TÉCNICO LISBOA

Renewable energy – technology, production costs and profitability

Pablo Pizcueta Pastor

Thesis to obtain the Master of Science Degree in

Energy Engineering and Management

Surpervisor: Prof. João Agostinho de Oliveira Soares

Examination Committee

Chairperson: Prof. Duarte de Mesquita e Sousa

Supervisor: Prof. João Agostinho de Oliveira Soares

Member of the Committee: Prof. Carlos Manuel Ferreira Monteiro

October 2017

Acknowledgements

First of all, I would like to thank my supervisor, Prof. João Soares, for his guidance and support during the elaboration of this thesis. A special thank to David, whose support has helped me during this thesis.

Thank to my friends and colleagues of the Master, which have made these last two years an incredible experience.

Thank you Silvia for supporting me during the hardest moments of the Master Program.

Thank to Innoenergy for giving me the opportunity to study this Master programm.

Last, thank to my parents, who have always supported me.

Abstract

The advancements in solar PV and wind energy, together with cost reductions have increased the competitiveness of these technologies in the power sector. The cost of generating electricity with these systems has plummeted in the last decades. Therefore, each day is more attractive to invest in such installations since they are becoming more profitable even without any government support in some locations. In this sense, this research wishes to build a financial and economic model to assess the profitability of solar PV and wind projects. This model is applied to two residential PV installations located in Portugal and Spain and a wind farm located in Argentina. Although all the projects are profitable under the conditions of the base case scenario, there are several differences between the factors considered and the methodology followed for each case, which result in the largest profitability for the Portuguese case, followed by the Spanish and finally the Argentinian. The influence of the different factors over the profitability parameters is analyzed through a sensitivity analysis, which concludes that the installation cost, electricity output and electricity price strongly affect the parameters. It is evidenced the importance of technology improvements and cost reductions, together with a favorable and reliable regulatory framework, in order to achieve larger profitability on PV projects.

Keywords

Electricity production cost; wind energy; solar PV energy; energy projects assessment

Resumo

Os avanços nas energias solar e eólica, juntamente com a redução de custos, aumentaram a competitividade destas tecnologias na produção de energia. O seu custo da geração de eletricidade conheceu uma descida substancial nas últimas décadas, pelo que cada vez há maior atração para investimentos nestes domínios, mesmo sem qualquer apoio do governo. Nesse sentido, este trabalho visa propor um modelo financeiro e económico para avaliar a rentabilidade dos projetos de energia solar e eólica. Este modelo é aplicado a duas instalações fotovoltaicas residenciais localizadas em Portugal e Espanha e um parque eólico localizado na Argentina. Embora todos os projetos sejam rentáveis nas condições do cenário de base, existem várias diferenças entre os fatores considerados e a metodologia seguida para cada caso, o que resulta na maior rentabilidade para o caso português, seguido pelo espanhol e, finalmente, pelo argentino . A influência dos diferentes fatores sobre os parâmetros de rentabilidade é analisada através de uma análise de sensibilidade, que conclui que o custo de instalação, a produção de eletricidade e o preço da eletricidade afetam fortemente os parâmetros. Consequentemente, evidencia-se a importância das melhorias tecnológicas e redução de custos, juntamente com um quadro regulatório favorável e confiável, para obter uma maior rentabilidade em projetos fotovoltaicos.

Palavras-chave:

Custos de produção de energia; energia eólica; energia fotovoltaica; avaliação de projetos de energia

Index

List of Tables

List of Figures

Abbreviations

ASC	Active Stall Control
BOS	Balance of System
BCS	Base Case Scenario
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expendidure
CAPM	Capital Asset Pricing Model
CIGS	Copper Indium Gallium Diselenide
CIS	Copper Indium Silicon
CNT	Carbon Nanotubes
CPV	Concentrating Photovoltaic
DFID	Doubly Fed Induction Generator
DPBP	Depreciated Payback Period
EPBP	Energy Payback Period
GHG	Greenhouse Gas
GSR	Global Status Report
GW	Gigawatt
HAWT	Horizontal Axis Wind Turbines
HC	Hot Carrier
IDAE	*Instituto para la Diversificación y Ahorro de la Energía*
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
kWh	kilowatt-hour
LCA	Life Cycle Analysis
LCOE	Levelized Cost of Electricity
NPV	Net Present Value
OECD	Organization for Economic Cooperation and Development
OPEX	Operating expense
PSC	Passive Stall Control

PV	Photovoltaic
QD	Quantum Dots
R&D	Research and Development
REN21	Renewable Energy Policy Network for the 21st century
SCIG	Squirrel Cage Induction Generator
TPES	Total Primary Energy Supply
VAWT	Vertical Axis Wind Turbines
WACC	Weighted Average Cost of Capital
WRIG	Wound Rotor Induction Generator

1 Introduction

Renewable energy technologies are in the spotlight of the power sector, yearly it is set a new record of capacity installed worldwide. The growing implementation of renewables in the electricity generation mix is a consequence of the innovation and development of the renewable energy industry, which is leading to a reduction in the cost of generating electricity with renewables. The technology improvement and cost evolution of the two most employed non-convectional renewable energy sources worldwide, solar photovoltaic and wind energy, are presented within this work.

In the photovoltaic (PV) industry huge advancements have been achieved in the last decades. In the technology side, continuous improvements in materials and manufacturing process are boosting the performance of PV installations. Whilst crystal silicon still being the most used technology, new materials are under research for future implementation. Additionally, the cost of PV has plummeted since the early 1980s and it is achieving grid parity in some locations. PV technology is in a really downward trend, which difficult the forecasting of the PV cost. In fact, in the last two years, the price of the PV modules has been drastically reduced to values forecasted to 2025. Whereas in 2015 the average price of PV modules for utility-scale projects, according to the International Renewable Energy Agency (IRENA, 2016), ranged between 0,52 $/W in India to 0,72 $/W in Japan, current prices for utility scale projects are as low as 0,32 $/W in some locations. Therefore, this work presents the evolution of technology and cost in the PV market during the last decades.

The technology improvements in the wind sector have been focused on scaling up the size of wind turbines, which have resulted in the current multi-megawatt wind turbines. In line with this increase, other improvements have been implemented like controlling systems, better materials, etc. Although the wind industry has experienced great reductions since the early 1980s, the cost of wind has been increased during some periods, mainly caused by market constrains and unfavorable financial support. The technology and cost evolution in onshore and offshore wind projects is within the scope of the work.

Finally, the main purpose of this work is to build a financial and economic model to assess different renewable energy projects. Therefore, this model includes the calculation of the main financial parameters used to evaluate the profitability of this type of projects; which are the net present value (NPV), internal rate of return (IRR) and discounted payback period (DPBP). Moreover, it is also calculated the levelized cost of electricity (LCOE) including and excluding the social cost of avoiding CO_2 emissions.

The financial and economic model will be applied to assess three renewable energy projects that are being installed within 2017, two residential PV installations in Spain and Portugal and a wind farm in Argentina. Each project included the most accurate information regarding installation and operating costs, capacity factor, useful life, capital cost and subsidies in order to perform the viability study. Moreover, it is performed a sensitivity analysis for each case in order to calculate the deviations in the profitability indexes evaluated when the value of a specific factor varies and the others that define the base case remain constant. This analysis evaluates the uncertainty with the most relevant factors, which are installation cost, electricity output, electricity price, operating expenses and discount rate.

2 Evolution of renewable energies

The increasing concern regarding global warming has placed renewable sources in the spotlight of the energy sector. The predominance of fossils fuels (i.e. oil, coal and natural gas) over the global primary energy consumption (Figure 1) is an unsustainable situation in the long run. When producing energy from such sources many pollutant substances are emitted to the atmosphere (i.e. carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), etc.). These substances are the main responsible for climate change. Therefore, non-pollutant energy sources like renewables are necessary in order to switch to a more sustainable scenario

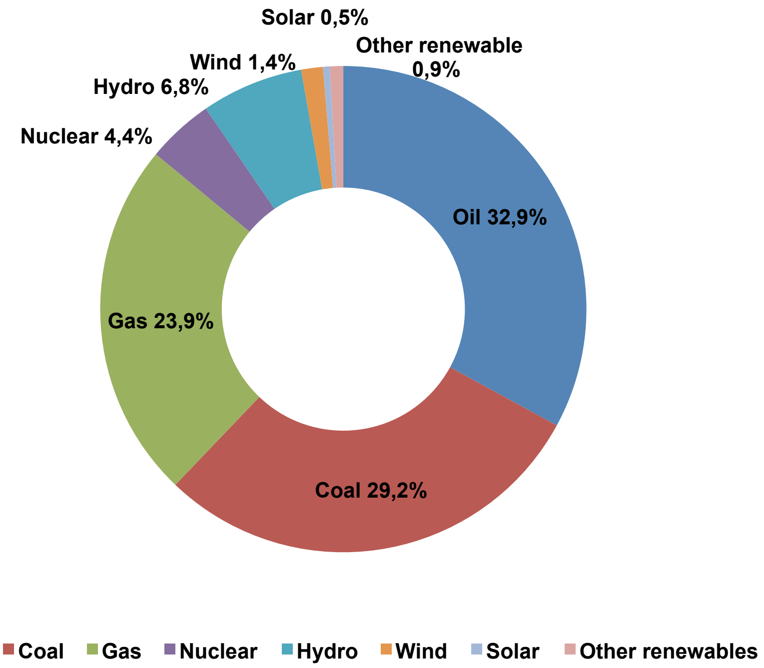
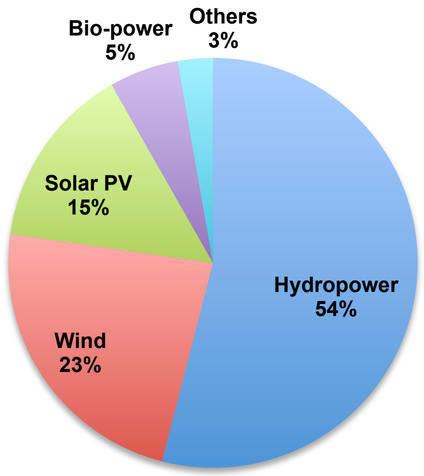


Figure 1 Primary energy consumption by source in 2015
Source: World Energy Council, 2016.

In the last decades, the major improvements regarding renewable energies have been in the power sector, where a trend towards the implementation of renewables in the electricity generation mix has been aimed. Currently, new capacity installed worldwide comes from renewable technologies, around 60%, surpassing the capacity of all the fossil fuels combined (REN21, 2016). On the contrary, the transport and heating sectors still need to experience a revolution towards the implementation of renewables in order to achieve a completely sustainable future.

Regarding the power sector, IRENA (2017) informed in a recent report that the total world´s installed capacity of renewable technologies is 2.006 gigawatts (GW). In which hydropower represented the main source, followed by wind power and solar energy. These three represent the main technologies for generating electricity from a renewable source. Bioenergy, geothermal and marine energy complete the world´s generation capacity from renewable energy technologies (Figure 2). Moreover, a record of renewable installed capacity was set again in 2016 with an estimated increase in renewable energies of 161 GW. Thus, net additions of installed capacity from renewable energy technologies have increased yearly since 2006.



[1]

Figure 2 Share of technologies over the total installed capacity of renewable energies
Source: IRENA, 2017

Although the global increasing trend towards generating electricity with renewable sources, there are differences between regions on the level of penetration according to the economic development or availability of resources (Table 1). The estimated renewable energy share of global electricity production in 2015 was 23,7%. The highest share of renewables corresponds to Latin America with 52,4% of the total electricity produced, which share has decreased according to 2005 values (59,3%). On the contrary, in the same period, Europe has experienced the greatest increase among all regions reaching 34,2% share of renewables.

Region	Share of RE in electricity production		
	2005	2010	2015
Africa	16,9%	17,4%	18,9%
Asia	13,9%	16,1%	20,3%
Europe	20,1%	25,7%	34,2%
Latin America	59,3%	57,7%	52,4%
Middle East	4,3%	2,0%	2,2%
North America	24%	25,8%	27,7%
Pacific	17,9%	18,6%	25,0%

Table 1 Share of electricity production with renewable sources by region in 2005, 2010 and 2015
Source: Wind Energy Resources, 2016

The increase of renewable technologies in the lasts decades has been possible due to a combination of factors, which has made possible the economic competitiveness of renewables against

[1] Other renewables included: Geothermal, marine and mixed plants

traditional sources. One of the main drivers of the penetration of renewables in the electricity generation mix is the technological improvements achieved in the sector. This progress in technology, together with economies of scale and experience acquired with cumulative power installed has led to a reduction in cost. Both the evolution of technology and cost of photovoltaic and wind energy technologies will be discussed in chapter 3. Furthermore, better financial conditions and a favorable regulatory framework has also helped to implement the renewable energies. The analysis of these two factors is also within the scope of this thesis and will be presented with the results of the real cases in chapter 6.

Notwithstanding the great improvements towards renewables energies in the last decades, it is necessary to increase the development trend in the power sector and create a similar path on the transport and heating sector in the near future. The world primary energy demand is expected to grow significantly as a consequence of the population increase and the economic growth of developing countries. Accordingly, renewable energy technologies represent the key in order to achieve a sustainable future, in which fossil fuel technologies share on the global electricity generation is reduced. In order to accomplish this scenario is important to analyze the factors that have led the energy revolution until now (e.g. technology innovation, reduction in cost, favorable policies, etc.) to understand better the challenges to be faced in the future.

This chapter summarized the evolution of both technology and cost for solar photovoltaic and wind energy technologies. We focus on factors that have affected the evolution of the photovoltaic and wind industry as a whole (i.e. technology improvements, cost reductions, markets, etc.) rather than focusing on the region-to-region and project-to-project variations. Accordingly, within this chapter the technologies most used around the world are presented. In the case of solar photovoltaic, there is more homogeneity worldwide, which is mainly explained by the concentration of modules manufactured in the Asiatic region. Table 2 shows the contribution of each country to the production of solar photovoltaic and wind technology. Thus it can be appreciated how the Asiatic region dominates the photovoltaic industry, 86% of market share, whilst the wind industry presents more distributed manufacturers around the world.

Photovoltaic industry		**Wind industry**	
China	62%	China	34%
Taiwan	12%	Germany	21%
Japan	4%	Denmark	12%
Malasya	8%	US	9%
Europe	3%	India	6%
US	1%	Spain	5%
RoW	10%	RoW	14%

Table 2 Share of each country in the total production of solar PV and wind technologies
Source: Own elaboration; Data from: REN21, 2015; REN21, 2016 and *Jäger-Waldau*, 2017

In reference to the cost of PV and wind energy, it is carried out mainly by two different means. The first methodology calculates the overall cost of a renewable generating facility, thus including all the expenses needed in order to start generating electricity. This cost is known as installation cost and it is measured in euros per watt (€/W). The second methodology is the LCOE, which measures the price of 1 kilowatt-hour (kWh) produced over the lifetime of an electricity generation plant, €/kWh

$$LCOE = \frac{\sum_{t=0}^{T} {C_t}/{(1+r)^t}}{\sum_{t=0}^{T} {E_t}/{(1+r)^t}} \tag{1}$$

Where C_t is the plant cost in year t, r is the discount rate and E_t is the electricity produced in year t.

Both methodologies are commonly used in order to assess renewable energy projects. The installation cost is mostly used by companies when evaluating the investment of a project, whereas LCOE is preferred for the evaluation of the economic feasibility of different electricity generation technologies or considering grid parity for new technologies (Branker et al., 2011). The calculation of these costs varies significantly by project and country, depending on several factors. The aim of this chapter is to represent the variability of prices during the recent history of solar and wind technologies to current values, and the reasons behind their trends. Therefore, the trends experienced by the more significant markets are presented (e.g. Germany and Japan with the PV systems and Denmark and US with wind systems.

LCOE calculations are performed by many means according to the factors considered in the equation. In this chapter the LCOE values are calculated excluding public benefits (e.g., carbon credits, Green Certificates), or other means of government incentives (e.g., feed-in-tariff, investment tax credits); as well as environmental benefits (e.g., pollution reduction, labor). These factors are included in the financial and economic model performed for assessing renewable energy projects and will be considered in the calculation of the real cases. Therefore, LCOE values analyzed within this chapter take into consideration the following key drivers: capital expenditure (CAPEX), operating cost (OPEX), energy output (i.e. the capacity factor of the installation), useful life, and cost of financing. The weight of each component on the calculated LCOE varies according to the technology.

2.1 Solar photovoltaic

The photovoltaic solar industry is one of the fast growing industries all over the world. In 2016, according to IRENA, solar photovoltaic energy grew by about 48% totaling 291 GW of installed capacity worldwide (Resourceirena.irena.org, 2017). Above 80% of such capacity is located in only 7 countries. China is the leading country in installed capacity with 26,6%, followed by Japan, Germany, Italy, UK and India. The top four countries in installed capacity and the cases of Spain and Portugal are represented below in Table 3. In addition, it shows the penetration of the PV technology in the national electricity mix, represented by the contribution of PV facilities to the total electricity generated in 2016. Such percentage is aimed to represent the importance of the solar PV technologies in the country. Although this share is small in all the countries, Germany, Japan and Spain produce between 3% and 7% of the total electricity with solar PV. Meanwhile, in China, US and Portugal the share of solar PV in the electricity generation mix is between 1% and 1,5%.

