship between the sound levels of wind turbines and people well-being, showing that stress symptoms such as headaches appeared in those who were annoyed by the presence of wind turbines.

But the comparison between the number of noise complaints about wind farms and about other types of noise states that wind farm noise is a small problem in absolute terms. Information from the US also suggests that complaints about noise from wind projects are rare and can usually be satisfactorily solved. Obviously, when talking about offshore wind turbine the problem of noise impact become less problematic since they are built far from houses and people.

Chapter 2: Financial modelling – Literature review – Capital budgeting

2.1 DCF financial modelling & decision making

Financial modelling is the task of building a representation of a real-world financial situation. Financial models are very topic and company specific since different assumptions and different parameters must be taken into consideration when evaluating different projects.

The output of the financial model is used for decision making, both inside or outside the company.

Thank you to the use of sensitivity analysis the financial model is also able to evaluate by which variables the final result is mostly affected by. Therefore, financial modelling is also good as risk management tool because financial issues and problems that are critical for the project can be firstly recognized and secondly addressed with the right technique, such as risk mitigation or elimination.

The discounted cash flow financial model is based upon the theory that the value of a project is equal to the present value of its projected future benefits, this valuation method uses forecasted cash flows and discounts them in order to obtain their present value which helps in evaluating investment potential.

Once the financial model has been built and the project has been validated the financial study will begin to understand and establish the optimum financing structure of the project, this analysis will take into account the various types of funding potentially available. This analysis will probably use debt cover factors and equity returns to establish an appropriate debt/equity ratio. When the analysis has established the preferred financing structure, detailed work will be undertaken to establish facility sizes and to explore the robustness of the finance structure under a number of sensitivity assumptions.

2.2 Existing financial modelling – Literature review

Information regarding existing financial models used to evaluate project profitability has been gathered. The different models used by industry were deeply analyzed to find out any limitations and/or opportunities.

Usually this type of financial model is owned by private companies that tend not to share their file and work. Therefore, not much is known about these models or at least the calculation file is not publicly available. The main critical points found in the public models analyzed were the following one:

- Not taking into account all the relevant factors that affect the final evaluation
- Wrong input assumptions of capex and opex costs
- Some critical assumptions that are correct in the ideal analysis but not in the real analysis
- User interface not properly designed and user friendly

To solve these issues some consideration can be underlined at a general level to identify standardized procedure:

- Have a clear understanding of the right variables that can affect the final result and must therefore be taken into account
- Recognize and separate the dependent and independent variables
- Considering uncertainty in the evaluation
- Develop a scheme for analytic or numerical solution and programme
- Understand the different scenarios

In addition, useful information regarding the scheduling of offshore wind project were extracted from [16], in which offshore wind project is divided in 5 main timing pillars:

- Development and consenting
- Production and acquisition
- Installation and commissioning
- Operation and maintenance
- Decommissioning and disposal

[16] develops for each of the above-mentioned phases the analysis of the main cost drivers that belong to each phase suggesting parametric equations to estimate these costs. These equations and information were considered when building the financial model.

Most of the financial model available in the literature assume as input variable the estimate of the capex and opex costs (Provided by third parties). Instead, the model developed in this thesis try to forecast these costs using parametric equations available in the literature. Therefore, the model results to be less site specific and more personable.

Another strength of this work is the inclusion in the evaluation of the so called "Decommission and disposal costs", in many works analyzed for example in [17] this category was not even mentioned and analyzed, not considering this category of cost would mean to reduce the Capex dramatically and therefore not making reliable analysis. The above category is relevant and must be considered since energy companies are obliged to removes all the structures and verify the clearance of the area upon the termination of the operational life of the wind farm.

2.3 Capital budgeting

In this chapter are presented the main and most famous methods that are usually used to evaluate the attractiveness of an investment. Whenever possible are illustrated the drawbacks of the different methodologies and possible ways to overcome these limitations.

2.3.1 Project life-cycle from an operational and financial prospective

Before focusing on the methods to evaluate the financial attractiveness, a few tradeoffs must be considered. The first thing that must be defined in an investment analysis is the Horizon T, all the evaluations and considerations must be outlined considering Horizon T as ending time. Beyond this horizon T the uncertainty become too high to make reliable forecasts and/or the technology become too obsolete to still benefit from positive inflows cashflows and/or regulations make impossible to proceed in the operational activity.

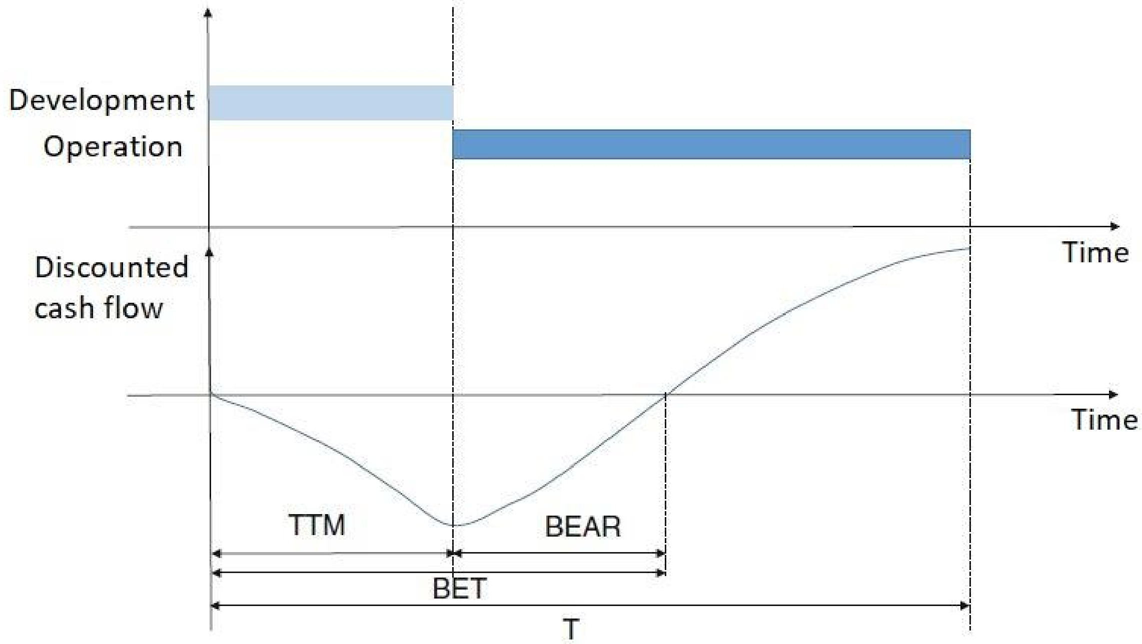

Figure 10: The operation and functional structure of a project lifecycle; source [18]

TTM, BEAR and BET are time interval that are helpful when dealing with the lifecycle of a project. Time to market (TTM) is defined as the length of time it takes from the start of the project to the availability of the resource on the market. Breakeven time (BET) is the time at which the investment is completely recovered while breakeven after release (BEAR) is the time interval between the availability on the market and the time at which the investment is recovered. Therefore, BEAR is the difference between BET and TTM.

From a financial viewpoint; in the development phase negative cash flow are generated, while in the operational phase, just after the time to market, the generation of positive cash flow can, usually on the long run, allow the recoup of the investment made. The slope with which the curve of discounted cash flow rise depends on many variables (Sales volume, contribution margin etc..).

2.3.2 Financial methods for project evaluations

2.3.2.1 Payback time

This method is often adopted because of its simplicity even if it has some intrinsic bias. The Payback time refers to the time required to recover the money spent in an investment as defined in part 3 of [19]. From a theoretical prospective, the payback time has some drawbacks since it ignores cost of capital (no discount of cash flow) and it ignores the generation of cash flow after the payback period. Therefore, a project with low payback time and low long-term cash flow generation would be preferable compared to a project with high payback time and high long-term returns; this would lead to a bias on the long run.

From a mathematical point of view, the payback time is calculated as follows:

$$Payback\ time = \frac{Total\ investment}{Cash\ inflow\ per\ period}$$

Projects would be accepted and started only if payback time is lower than a recovering time defined by the company.

2.3.2.2 NPV (Net present value)

The net present value is the most common methodology applied when evaluate the profitability of an investment. The NPV is the value of all future cash flows (positive or negative) over the entire life of a project discounted to the present. NPV is calculated with this formula:

$$NPV = -I_0 + \sum_{i=0}^{T} \frac{CF_i}{(1+r)^i}$$

Where I_0 = Initial investment; r = discount rate; CF_i = Cash flow at i-period and T= Time horizon

If NPV > 0 the investment should be carried out, otherwise not.

The cash flows are discounted for two main reasons, to adjust for the risk of an investment opportunity and to account for the concept of time value of money. The first concept reflects the extra return investors demand because they want to be compensated for the risk that the cash flow might not materialize after all. The second is based on the theory that money in the present is worth more than the same amount in the future; this is both because inflation and for potential earnings that could be made using the money in the intervening time.