Country	Share of the worldwide installed capacity	Share of the country´s electricity mix
China	26,6%	1,11%
Japan	14,3%	4,3%
Germany	14,1%	6,8%
US	11,3%	1,3%
Spain	1,7%	3,1%
Portugal	0,2%	1,5%

Table 3 Share of the total capacity installed and percentage of the electricity generated with PV energy in 2016
Source: Own elaboration; Data: IRENA, 2017; REE, 2016; APREN, 2016; EIA, 2017; Fraunhofer ISE, 2017 and China Energy Portal, 2016.

It is relevant to point out that the Asiatic countries embraced almost half, 48%, of the total installed capacity worldwide. This domain over the photovoltaic generation capacity is a direct consequence of the previous data presented in Table 2, regarding the PV module manufacturing control of companies located in Asia.

2.1.1 Technology

Photovoltaic is the conversion of radiation into electricity. The solar cells contain layers of semiconductors materials, which create an electricity flow when the light falls on the cell (Figure 3). The electrical power each cell generates is determined by the intensity of the light. The requirements of a solar cell to be consider for photovoltaic uses are: small band gap, between 1,1 and 1,7 electron volt (eV), the smaller the easier for an electron to jump from one band to the other so increasing conductivity; availability of the material; good photovoltaic conversion efficiency and easy production technique (Goetzberger *et al.*, 2002). Therefore the evolution of technology in the PV industry is characterized by the search of materials that integrate most of these requirements. Moreover, the improvement in the properties of the materials already on the market has been also a field of research and development in the PV industry.

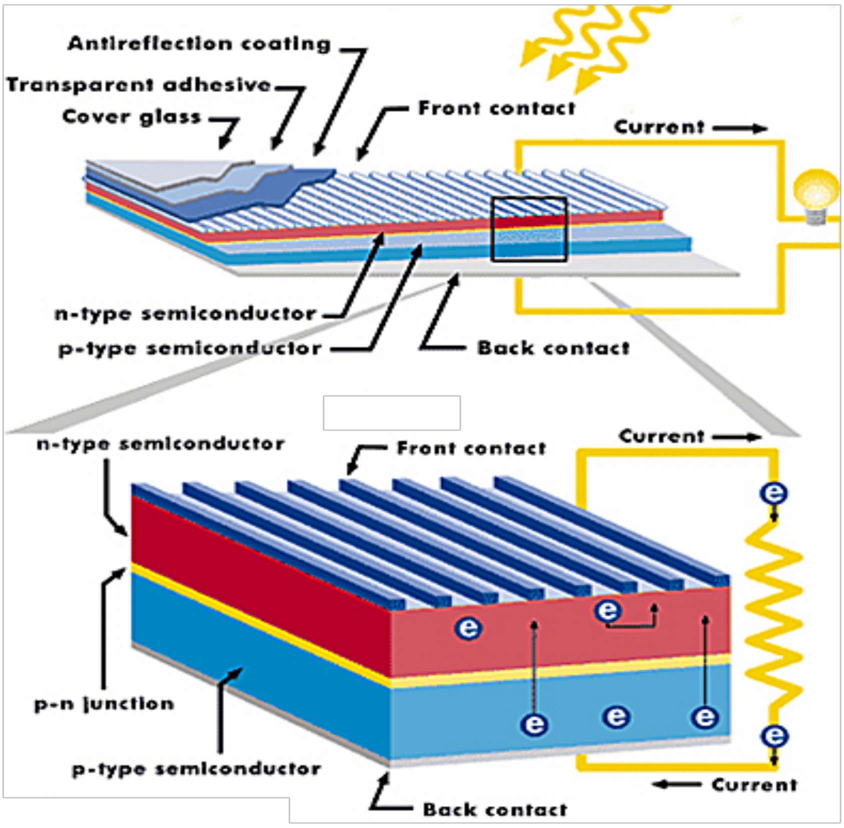


Figure 3 Crystalline silicon module and cell structure
Source: Solarcellcentral.com

Accordingly, there are different types of technologies with some of these characteristics, which are categorized in three different generations according to the raw material used and the maturity of the technology in the market (Figure 4). The first generation uses crystalline silicon (c-Si) as raw material, either in the form of monocrystalline or polycrystalline, which are fully commercial technologies. Within this generation, it also includes gallium arsenide (GaAs) solar cells. The second generation is known as thin film technologies. Within this group, three main families are distinguished: (1) Amorphous silicon (a-Si); (2) cadmium telluride (CdTe) and (3) copper indium selenide (CIS) and copper indium gallium diselenide (CIGS). Some of these technologies are already fully commercial while others still in development phases. Finally, the third generation includes PV technology that is under research and has not reached the market yet because still in early phases of R&D (i.e., organic and polymer cells, Dye-sensitized, concentrated PV, etc.) (Tyagi *et al.*, 2013, Sampaio and González, 2017).

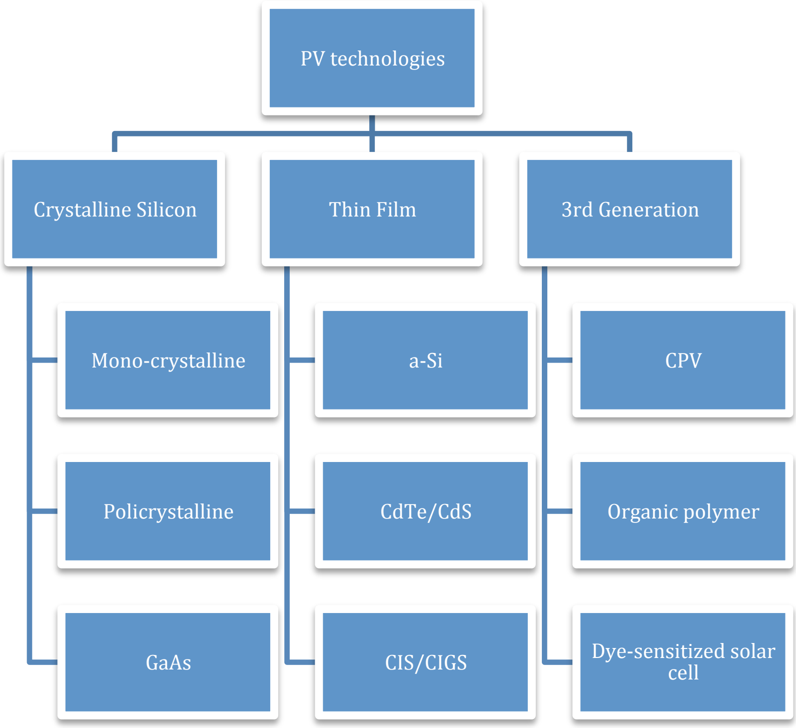


Figure 4 Classification of technologies according to raw material used and maturity on the market
Source: Own elaboration

Crystalline silicon cells are the most used technology in the PV industry due to its high efficiency and abundance on earth. Additionally, it has an ideal band gap for the terrestrial solar spectrum (1.12 eV), it is generally stable and non-toxic (Sampaio and González, 2017). However, they have high fabrication cost, long energy return time, large amounts of energy are required during its life cycle and very pure materials and perfect crystal structure are needed in comparison to other PV technologies. According to the methodology to fabricate Si wafer crystalline silicon cells can be divided into two types, monocrystalline and polycrystalline. Monocrystalline PV modules are characterized by their higher efficiency than polycrystalline. Better efficiency of the modules is the main reason that popularized the used of monocrystalline modules until the late 1990s. Afterwards, the advancements in manufacturing techniques allowed start fabricating polycrystalline solar modules. This technology replaced the previous one due to its lower manufacturing cost, better appearance, shorter energy return time, less energy required during its life cycle and because the crystal does not have to be perfect. Regarding GaAs modules, they have higher efficiency and they are lighter compared to c-Si technologies. In addition, they have high heat resistance. Although good technological properties the material and manufacturing process are costly. Thus this technology has been mainly used in space applications or concentrator PV.

Compare to crystalline silicon thin-film solar cells cost less to be produced because require less material from the semiconductor to be manufactured (99% less material) but it has lower efficiency. (1) Amorphous silicon is a non-crystalline form of a random atom structure that gives a high band gap (1.7 eV). The main drawbacks of this material are its low efficiency and the degradation caused by light. (2) Cadmium telluride is a promising material to be used in the manufacturing of solar cells due to its low cost and high efficiency (up to 15%). But the toxicity of cadmium is an environmental issue that limits the used of this substance. Additionally, the scarcity of Telluride might affect the cost of the module due to increasing prices. Finally (3) CIS and CIGS are still in a developing phase but high optical absorption coefficients and electrical characteristics of the semiconductor elements conforming this solar cell might create good solar modules.

Third-generation PV technologies were the latest to be discovered. Within this group it is possible to distinguish between technologies under demonstration like multi-junction concentrating PV (CPV) or organic solar cells and new concepts in early phases of R&D like carbon nanotubes (CNT) or quantum dots, more focus in new technology for processing PV solar cells. These innovations aimed to be the future of PV technologies.

CPV uses optical devices in order to concentrate the solar radiation onto very small and highly efficient solar cells. These solar cells consist on a stack of layers made by semiconductors from groups III to V of the periodic table, which offer the best conversion efficiency of light into electricity, up to 46% for CPV cells under laboratory conditions. This is possible because the layers have different band gap and absorption spectrum, thus embracing a larger solar spectrum. Nevertheless, it has an expensive manufacturing cost compared to conventional PV.

Organic and polymer cells are the technology that showed high potential to replace in the future silicon PV modules due to its disposability, low price and mechanical flexibility for manufacturing solar cells, organic modules can be applied almost anywhere (Tyagi et al., 2013). However, efficiencies of these solar cells are not yet ready to compete against silicon technologies. The large energy gap of the semiconductor polymers (2.0 eV) limits the absorption of solar photons, which directly affects the efficiency of the cells (11,5%) (NREL, 2017). In addition, a major issue is the instability of the organic cells. Therefore researchers are focusing on dealing with these two issues for its future implementation in building-integrated applications.

Dye-sensitized solar cells (DSSC) present similar commercial efficiencies as organic cells, 11,9% because it has not been found yet a dye that can absorb a broad solar spectrum. Nevertheless, this technology aims to obtain good conversion efficiencies of sunlight into electricity. Moreover, it aims to reduce the cost of the device because is easy to manufacture and maintain a good stability over time. The main difference of this technology compared to conventional solar cells is that the element responsible for the absorption of light is separated from the transport mechanism of the charge carriers (Wu *et al.*, 2005).

Regarding the new technologies in early phases of R&D, rather than looking for new semiconductors materials to improve solar cell characteristics, new technology for PV cell production is being pursued. Nanotubes (CNT), quantum dots (QDs) and hot carrier (HC) are the devices being under research for the application of the nanotechnology in the production process of the PV solar cells. This new technology would be able to enhance the mechanical characteristics of the material, reduced cost and weight and provide good electrical performance.

However most of the third generation technologies have not reached the market yet, so the photovoltaic industry has been formed by crystalline silicon and thin film technologies. In particular, monocrystalline and polycrystalline have controlled the PV industry (Figure 5). At the beginning was mono-Si the technology dominating the market due to its better conversion efficiency of light into electricity. This trend has periodically changed to a domain of multi-Si, which controls the PV market (69% of the production of PV modules in 2015). The switch from monocrystalline to polycrystalline was due to advancements in the PV industry focused on reducing cost and increasing the rate of production. Therefore the efficiency of the solar cell, as well as its cost, played an important role in determining the share of each technology in the market. Other factors like useful life and carbon footprint also influence the market. Within this chapter, all these factors will be analyzed, with an exception of the cost. Cost analysis will be executed in the following chapter.

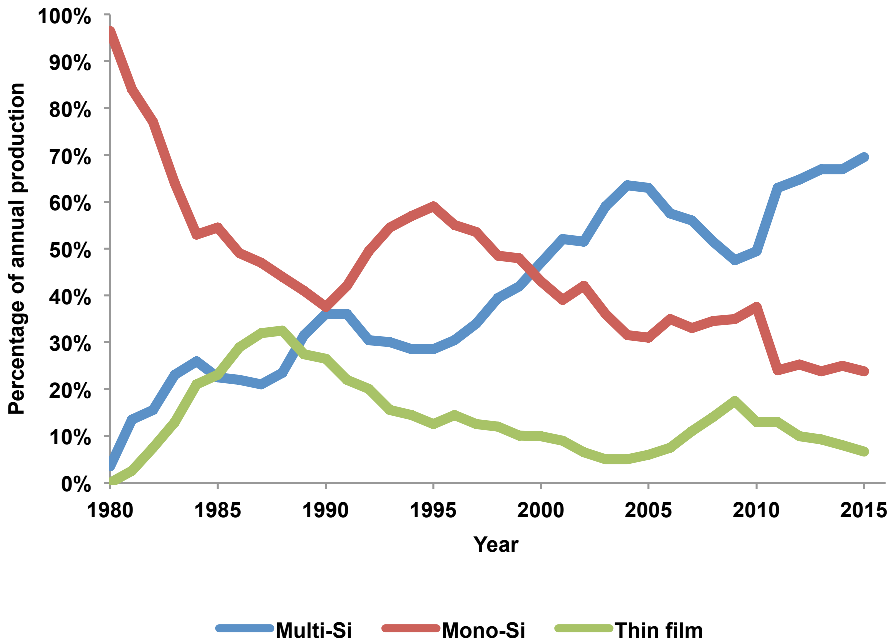


Figure 5 Percentage of annual PV module production according to PV technologies
Source: Own elaboration; Data: Sampaio and Gonzalez, 2017; Fraunhofer ISE, 2016

The efficiency of solar cells is one of the main factors in determining the position of each technology in the market. Therefore, researchers in the PV industry focus its efforts in improving the efficiency. Accordingly, Figure 6 shows the evolution of best research cell efficiencies obtained in the laboratory (i.e. measured under standard testing conditions) for different types of technology. Moreover, Table 4 summarized current laboratory efficiencies of the main technologies used in the market.

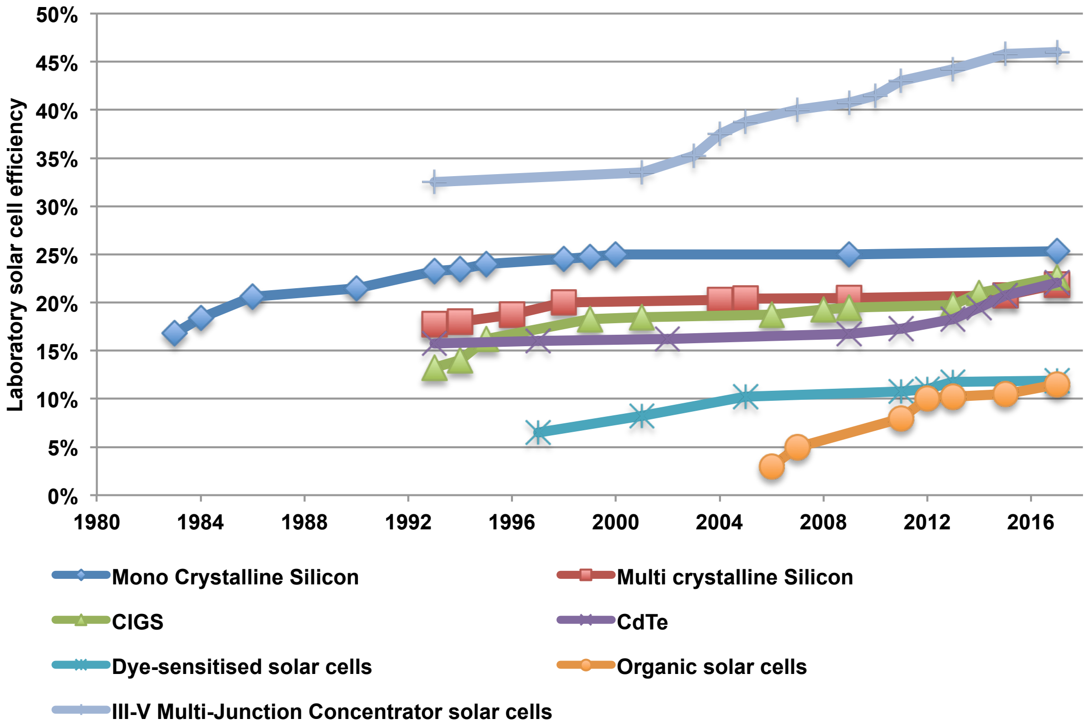


Figure 6 Solar cell laboratory efficiency evolution
Source: Own elaboration; Data: Progress in PV: Research and Applications and Nrel.gov, 2017

Monocrystalline silicon experienced an early increase in cell efficiency that led it to dominate the market. This technology has improved its efficiency more than 80% in 40 years, from 13,8% to 25,3%. A smaller increase of 46% has been achieved in multicrystalline, which current efficiency is 21,9%. Thin film technologies have also improved their efficiencies considerably, positioning their efficiencies right above multicrystalline levels, with an exception of amorphous silicon technology whose best efficiency result is 14%. Regarding third generation technologies, a wider range of results is presented. On one side, technologies like organic and dye-sensitized solar cells have the lowest efficiencies, 11,5% and 11,9% respectively. Although the low efficiencies of organic solar cells, they have improved efficiency considerably, from 3% in 2001 to 11,5% in 2016, which supports its great potential. On the other side, multi-junction solar cells have the highest levels of efficiency among all cell materials with 46%. Nevertheless, a barrier for the implementation of this technology in the market is the complexity and high manufacturing cost, wiring and laying out different structures is costly. Until now, multi-junction solar cell technology is only being used in applications where good performance is essential and the cost is not an issue, like military and space applications. Finally, it is important to make a distinction between cell and module efficiencies. Although in this section cell efficiencies are utilized for comparing among different technologies and represent its evolution, module efficiencies the ones used in order to calculate real power output of photovoltaic systems. Module efficiencies are below solar cells ones due to losses in the manufacturing process, for instance SunPower achieved best commercial module efficiency in 2016 with a 24,1% (SunPower – US, 2017)

Technology	Efficiency
Monocrystalline	25,3%
Multicrystalline	21,9%
CdTe	22,1%
a-Si	14,0%
CIGS	22,6%
Organic cells	11,5%
Four-junction (CPV)	46%

Table 4 Laboratory efficiencies of different technologies
Source: Nrel.gov, 2017 (Rev. 14/04/2017)

Besides the inherent efficiency of each technology, there are some factors that affect the efficiency during operations (i.e. energy output of a PV module), which are temperature, dust or irradiance. The performance under unpleasant conditions varies among the different type of solar modules. Regarding temperature, when it increases in a PV module its band gap is decreased, thus reducing the output voltage. Temperature has a higher influence in monocrystalline silicon than it does in polycrystalline and thin film technologies. Whereas efficiency decreases by 15% in monocrystalline solar cells, thin film efficiency is only reduced by a 5% (Kumar et al. 2011). Contrary to temperature behavior, when irradiance increases the efficiency of solar cells also increases due to a greater number of photons hitting the module, so creating more electron-hole pairs and accordingly more current in the PV cell. A study conducted by Eikelboom and Jansen (2000) regarding different PV technologies concludes that thin film technologies are better under low irradiance conditions. Again, thin film technologies present better performance under unpleasant conditions. Finally, dust affects the efficiency of the solar cells because it blocks the coming irradiance. From an experimental study (Goossens and Kerschaever, 1999) it is concluded that the power output decreases drastically as dust density increases without mentioning any difference between technologies.

Another important factor in determining the influence of a technology in the market is the life span of the solar cell. The reliability of photovoltaic modules is very important when determining the economic viability of a power installation. Accordingly, the degradation rate of the different solar cell technologies plays a key role because a higher degradation rate means lower power output and shorter useful life. Although there is no consensus about the definition of failure of a PV module, typically a 20% decline is considered failure. Accordingly, manufacturer´s warrant period is usually 20-25 years, which is also used as the useful life of PV modules. However, current studies have demonstrated that the useful life of old technologies is above 25 years, and new ones are expecting 30 years life time or even more (Realini, 2003; Harrabin, 2009). The degradation rate is affected by many factors (climate conditions, technology, energy yield…), thus each technology has a range of degradation rates. A study performed by the NREL (2012) has presented these ranges for each technology, which are summarized in Table 5. Moreover, the same study shows a mean degradation rate of 0,8%, with 78% of all the analyzed data with a value below 1%/year.

Technology	Degradation rate per year [%]
Monocrystalline	0,4 – 0,7
Multicrystalline	0,5 – 1
CdTe	0,75 – 1,5
a-Si	0,1 – 1,25
CIGS	0,6 – 2

Table 5 Range of the annual degradation rate of each technology
Source: NREL, 2012

The footprint of different solar photovoltaic technologies also influences the market penetration of the technology. A good way of determining the environmental impact of a photovoltaic technology is trough a life cycle analysis (LCA), in which the whole process of a PV installation is evaluated, from its inception to its disposal. Generally, there is not a unique approach to perform an LCA as explained by Wong *et al.* (2016). Moreover, results obtained can vary widely according to location, where either the PV module is produced or installed. The results obtained in this analysis are used in decision-making on energy policies and on investment decisions in R&D. The two metrics most used in order to assess the environmental impact of a PV installation are global warming, expressed as the emission of CO_2-eq. per kWh produced, and the energy payback period (EPBP). In the case of global warming, results for different PV technologies are displayed in Table 6 from a study performed by Dominguez-Ramos et.al. (2010), which concludes that silicon crystalline is the most pollutant technology. This result is a consequence of the high electricity requirements for the PV module production that is mainly carried out in China (Table 2), which electricity generation mixed is characterized by the used of coal. Table 6 also shows the EPBP of c-Si and thin film technologies for the same location in Germany. Where it is shown that monocrystalline is the technology with greater EPBP, followed by a-Si and multicrystalline. CIGS and CdTe on the contrary, have the lowest EPBP. It is also important to remark that the installation region of the PV facility affects these values. Thus, locations with higher solar resources have lower values of global warming and EPBP. For instance, in south Europe regions, EPBP is as low as 2 years (J Peng *et al.*, 2013).

Technology	CO_2-eq/kWh	EPBP
Monocrystalline	50	3,3
Multicrystalline	50	2,1
CdTe	23	1,2
a-Si	42	2,4
CIGS	-	1,75

Table 6 Global emissions and EPBP of current technologies used in the market
Source: Fraunhofer ISE, 2016; Dominguez-Ramos *et al.*, 2010

Notwithstanding c-Si solar technologies are the most pollutant and required more energy to be produced, still hoarding the PV market. Therefore, it can be concluded that there are some factors that are more relevant regarding technology decision-making. In this sense, efficiency and degradation rate becomes more relevant factors because they determine the energy output of an installation through its useful life. The other factor that is also relevant in the decision-making is the cost of the technology, aspect that is analyzed in the following chapter.

2.1.2 Cost

The analysis of the evolution in PV technology cost is accomplished by analyzing both the installation cost of generation facilities and the LCOE. These costs present a wide range of values according to the type installation (i.e. residential, commercial or utility-scale systems) and the location where it is placed (Table 7). The differences between the values presented in Table 7 regarding installation cost are a consequence of the labor cost, which directly affects the construction cost. Likewise, higher labor cost in manufacturing countries also increases PV modules prices. Accordingly, Japan presents the highest installations cost whilst China presents the lowest. Meanwhile, LCOE values are influenced by the overall installation cost but also by the solar resource of the location. Thus Portugal and Spain present lower LCOE than Germany, which has a lower installation cost. Although different locations have different absolute costs, in the last decades there is a downward trend in the installation cost and LCOE, which has affected the market globally.

Country	Installation cost [$€_{2015}$/W]		LCOE [$€_{2015}$/kWh]	
	Roof-mounted	Large scale	Roof-mounted	Large scale
China	0,66	0,85	0,05-0,09	0,05-0,08
Japan	2,83	2,34	0,20-0,34	0,16-0,26
Germany	1,34-1,82	1,09	0,11-0,25	0,08-0,14
US	1,59-2,05	1,46	0,07-0,18	0,05-0,09
Spain	1,46-1,77	1,13	0,09-0,15	0,08-0,12
Portugal	1,22-1,70	1,34	0,07-0,15	0,07-0,11

Table 7 Installation cost and LCOE for residential and utility-scale projects in different countries
Sources: IEA and NEA, 2015

The installation cost of a PV facility is divided into the cost of the PV module and the balance of system cost (BOS). The cost of the module is determined by raw material prices, cell manufacturing and assembly cost. Whilst the cost of the BOS includes items like electric system (e.g. inverter, wiring, etc.), structure and installation cost. The most important components in the overall cost of the PV installation are PV modules and inverter, which costs represent up to 66% of the total cost (i.e. for a ground-mounted PV system). The share of the PV modules over the installation cost has dropped considerably in the last decades. In the early days of PV generation plants modules represented above 80% of the initial investment. This share has been reduced to 40% thanks to the improvements in the modules. Inverters have also experienced great reductions. These two components have been the most relevant in reducing the installation cost of PV systems.

Regarding the module cost, Figure 7 represents the evolution of the cumulative production of PV panels since 1980 for crystal silicon and thin film technologies (CdTe). This reduction in cost is the result of technological innovation, manufacturing automation and economies of scale. Introducing bigger manufacturing plants has allowed decreasing substantially the price of per module produced. Likewise, improvement in the machinery has enhanced the overall efficiency of the plant and reduced the breakage of cells during the fabrication process. The PV module market is in a very dynamic situation, which makes it very unpredictable to forecast; within the last two years, the price has drastically been reduced to values forecasted to 2025. Whereas in 2015 the average price of PV modules for utility-scale projects, according to IRENA, ranged between 0,52 $/W in India to 0,72 $/W in Japan, current prices for utility scale projects are as low as 0,32 $/W in some locations[2].

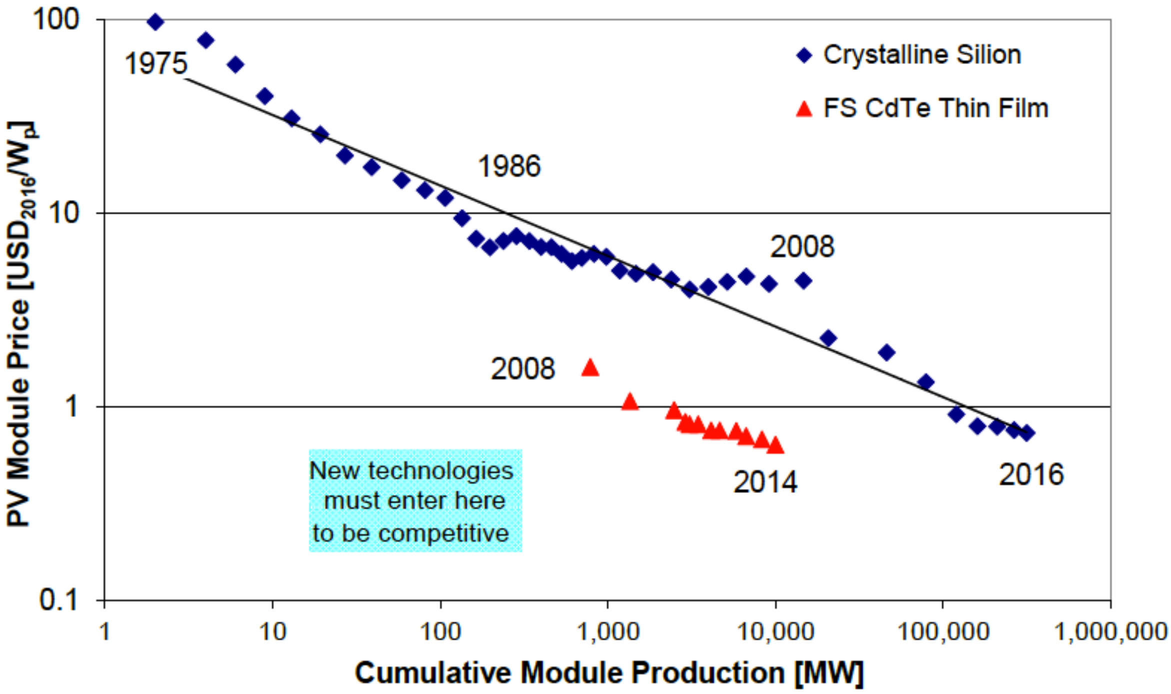


Figure 7 Learning curve of the photovoltaic modules
Source: Jäger-Waldau, 2016

Similar levels of cost reduction have been achieved with inverter technology, which cost has dropped in the last decades to almost 0,10 €/Wp from 1 €/Wp. The main reasons behind this reduction are the improvement of efficiencies and power density, whose drivers were new circuit topologies and better power semiconductors. Additionally, inverters have become smarter, they are able to monitor and communicate the system conditions during operation in order to improve the performance of the PV installation. Moreover, new generations of inverters are able to interact with the power grid by providing reactive power during grid errors. A recent research about the potential reduction on the price of inverters forecasted a considerable reduction in 2050. This reduction ranged, according to different scenarios, between 0,021 €/Wp and 0,042 €/Wp (Energiewende, 2015).

[2] Price from projects elaborated in 2017 and obtained by interviews with professionals working in the utility-scale business of PV systems.

Another important factor leading the reduction of the overall cost of PV systems is the improvements in efficiency, which have allowed increasing the power per square meter of the module. This improvement had a direct impact in reducing the cost of watt peak installed and balance of system due to less raw materials and amount of structure needed for the installation. Therefore smaller systems are needed in order to generate the same amount of electricity. It is estimated that doubling the efficiency of a PV module the cost of both module and BOS is reduced. In the case of modules, it can be reduced up to 78% for thin-film technologies. Table 8 summarizes reductions of different components and technologies when efficiency is double

Module	
Thin film	78%
Crystalline	50%
BOS	
Inverter	49%
Structure	59%
Wiring	22%
Land	59%

Table 8 Reductions in PV components when efficiency of PV modules is doubled
Source: IDAE, 2011

The reduction in the cost of PV modules and inverter, together with the improvement in efficiency has led to decrease the installation cost of residential and utility-scale solar systems. Figure 8 presents the reduction in the cost of residential PV installation for different regions (Germany, Japan and the US. The reduction in module cost in the last decades has been the leading factor for reducing the overall installation cost, it is forecasted that reduction in BOS will represent the next leading factor in reducing the plant cost. In fact, it is estimated that about 70% of the reduction of installation cost in utility-scale PV systems will be due to reductions in BOS (Irena, 2016).

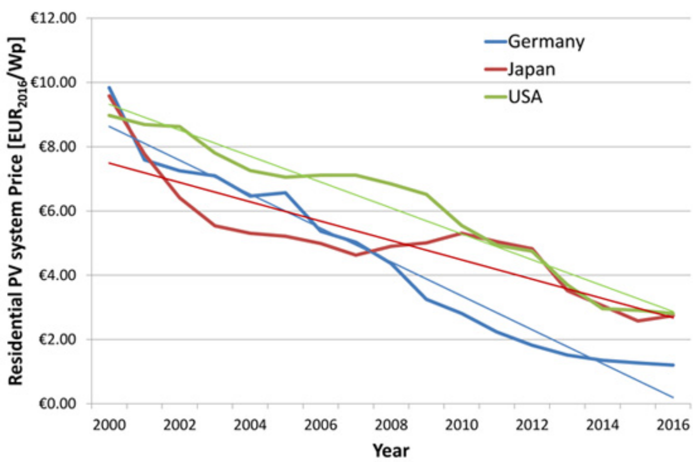


Figure 8 Residential PV system installation cost development over the last decades
Source: Jäger-Waldau, 2016

As aforementioned, PV generation cost is determined by CAPEX, OPEX, energy output, operation lifetime and cost of capital. Within these parameters, the investment cost, energy output and cost of financing are the most critical in order to provide cost reductions. Although OPEX and useful life are not the key items in the reduction of LCOE, they have an important role in electricity generation. Therefore, as presented in Figure 9, LCOE has experienced a downward trend in the last years. Reduction in installation cost has been the main reason for such decrease, but it has not been the unique reason. The improvements in efficiency have led to greater energy outputs through its useful life. Additionally, the energy output of the PV systems has increased due to better management of the factors that directly affect the efficiency of the solar panel during operation (i.e. temperature, irradiance and dust). Many studies are focused on studying how to keep the temperature low in the cell in order to make the photovoltaic cell to operate in its optimal conditions.

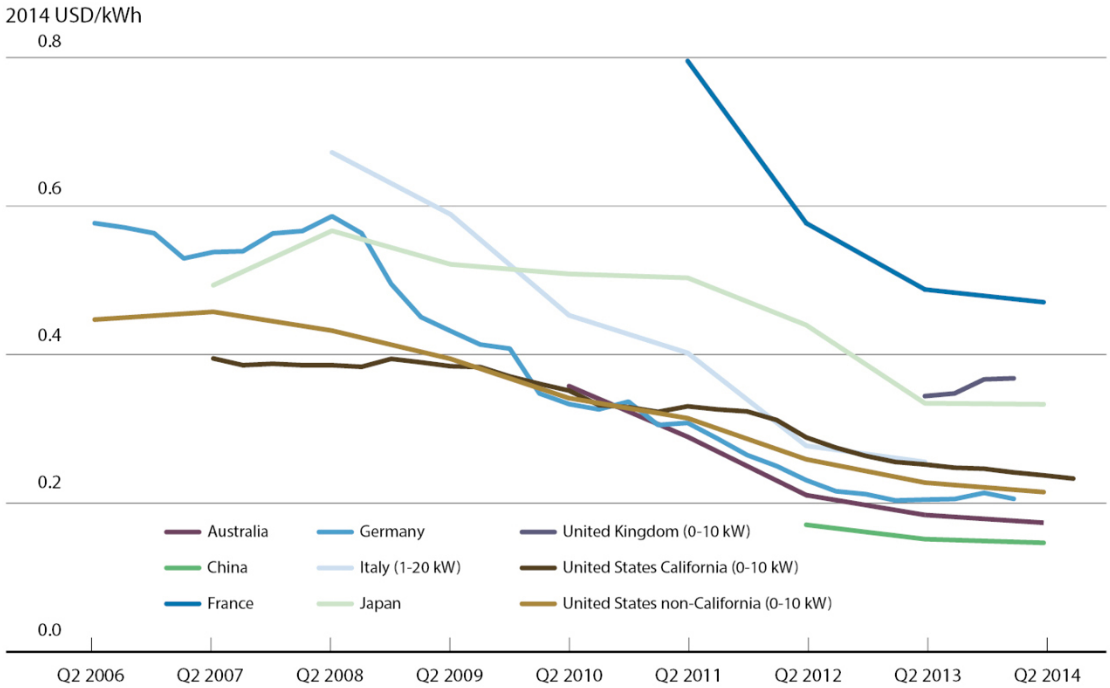


Figure 9 LCOE evolution of residential systems in different locations
Source: World Energy Council, 2016.