2.3.2.3 The WACC as discount rate

The discount rate is the rate of interest used to determine the present value of the future cash flows of a project. In the case of a project that has the same risk as that of the average project of the company the discount rate is equal to the weighted average cost of capital (WACC). The WACC is a calculation of a firm's cost capital in which each category of capital is proportionately weighted. The formula, since a company has two primary sources of financing – debt and equity – is:

$$WACC = \frac{E}{E+D} * Cost\ of\ Equity + \frac{D}{E+D} * \text{Cost of Debt}$$

Where: E = Market value of firm's equity; D = Market value of firm's debt

A focus on cost of equity and cost of debt is necessary:

- Cost of equity = The cost of equity is defined in [20] as "the rate of return required by the company's ordinary shareholders in order for that investor to bear the risk of holding that company's shares". The Capital asset pricing model (CAPM) was developed to estimate the required rate of return on equity:

$$Cost\ of\ equity = r_f + \beta * \left(\mathrm{E}(r_m) - r_f\right)$$

Where: r_f= risk free rate of return, β= Beta of the security, $E(r_m)$= expected market return

Since this formula provides an estimation of a cost of equity it can be considered the calculation of a return for a risky investment. For this reason, to the risk-free rate, that is the theoretical return interest rate that would be paid by an investment with zero risk, must be added the market risk premium multiplied by Beta.

Beta is a measure of a stock's risk of volatility compared to the overall market; a Beta > 1 indicates that our security is more volatile compared to the market while a Beta < 1 means that our security is less subject to volatility. The Beta is multiplied by the market risk premium that takes into account, in a quantitative way, the extra return demanded by market for this increased of risk. Summing the risk-free rate return and the Beta multiplied by the market risk premium we obtain the return required by the company's ordinary shareholders.

- Cost of debt: a company's cost of debt is the effective interest rate that it pays on its debt. Since usually interest expense is deductible it is generally more useful to calculate a company's after-tax cost of debt.

$$Cost\ of\ debt = Effective\ interest\ rate * (1 - corporate\ tax\ rate)$$

Since now we have made our considerations based on the assumption that the project under analysis has got the same risk as that of the average project of the company. For projects that has a different risk exposure compared to the average of the company some other considerations must be drawn. A good approach is to alter the discount based on the real risk of the project.

Through the application of the Capital asset pricing model and the pure play approach it is possible to choose an appropriate discount rate.

The formula of the Capital asset pricing model can be used to estimate the cost of equity with an adaption on the Beta; in this case the equity Beta must be substitute with the project beta that can be estimated using the pure play method. The pure play method consists in finding a publicly traded company (from now on "Pure play company") which usually engages in projects very similar to the one that is under analysis and adopt its equity Beta. The equity Beta of the pure play company must then be unlevered to remove the effect of the capital structure of the company. This can be done thank you to this formula:

$$\beta_a = \frac{\beta_e}{1 + \frac{\mathrm{D}}{\mathrm{E}} * (1 - t)}$$

Where: β_a = Project Beta; β_e = Equity Beta of the pure play company; E = Markey value of pure play company equity; D = Market value of pure play company debt and t = tax rate of pure play company

This formula, called Unlevered Beta, is able to measure the real performance in relation to market movements without the effects of the company's debt factor.

The project Beta (β_a) should then be inserted in the capital asset pricing model formula to obtain the cost of equity of the project.

The discount rate determined using this approach will be higher or lower than the weighted average cost of capital. It will be higher if the project is riskier and lower if the project is considered more secure.

2.3.2.4 IRR (Internal rate of return)

The internal rate of return is defined in [19] as the discount rate that sets the NPV of the project's cashflow equal to zero. In mathematical terms:

$$0 = -I_0 + \sum_{i=0}^{T} \frac{CF_i}{(1+IRR)^i}$$

Where I_0 = Initial investment; IRR = Internal rate of return; CF_i = Cash flow at i-period and T= Time horizon

The IRR represents the average annual return over the years of the investment, consequently, if the IRR is higher compared to the returns of other alternatives investment with same risk and maturity, the investment must be undertaken otherwise not.

The IRR provides also useful information regarding the errors that can be committed when estimating the cost of capital. Let's suppose an IRR=12% and a cost of capital=10%, if the cost of capital is higher than 12%(=IRR), the NPV is negative and consequently the investment must not be undertaken. The decision to accept an investment is correct as long as our estimate on the cost of capital (=10%) is within 2% of the true cost of capital. As defined in [19] the difference between the cost of capital and the IRR is the maximum estimation error in the cost of capital that can exist without altering the original decision.

However, the IRR is subject to some issues:

- IRR is a true estimate of a project's annual return on investment only when the project generates no interim cashflows, or when those interim cashflows can be invested at the actual IRR. When the calculated IRR is higher than the true reinvestment rate for interim cashflows, the measure will overestimate, sometimes in a significative way, the annual equivalent return from the project. The formula assumes that the company has additional projects with equally attractive prospects, in which to invest the interim cashflows.

- It can only be applied for investments in which the distribution of cashflows has an initial negative expenditure at the beginning and there are no permutations in the mathematical signs of the annual cashflows → if these conditions are not meet multiples IRRs are found

- It is misleading when comparing multiple projects of different lengths. A short project may have a high IRR consequently appearing to be a good investment, but it may have also a low NPV. Conversely, a long project might have a lower IRR, but it may have a steady earning return that add value to the company over time.

In order to being able to evaluate as best a scenario it is suggested not to take IRR as only method of evaluations. A compounding of IRR and NPV can be a good approach to evaluate the attractiveness of an investment.

2.3.3 Multicriteria methods for projects evaluation

When dealing with project's selection multicriteria methods can be adopted. The financial methods above described are based on quantitative information, in some circumstances it is important to based decisions on a wide number of dimensions that can have both a quantitative and qualitative character. As example, since it would be impossible to provide a complete and exhaustive list, one can adopt:

- Financial aspects (e.g. NPV, Payback time etc.)
- Environmental aspects (e.g. Energy consumption, Carbon emissions etc.)
- Risk exposure (e.g. Project complexity, Technology risk etc.)
- Operational aspects (e.g. Time required, budgeted cost etc.)
- …

Some of these qualitative risks can be modeled thank you to the choice of a proper discount rate, however as it has already been described, this "adaption" would be difficult and subject to mistakes. For other dimensions, for instance for the environmental impact, this translation would be incorrect and inherently would lead to errors. For the reasons above mentioned, a proper method must be chosen to take into account for qualitative information too.

The Analytical Hierarchy process (AHP) appears to be the best method among the many multicriteria method available in the literature since it has the aim of providing objectives around a strategic decision.

A brief description of the AHP method follows, based on the information provided by [21] : In order to apply the AHP some steps must be taken in consideration:

- Break down the decision into a hierarchy of goals, criteria and alternatives
- Calculate the weights for each criterion: the criteria are compared pairwise based on the goals to assess their weights
- Derive local preferences for the alternatives based on each criterion

- Derive overall preference for the alternatives: all alternative priorities obtained are combined as a weighted sum, taking into account the weight of each criterion, to establish the overall priorities of the alternatives. The alternative with the highest overall priority constitutes the best choice
- Perform sensitivity analysis on the weights to understand how the final choice may change
- Make a final decision based on the sensitivity analysis and on the final result obtained

Chapter 3: Case study

3.1 Overview of the phases of the project

In this section an overview of the phases of an offshore wind project is provided. According to [16], the phases of an offshore project are five: Development and Consenting (D&C), Production and Acquisition (P&A), Installation and Commissioning(I&C), Operation and maintenance(O&M) and Decommissioning and Disposal (D&D).
The thesis is organized taking in consideration these five pillars and consist of different modules that are presented here:

- Description of the project/case study: It illustrates the project with details on technical information and information regarding the cost of the vessel, cost of the personnel etc.
- CAPEX module: It includes the analysis on Capex costs related to the D&C, P&A, I&C and D&D phases
- OPEX module: This chapter analyze the operational cost per MWh generated by the wind farm O&M
- Revenue model: In this module information regarding electricity price and total energy produced are given to derive the revenue of the project
- Project financing: This module contains information regarding parameters that are related to the project expenditures, namely the WACC, the debt/equity ratio etc.

A chapter dedicated to the result concludes the thesis that summarize the return of the investment which can support different types of investors in various periods of a wind farm life, considering also the technical parameters.

3.2 Description of the project

This part analyses the characteristics and assumption regarding the reference offshore wind farm. The reference offshore wind farm corresponds to a realistic one located in North Sea (UK). Detailed information regarding the technical aspects are given in table 1. The average water depth at the offshore wind site is on average 40 meters. The wind farm is situated at 40 km distance from the port and is composed by 67 wind turbines, each one generating a power of 6MW. Therefore, the total wind farm capacity is 402 MW.