Another important component that has not been discussed yet in this chapter is the financial cost. Investors apply a certain discount rate to the projects according to their perception of risk of the technology. Very innovative technologies imply high financial risk, thus higher rates of return. Since first PV installations, confidence and reliability on these projects have increased. Thus, discount rates applied to PV projects have decreased considerably. Table 9 shows how a different rate of return can affect the LCOE of a PV project.

WACC	LCOE [€$_{2015}$/kWh]
0 %	0,056
2,5 %	0,073
5 %	0,092
7,5 %	0,112
10 %	0,135

Table 9 Values of the PV LCOE for different WACC
Source: IRENA, 2016

Although the O&M cost of a PV system is not an important item within the generation cost of a PV technology, still important to clean and maintain the photovoltaic modules because an inadequate maintenance can diminish the production of electricity up to 30% for moderate dust conditions (Sarver *et al*., 2013). In 2015, the annual OPEX values range between 10 €/kWp for Residential installations to 30 €/kWp for commercial and utility-scale systems (Theologitis *et al*., 2016). Yet a reduction could be achieved by implementing new technology, for instance robots for detecting faults and keep cleaned the modules or special layers to avoid the dust settling on the panels. These are some of the new advancements already implemented or in the developing phase for future implementation.

In conclusion, the most relevant factors in determining the technology dominating the market are efficiency and degradation rate, which determine the electricity production of the installation; and the costs of the technology. It is important for PV systems to have a LCOE similar to the traditional technologies, which will allow PV systems to compete against such technologies. Accordingly, the PV industry uses the technology that allows presenting a lower LCOE, which currently is achieved by multicrystaline PV modules. The future technology used in the PV sector and its cost are unpredictable due to the dynamisms of PV industry seen in the last years.

2.2 Wind energy

Wind energy production has grown rapidly over lasts decades, mainly supported by technology advancements and cost reductions but also helped by favorable energy policies created by governments. Although the new capacity installed decreased around 20% from 2015 values, 2016 new added capacity reached 51,2 GW and since 2007 new additions have surpassed the 20 GW. According to IRENA (2017), the total capacity installed worldwide equals 466 GW. This capacity is mainly distributed between China, Europe and US. Table 10 shows that China is the leading country in wind capacity with almost 148,6 GW installed followed by US and Germany with 81,3 GW and 49,7 GW respectively. Other countries like India and Spain, UK and France have more than 11 GW of wind capacity. The share of wind capacity below presented corresponds to both onshore and offshore applications. Most of the offshore installations are placed in European countries, almost 89% of the global offshore capacity.

Country	Share of the total installed capacity	Share of electricity
China	31,9%	4,02%
US	17,4%	5,5%
Germany	10,7%	14,2%
Spain	4,9%	18,6%
Portugal	3,3%	23,2%

Table 10 Wind capacity installed worldwide and share of each country over the total installed capacity
Source: Own elaboration; Data: IRENA, 2017; REE, 2016; APREN, 2016; EIA, 2017; Fraunhofer ISE, 2017 and China Energy Portal, 2016.

2.2.1 Technology

The evolution of the wind energy sector is a combination of engineering and scientific skills and entrepreneurial spirit. In the recent history of wind power, there were several improvements in the technology of wind turbines, the scaling up factor of the turbines is the most relevant one. In this sense, the average power capacity has increased from 0.05 MW in 1985 to 2,20 MW in 2014 (IEA-ETSAP and IRENA, 2016). Likewise, other developments in alternative materials, power control system, electric systems, foundations and drive train mechanisms have been also relevant in other to achieve the current multi-megawatt power generations machines. For instance, in September 2016 the Vestas' V164-8.0 MW, the largest turbine in the world, was installed at the Burbo Bank Extension offshore wind farm, standing at 195 meters.

According to the type of installation, it is possible to distinguish between onshore and offshore applications. Traditionally onshore installations have occupied the whole wind market. Lately, new advancements are allowing offshore facilities to enter into the electricity generation market. Nowadays there is around 466 GW of wind energy installed worldwide, offshore wind only accounts for 3% of the total installed capacity (i.e. 14 GW). Regarding onshore facilities, turbine´s cost represents 60-80% of the total investment cost (i.e. rotor blades, gearbox, generator, transformer, power converter, tower, hub, cabling, etc.). Thus, many efforts have been made in order to improve the overall performance of the turbines with the aim of enlarging the energy output generated per turbine. These improvements have made possible the installation in offshore locations, where larger energy outputs are needed in order to make economically feasible the overall cost of placing such facilities in the sea. Additionally, offshore wind faces other technical issues like foundations, electrical systems or installation and maintenance, which improvements have been relevant for the deployment of such technology. Accordingly, in this chapter, the technological advancements in both onshore and offshore applications are described. It is important to remark that technological advancements in the onshore industry have helped the apparition of the offshore industry.

Regarding turbine technology, it is possible to categorize them according to the rotating axis of the wind turbine. If the rotation axis is parallel to the ground, it is known as horizontal axis wind turbine (HAWT). On the contrary, if the axis is perpendicular to the ground it is called vertical axis wind turbine (VAWT). Despite the many advantageous features of VAWT like independency wind direction, production of electricity in a wide range of velocities, better performance under unpleasant condition, etc. (Islam *et al*., 2013); its presence in the market has been rare since first commercial power wind generators where launched, mainly because the lower efficiency in transforming mechanical into electrical power. Nevertheless, currently VAWT are under many research and development projects for implementation in urban areas and small wind projects because it can generate electricity at low velocity and noise levels. In any case, the mainstream design in the market has been the HAWT, thus this chapter is focused on the description of the main technological improvements in the HAWT. Figure 10 presents the main components that convert the wind velocity into electricity, which is analyzed in the present chapter.

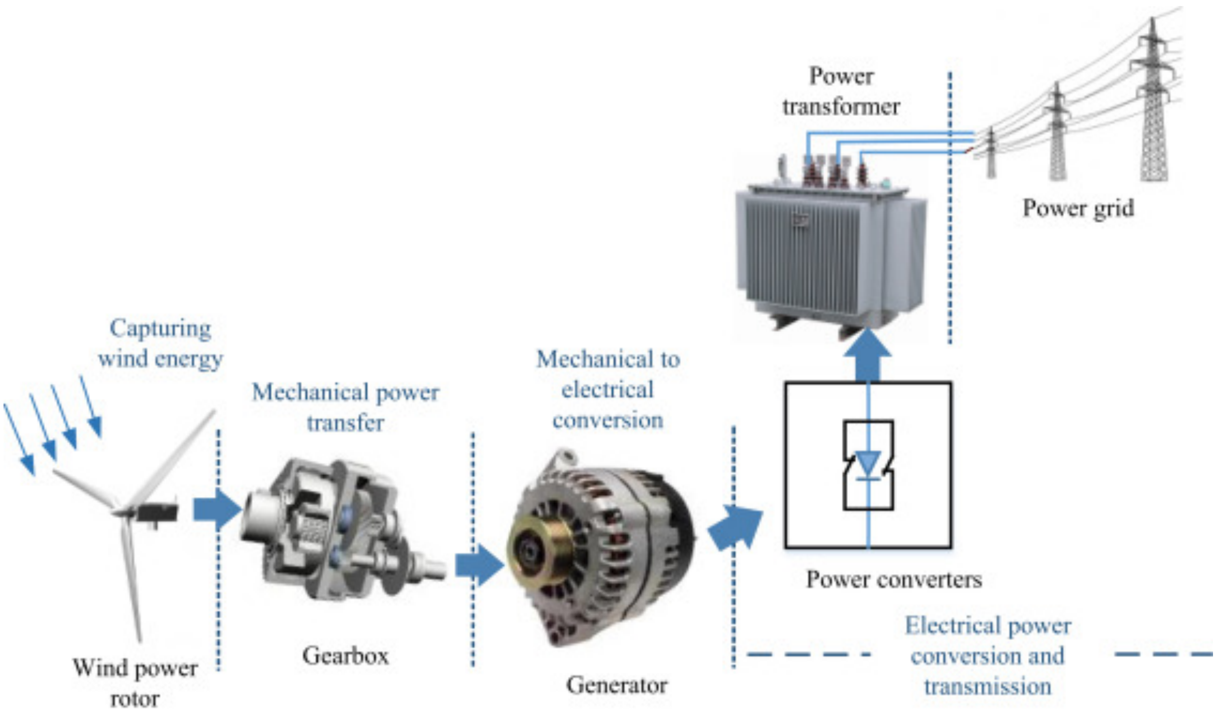


Figure 10 Components of a typical HAWT
Source: Kumar *et al*., 2016

Scaling up wind turbines has been the major trend since commercial generators were available. On one side, larger blades have been produced in order to increase the capture and conversion of wind velocity into rotational energy. Consequently larger turbine rotors have been demanded by the wind industry, from around 40 m of rotor diameter in the early nighties to 164 in 2016 (V164-8 MW). Figure 11 shows the evolution in rotor size for different markets. The US presents the largest average rotor diameter compare to Europe and Asia because it is a market dominated by medium wind speed characteristics. On the contrary, Europe presents more variability on the wind resource according to each region, which explains the differences between Europe and Germany (lower wind locations that Europe average). In this sense, technology material played a key role. Originally, wood epoxy materials were used in the manufacturing of both small and big blades. Likewise, other materials like steel or aluminum were also considered but rejected due to heaviness and uncertainty on fatigue response, respectively. The evolution of the use of polyester resin and glass fiber has dominated the manufacturing blade industry, allowing the increases in dimensions of the rotor. More innovative materials like carbon fiber-reinforced plastic might play a key role in the near future when its price become competitive due to its high strength to weight ratio. Developments in aerodynamics have also enhanced the enlargement of rotor diameters.

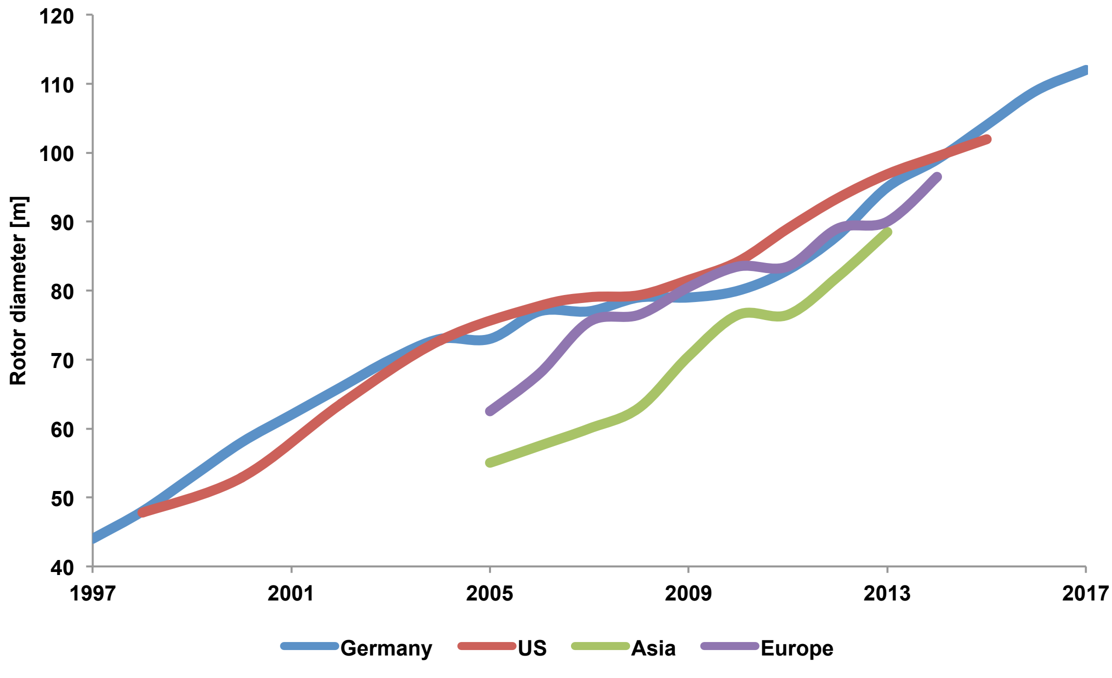


Figure 11 Average rotor diameter evolution (1997-2017) of the annual installed capacity
Source: Own elaboration. Data from: Serrano-Gonzalez and Lacan-Arántegui, 2016; and Windmonitor,iwes.fraunhofer.de, 2017

On the other side, hub height has been also continuously increased motivated by larger rotor diameters and higher and more constant wind velocities. Moreover, new wind farm locations characterized by lower wind velocities have also increased the demand for higher towers. In this sense, the height where the hub is place is a compromise between greater energy yields and cost of the tower, thus presenting large variations between different projects. Regarding the tower, cylindrical steel towers have been traditionally the most used solution for turbine towers. However, the demand of higher hub heights is provoking new configurations to emerge like concrete towers or hybrids ones made of steel (top) and concrete (base). These new possibilities arise due to problems in transportation of great tubular sections and volatility of steel price, which affects the overall cost of the installation. Additionally, concrete can be supply by local markets and concrete towers are built on site or composed by precast sections, which facilitate transportation and reduces the cost. Naturally, larger rotor diameters and higher hub heights have resulted in increasing rated power of the wind turbines. The evolution of rated power of the turbines is plotted in Figure 12. In this case, the European market presents the greatest average nameplate capacity, followed by the US and China. In the German case, it is possible to appreciate how the capacity of the turbines has increased in the last decades, from 0,63 MW in 1997 to 2,875 MW in 2017.

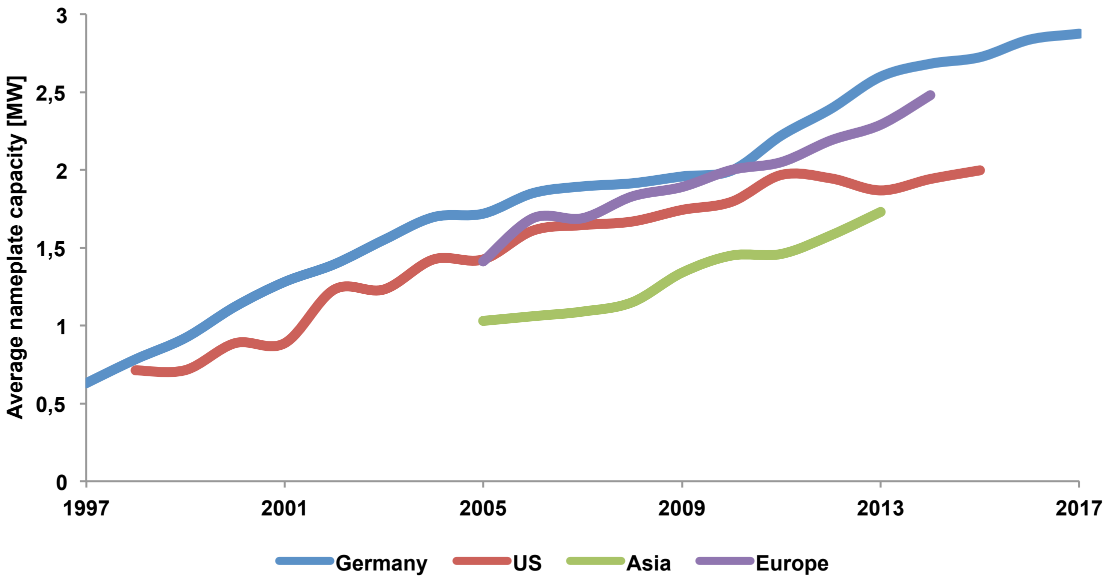


Figure 12 Average nameplate capacity evolution in MW between 1997 and 2017
Source: Own elaboration. Data from: Serrano-Gonzalez and Lacal-Arántegui, 2016 and Windmonitor,iwes.fraunhofer.de,

Another criteria usually employed to categorized wind turbines is the drive train system configuration. Traditionally, wind turbines have been divided into four configurations according to the drive train system (Hassan, 2004; Bang et al., 2008), (1) constant speed; (2) variable speed with a resistance in the rotor; (3) doubly-fed induction generator (DFIG) and (4) variable speed with full-scale frequency converter. Recently, the last type of configuration was divided into three more categories due to market evolution (Serrano and Lacal 2014; Vázquez *et al.* 2016), (4) direct drive machines with full-scale power converter; (5) medium-/high speed synchronous generator and (6) high-speed asynchronous generator, both equipped with gearbox and full converter. Figure 13 represents the configuration of these six types of drive train systems that classify wind turbines.

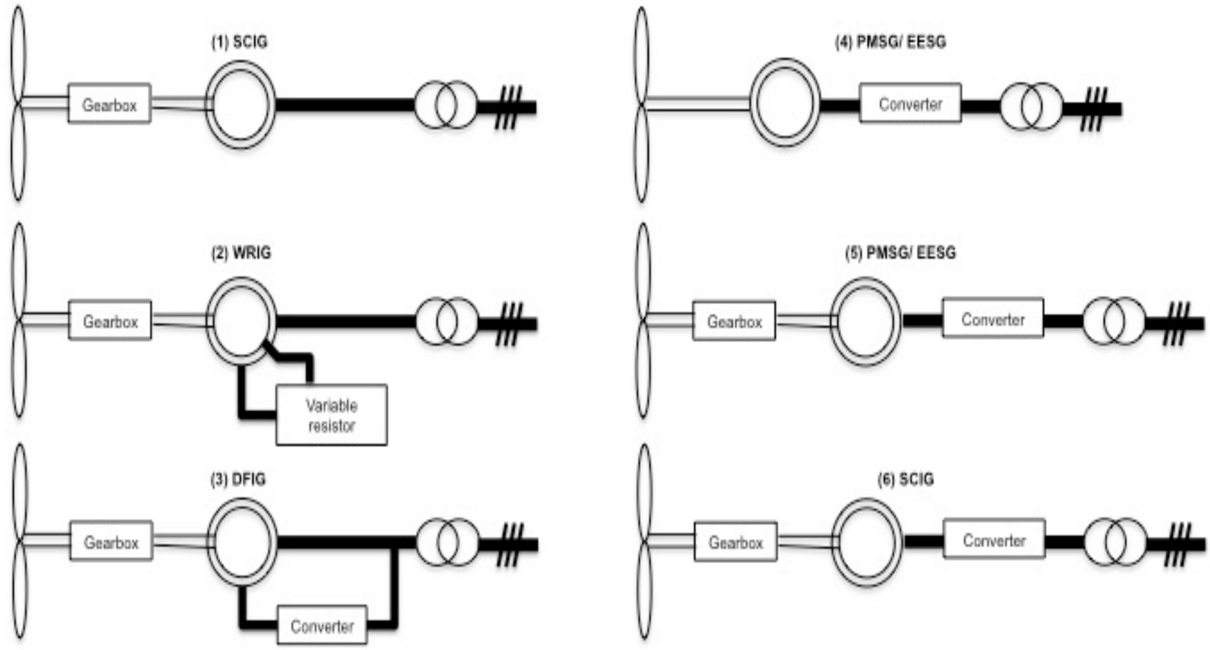


Figure 13 Sketch of drivetrain differences between turbine configurations
Source: Own elaboration. Data from: Hassan, 2004; Bang et al., 2008 and Serrano and Lacal, 2014

The first two configurations are included inside fixed speed wind turbines that were the most installed types of drive systems until the early 2000s (Figure 14). These types of generators are designed to maximize its efficiency at one wind speed. In the case of constant speed designs (1) an asynchronous squirrel cage induction generator (SCIG) is employed. In the case of (2), it uses a wound rotor induction generator (WRIG) that allows limited variable speed control (generally 0-10% above synchronous speed) due to a series of resistance connected with the rotor of the generator. The other four designs are characterized by the possibility of maximizing the efficiency of the wind turbine over a range of wind speeds by keeping the generation torque nearly constant, thus the generator absorbs the variations in wind velocities. The main advantage of these designs is the connection through a power converter to the grid, which provides high control capabilities (e.g. control over active and reactive power, influence on network stability and improved power quality). These configurations are replacing the fixed speed drive train systems in the market.

In the case of DFIG (3), the stator is directly connected to the grid whereas the rotor is connected through a partial-scale power converter that permits the control of the rotor speed by controlling its frequency. The converter only controls 30% of the energy generated. DFIG is the most commonly employed generator design within wind turbine manufacturers around the world because of its good performance and its relatively inexpensive power converter (compare to full power converters). It has been dominating the market since the mid 2000s; in fact 68% of the installed wind turbines in 2015 included this configuration (Figure 14). Although the great domain of this configuration in the market, stricter grid codes (e.g. full control of amplitude and frequency of voltage) are forcing other configurations to be implemented.

In this sense, direct drive with full-scale power converter (4) was the first configuration in the market that allowed to fully control the power feed into the grid. Moreover, it simplifies the nacelle system, increases reliability and avoids gearbox problems that are the main cause of halt in electricity production of wind turbines. Additionally, they required less maintenance because it has less moving parts. This type of direct drive systems can be either combined with an electrically excited synchronous generator (EESG) or a permanent magnet synchronous generator (PMSG). The type of generator used mainly relies on the region where the turbine manufacturer is located because of the raw material used to construct the generator. For instance, PMSG is mainly used in the Asiatic market because two materials utilized to manufacture the generator (neodymium and dysprosium) are mostly found in China. Meanwhile, in the European market, the EESG is the generator implemented in direct drive systems. In the US, such systems are not commonly installed.

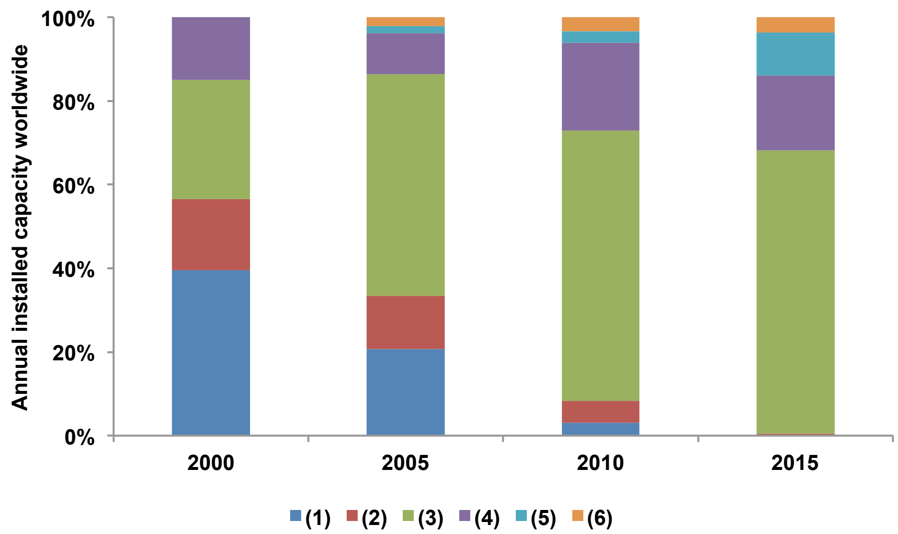


Figure 14 Evolution of the type of drive train system utilized in onshore wind plants (2000-2015)
Sources: Own elaboration. Data from: JRC wind report, 2016

Another configuration characterized by complete power control includes either any of the previous synchronous generators plus a gearbox (5), which allows reducing the size and weight of the electric generator compare with direct drive systems. Currently, all the manufacturers producing this configuration used PMSG. The last type of drive train system (6), besides the power controller and gearbox, uses a high-speed asynchronous generator. A SCIG it is used in order to account for a more robust and cheap electric generator. Its main drawback is the necessity of a bigger gearbox required. These two configurations have a market share of 10,3% and 3,7% respectively in 2015. Regarding the latter, it is being mainly implemented in North American wind plants.

It is also common to divided wind turbines according to the type of control system utilized for managing the output. There are two ranges where it is useful to implement the control systems. For medium-wind velocities, it makes the wind turbine to operate in its maximum power coefficient by adjusting the tip speed ratio (i.e. the relationship between the linear speed of the tip blade and incoming wind velocity). For high-wind speeds, above the rated velocity, it is necessary to reduce the output power in order to avoid excessive loads on the rotor and prevent damages on the turbine. Therefore, it is possible to identify four types of control systems according to the range where they are applied and the way the power is controlled: (1) passive stall control (PSC); (2) active stall control (ASC); (3) pitch control and (4) individual pitch control.

PSC is the simplest, most robust and cheapest control system. The aerodynamic design of the blades causes the rotor to stall (i.e. loss efficiency) for wind velocities above the rated one. Thus, the energy captured is controlled by gradually losing aerodynamic efficiency. The angle of attack is maintained constant under all operating conditions, which provokes that under wind gust the blades are subjected to high stress. Moreover, it lacks assistance for start operating. This system results in lower efficiencies under low wind conditions. Until the mid-90s, stall regulation was the predominant technology installed on the wind turbines. This trend switched, with the introduction of multi-megawatt wind turbines, to pitch control systems. This system allows facing the blade into or away from the wind in order to increase or decrease the output power, respectively. Thus, within the range between cut-in and rated speed the angle of attack is changed in order to maximized the power coefficient. This is possible by adjusting the tip-speed ratio of the turbine when turning the blades into the wind. Contrarily, above rated wind speed the blades are turned away in order to reduced the angle of attack, so limiting the output power. Pitching control systems allow better performance of turbines, assisted start-up and emergency stop. The main drawbacks are the complexity of the pitching system and the power fluctuations that appear at large wind speeds. Another configuration that also includes pitch control is ASC. At wind speeds lower than the rated one, it maximizes the efficiency of the wind turbine like in pitch control. Whilst at wind velocities above the rated one, the blades are pitched into a larger angle of attack (i.e. in the opposite direction as in pitch-control systems) in order to go into deeper stall conditions. Additionally, to pitch controlled wind turbines, this system allows a smooth limitation of power by reducing the power fluctuations at high wind speeds. However, the market share of this power control system has been small. As a consequence of higher rotor diameters, asymmetric loads on the blades are becoming more critical. Thus, individual pitch control arises as an option to reduce the asymmetric loads in order to increase the operational life of wind turbines. This system allows pitching individually each blade during the rotation of the wind rotor. Working under this condition implies operating the pitch control under more demanding conditions and a more complex algorithm. Individual pitch control has been included in more than 20% of new wind installations since 2009 (Serrano and Lacal, 2016).

In offshore projects, besides the aforementioned evolution of wind turbines, the foundations and grid connection have also played an important role in the industry, which have led to the current status of offshore installations. Regarding foundations, most of the installations use the mono-pile foundation type, a really well-known technology traditionally used in the oil industry and the most economical option available at the moment. The main drawback of mono-pile foundations is the issues during installation process because is affected by sea conditions. Additionally, for deep waters, mono-pile technology becomes economically unviable. These are the main reason why floating foundations are in a mature stage of R&D. The connection of the wind farms to the grid is also an issue due to long distances from shore, thus electricity losses over the power lines. Therefore, the use of high voltage direct current (HVDC) cables considerably reduces the losses over long distances compared to the high voltage alternating connection (HVAC). These two variables heavily increased the installation cost when water depths and distances to shore are enlarged.

Along the recent history of the wind industry, other advancements in technology have improved the overall performance of wind turbines. For instance, the turbine´s electronic controller, which monitors and controls the turbine and collects useful data (e.g. rotational speed, temperature of hydraulics, blade pitch, nacelle yaw angles to wind speed, etc.), is facing new developments that will allow forecasting the upcoming winds. Thus, increasing considerably the performance of wind turbines.

2.2.2 Cost

The cost of onshore wind energy has experienced a remarkable decrease since first wind turbines were launched into the market. This reduction is a consequence of the technology improvements, economies of scale and learning. Nevertheless, the cost of onshore wind has not always experienced a downward trend. In fact, between 2004 and 2009 the cost of wind energy increased considerably. The main factors affecting the cost of onshore wind in the last decades are described within this chapter. Moreover, although the offshore wind farms still present a small share in the wind power sector, it has also experienced diminishing prices in the last years, which has forced to start implementing more offshore wind farms in new markets. Thus, the factors leading this decrease in costs are described in the following section.

Like in the PV industry, the cost of wind energy varies between different regions and technologies (Table 11). The installation cost in offshore applications doubles the required cost in onshore. Accordingly, the LCOE also represents values far from being competitive against other technologies. The installation cost is dependent of main factors like labor cost and development of the local wind industry. In the case of LCOE, besides these factors, the quality of the wind resource is also a key aspect.

Country	Installation cost [$€_{2015}$/W]		LCOE [$€_{2015}$/kWh]	
	Onshore	Offshore	Onshore	Offshore
China	1,09-1,28	-	0,066-0,075	-
US	1,43-1,58	4,13-5,33	0,047-0,072	0,152-0,172
Germany	1,68	5,41	0,098	0,197
Spain	1,49	-	0,109	-
Portugal	1,46	4,86	0,090	0,238

Table 11 Installation and LCOE in different regions for onshore and offshore wind projects
Source: IEA and NEA, 2015

In addition, the share of each component over the installation cost of a wind farm (onshore and offshore) is presented in Table 12. It is important in order to identify the components which improvements will result in greater reductions in the overall installation cost. In onshore projects, the share of the turbines over the total installation cost varies around 65% to 85%. Thus, main changes in the CAPEX of a project are a consequence of the price of the wind turbine. Meanwhile, in offshore projects the variation of other components like foundation and electric infrastructure, 21% and 23% respectively, also result in changes in the installation cost of a wind farm.

Component	Share of the total cost	
	Onshore	Offshore
Wind turbine	64%	47%
Foundations	16%	23%
Electrical infrastructure	11%	21%
Planning & Miscellaneous	9%	10%

Table 12 Share of each component over the total installation cost of onshore and offshore wind plants
Source: IRENA 2012

Hence, fluctuations in the turbine cost have affected the price of the installation cost in wind projects. In the history of wind turbines, it is possible to distinguish three different periods. The first period embraces the years before 2004, where turbine prices were decreasing at a fast rate, 10% reduction with double cumulative power installed. The main factor guiding this trend was the scaling up of wind turbines, technological improvements allowed great increases in the output power of the turbines with slight increases in prices. During the second period, 2004 to 2009, a pattern of increasing turbine prices was dominating the market. This phenomenon is easily explained by the great increase in wind turbines demand along with constraints in the supply side. The turbine manufacturers were not prepared for such an increase, neither were the sub-suppliers of turbine components (The facts, 2009). Moreover, the increase in commodity prices, in particular steel and copper, contributed to the increase in prices during this period that peaked in 2009. Since then prices have declined considerably, showing a reversal of the upward trend. Prices are diminishing, mainly caused by the reduction in commodity prices. In addition, economies of scale within the manufacturing wind industry plus the increased competition forced by emerging manufacturers has helped to return to decreasing rates similar to the first period. The price during the last two periods is plotted in Figure 15. After 2012, there are two graphs in order to represent the turbine price, which are used to refer to the cost of the traditional wind turbines (lower) and the new wind turbines (upper) with larger rotors and taller towers. These new turbines are more expensive but achieve greater capacity factors than the traditional ones.

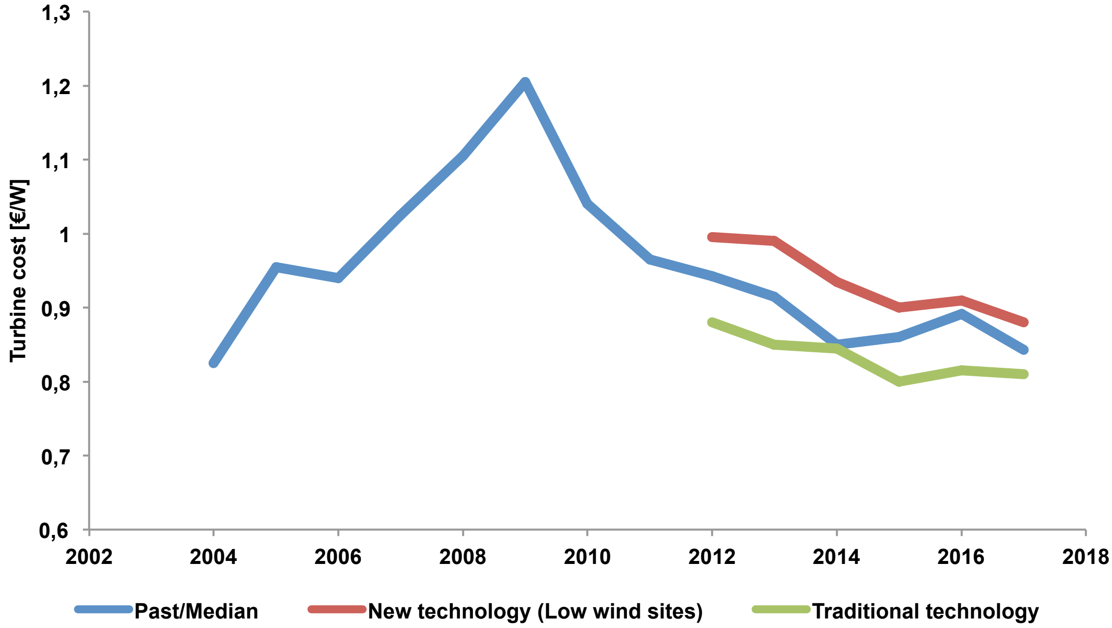


Figure 15 Turbine cost evolution over time for different project sizes
Source: Own elaboration; Data: Lacal et al., 2014; Lacal, 2013

The installation cost of onshore wind projects has followed a similar path. It cost was strongly reduced during the first period, then it experienced a slight increased during 2004 to 2009 and finally decreased again (Figure 16). In last years, the reduction in the installation cost has been cushioned due to the impossibility to access good wind locations. Thus, wind farms required taller towers and larger blades to produce electricity.