The wind farm is composed by one substation that will collect all the energy generated by all the turbines and will transfer it to shore thank you to seabed cables. An onshore substation has the responsibility to transfer the energy to the grid. A wind farm of approximately 400 MW has been chosen since many articles and studies are available in the literature that could facilitate comparisons of results and assumptions.

General information		
Item	**Unit**	**Value**
Wind farm total capacity	MW	**402**
Projected operational life of the wind farm	Years	**25**
Construction years	Years	**5**
Power per wind turbine	MW	**6**
Number of turbines	Unit	**67**
General site characteristics (Distance from port to offshore farm)	Km	**40**
Water depth	Meters	**40**
Wind turbine Rotor diameter	Meters	**126**
Offshore cable length	Meters	**38.000**
Onshore cable length	Meters	**48.000**
Rotor diameter	Meters	**126**

Table 1: General information regarding the chosen offshore wind farm; source: own model

The construction period including all the phases is assumed to be 5 years, the operational life of the wind farm is assumed to be 25 years. Since energy companies have to remove all the structures and verify the clearance of the area once the operational life is over, 2 years for the decommissioning and disposal are assumed.

3.2.1 Vessel Information

The usage of many vessels is required to build the wind farm. The vessels are required in almost all the phases of the project and represents a big portion of both Capex and Opex. In table 2 a list of all the vessels used in the project is present with their reference price per day.

Vessels information		
Item	**Unit**	**Value**
Rent workboat - Crew transfer vessel	£/day	**3.500**
Rent vessel for turbine installation	£/day	**100.000**
Rent vessel for foundation	£/day	**112.000**
Rent vessel for Scour protection	£/day	**13.800**
Rent vessel Cable laying (Array)	£/day	**80.000**
Rent vessel for Cable laying (Export)	£/day	**100.000**
Rent vessel Cable laying (Remotely Operated underwater vehicle)	£/day	**82.500**
Rent vessel for cables removal	£/day	**20.000**
Rent vessel for Substation installation and Decommissioning / Turbines and foundation removal	£/day	**135.000**

Table 2: Vessels information; source: own model

Information regarding the vessel used and further data are provided in the respective section of the thesis.

3.2.2 Personnel cost

Apart from the vessel crew, additional workers are hired to perform mechanical/electrical operations for all the phases of the project. A single worker cost 270£/day and 12 working hours per day are assumed.

3.3 Capex module

The capex is defined as the amount spent to acquire or upgrade a productive asset in order to increase the capacity or efficiency of a company. For wind power project the CapEx accounts for the dominant part of costs.

3.3.1 Development and consenting phase (D&C)

Belong to this phase all the costs that are prior to the financial close (time in which an agreement between investors, construction company etc. is meet). Costs associated to this category are costs required to realize preliminary studies to understand the feasibility and the possible profitability of the project. In this category are present also the contingency costs.

These costs are not constant for different wind farm and vary a lot across sites. Looking at the literature the estimation of these costs is not easy and standardized. In [22], about £60 Million for a wind farm of 500 MW are assumed. In [23], instead, these costs account for about £200 Million for a wind farm of the same capacity. In table 3 are indicated the costs associated to the development and consenting phase for our case study, assuming a conservative scenario.

Development and consenting phase information		
Item	**Unit**	**Value**
Legal costs	£ million	**11**
Environmental costs	£ million	**9**
Engineering costs	£ million	**3**
Contingency costs	£ million	**45**
Project management costs	£ million	**30**
Insurance costs during construction	£ million	**15**

Table 3: Costs information regarding the development and consenting phase; source: own model

3.3.2 Production and acquisition phase (P&A)

3.3.2.1 Wind turbines

As already mentioned the wind turbines are one of the most expensive component of an offshore wind project. Their cost is usually expressed as a function of the capacity. In [23] a parametric expression is used to estimate the wind turbine cost:

$$C_{wind\ turbines} = 3 * 10^6 * \ln(P_{wt}) - 662400$$

Where P_{wt} represents the capacity of a single wind turbine. Considering wind turbines with a capacity of 6MW; the cost for a single wind turbine accounts for about £4,712 Million/turbine. To this value must be added the tower costs that as [22] suggests for a wind turbine of 6MW are £1,3 Million per tower. Therefore, the cost of acquisition of one wind turbines including the tower costs is approximately £6 Million. Just for information General electric is building the most powerful and the biggest offshore wind turbine (Halide-X) in the world to date, the dimensions result to be enormous, 220 meters for the rotor and 107 meters rotor long blades.

3.3.2.2 Foundations

Foundations are relevant to provide stability and security to the wind turbines. As already mentioned there are different type of foundations. The most common substructure type nowadays is the monopile. For this reason, the monopile foundations are assumed for the case study. Obviously, the cost of the foundation depends largely from the type of foundations chosen, the depth of the water at the wind farm site, the waves etc.

In [24] a parametric equation is used to forecast the cost of the foundation; this equation links the cost of the foundations with the turbine geometry (hub height(h), the rotor diameter(d)) and the water depth(WD)):

$$C_{foundation} = 320000 * P_{wt} * \big(1 + 0.02 * (WD - 8)\big) * (1 + 8 * 10^{-7}(h * \big((d/2)^2 - 100000\big)\big)$$

Where P_{wt} represents the capacity of a single wind turbine. Applying this equation to our case study the cost of a single foundation appears to be approximately £3 Million. This numbers could seem high but is justifiable given the high-water depth at the wind farm site.

3.3.2.3 Cables

Cables are determinant to transfer energy across all the elements of the offshore project. A distinction among cables must be underlined:

- Array cables: Cables that allow the interconnection of all the turbines at the wind farm site. These cables obtained energy from each wind turbine and transfer it to the offshore substation. Usually Mean voltage (MV) submarine cables are used as array cables. In order to estimate the length of the array cables an equation from [25] is used that use as input parameters the number of the wind turbines(n_{wt}) and the rotor diameter(d):

$$L1 = 1.125 * n_{wt} + 1055 * d - 122640$$

- Offshore cables: Offshore cables are usually high-voltage alternating current (HVAC) or high-voltage direct current (HVDC). The offshore cables have the responsibility to transfer energy from the offshore substation to the onshore one. The distance from the offshore substation and the onshore one is assumed to be equal to the distance from the substation to the port (40 Km). The connection occurs thank you to three subsea export cables.

- Onshore cables: Provide the transfer of the energy from the onshore substation to the grid connection. It is assumed a distance of 20km from the onshore substation to the grid connection. As for the offshore cables, three export cables are assumed.

In table 4 information regarding the total length of the different cables and the costs per meter for each is provided. The cost per meter for the different cable was taken by [26].

Cables information		
Item	**Unit**	**Value**
Array cables length	Meters	**85.665**
Offshore export cable length (x3)	Meters	**120.000**
Onshore export cable length (x3)	Meters	**60.000**
Cost per meter for array cable	£/Meter	**190**
Cost per meter for Offshore cable	£/Meter	**780**
Cost per meter for Onshore cable	£/Meter	**260**

Table 4: Cables information regarding length and cost; source: own model

3.3.2.4 Substations

Offshore substation is required because of the high capacity of the wind farm and the quite high distance from the onshore substation to the offshore one. In fact as [27] says it is considered appropriate to install offshore substation for projects located at >20 km from the onshore location. An offshore substation should include the electrical equipment to transform the medium voltage to the transmission network high voltage. This equipment will be supported on a jacket foundation. In order to estimate this cost a parametric equation was used taken from [28]:

$$CoS = 539 * P^{0.678}$$

Where CoS stands for cost of the offshore substation in K£, P the wind power capacity in MW. This equation suggests us that the cost of acquisition for the offshore substation is approximately 31.5 Million.

As a precautionary measure, considering figure 18 that shows the cost of the offshore substation for many different projects a cost of 38 Million is adopted. The onshore substation was assumed to cost half of the cost of the offshore one.

Park	Source	Cost	$\frac{k€_{2016}}{MW}$
CS-2	(Douglas-Westwood, 2010, page 38)	0.7 MNOK/MW @ 600 MW[1]	95
CS-4	(Green et al., 2007, page 4)	40.52M$/500MW	68
CS-1	(Nikolaos, 2004, page 98)	25 M€/495MW	61
CS-7	(Nielsen, 2003, page 13)	15 M€/ 240MW	78
Est-5	(ODIS, 2009, page 44)	28 M£/160MW[2]	224
CS-6	(ODE, 2007, pages 38,40)	(7.5+1.5) M£/108MW	141
Est-3	(Garrad Hassan, 2003, page I.5)	5 M£/100MW	90
1.Md	(Slengesol et al., 2010, page 89)	4.4 M€/40MW	143
1.Md	(Larsen et al., 2005, page 2)	4.51 M€/40MW	135

Figure 18: Cost of many offshore substation for different projects; source:[28]

3.3.2.5 Control system

Thank you to the development of the technology recent wind farm have integrated an automated control device that allow to monitor, to obtain data and to optimize the efficiency to have better revenue generation. Sensors are incorporated in this device. Each turbine is equipped with one of these monitor systems. The cost for a single system is about 75K£/turbine.