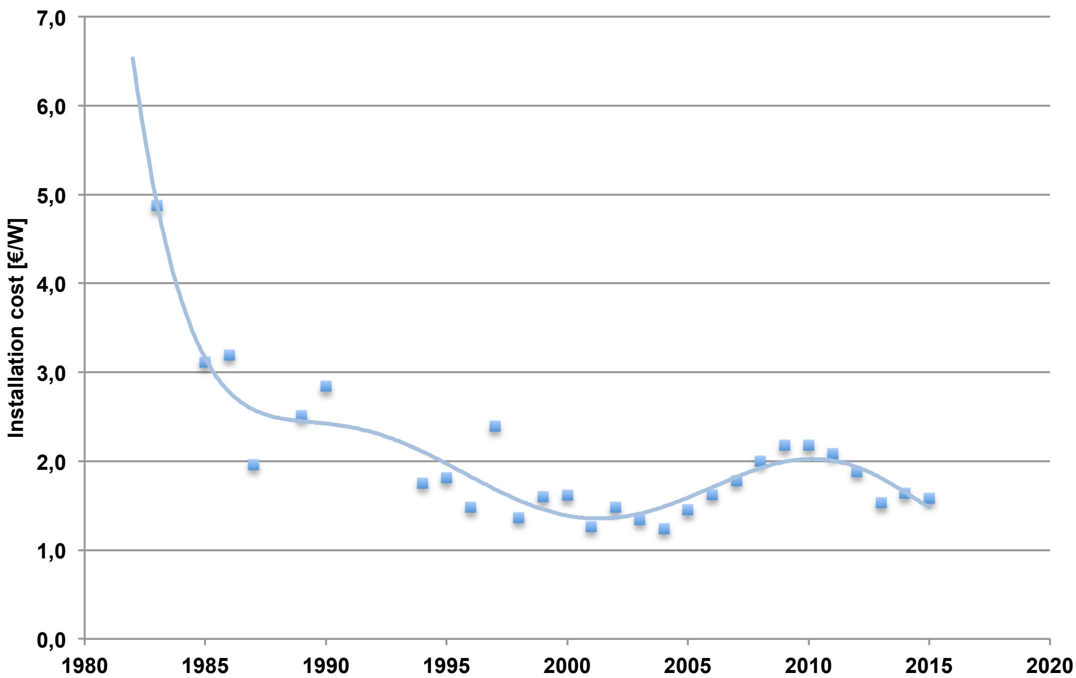


Figure 16 Installation cost of onshore and offshore plants over time
Source: Wiser and Bolinger, 2016

Although the installation cost of offshore wind projects has been decreasing due to advances in the reliability of the wind turbines and also by adapting the offshore oil & gas foundation, transport and installation experienced to the wind offshore conditions, larger investments needed in order to install the wind farm in deeper and further locations from shore has increased the overall installation cost (Table 13).

Factors	**2001**	**2015**[3]
CAPEX [€/W]	3,05	4,32
OPEX [€/kW/year]	209,15	117,15
Capacity factor [%]	35%	46%
Water depth [m]	10	25
Distance from shore [km]	20	40
LCOE [€/kWh]	0,24	0,17

Table 13 Comparison of typical offshore wind farms characteristics and installation cost commissioned in 2001 and 2015
Source: IRENA, 2016

The LCOE of wind generation technologies includes the CAPEX, OPEX, capacity factor of the plant, operational life and cost of financing. CAPEX, capacity factor and cost of capital affect greatly the LCOE. However, OPEX and the useful life of the plant also have important roles within the calculations. It is important to mention that these components also have different weights on the calculation of LCOE for onshore and offshore applications. Therefore, the evolution of these factors and the impact on the LCOE are then presented (CAPEX evolution has been already stated).

OPEX includes both fixed and variable operation and maintenance cost, which ranges from 20% to 25% of the total LCOE. Whereas fixed cost includes grid access fees, insurance, administration and scheduled maintenance service, variable cost includes unscheduled maintenance and replacements of components. Gathering data to unify values of OPEX in wind projects is a difficult task because they are presented in different ways according to the reference source. In addition, O&M costs tend to increase through the operational life of wind turbines (i.e. two turbines operating in 2016 might have a completely different O&M cost depending on the year they were installed because the probability of component failure increases with time). Nevertheless, it is clear that OPEX values in wind energy projects have decreased through the years. Regarding onshore installations, Figure 17 shows this downward trend, which was led by continuous increases in turbine size and improvements in components that have resulted in larger capacity factors, thus decreasing the fixed costs per kilowatt-hour generated. Figure 17 also shows the decrease in the variability of O&M cost through the years, presenting narrower range in the last years. Regarding offshore installations, Table 13 shows that OPEX has decreased in 15 years almost by 50%, led by improvements in monitoring and prognostics and development of systems to access the turbines.

[3] Values convert to €/W from $/W using the average conversion rate of 2001 (0,89$) and 2015 (0,902$)

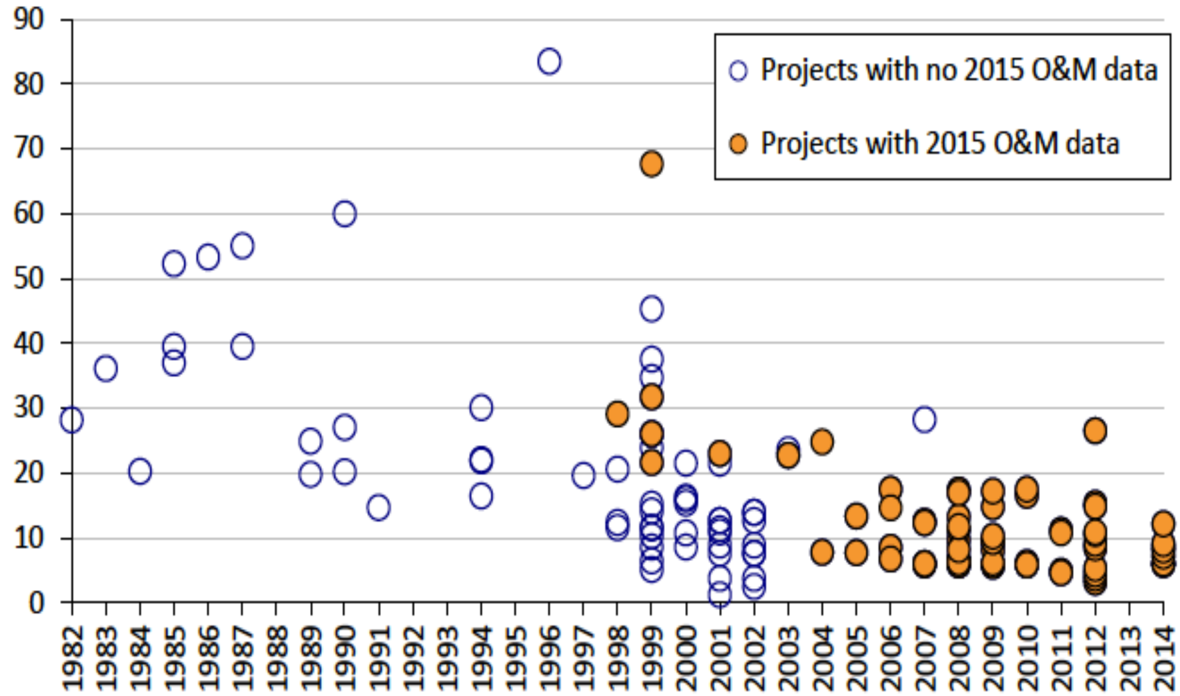


Figure 17 Average annual OPEX over time
Source: Wiser and Bolinger, 2016

The role of both capacity factor and capital cost are also relevant in LCOE calculations. Table 14 shows variations in the LCOE according to different values of capacity factor and discount rates. The energy output of the wind farms has increased as a consequence of the technological evolution. Moreover, increases in the capacity factor in both onshore and offshore installations are expected in the near future. The interest rate of wind projects, on the contrary, has decreased with the maturity of the technology. While onshore projects have already achieved a high degree of confidence for investors to finance such investments, offshore projects still presenting elevated financing cost due to its more immaturity in the market. However, interest rates have dropped significantly in the last years as a consequence of the more reliability on projects helped by the support of some governments (e.g. Dutch and British).

Discount rate	**Capacity factor**				
	25%	**30%**	**35%**	**40%**	**45%**
5,5%	7,28	6,38	5,70	5,17	4,79
10%	8,72	7,44	6,45	5,78	5,25
12,6%	10,98	9,4	8,27	7,44	6,83
14,5	12,12	10,30	9,10	8,12	7,44[4]

Table 14 LCOE [c€/kWh] of onshore wind at different capacity factors and discount rates
Source: IRENA 2012

[4] Values presented in c€/kWh using the average conversion rate from dollar to euro in 2010 (0,755$)

Since early 1980s LCOE of onshore wind has experimented different trends. From the 1980s until 2004, the LCOE of wind energy experienced great reductions due to increases in performance (i.e. greater energy outputs), reductions in CAPEX and in capital cost. LCOE of onshore wind installations declined by a factor of five, from 0,25 $/kWh to 0,050 $/kWh (Wiser and Bolinger, 2011; DEA, 1999). Between 2004 and 2008 the LCOE increased up to 0,075 $/kWh due to the aforementioned increase in CAPEX and hence cost of capital. However, this increase did not have a proportional effect on LCOE due to increases in capacity factor. Since then, this upward trend was reversed due to reductions in capital cost and CAPEX and technological improvements. Thus, current LCOE values are around 0,055 $/kWh.

Regarding offshore projects, Table 13 shows a 30% reduction in the last 15 years. However, it has not always been a downward trend. Great reductions in the following years after the construction of the first offshore wind farm (coast of Vindeby in Denmark, 1991) were achieved. However, the LCOE was drove up to 0,19 €/kWh by 2010 due to mishaps in the construction (increase in turbine prices) and operation, together with the hesitant of governments to support this form of renewable energy, which increased the financing cost. Investors were reluctant to invest in such projects without clear support from governments (i.e. increasing the perception of risk of financiers). This trend was reversed thanks to initiatives like the Offshore Wind Accelerator in the UK and the Far- and Large Offshore Wind program in the Netherlands. In fact, the first tender under the new support regime in the Netherlands for two wind farms (Borssele I and Borssele II) presented a winning bid of 87 €/MWh[5], which is a 54% decreased from 2010 values.

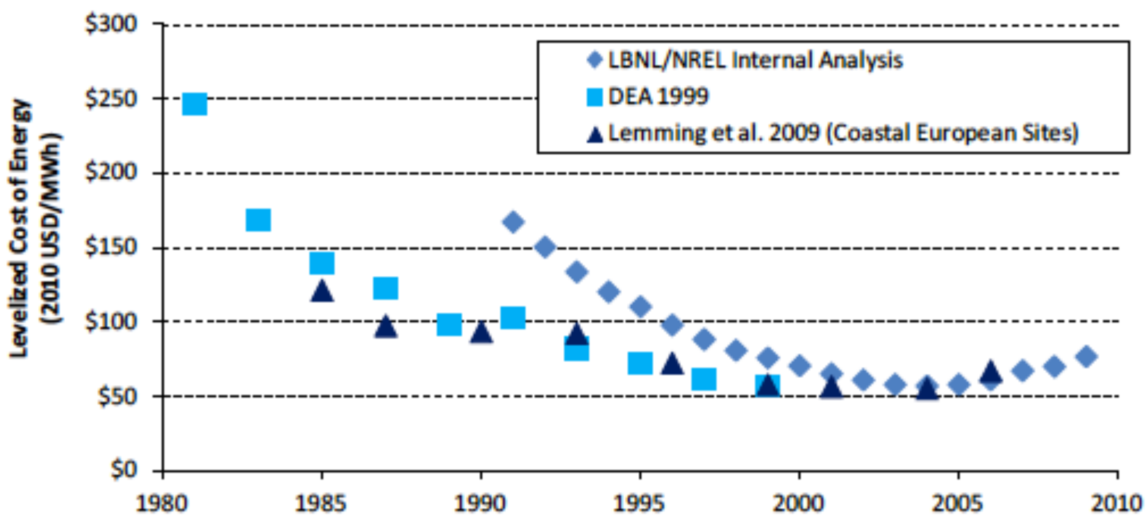


Figure 18 Estimated LCOE for wind onshore energy between 1980 and 2009 for the US and Europe
Source: Wiser and Bolinger, 2011

Therefore, the cost of wind technologies is currently on a downward trend, which is being mainly impulsed by technology advancements and greater competition within manufacturers. The improvements achieved in the wind industry are boosting the performance of wind farms, thus

[5] Dong energy presented in the tender (July 2016) an offer of 73 €/MWh, which added to the grid connection cost published (14 €/MWh) results in the 87 €/MWh

producing greater amounts of electricity. Likewise, favorable regulatory frameworks are leading to higher competition in the market, which is diminishing the price of turbines and its components.

Both PV and wind technologies have considerably improved the performance of their systems, which have allowed to produce larger amounts of electricity per watt installed. Moreover, through the economies of scale, experienced acquired and competitiveness the price of these technologies have been significantly reduced. The consequences of such improvements within the PV and wind industry are making the projects profitable without government support. Thus, increasing the interest of investors. In this framework, it has been elaborated a tool to assess the profitability of wind and PV projects, which is presented in the following chapter.

3 Financial and economic model

The financial and economic model elaborated is presented within this chapter. Firstly, we present the financial parameters employed to evaluate the economic viability of the projects. Secondly, it is illustrated the different parts of the model and the assumptions considered to calculate the parameters. The model is able to perform a financial analysis through the calculation of the most relevant parameters when a set of input variables is defined. Finally, this model is applied to three real projects, which are presented in the following chapter.

3.1 Financial parameters

In order to choose the right financial and economic parameters for analyzing renewable energy projects, a literature review has been performed. As expected, It has been found that the most widely used parameters to assess profitability are the net present value and internal rate of return, and the discounted pay back period is a widely used parameter in financial studies to assess risk. Another extensively used parameter is LCOE, which is commonly used in the literature as a benchmarking tool to compare the cost of generating electricity with different technologies or to evaluate if a certain technology has achieved grid parity. Furthermore, the relevant items to perform a comprehensive financial and economic analysis are energy output, operating and investment cash flows, discount rate, subsidies and externalities. Although the two latters are not always considered in all the literature reviewed, they have been considered in the financial and economic model. Table 15 summarizes some of the literature reviewed, presenting the parameters and data utilized in each paper.

The cash flows used in this model to calculate the NPV are in constant euros (i.e. excluding the effect of inflation), thus the discount rate utilized in Equation 2 is the real discount rate. This rate is calculated by applying Equation 3.

$$NPV = \sum_{t=0}^{T} \frac{CF_t}{(1+r_r)^t} \tag{2}$$

Where CF_t is the real cash flow in year t; r_r is the real discount rate; and T is the economic lifetime of the project.

Source	Financial parameters	Input data[6]	Installation	Location and year	Comments
Branker *et al.*, 2011	LCOE	CAPEX; AO&M (inverter); AEO; project lifetime (20-25 y); incentives & subsidies; financing terms; r; T and i	PV-Result per watt installed	Ontario, Canada (2011)	Sensitivity analysis: LCOE deviations. Variables: r, CAPEX, AEO and financing terms. Analysis performed by SAM
Talavera *et al.*, 2011	NPV; DPBP; IRR and LCOE	CAPEX; AO&M (1% CAPEX + g); AEO; project lifetime (25); incentives & subsidies (0); financing terms, r_n (3,26% = WACC); elect. €; T and i (3.3%)	PV-8 public buildings (40 – 398 kWp)	Jaén, Spain (2011)	Sensitivity analysis: LCOE deviations from a defined base scenario. Variables: CAPEX, AEO, r_n. Not subsidies considered at the time of the project
Swift, 2013	LCOE and IRR	CAPEX; AO&M (1% CAPEX + g); AEO; project lifetime (25); incentives & subsidies; financing terms; r_n (7% = WACC) and i (1,6%)	PV-Commercial installation in 4 locations (50 kWp)	Honolulu, Hawaii; Newark, New Jersey; Phoenix, Arizona; Minneapolis, Minnesota	Variations on the results: IRR (-8,27% - 31,60%); LCOE (0,055 – 0,18 €/kWh)
Girard *et al.*, 2015	LCOE	CAPEX; AO&M (1,2% CAPEX + i); AEO; project lifetime (25); incentives & subsidies; financing terms; T (society tax 15% & Energy producers 7%) r (12%) and i (1,25%)	Power plant (100 kWp), ground-mounted, fixed angle	El Baico, Baza, Granada, Spain (2015)	LCOE 0,132 €/kWh (r =12%). Comparison of producing electricity with PV solar and combine cycle
Hammond *et al.,* 2011	NPV and Cost-benefit analysis (CBA)	CAPEX; AO&M (inverter); AEO; project lifetime; incentive & subsidies	PV-Household (2,1 kWp)	United Kingdom (different AEO has been considered)	Subsidies: FiT (37,8 p/kWh elec. generated + 3.1 p/kWh elect. exported). Sensitivity analysis: elec. €, r, CAPEX, AEO and subsidies.
Chandel *et al.,* 2013	NPV; IRR; SPBP and DPBP	CAPEX, AO&M (fixed); AEO; project lifetime (25)	2,5 kWp-PV	Jaipur, India (2011)	Sensitivity analysis: plant life (15-25 years); discount rate (6-15%); pre and post tax