3.3.3 Installation and commission phase (I&C)

As [16] mentions this phase involves all the activities related with the transportation and installation of the different components. The typical installation scheduling for an offshore wind project starts with the installation of the foundations and scour protection. The erection of the tower and the wind turbines installation follow. After the installation of the wind turbines the installation of the offshore substation is performed followed by the cable laying.

3.3.3.1 Foundation installation

The foundation installation cost heavily depends on the cost to rent the vessel, on the personnel costs required for the installation and by the necessary assumptions required for the weather.

The total time to install the foundations results to be 1287 hours that corresponds to 134 days assuming a weather adjuster of 0,8 and 12 hours working per day. The total installation time has been calculated using the equation provided by [16]:

$$T_{found\ install} = 2 * N_f * T_{port} + 2 * n_{wt} * T_{site} + n_{wt} * T_{load} + T_{port\ to\ farm} + T_{betturb} + n_{wt} * T_f$$

Where, N_f is the number of voyages, T_{port} is the time of jacking at the port, n_{wt} is the number of turbines, T_{site} denotes the time of jacking at installation site, T_{load} is the loading time $T_{port\ to\ farm}$ represents the travel time from port to the wind farm, $T_{betturb}$ is the travel distance between turbines and T_f is the offshore installation time of the monopile.

All the input parameters used to define these variables above mentioned are represented in table 5.

Installation of foundations information		
Item	**Unit**	**Value**
Required installation days per MW installed	Days/MW	**0,3**
Total days to rent the foundation vessel	Days	**134**
Effective personnel time to install all the foundations	Days	**134**
Number of workers for the installation of foundations	Unit	**30**
Total time to install all the foundations	h	**1.287**
Numbers of voyages	Unit	**22**
Time of jacking at the port	h	**2**
Time of jacking at farm site	h	**1**
Total time to travel between turbines	h	**3**
Monopile foundation loading time	h/turbine	**4**
Monopile installation in the subsea	h/turbine	**5**
Total travel time from port to farm	h	**447**
Average time to travel between turbines	h	**0**
Jack up vessel capacity of foundations	Units/trip	**3**

Water depth at the port	m	**20**
Jacking up speed	m/h	**30**
Water depth at wind farm site	m	**40**
Vessel speed	Km/h	**4**
Mean distance between consecutive turbines	m	**250**
ADJweather	Unit	**0,8**
Voyage time	h	**10**
Distance from port to offshore farm	km	**40**

Table 5: Data regarding installation of foundations; source: own model

A specific vessel (Vessel for foundation) has been used to install the foundations. The cost related to this vessel is listed in tables 19. Apart from the vessel crew, 30 workers are assumed to perform the installation. Therefore, the total cost for the installation of the foundation is the sum of the rent for the vessel plus the cost of the personnel (30 workers working for 134 days). The total cost, assuming the information above given is approximately £16,1Million.

3.3.3.2 Wind turbines installation

Turbines are installed after the foundations have been placed. According to [29], the installation time per megawatt for the wind turbines have decreased enormously in the last years reaching on average 0,62 days/MW in 2017.

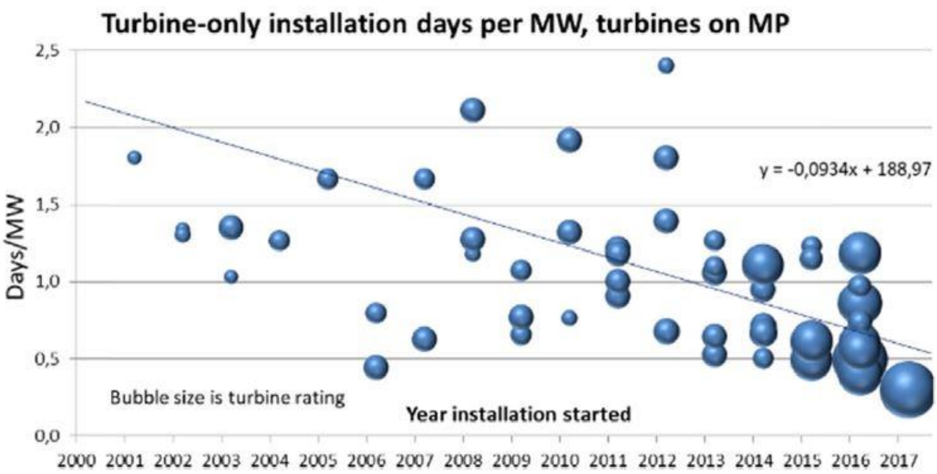

Figure 19: Evolution of the installation time for only offshore wind turbine over time with monopiles; source: [29]

The figure 19 shows graphically how this installation time for wind turbine decreased in the last years. Therefore, considering that the wind farm capacity is 402 MW the total time to install the wind turbine is almost 250 days.

A specific vessel is used to install the wind turbine and the related cost is provided in table 19. 50 workers are assumed necessary to install the wind turbines. The total cost for the installation is £28.2 Million given by the sum of £24.9 Million for the rent of the vessel and by £3.3 Million for the payment of the personnel.

3.3.3.3 Scour protection installation

Once the foundations are installed they need to be protected against erosion. In most cases gravel and rock materials are used to apply a solid erosion protection layer. In fact, without this protection, scour phenomena would appear damaging the structure.

The amount of scour protection is site specific, it depends on the marine currents. Some site may not need the installation of the scour protection. The data represented in table Y, used as input data were taken from [30]. The total time required per trip is the sum of the loading time plus the dumping time and the travel time. Considering the capacity of the rock-dumping vessel and the ton of rocks required for each turbine a total of almost 17 trips is required. Considering 12 working hours per day and a weather adjuster of 0,85, 59 days are required for the scour protection installation. The installation cost of scour protection was then estimated considering the vessel day rate.

Scour protection installation information		
Item	**Unit**	**Value**
Total effective days for scour protection installation	Days	**59**
Total time	h	**597**
Total time required per trip	h	**36**
Tonnage of scour protection per unit	Ton/turbine	**8.000**
Rock-dumping vessel capacity	Ton	**32.000**
Number of trips required for the scour protection	Unit	**17**

Loading time per trip	h	**10**
Dumping time per trip	h	**24**
Travel time	h	**2**
Distance from port to offshore farm	km	**40**
Speed of the vessel	km/h	**24**
ADJ weather	Unit	**0,85**

Table 6: Data regarding the scour protection installation; source: own model

3.3.3.4 Cables installation

To perform the cables installation a specific vessel must be used (Remotely Operated underwater vehicle). The installation rate written in table 7 were extracted from [30]. Considering the length of the cables mentioned in table 4 and the rates, the effective days can be easily calculated. A weather adjuster of 0.5 has been used to consider also the sea condition.

Cables installation information		
Item	**Unit**	**Value**
Effective days required for the installation of export cables (Offshore)	Days	**150**
Effective days required for the installation of export cables (Onshore)	Days	**75**
Effective days required for the installation of array cables	Days	**286**
Installation rate of export cable	km/day	**1,6**
Installation rate of array cables	km/day	**0,6**
ADJ weather	Unit	**0,5**

Table 7: Information regarding the cables installation; source: own model

3.3.3.5 Substation installation

The substation installation is assumed to be performed by a heavy lift vessel. The installation time is composed by the installation of the jacket foundation and the installation of the substation topside plus the voyage time. The voyage time is estimated considering the speed of the vessel and the distance from the port to the offshore wind farm. The total installation time, provided by [16], is :

$$T_{substation} = (n_{subst} * R_{subst} * D_{pile}) + T_{reposit} + T_{substjacket}$$

Where, n_{subst} is the number of piles for the substation, R_{subst} is the rate of pilling the piles of the substructure, D_{pile} is the depth of pile under the soil, $T_{reposit}$ represents the time to reposit the vessel and $T_{substjacket}$ is the installation time of the substation's jacket.

Installation of offshore substation information		
Item	**Unit**	**Value**
Total effective installation days for the substation	Days	**10,1**
Total installation time for substation	h	**55**
Total time for transport the offshore substation	h	**5**
Speed of the substation vessel	km/h	**15**
Number of piles per substation foundation	Unit	**4**
Rate of piling the piles of the substructure	h/m	**0,1**
Depth of pile under the soil	m	**40**
Reposition time of the vessel	h	**12**
Installation time of the substation's jacket	h	**25**
ADJ weather	Unit	**0,5**

Table 8: Data regarding the offshore substation information; source: own model

3.3.4 Disposal and decommissioning phase (D&D)

As already mentioned energy companies are obliged to removes all the structures and verify the clearance of the area upon the termination of the operational life of the wind farm. This module has the goal to forecast the cost to remove the wind turbine as well as the substation, the cables etc.

The main four components to be removed are the turbines, the foundations, the offshore substation and the cables. A fifth element has been added called site clearance.

To estimate the cost to remove both the turbines and the foundations the inputs data in table 8 were used. The total cost to remove all the turbines and foundations account to be almost 70

M£. To perform this activity a specific vessel must be used that is also used for the removal of the offshore substation.

Turbine and foundation removal – INPUTS		
Remove time per turbine with a self-propelled jack up vessel	h/turbine	**20**
Complete turbines (including foundations) capacity of a Jack up vessel	Turbines/trip	**4**
Number of jacks up vessels for the removal of the wind turbines	Unit	**3**
Number of workboats employed for the decommissioning of the turbines	Unit	**2**
Number of technicians per workboat	Unit	**8**
Offloading time of turbines/monopiles	h/item	**8**
Time to cut the foundation	h/foundation	**8**
Time to lift the item and place on the deck	h/item	**13**
Turbine and foundation removal – OUTPUTS		
Total duration of each trip which equals the sum of the travel time to and from site, the removal time of turbines and monopile, the loading time and the intra-field movement time of the jack up vessel	h	**312**
Total time per trip (adjusted to weather and working hours)	Days	**30,6**
Total effective days for turbines and monopiles removal divided by the number of vessels	Days	**171**
Total cost of hiring technicians and workboats during the decommissioning of the wind turbines	£	**1.933.278**
Cost for removing all wind turbines with monopiles	£	**69.167.647**

Table 9: Inputs and outputs information regarding the turbine and foundation removal; source: own model

The removal time for the offshore substation is assumed to be equal to the removal of 4 completed turbines (Wind turbine + Foundations). Information regarding this removal are provided in table 9.

Offshore substation removal – outputs		
Total time for the removal of the substation (Assumption Removal of the substation = 4 turbines completed removal)	days	**30,6**
Total cost for the removal of the substation	£	**4.129.412**

Table 10: Data information regarding the offshore substation removal; source: own model

Cables can be cut in several sections while they are removed, therefore less expensive vessels can be used. Data in table 10 regarding the rate of removal of the cables were taken from [30].

Cables removal		
Rate of removal of inner-array cables	m/day	**800**
Rate of removal of export cables	m/day	**1200**
Days required	days	**322**
Cost of cables removal	£	**6.441.625**

Table 11: Cables removal data; source: own model

The site clearance area has been estimated using the following equation provided by [16]:

$$Area = -51.5 + 0.41 * d + 0.65 * N \quad (In\ km\ )$$

Where d is the rotor diameter and N is the number of turbines. Data regarding the area to clear and the cost are provided in table 11.

Site clearance		
Area	km^2	**44**
Total cost for site clearance	£	**2.622.600**

Table 12: Site clearance assumptions and calculations; source: own model

3.4 Capex per phase

According to the estimates an initial investment of £ 1.163.043.305 is required. Figure 20 shows the cost breakdown divided for the main phases of the project. The phase that accounts for the highest cost is the production and acquisition phase. To this phase, as can be seen easily from table 12, belongs the three main cost drivers of the project (wind turbine acquisition cost, foundations acquisition cost and transmission system acquisition cost). The second largest contributor to the investment is the installation and commissioning phase that include the transport and the installation of all the components for the offshore wind farm. In this phase the cables installation accounts to be the most expensive one. The third largest contributor to the capex is the development and consenting phase, in this category are inserted all the costs that are prior to the financial close (time in which an agreement between investors, construction company etc. is meet). Costs associated to this category are costs required to realize preliminary studies to understand the feasibility and the possible profitability of the project.

The last contributor that accounts for about the 7% of all the capital expenditure is the disposal and decommissioning phase, this category accounts for the removal of all the components of the wind farm plus a contribution provided by the site clearance.

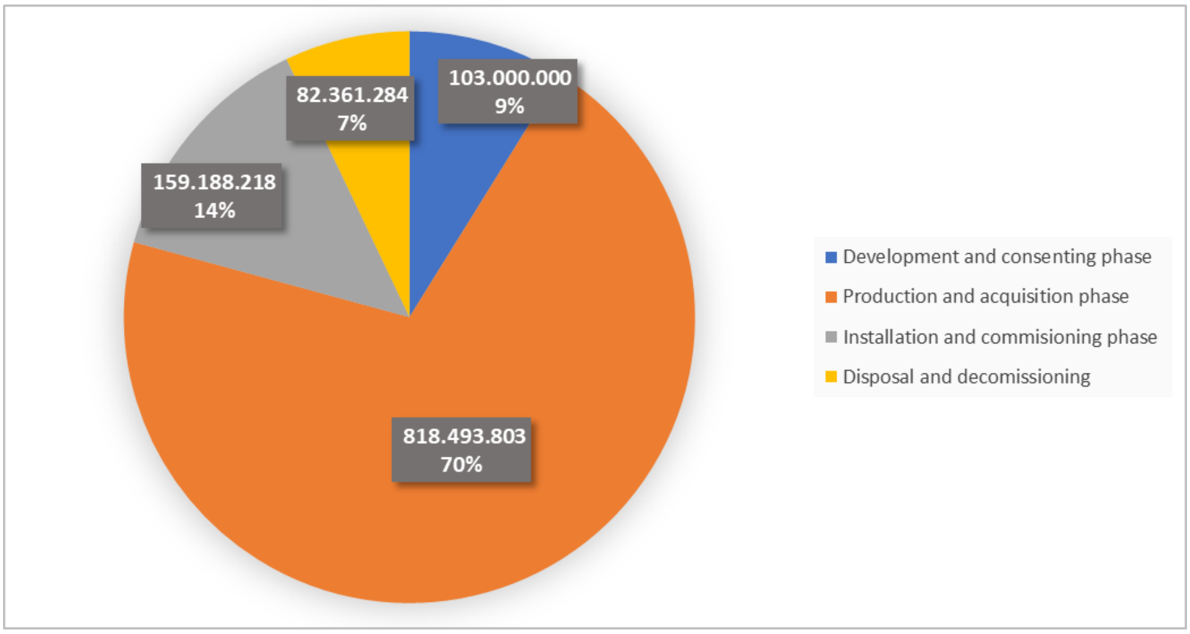

Table 13: Capex distribution across the phases; source: own model

A detailed cost breakdown of the capex module is provided in table 12 where all the cost drivers are listed and quantified.

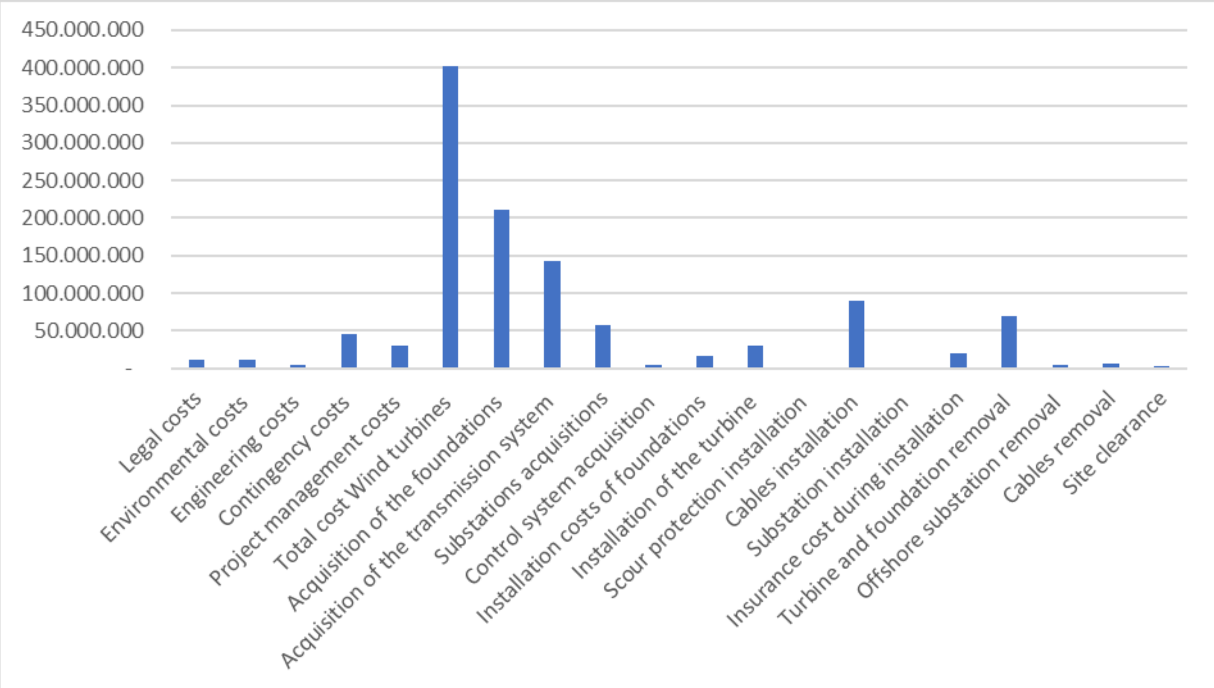

Table 14: Detail cost breakdown for the capex module; source: own model

The estimated capex looks to be consistent and reliable considering a number of previous studies as table 13 shows.