[6] CAPEX, overall installation cost; A0&M, annual operation and maintenance cost (g is the annual escalation factor); AEO, annual energy output; r_n, nominal discount rate; WACC, varies according to the financial resources chosen; elect. €, price of the electricity sold/saved; T, taxes and i, inflation

Source	Financial parameters	Input data[6]	Installation	Location and year	Comments
Bakos G. C., 2008	IRR; ROI; Year-to-positive cash flows: NPV	CAPEX, AO&M (fixed); AEO; project lifetime (20 years); incentive & subsidies (55% CAPEX + Feed-in Tariff); T	60 kWp-PV	Greece	-
Rehman *et al*., 2005	IRR; SPBP; Years-to-positive cash flows; NPV; Profitability index; energy production cost and annual life cycle savings	CAPEX; AO&M (g=4%), replacement of inverter every 5 years; AEO; lifetime; r; i; elect. €; avoided cost (positive externalities)	5 MWp-PV	41 locations in Saudi Arabia	RetScreen software is employed to perform the economical feasibility
Talavera *et al.,* 2008	IRR	CAPEX; AEO; lifetime (25 years); r; i; initial investment subsidie; elect. € (escalation rate)	PV-Result per kWp installed	Euro area; USA and Japan	Sensitivity analysis (deviations of the IRR): r; AEO; CAPEX; elect. € and installation subsidies.
EL-Shimy, 2009	IRR; SPBP; Years-to-positive cash flows; NPV; benefit-cost ratio (BCR); energy production cost (LCOE), etc.	CAPEX; AO&M (g=4%), replacement of inverter every 5 years; AEO; lifetime; r; i; financing conditions; elect. € (escalation rate); avoided cost (positive externalities)	10 MW PV-grid connected power plant	29 locations in Egypt	RetScreen software: production, financial and GHG emission analyses
Gómez *et al.,* 2010	IRR (project, debt, equity); NPV (r=7,98%); EBIT	CAPEX; AO&M (detailed); AEO (0,2%- after 4th year); lifetime; financing conditions; elect. €; WACC (calculated)	Onshore wind farm-30MWp	Soria, Spain	Comprehensive technical and financial analysis of the wind project. Sensitivity analysis: P90 and reduction in Tariff
Weaver, 2012	NPV and IRR	CAPEX; AO&M; AEO; elect. €; subsidies and incentives; decommissioning cost	Offshore wind farm 60MWp	North Hoyle, Wales and Scoby Sands, England	Sensitivity analysis over the financing cost
Nouni et al.,	Levelized unit cost of electricity (LUCE)	CAPEX; AO&M; AEO; r and project lifetime	Decentralized PV, 1 to 25 kWp	18 different locations in India	

Table 15 Financial parameters and input data employed in some of the research paper reviewed regarding project appraisal of renewable energy installations
Source: Own elaboration; Data from: Table (Sources)

$$(1 + r_n) = (1 + i)\times(1 + r_r) \quad (3)$$

Where r_n is the nominal rate (current prices); i is the inflation and r_r is the real rate (used with constant prices).

The nominal rate that is used in this model is the weighted average cost of capital (WACC), which represents the weighted average cost of capital taking into account the sources of financing. Accordingly, the real discount rate is equal to:

$$r_r = \frac{(1 + WACC)}{(1 + i)} - 1 \quad (4)$$

Furthermore, the real IRR is calculated within this model. In order to compare with other alternatives, the nominal IRR is calculated by using Equation 5.

$$IRR_n = (1 + i)\times(1 + IRR_r) - 1 \quad (5)$$

Where IRR_n is the nominal IRR, i is the inflation and IRR_r is the real IRR.

The discounted payback period (Equation 6) is widely used in countries suffering from high inflation or subjected to social or political turbulence. The main drawback of this indicator is that ignores later year cash flows.

$$\sum_{t=0}^{PB} \frac{CF_t}{(1 + r_r)^t} = O \quad (6)$$

Here PB is the number of periods it takes before the discounted cumulative cash flows equal the initial investment; CF_t is the net cash flow in year t and r_r is the real discount rate.

LCOE is used as a benchmarking tool to assess different energy technologies; it measures the cost of producing one unit of electricity (kWh) over its lifetime. Moreover, it is also useful to compare if a technology has already achieved grid parity (i.e. the price of electricity on the grid). The main issue regarding LCOE analysis is that many different results can be obtained depending on the information consider within the calculations. Commonly, LCOE is calculated considering initial capital, discount rate, operating cost and the energy output. However, within the operating cost it is not always considered the full cost of operating the power plants, such as insurance subsidies (nuclear) and fuel subsidies (fossil), decommissioning and environmental and social cost. Therefore, both LCOE are calculated using Equation 1 (Chapter 3) for evaluating the cost of producing electricity in the different cases.

3.2 Construction of the model

The financial and economic model presented in this section should allow any investor, an individual or a company, to analyze the profitability of an investment considering the most relevant variables when assessing renewable energy projects. The model is composed of three main parts: (1) input data, where all the specific information of a project is introduced; (2) the calculation tools, where the input data is analyzed and computed in order to obtain the financial indicators; and (3) output data, where all the results obtained are summarized.

3.2.1 Input data

The first step to proceed with the financial model is to fill the necessary input data summarized in Table 16. In order to be more accurate when calculating different cases, it is necessary to include the installation type. In this sense, it has been considered two different business perspectives, self-consumption and power plants. In the self-consumption case, it is possible to choose between three alternatives: (1) PV system with batteries not receiving compensation from electricity feed into the grid; (2) PV system with no batteries nor compensation from the electricity feed into the grid; and (3) PV with no batteries but being compensated for the electricity feed into the grid. Meanwhile from the business perspective also 3 alternatives are considered: (1) PV utility scale; (2) onshore wind plant; and (3) offshore wind farm. It has been defined these six alternatives in order to consider the most common installation possibilities within PV and wind energy.

Inputs	Units	Symbol
Installation type	-	B&NS; NB&NS; NB&S; PV utility-scale; onshore wind & offshore wind
Capacity installed	kWp	
Electricity production (Year n)	kWh	Q_n
Annual degradation rate	%	r_d
Useful life	years	T
Price of electricity consumed	€/kWh	P_c
Price of electricity sold	€/kWh	P_s
Initial investment	€	I
Start operations	year	n
Operating expenses (Year n)	€	C_n
Annual increase in operating expenses	%	r_i
Corporate tax rate	%	τ
Weighted Average Cost of Capital	%	WACC

Inputs	Units	Symbol
Real discount rate	%	r_r
Inflation	%	i
Investment subsidies	€/kWp	I_s
CO_2 avoided	$kgCO_2/kWh$	M_{CO2}
Social cost of CO_2	$€/kgCO_2$	P_{CO2}

Table 16 Input data variables of the financial model
Source: Financial and economic model

After defining the installation type it is necessary to define other variables directly related to the energy output like installed capacity, estimated electricity generation during the first year of operation, degradation rate and project lifetime. Moreover, variables linked with operating and investment cash flows like price of electricity, investments, subsidies and operating expenses are also included. Finally, it is defined the rate used to discount future cash flows to present values. As already stated the real discount rate is used within the model, which is calculated by using Equation 4 that requires as input data the inflation and WACC. The WACC is calculated by applying Equation 7 (Soares *et al.*, 2006).

$$WACC = \%E \times r_e + \%D \times r_d \times (1 - \tau) \tag{7}$$

Where %E is the percentage of the project financed by equity; r_e is the cost of equity; %D is the percentage of financing that is debt; r_d is the cost of debt; and τ is the corporate tax rate.

The WACC takes into account the weights of equity and debt applied in the project and calculates the cost of each source. The cost of debt is generally the interest rate of the money borrowed from a financial institution. Regarding the cost of equity, it is important remarking the difference between companies or individual investors when calculating the WACC. From the individual investor perspective the cost of equity is calculated by adding the risk free interest rate to a subjective risk premium, where the former is the rate of return applied to safe investments as bonds or government saving accounts and the latter accounts for the uncertainty in investing in the project (from the investor perception). A similar methodology is applied for companies not listed in on a stock exchange market. Meanwhile, from the perspective of a company that is listed on the stock exchange market more complex calculations have to be performed. Commonly the capital asset pricing model (CAPM) is applied to calculate the cost of equity of listed companies, which is presented in Equation 8. Moreover, another difference between companies and individual investors is the corporate tax rate, which is considered zero in the case of individual investors.

$$c_E = R_f + \beta_i(E[R_m] - R_f) \tag{8}$$

Where R_f is risk-free interest rate; β_i is the beta of the stock i and $E[R_f]$ is the expected rate of return of the stock market.

3.2.2 Capital investment

In the model, the different investments during the project life are placed in the year in which they occur (Table 17). These investments are counted as an expense at the end of the year. Likewise, the investment cash flows of each year (ICF_t) are included in order to calculate the net cash flows each year (CF_t). Although renewable energy projects are capital intensive (i.e. great amounts of capital are needed at the beginning of the project) there are other investments during the lifetime of the project. These reinvestments are generally associated with scheduled replacement of equipment (e.g. the replacement of the inverter in PV projects or the gearbox in wind projects).

Year	0	1	2	3	(…)	T (serviceable life of the project)
ICFs	-€	-€	-€	-€	-€	-€

Table 17 Investment cash flows during the operating lifetime of the project

3.2.3 Revenues

The source of revenues for renewable generating facilities comes from saving or/and selling electricity (according to the type of installation). Therefore, the annual revenue (R_t) is calculated by using the following expression.

$$R_t = Q_{saved,t} \times P_c + Q_{sell,t} \times P_s \tag{9}$$

Where $Q_{saved,t}$ is the annual electricity savings; P_c is the price of each kWh consumed; $Q_{sell,t}$ is the annual electricity sell to the grid; P_s is the price of the electricity sold.

The annual electricity savings term ($Q_{saved,t}$) is only considered in the self-consumption models. This value is calculated using Equation 10, which includes the percentage of the electricity produced that is absorbed by the load (i.e. residential building, factory, commercial building, etc.) and the degradation rate (for annual reductions in electricity generation). Thus, the revenues obtained from saving electricity are calculated by multiplying this term times the price of the electricity consumed (P_c), which varies among different locations. Whilst in countries without subsidies to self-consumption from renewable energies it is considered equal to the variable part of the electricity bill, in countries with government support the final price will be larger than the variable part of the electricity bill.

$$Q_{saved,t} = \%Q_{saved} \times Q_{gen,n} \times (1 - r_d)^{t-n} \tag{10}$$

Where % Q_{saved} is the share of the total production that it is absorbed by the load, r_d is the annual degradation rate, t is the evaluated year and n is the year in which the plant starts operating.

On the contrary, $Q_{sell,t}$ account for the electricity feed into the grid (Equation 11). In self-consumption models, this term accounts for the excess of electricity feed into the grid. The compensation the owner of the renewable system will receive when injecting electricity to the grid varies among countries[7]. Regarding power plants, all the revenues come from this term of the equation. Commonly, the generation with renewable energies is regulated by different means according to the country[8]. Thus, it would be necessary to calculate the price perceived for the electricity fed into the grid (P_s).

$$Q_{sell,t} = \%Q_{sell} \times Q_{gen,n} \times (1 - r_d)^{t-n} \quad (11)$$

Where $\%Q_{sell}$ is the share of the total production that it is sold to the grid, r_d is the annual degradation rate, t is the evaluated year and n is the year in which the plant starts operating.

3.2.4 Operating expenses

Operating expenses are all the expenses that occur during the serviceable life of the generating facility. Such costs are presented by different means according to project and countries. Therefore, in order to harmonize the different costs considered in the renewable energy projects, it has been considered the following items: (1) fixed O&M cost [€/kW], which considers all the fixed cost that need to be assumed; (2) variable O&M cost [€/kWh], which accounts for the costs associated with the electricity generation of the plant; (3) additional fixed costs [€/kW] that considers extra charges related with the capacity installed; and (4) additional variable costs [€/kWh] that includes fees or charges to electricity generation. These four items added together account for the annual operating expenses of the installation ($Opex_t$).

Commonly, (1) and (2) are costs that are related to the type of installation and technology (i.e. residential or utility-scale PV, offshore or onshore wind, etc.). Moreover, these costs represent the major expenses in a renewable energy project. Although such costs vary according to projects, average market values found in the literature reviewed have been defined in order to facilitate the computation of the model in case these values are unknowns. Table 18 includes the values that have been considered within the model for the calculation of the O&M costs. Moreover, it has been considered an annual escalation factor of the operating expenses (1%) in order to account for the higher demand of the equipment with the years. The values of (3) and (4) are generally linked to the country where the installation is going to be located, thus it has not been possible to represent average values. However, in the case studies, these values are presented for the different projects.

Operating expenses	Residential PV	Utility-scale PV	Onshore	Offshore
Operating expenses	1% CAPEX [€]	1,2% CAPEX [€]	44 [€/kW-year]	86 [€/kW-year]

Table 18 Operating expenses per installation type
Source: Talavera *et al.*, 2011; Berkeley Lab et al., 2016

[7] The most common compensation systems are; (1) net metering (the same value or a value based on the retail electricity price); (2) feed-in tariff (FiT) or green certificates (GC); (3) regulated wholesale market price; and (4) no value (it is lost)

[8] These are the main systems employed: Feed-in tariff, which present three methods: (i) market price + premium, (ii) regulated tariff and (iii) market price with fixed market share; and (iv) quota obligation with tradable green certificates (TGC) that perceives the market price + certificate´s price

3.2.5 Depreciation and amortization

The overnight cost of a renewable energy project is allocated over its useful life by using depreciation and amortization. In this model, a linear depreciation methodology over a specific period is employed, which means that an asset looses yearly the same value. This allows companies to write off the value of the assets over time. This depreciation of the assets is only applied to companies, not to individual owners. The value depreciated each year (D_t) is the sum of the depreciation of the different assets, which is subtracted from the EBITDA to reduce the amount of taxes paid.

3.2.6 Tax liability

The tax liability (T_t) is the product of the operating income times the corporate income tax rate, which varies according to the regulation in each country (e.g. 35% in Argentina). Therefore, the tax liability is equal to:

$$T_t = \tau \times (R_t - Opex_t - D_t) \tag{12}$$

Where τ is the corporate income tax rate

3.2.7 Net cash flows

The net cash flow (CF_t) of each year is the sum of the investment (ICF_t) and operating cash flows (OCF_t). The operating cash flows include revenues, operating expenses and tax liability. Asset D&A is excluded from the formula.

$$OCF_t = (R_t - Opex_t - D_t) \times (1 - \tau) + D_t \tag{13}$$

Accordingly, the annual cash flow is equal to:

$$CF_t = OCF_t - ICF_t \tag{14}$$

3.2.8 Levelized cost of electricity

This parameter is a good measure of the profitability of the project when compared to the price of the electricity sold or saved. The LCOE is calculated by two means, excluding or including externalities. The former is calculated by applying Equation 15, which includes the investments and operating expenses during the useful life.

$$LCOE = \frac{\sum_{t=0}^{T} {(Opex_t + ICF_t)}/{(1 + r_r)^t}}{\sum_{t=0}^{T} {E_t}/{(1 + r_r)^t}} \tag{15}$$

Where E_t is the annual electricity production, which is calculated with the electricity generation in the first year of operation and the degradation rate (Equation 16)

$$E_t = Q_n \times (1 - r_d)^{(t-n)} \quad (16)$$

Where Q_n is the electricity production during the first year of operation, r_d is the discount rate, t is the evaluated year and n is the year in which the plant starts operating.

The LCOE including externalities has been calculated by considering the social cost of avoiding CO_2 emissions to the atmosphere. In order to proceed with such calculation, it has been considered a factor of electricity generation - CO_2 emission intensity ($kgCO_2/kWh$), which measures the emissions of CO_2 associated with the generation of 1kWh of electricity produced in a certain country. Moreover, it has been considered a cost for each unit of CO_2 emitted to the atmosphere (€/$kgCO_2$). This cost is considered equal to the price on GHG emissions imposed by governments and organizations. The official CO_2e prices vary around 5 \$/Tn. CO_2 up to 126 \$/Tn. CO_2 (World Bank, 2017). The most famous CO_2 trading market, the emission trading system of the European Union (EU ETS), has a price of 5,5 \$/Tn. CO_2 (Sendeco CO_2, 2017). Considering these two terms, it is possible to calculate the economic value of generating electricity with renewable energy sources. Equation 17 calculates the annual avoided cost to the society as a consequence of the electricity generated with renewables. It has been considered that the emissions of CO_2 by renewable sources are null.

$$Ex_t = E_t \times M_{CO2} \times P_{CO2} \quad (17)$$

Accordingly, the LCOE counting with positive externalities of avoiding CO_2 emissions is calculated using the following equation. Thus if this LCOE would be compared with the price for the electricity saved/sold, the project would be more profitable.

$$LCOE\_e = \frac{\sum_{t=0}^{T} (Opex_t + ICF_t - Ex_t) / (1 + r_r)^t}{\sum_{t=0}^{T} E_t / (1 + r_r)^t} \quad (18)$$

3.2.9 Output data

Finally, all the financial parameters calculated through the model are summarized in the output datasheet. These values are evaluated to either accept or reject the project. Table 19 shows the results presented at the end of the financial and economic analysis

Parameter	Output
Installation type	(1), (2), (3), (4), (5) or (6)
NPV	€
IRR	%
Payback period	Graph
LCOE	€/kWh
LCOE (externalities)	€/kWh

Table 19 Output values of the financial and economic model

4. Three real case studies: residential PV systems in Spain and Portugal, and wind project in Argentina

In the following chapters, the financial and economic model is applied to three real cases regarding solar PV and wind energy projects. Firstly two residential solar PV cases are presented, which include the analysis that should be performed by the owner of the household to assess the profitability of such projects. Secondly, it is presented an onshore wind project in order to show the differences between both technologies and the approach followed when a project is addressed from the company perspective. Within this chapter, we detail the input data employed for the base case scenarios of the three case studies. The results obtained for the base case scenarios and the sensitivity analyses are presented in the following chapter.