Wind farm	Fnd.	Capacity	CAPEX	Dist. km	Depth m	Curr.	Norm. factor
Dudgeon	MP	67×6MW	1300M£	35	12–24	$\$_{2014}$	0.737
Wikinger	Jk	70×5MW	1350 M€	35	36–40	$\$_{2014}$	0.737
Nordsee One	MP	54×6.15MW	1200 M€	45	28	$\$_{2014}$	0.737
Cape Wind	MP	130×3.6MW	2620 M$	11	3–15	$\$_{2010}$	0.879
Bluewater Wind	MP	150×3MW	1000 M$	24	10–33	$\$_{2010}$	0.879
Coastal Point	Jk	60×2.5MW	360 M$	8	15	$\$_{2010}$	0.879
Garden State	Jk	96×3.6MW	1500 M$	33	21–30	$\$_{2010}$	0.879

Table 15: Benchmarking capex data regarding offshore wind project; source: own model

3.5 OPEX – Operational cost

Operational cost represents a consistence cost driver when evaluating the profitability of an offshore wind farm. Under this category are listed all the costs that are related with the monitoring, scheduled and unscheduled maintenance etc. To perform all these operations are required personnel, vessel charter etc.

Different sources were analyzed to evaluate this cost. According to [31] the operational cost is £21.26/MWh and start from the first year of operation. According to respectively [32], [33], [34] and [35] the operational cost(£) per MWh generated is respectively 24.00, 25.75, 17.1 and 35.5.

To evaluate all these sources equally for the case study an operational cost of £24.722/MWh is assumed.

3.6 Revenue

The revenue is generated by multiplying the total energy produced of the offshore wind farm with the price of electricity. It is assumed that all the energy produced is sold. The first step is to calculate the total energy produce, the second will be to estimate the supported price of electricity.

$$T.e.p.Y = Installed\ capacity(MW) * 8760(numbers\ of\ hours\ per\ year) * capacity\ factor$$

Where T.e.p Y stand for total energy produced per year. As already mentioned the capacity factor is a measure that heavily influence the performance of a wind farm. Based on figure 10, on [16] and on [17] a capacity factor of 0.48% is assumed. Nevertheless, the capacity factor is mostly determined by the availability of wind.

Thank you to this data we now can calculate the total energy produced for the 25 years of operational life of the wind farm:

- Energy produced per year: 402MW*8760hours*0.48%= 1.690.329.6 MWh

3.7 Supported price

Since the project is placed in UK the policy instruments supporting the renewable industry is valid. The contract for difference (CfD) scheme is effective in United Kingdom for companies generating energy from renewable sources. The purpose of the CfD is to incentivize investments in new-low carbon electricity generation in the UK by providing stability and predictability to future revenue streams.

The CfD is a long-term contract between an electricity producer and a low carbon contract company (LCCC), a government owned company. The contract enables the producer to stabilize its revenue at pre-agreed price (The strike price) for the duration of the contract. According to the Cfd scheme, the producer sells energy through a usual power purchase agreement (PPA) to a trader at an agreed reference market price. If this reference market price for electricity is below the Strike price set out in the contract, payments are made by the LCCC to the producer to make up the difference. Instead, when the reference price is above the strike price, the producer pays LCC the difference. For the case study, the strike price adopted amounts to £143/ MWh, that corresponds to the strike price for 2018/2019 (as indicated in [36]).

3.8 Project financing

The project is financed by a mix of debt and equity. The amount of debt is 40% and the rest is financed by equity. In United Kingdom the largest commercial banks such as UniCredit, Lloyds and BNP Paribas provide loans for renewable project. The debt will be repaid in 12 years starting from the first year of operation of the project. Table 14 shows the financial structure of the project.

Financing structure	**%**	**Amount £**
Total capex	100	1.163.043.305
Debt	40	465.217.322
Equity	60	697.825.983

Table 16: Financial structure; source: own model

3.9 Weighted average cost of capital

The developers of the project are assumed to be Traditional Energy companies, Renewable energy and electricity transmission companies in the United Kingdom. As traditional company are assumed companies that operate in the Oil&gas sector such as Equinor and Statkraft. As wind turbines developer is assumed Vestas and as electricity transmission company is assumed

National Grid. As already mentioned the weighted average cost of capital will be calculated as follows:

$$WACC = \frac{E}{E+D} * Cost\ of\ Equity + \frac{D}{E+D} * \text{Cost of Debt}$$

3.10 Cost of debt and cost of equity

Based on the financial structure and the debt structure the cost of debt is assumed to be 3.25%. To calculate the cost of equity an already mentioned formula will be used:

$$Cost\ of\ equity = r_f + \beta * \left(\mathrm{E}(r_m) - r_f\right)$$

Where: r_f= risk free rate of return, β= Beta of the security, $E(r_m)$= expected market return.

The risk-free rate is the theoretical return required over a particular period of time on a loan with zero risk. The risk-free interest rate is based on benchmark government bond yields. As the investment is to be based in the UK, the sterling risk free rate has been used to construct a yield applicable to an investment in the UK. The lifetime of the project is 30 years, so the UK government gilts (bonds) for 30 years are used in order to calculate the risk-free rate. The yield provided by this bond is approximately 1.735% as [37] suggests.

The market risk premium is defined in [38] as " The difference between what an investor expects to make as a return on an equity portfolio and the risk-free rate of return". As [38] also added this value historically has averaged between 3.5% and 5.5%. Therefore, for this case study a market risk premium of 4.5% is assumed.

3.11 Beta Calculation and WACC calculation

The developer of the project is assumed to be Starkraft, Norway's largest energy producer, a company fully owned by the Norwegian State. The Beta will be calculated based on the peer group companies as soon as Starkraft is not listed in the stock market. The three companies chosen as peer group to estimate the beta of Statkraft and therefore the Beta of the Project are

Vortex, Vestas and Siemens Gamesa, these three have been chosen because are some of the largest renewable energy companies.

However, the betas have to be adjusted or unlevered in order to take out the effect of gearing. The gearing is the ratio between the external debt and market value of equity. The external debt includes the bank loan and bonds. The gearings are obtained from consolidated financial statements of these companies. In this condition, the gearing is used as debt/equity ratio to calculate the unlevered beta from levered beta.

	Nordex	Vestas	Siemens Gamesa
Levered Beta	1.25	1.29	1.38
Gearing (Debt/Equity)	0.79	1.08	1.33
Unlevered Beta	0.78	0.71	0.68

Table 17: Beta information regarding the peer group companies; source: own model

To calculate the unlevered beta the formula explained in chapter 2 was used and it is remembered here:

$$\beta_u = \frac{\beta_l}{1 + \frac{\mathrm{D}}{\mathrm{E}} * (1 - t)}$$

Where β_u is the beta unlevered, β_l the beta levered, $\frac{D}{E}$ the ratio between debt and equity of each company and T the tax rate (19%).

The unlevered beta of the project is assumed to be around 0.74 (the average of unlevered beta of the peer group). The debt/equity ratio of the project is 0.4/0.6, the levered beta of the project is around 1.1 according to the formula:

$$\beta_l = \beta_u * (1 + (1 - T) * \frac{D}{E})$$

Now it is possible to calculate the cost of equity using the capital asset pricing model. The cost of equity results to be 6.685%. While the WACC is 5.31%.

3.12 Tax rate and capital allowances

The tax rate used (19%) is the main corporation tax in the UK as mentions by [16]. In UK is available the tax depreciation through capital allowances regime, according to which the 18% of qualifying expenditure on equipment is reduced as [39] says. The effect of depreciation is estimated by dividing the equipment cost of the wind farm, $C_{equipment}$, over the total life span of the asset and deducting 18% of this annual cost from the tax payment. Therefore, the net tax T_{net} can be calculated by deducting the depreciation credit D_{Credit} from the yearly tax payment, $T_{payment}$ as shown below:

$$D_{Credit} = \frac{C_{equipment}}{n} * d_{rate}$$

$$T_{net} = T_{Payment} - d_{credit}$$

$$T_{payment} = T_c * Pgr$$

Where T_c is the corporate tax rate paid every year and the Pgr represents the gross profit. To calculate then the net profit is necessary to subtract T_{net} from Pgr.

Chapter 4: Profitability analysis

In this section are presented the results and the returns of the offshore wind project, a sensitivity analysis on respectively the investment cost, the net capacity factor and XX follow.

4.1 Results

According to the Excel attached the offshore wind project is proved to be profitable and feasible. On the baseline scenario the NPV of the investment was calculated to be 467.4 M£ with a discount rate (=WACC) of 5,31% with an IRR=8,36%.

The BET (Breakeven time) is reached between year 19 and year 20 as table 15 shows. Table 15 shows both the discounted cashflow and cumulated cashflow for every year of the project.

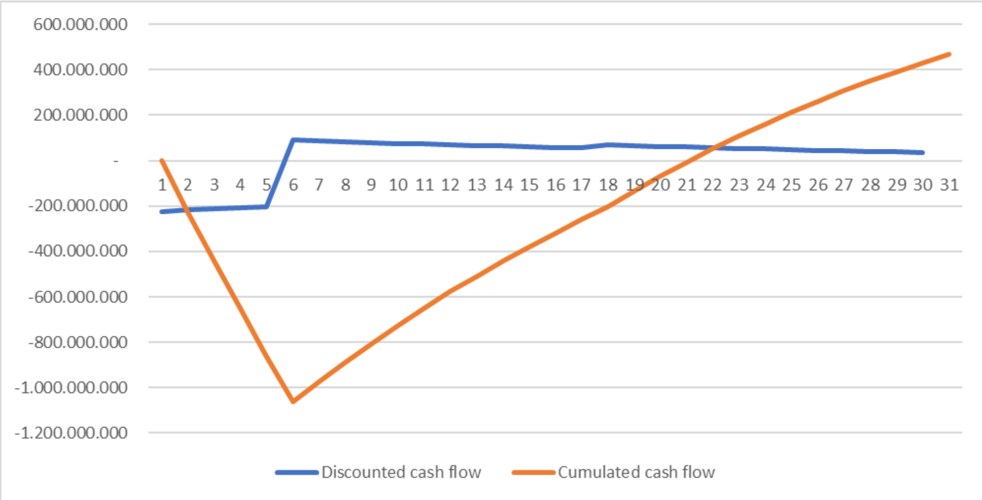

Table 18: Discounted cash flow and cumulated cash flow of the project; source: own model

Table 16 shows the net income of the offshore wind project; no income is reported in the first 5 years because the construction period lasts exactly five years. Therefore, the depreciation, the interest start being “paid” from the 6th year.

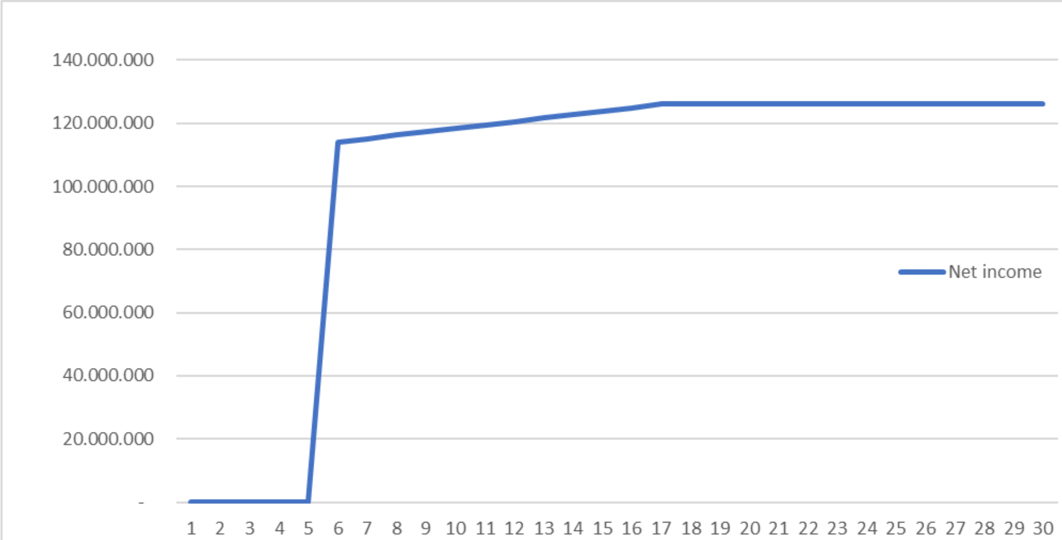

Table 19: Net income evolution for the project; source: own model

4.2 Sensitivity analysis

In the baseline scenario assumptions are made to the current conditions resulting in a reasonable NPV and an IRR greater than the WACC. However, the change in endogenous variables such as the capex, the opex, the net capacity factor etc. can affect heavily the profitability. This section explains what the possible effect of some changes in variables such as capex, opex etc. can be on the profitability.

4.2.1 Sensitivity analysis – Capital expenditure (Capex)

As already mentioned all the technologies required for an offshore wind farm is still immature and under studies, therefore it is not easy to make an estimate 100% reliable and secure about the initial investment. To solve this problem table 20 has been developed. Table 20 shows what would be the NPV and IRR with different capex investment. If project investment cost would increase by around 38% (1615 GBP million) from the normal baseline scenario the NPV of the project would be almost equal to zero and the IRR would be equal to the WACC. This is considered the maximum initial investment cost that would still generate a profitable investment. Table 20 analyses also other possible scenarios; in yellow is highlighted the baseline scenario.

Capex (£)	NPV (£)	IRR (%)
1.050.000.000	583.820.497	9,41%
1.100.000.000	532.330.845	8,93%
1.163.043.305	467.409.289	8,36%
1.200.000.000	429.351.542	8,05%
1.250.000.000	377.861.891	7,65%
1.300.000.000	326.372.239	7,28%
1.400.000.000	223.392.936	6,59%
1.500.000.000	120.413.634	5,96%
1.600.000.000	17.434.331	5,40%
1.615.000.000	1.987.435	5,32%

Table 20: Sensitivity analysis on Capex; source: own model

4.2.2 Sensitivity analysis – Operational expenditure (Opex)

Another relevant cost that can affect heavily the final financial result is the operational expenditure (Opex). In the baseline scenario a cost of 24,722 £ per MWh generated is assumed for operational expenditure. Table 21 shows the different scenario for a change in the opex cost on NPV and IRR. Although, the NPV and IRR result to be less sensitive to a change in the Opex rather than to a change in the Capex, this is due to the fact that the expenditure of Capex is higher compared to the expenditure on Opex. In yellow is again highlighted the baseline scenario.

Opex (£/MWh)	NPV (£)	IRR (%)
18	564.503.475	8,94%
19	550.059.234	8.85%
20	535.614.993	8,77%
21	521.170.753	8,68%
22	506.726.512	8,60%
23	492.282.271	8,51%
24,722	467.409.289	8,36%

26	448.949.549	8,25%
27	434.505.309	8,16%
28	420.061.068	8,07%
29	405.616.827	7,99%
30	391.172.587	7,90%

Table 21: Sensitivity analysis on operational expenditure (Opex); source: own model

4.2.3 Sensitivity analysis – Combination Capex and Opex on NPV and IRR

It is interesting to see how NPV and IRR would change due to a simultaneous change in both Capex and Opex. For this reason, a sensitivity analysis has been performed using a function called "What-if analysis" implemented in Excel. The results of this analysis are represented in table 22 for the NPV and in table 23 for the IRR. The more the green become darker the more the NPV result to be positive. Obviously, the highest NPV would be in correspondence of the lowest Capex and the lowest Opex and this is what table 22 shows. If we assume a Capex of 1600 M£ an Opex of just 26 £/MWh is enough to make the investment not profitable. The consideration above written related to the NPV are also valid for the IRR that is represented in table 23.

		Capex									
		1.050.000.000	1.100.000.000	1.163.043.305	1.200.000.000	1.250.000.000	1.300.000.000	1.400.000.000	1.500.000.000	1.600.000.000	1.615.000.000
Opex	20	652.026.201	600.536.550	535.614.993	497.557.247	446.067.595	394.577.944	291.598.641	188.619.338	85.640.035	70.193.140
	21	637.581.961	586.092.309	521.170.753	483.113.006	431.623.355	380.133.703	277.154.400	174.175.097	71.195.794	55.748.899
	22	623.137.720	571.648.069	506.726.512	468.668.766	417.179.114	365.689.463	262.710.160	159.730.857	56.751.554	41.304.658
	23	608.693.479	557.203.828	492.282.271	454.224.525	402.734.873	351.245.222	248.265.919	145.286.616	42.307.313	26.860.418
	24,7	583.820.497	532.330.845	**467.409.289**	429.351.542	377.861.891	326.372.239	223.392.936	120.413.634	17.434.331	1.987.435
	26	565.360.757	513.871.106	448.949.549	410.891.803	359.402.151	307.912.500	204.933.197	101.953.894	- 1.025.409	- 16.472.304
	27	550.916.517	499.426.865	434.505.309	396.447.562	344.957.911	293.468.259	190.488.956	87.509.653	- 15.469.650	- 30.916.545
	28	536.472.276	484.982.624	420.061.068	382.003.321	330.513.670	279.024.018	176.044.716	73.065.413	- 29.913.890	- 45.360.786

Table 22: Simultaneous sensitivity analysis on Capex and Opex for the NPV; source: own model

		Capex									
		1.050.000.000	1.100.000.000	1.163.043.305	1.200.000.000	1.250.000.000	1.300.000.000	1.400.000.000	1.500.000.000	1.600.000.000	1.615.000.000
Opex	20	9,84%	9,34%	8,77%	8,45%	8,04%	7,66%	6,96%	6,32%	5,75%	5,67%
	21	9,75%	9,26%	8,68%	8,37%	7,96%	7,58%	6,88%	6,25%	5,68%	5,60%
	22	9,66%	9,17%	8,60%	8,28%	7,88%	7,50%	6,80%	6,17%	5,60%	5,52%
	23	9,57%	9,08%	8,51%	8,20%	7,80%	7,42%	6,72%	6,10%	5,53%	5,45%
	24,7	9,41%	8,93%	**8,36%**	8,05%	7,65%	7,28%	6,59%	5,96%	5,40%	5,32%
	26	9,29%	8,81%	8,25%	7,94%	7,54%	7,17%	6,48%	5,87%	5,31%	5,23%
	27	9,20%	8,72%	8,16%	7,85%	7,46%	7,09%	6,40%	5,79%	5,23%	5,15%
	28	9,11%	8,63%	8,07%	7,77%	7,37%	7,00%	6,32%	5,71%	5,15%	5,08%

Table 23: Simultaneous sensitivity analysis on Capex and Opex for the IRR; source: own model

4.2.4 Sensitivity analysis - Net capacity factor

The net capacity factor affects heavily the production of energy of the wind farm ad therefore the revenues of the wind farm. As already mentioned the net capacity factor depends heavily on the technology, on the types of turbine and on the wind speed. It is for sure possible to make forecasts, but uncertainty still exists. Table 24 summarize the NPV and IRR that would be obtained with different Net capacity factor. Both NPV and IRR result to be very sensitive to a change in the net capacity factor. Just a change of 2% on the net capacity factor would generate a change of almost 30 M£ on the NPV. In yellow again is highlighted the baseline scenario.

Net capacity factor (%)	NPV (£)	IRR (%)
0,45	363.340.340	7,73%
0,46	398.029.990	7,94%
0,47	432.719.639	8,15%
0,48	467.409.289	8,36%
0,49	502.098.938	8,57%
0,5	536.788.588	8,77%
0,51	571.478.238	8,98%
0,52	606.167.887	9,18%
0,53	640.857.537	9,38%
0,54	675.547.186	9,57%

Table 24: Sensitivity analysis on the Net capacity factor; source: own model

4.2.5 Sensitivity analysis – Debt ratio

The debt ratio also affects both NPV and IRR. One of the advantages of using more debt is to reduce the cost of Capital because in general the debt is cheaper than equity. This bring a reduction of the WACC. However, using more debt also increase the interest expense and the principal repayment causing the increase of the cashflow outflow of the project that negatively affect the cash flow of the project. In the project, the increase of debt ratio leads to the decrease of both NPV and IRR, although the WACC goes down. The decrease in both NPV and IRR is mainly due to the higher payment of the interest to the bank that is not balanced by the decrease of the WACC. However, the NPV (assuming the extreme scenario of a debt ratio of 80%) is still positive with an IRR of 5,55% and an NPV higher than 315 M£. In general, as said, the increase in debt ratio negatively impacts the profitability of the investment. In yellow again is highlighted the baseline scenario.

Debt ratio (%)	**20**	**30**	**40**	**50**	**60**	**70**	**80**
WACC (%)	6%	5,65%	5,31%	4,96%	4,62%	4,28%	3,93%
NPV (M£)	518.7	494.8	467.4	436.1	400.7	360.8	316.1
IRR (%)	9,78%	9,07%	8,36%	7,65%	6,95%	6,25%	5,55%

Table 25: Sensitivity analysis on the debt ratio; source: own model

4.2.6 Sensitivity analysis – Delay time

To conclude, a sensitivity analysis on the delay time of the construction of the project is proposed. This scenario assumes that the sum of the construction time and the operational life remains 30 years. Therefore, considering a delay time in the construction of 5 years means that the construction period would be of 10 years and the operational life would lasts 20 years. Under this scenario the project would not be profitable with a negative NPV and an IRR<WACC. Other scenarios are considered in the analysis and are listed in table 26.

Delay time (Year)	**1**	**2**	**3**	**4**	**5**
NPV (M£)	348.8	242.4	145.2	55.7	- 27.2
IRR (%)	7,63%	6,96%	6,32%	5,71%	5,11%

Table 26: Sensitivity analysis on the construction time; source: own model

Conclusion

The Paris agreement on climate change signed in April 2016 negotiated by 196 state parties has the aim of strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. To meet this important agreement a massive introduction of renewable source to produce energy must be made.

The “classic” and “old” renewable energy source such as hydroelectric and geothermal have already been almost fully deployed and are considered mature technologies, not subject to radical improvements in the future. Here the importance of Solar and Wind that are today two major renewable energy sources that have the potential to make us meet many of the climate challenges that the world is facing. Thank you to the technological development, these two technologies have become extremely competitive and with the help of government policies will have a higher and higher market shares in the future.

In particular, offshore wind has seen an enormous growth in the last years and investments have reached a reasonable maturity with more than 90 wind farms in operation in the European countries. The advantages of wind power are many resulting in a considerable growth demand for this technology. This thesis is the result of an intensive collaboration with RINA S.p.A, company sited in Genoa (Italy).

An innovative and accurate Discounted Cash Flow Financial Model for Offshore wind power projects is verified and developed, with the objective to facilitate the evaluation and the decision-making process in Offshore wind projects for possible investors.

This thesis is a result of a deep analysis of the entire value chain of the wind power. The initial section of the work is a focus on the state of art analysis documenting the general investment trends in the market, the emerging evolutions in the different countries and the presentation of important index to predict the possible actual and future interest in the technology. After a brief and non-technical explanation of how a wind turbine works is developed an environmental and risks assessment for an offshore wind power project. After that, in chapter two is performed the literature review regarding Offshore financial model to analyze what is available in the literature regarding this topic, the chapter finishes with a theoretical sub-chapter regarding the financial and non-financial methods to evaluate the profitability of an investment.

The final section is dedicated to the case study that is analyzed in depth along the five typical phases of an energy project here mentioned: Development and Consenting, Production and Acquisition, Installation and Commissioning, Operation and maintenance and Decommissioning and Disposal. To each of this phase are linked different costs, these costs are estimated using the most recent equations available in the literature.

After having set a series of financial hypothesis, investments returns are calculated with a detailed assessment that takes in consideration the technical parameters of the problem. First, a deterministic model is developed, based on a realistic case study of an Offshore wind farm in UK, follows a sensitivity analysis to test how input parameters influence the model output. The sensitivity analysis highlights that the model outputs are extremely sensitive to the initial capital expenditure, as well as to some financial parameters and revenue parameters. In addition, all the main critical issues faced during the assessment of an Offshore project are evaluated and explained. Limitations of creating a model of this type include the difficulty of performing economic and political scenarios in the industry and also being able to link these economic and political scenarios with the model. As already mentioned, the thesis develops a case set in United Kingdom therefore all the economic assumptions such as taxation and capital allowances are adapted to the UK market.

Compared to onshore wind, offshore wind remains a step behind mainly because of the higher capex compared to onshore. This is confirmed also by the case study analyzed, as broadly described the calculated IRR of the project is 8.36%. As many sources mention usually for classic renewable energy projects (Onshore wind and Solar) the IRR stands in the range of 9%-11%. However, competition between equipment providers such as Vestas, Siemens Gamesa, GE Renewable energy will for sure allow for a decrease of cost that will cause a decrease of project costs and therefore a higher IRR. This cost decrease will affect both offshore and onshore wind projects. An advantage of offshore wind compared to onshore might be the economies of scale, on average, offshore wind projects are way bigger in term of MW installed, this might allow the exploitation of more economies of scale to try to get close to the attractiveness of onshore wind.

Another factor that must be considered when dealing with project of this type is the complexity, risks are intrinsic in the development of the project and they can be found at different levels and at different steps of the development as broadly described in chapter 1; an appropriate risk assessment and mitigation must be performed to assure the profitability and the "success" in the development of the project. The environmental impact of wind turbines is not zero. The main impacts are the ecological, the visual and the noise one. However, the effect on the environmental are way less negative compared with the conventional fossil fuels, wind turbines during their lifetime do not pollute the atmosphere with greenhouse gases and do not create any problems for future generations with radioactive waste therefore wind power can be considered one of the greener sources of energy.

To conclude, wind and solar, due to their nature, are stochastic energy sources, depending one from the wind and the other one from the sun. Obviously, humans cannot rely only on wind and solar as their only source of energy, integrations with other renewable and not renewable energy source must be made. Most probably, in the medium/long term Europe will continue to rely heavily on natural gas. Natural Gas will be needed to stabilize the grid on peak demand and as stabilizer when green sources such as wind and solar are not available.

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