4.1 Residential PV system in Santarém, Portugal (case 1)

In this chapter, the data introduced as input values in the financial and economic model of the PV system in Santarém are presented. These values represent the base case scenario.

4.1.1 Location and characteristics

Residential PV installation of 1,56 kWp placed in the city of Santarém in Portugal. This system is sized to cover the base household electricity consumption (i.e. the electricity consumed by the home appliances that are always working). Therefore, the household will consume most of the electricity generated by the installation. The surplus of electricity will be given away for free to the grid system because to store it in batteries or sell it is economically unfeasible. The batteries are an expensive component that is unprofitable under this circumstance. The serviceable life of the installation is 25 years, which is twice the life span of the inverter installed.

4.1.2 Regulatory framework

Regarding self-consumption systems in Portugal, a unique regulatory scheme was published in 2014 (DL 153/2014). This scheme includes self-consumption (UPAC) and small production units (UPP). Within UPAC three sub-groups are distinguish: (1) <200 W – 1,5 kW; (2) 1,5 kW- 1 MW; and (3) >1 MW. UPP allows installations up to 250 kW, with an annual quota of 20 MW. PV-production units for self-consumption (UPAC) have to be dimensioned according to the consumption needs. These installations receive for the electricity sold 10% less than the market price (Equation 19).

$$R_{UPAC,m} = E_{provided,m} \times OMIE_m \times 0{,}9 \tag{19}$$

Where, $R_{UPAC,\ m}$ is the remuneration of the electricity provided to the Portuguese electricity grid (RESP) during the month m, measured in €; $E_{provided,\ m}$ is the electricity supply during month m, measured in kWh; and $OMIE_m$ is the simple arithmetic average of the prices of the Portuguese market operator of energy (OMIE) during the month m, measured in €/kWh.

4.1.3 Investment

The solar system includes six PV modules of 260W each (Axitec), an inverter of 1500W (SMA Sunnyboy) and a monitoring system to remotely control the performance of the installation. The total system cost also includes the structure of the modules, the electric system and the installation cost, which equals 2.386,40€ (VAT included). The breakdown cost of the installation is presented in Table 20.

Components	Cost [€]
PV modules	925,02
Aluminum structure	103,5
Electric system	156,14
Inverter (monitoring)	575,50
Installation	180
Total (VAT excluded)	**1.940,16**

Table 20 Breakdown cost of the residential PV installation in Santarém, Portugal
Source: Own elaboration. Data: owner of the installation

Therefore, the cost of the installation measured in euros per watt equals 1,24. This value compared to the data presented in Table 7, shows the decrease in price in one year. The cost of small installations was 1,7 €/W, thus a decrease of almost 50 c€ per watt in one year.

4.1.4 Revenues and operating costs

The line of revenues in this project comes from the electricity savings obtain yearly due to the electricity consumed by the PV system. The electricity consumption has been calculated subtracting 10% of the electricity, which corresponds to the electricity that cannot be absorbed by the system and it is feed into the grid. Regarding the annual electricity generated by the system, real data obtained from the monitoring system of the installation (in operation since February 2017) and online software to estimate the production of PV systems (PVGIS[9]) has been used to calculate the electricity generated by the system. Table 21 shows the results obtained from the two sources and the estimated electricity production, which has been calculated using the data from the monitoring system and extrapolating it to the rest of the periods applying the monthly variation calculated by the software. Accordingly, the estimated annual electricity generation is 2740 kWh.

[9] Online free solar photovoltaic energy

Month	Software PVGIS [kWh]	Real data [kWh]	Estimated production [kWh]
January	133	-	146,3
February	163	33,65 (7 days)	179,2
March	216	202,9	202,9
April	215	266,9	266,9
May	238	261,7	261,7
June	244	281,4	281,4
July	262	-	302,2
August	258	-	297,6
September	225	-	259,5
October	189	-	218,0
November	144	-	166,1
December	123	-	141,9
TOTAL	2410		2740

Table 21 Electricity production of the residential PV system in Santarém, Portugal
Source: Own elaboration. Data from: PVGIS software and Sunny Portal

An electricity price of 0,164 €/kWh is considered, which is the variable price of the electricity bill, plus a 23% in order to consider the VAT of Portugal applied to the electricity bill. Therefore, 0.2018 €/kWh will be considered as the electricity price used to calculate the annual revenues of the PV system.

Regarding the operating cost for household, it is commonly considered that the only cost is the replacement of the inverter, which in this case will be replaced after 13 years of operation (Branker et al., 2011, Geoffrey et al., 2011). However, in order to be more accurate and account for the cost of small replacements in the electric and monitoring system plus the cleaning of the PV panels it is defined the annual O&M equal to 1% of the installation cost (Talavera et al., 2011, Swift, 2013). These operating expenses are increased annually by 1%.

4.1.5 Financing

This PV system was fully financed by the owner (i.e. the percentage of financing that is debt is equal to 0%). Thus in order to calculate the WACC, it has been only analyzed the cost of equity. In this sense, the risk free interest rate was considered to be equal to "*os Certificados do Tesouro Poupança Mais*" (CTPM), a financial product issued by the Portuguese Government, which offers a guaranteed interest rate equal to 2,23%. Regarding the subjective risk premium is has been considered a 1,27%. Thus, the total cost of equity equals 3,5%; which in this case is equal to the WACC (Equation 20).

$$WACC = 1 \times 0{,}035 + 0 \times 0{,}0589 = 3{,}5\% \tag{20}$$

Although the cost of debt is not relevant in the base case scenario, in the sensitivity analysis it has been considered the effect of financing the project with debt over the profitability indexes. Accordingly, a bank operating in Portugal (Santander Totta) was asked about the interest rates for loans to individuals for installing PV system. Only a credit line to individuals existed in 2010, which interest rate was 1,5% + Euribor. The Euribor during 2010 averaged 1.35%. Thus the interest rate applied to the loan at that time would have been around 2,9%. However this line credit was no longer available, so it has been considered 5,89%, the average banking interest rate in Portugal for the period (tradingeconomics.com).

4.1.6 Externalities

According to the World Bank (Carbon Pricing Watch, 2017), the Portuguese carbon tax is equal to 7 €/Tn. CO_2. Moreover, according to the Portuguese generation mix, it is considered a factor of electricity generation - CO_2 emission intensity equal to 0,7 kg CO_2/kWh ("SMA Solar Technology AG – Sunny Portal", 2017). Therefore the annual avoided cost for the society will be equal to the following expression.

$$Ex_t = E_t \times 0{,}7 \times 0{,}007 \tag{21}$$

4.1.7 Input values

Table 22 summarizes all the parameters presented above, which are the values used to calculate the financial parameters of the base case study of the residential PV installation in Santarém, Portugal.

Inputs	Units	Symbol
Installation type	-	NB&NS
Capacity installed	kWp	1,56
Electricity generated	kWh	2740
Annual degradation rate	%	0,5
Useful life	years	25
Price of electricity consumed	€/kWh	0,2018
Price of electricity sold	€/kWh	-
Initial investment	€	2382,4
Start operations	year	1
Operating expenses	€	23,82
Annual increase in operating expenses	%	1
Corporate tax rate	%	0
WACC	%	3,5

Inputs	Units	Symbol
Real discount rate	%	1,97
Inflation	%	1,5
Investment subsidies	€/kWp	0
CO_2 avoided	$kgCO_2/kWh$	0,7
Social cost of CO_2	$€/kgCO_2$	0,007

Table 22 Data used in the Portuguese case study

4.2 Residential PV system in Valencia, Spain (case 2)

The data used for the calculation of the base case scenario of the PV system installed in a household in Valencia is presented in the following sections. In this case, the PV system is not yet installed. Thus the values presented are mainly based on the technical studies presented by the installation company and information collected from the owner.

4.2.1 Location and characteristics

The PV installation is designed to cover over half of the current electricity consumption, thus an installation of 6,72 kWp is needed. The system is going to be located in a household in Valencia, Spain. Due to the unfavorable regulatory framework (none compensation is received from the electricity feed into the grid), a storage system will be acquired in order to store the surplus of electricity during peak sun hours. It is estimated a serviceable life for the PV system to be 30 years.

4.2.2 Regulatory framework

The Royal Decree Law (RDL) 1/2012 suppressed the financing support (i.e. feed-in-tariff) to all new electricity generation facilities within the special regime, which includes renewable energies, cogeneration and waste. Thus, such technologies only received the market price for the electricity produced. Afterwards the Royal Decree (RD) 413/2014 eliminated the concept of the special regime, so renewable energies are assessed as the rest technologies in the market. They are evaluated according to their implication on the electric system instead of for the installed capacity. The reason behind this RD was the wide penetration of renewables on the systems. This RD includes generation facilities with installed capacity above 100 kW installed.

In 2015 a RD was published in order to provide a regulation for self-consumption installations. The RD 900/2015 imposes fees to the generation and capacity installed at almost all self-consumption facilities, aiming to confront the cost and tariff deficit[10] in the Spanish electric system. All the installations below 10 kW or located in the Canary Islands, Ceuta or Melilla are exempt of paying the variable fees, but they do need to pay the term related to power installed. Within this regulation are

[10] The Spanish electric systems have acquired a debt due to several decisions that have been taken since 2002: nuclear moratorium, subsidies to renewable (PV technology has the greater implications), limitation to the price of the consumer, etc.

considered all the installations with capacity installed below 100 kW connected to the grid, off-grid systems are not considered.

4.2.3 Investment

The installation will include twenty-four PV modules of 336 watts each and the Ampere tower, which is a compact unit that includes the inverter, batteries and monitoring system. Moreover, the Ampere tower includes a software that allows buying electricity from the grid when the price is low. The total budget of the PV system is 14.610,40 €, which breakdown cost is presented in Table 23. Moreover, it would be necessary a reinvestment on the Ampere Tower during the year 15th of operation[11].

Components	Cost [€]
PV modules	2822,4
Ampere Tower	7600
Structure	1680
Electric system	1008
Installation	1500
Total (VAT included)	**14610,4**

Table 23 Breakdown cost of the residential PV system in Valencia, Spain
Data from: Ampere Energy

It is important to mention the weight of the Ampere Tower over the total cost, which represents more than 50%. The high cost of this device is explained by two reasons: first, its innovative features that are pioneering in the market and second, the extra cost of the storage system. Therefore, the price of the installation cannot be directly compared with the values presented in Table 7. The overnight cost of the installation equals 2,17 €/W, which would be considerably lower if only an inverter would be placed.

4.2.4 Revenues and operating costs

The only source of revenue comes from the savings in the electricity bill due to consumption of electricity from the PV panels. In this sense, it is necessary to estimate the amount of electricity that would be extracted from the solar source. The information regarding the installation has been provided from a pre technical study done for the PV installation[12], which concludes that the household will be able to produce 8.740 kWh in the first year of operation. The annual production for the following years will be calculated taking into account a degradation rate of 0,5%. Therefore, the electricity saved yearly by the household will be the annual production minus the parasitic consumption. The total electricity saved in the first year of operation is equal to 8.477,8 kWh. Although it will not be possible to consume all the produced electricity instantly, the surplus will be stored in the batteries and consume

[11] Value provide by the manufacturer (Ampere Energy)
[12] The company assessing the technical viability of the project performed the technical study.

during not production periods. Consequently, the annual revenue each year will be the electricity saved yearly times the price of the electricity consumed (Table 24). As a consequence of the decrease in electricity production, the revenues are being reduced annually. In this household, the variable price of the electricity is equal to 0,153 €/kWh. In addition, there is an electricity tax to consumers (5%) and the VAT (21%). Thus the final price of the electricity consumed results in 0,193 €/kWh.

Regarding the operating expenses, it has been considered (as in the previous case study) 1% of the overnight cost of the installation as the O&M cost of the system. These expenses will grow annually at a rate of 1% in order to account for the larger probability of component failure (Table 24). In addition, due to the new regulation for self-consumption (RD 900/2015), installations with storage systems have to pay an annual fee. This fee is equal to 9 € times the maximum generation capacity of the installation, which is considered equal to the installed capacity (for simplicity purposes). Therefore the annual cost of having batteries will be around 60 €.

Revenues & Operating expenses	1	2	3	4	…	15	16	(…)	30
Revenues [€]	1391,2	1384,3	1377,3	1370,4	…	1296,9	1290,4	(…)	1203,0
Operating expenses [€]	206,5	208,6	210,7	212,8	…	237,4	239,8	(…)	275,6

Table 24 Annual revenues and operating expenses during the serviceable life of the installation

4.2.5 Financing

The PV system will be fully paid by the owner, who is not planning to ask for a loan unless a commercial bank provides good financial conditions. Therefore, the calculation of the WACC in the base case scenario only considers the cost of equity. In this sense, the risk free interest rate is equal to 2,957%, which represents debt bonds for 30 years offered in the last tender of 2017 by the Spanish Government. Regarding the subjective risk premium, it has been considered the same rate as in the Portuguese case (1,27%). Consequently, the total cost of equity equals 4,23%, which in this case is equal to the WACC. The inflation rate considered in the calculation equals 1,5%. Although the cost of debt is not relevant in the calculation of the base case scenario, it is calculated within the sensitivity analysis the influence of such factor over the profitability. Therefore, it has been considered a value of 7,18%, which is the effective annual rate of loans for investments in a PV installation of single-families.

4.2.6 Externalities

In this case, it would be considered as the cost of emitting CO_2 the price of the emission trading system of the European Union (EU ETS), which is equal to 5 €/Tn. CO_2 (World bank, 2017). In addition, 0,340 kgCO_2 are emitted in Spain for each kWh of electricity generated ("Live CO2 emissions of electricity consumption", 2017; "Overview of electricity production and use in Europe", 2016). Thus, the externalities cost in this project is calculated using Equation 22.

$$Ex_t = E_t \times 0{,}340 \times 0{,}005 \qquad (22)$$

4.2.7 Input values

Table 25 shows the values considered in the calculation of the base case scenario of the PV system.

Inputs	Units	Symbol
Installation type	-	B&NS
Capacity installed	kWp	6,72
Electricity generated	kWh	8740
Annual degradation rate	%	0,5
Useful life	years	30
Price of electricity consumed	€/kWh	0,193
Price of electricity sold	€/kWh	-
Initial investment	€	14610,4
Start operations	year	1
Operating expenses (Year n)	€	208,25
Annual increase in operating expenses	%	1
Corporate tax rate	%	0
WACC	%	4,23
Real discount rate	%	2,69
Inflation	%	1,5
Investment subsidies	€/kWp	0
CO_2 avoided	$kgCO_2/kWh$	0,340
Social cost of CO_2	$€/kgCO_2$	0,005

Table 25 Input data of the residential PV installation in Valencia

4.3 Wind farm La Castellana in Argentina (case 3)

It is presented the data used in the calculation of the base case scenario of the wind farm in Argentina. Some of the values introduced in the model are based on assumptions due to confidentiality issues when obtaining the real data. Thus, it might not reflect 100% the real situation.

4.3.1 Location and characteristics

The Castellana wind project will add 99 MW of renewable energy to the Argentinean generation mix. The wind farm will be located south of the province of Buenos Aires, 36 km northwest of the city of Bahia Blanca. It has signed a power purchase agreement (PPA) for 20 years with the wholesale electric market administrator (CAMMESA), which will pay a bidding price of 61.50 $/MWh for the electricity injected into the national interconnection system. The construction of the project started the first quarter of 2017 and the construction period is expected to last for 18 months.

4.3.2 Regulatory framework

The Law 27.191, which supports the use of renewable energies, was approved in 2015. This law aims to achieve an 8% of the total electricity production from renewables by 2018 and a 20% in 2025. Moreover, this regulatory framework allows planning, in the long run, providing more confidence to investors.

4.3.3 Investment

The investment of the wind farm includes the cost of 33 wind turbines of 3 MW each, the civil work (mainly roads and foundations), the electrical work (cabling, interconnection and substation) and other costs (viability studies, project management, etc.). The breakdown cost of each part is presented in Table 26, which sum is equal to 121.894.494 €. The investment it is done in two stages, at the beginning (year 0) it has been paid the expenses related to launching the project (licenses, taxes and technical studies). In the initial investment will be also paid 30% of the main equipment, which also accounts for the transportation and assembly costs of the turbines. The rest of the investment, 70% of main equipment plus the civil and electric work and other expenses will be paid in the first year.

Components	**Cost [€]**
Technical studies and licenses	1.002.647
Main equipment (wind turbines, includes installation and assembly)	83.948.874
Civil work	12.678.923
Electrical work	13.727.145
Others	10.536.905
Total (VAT included)	**121.894.494**

Table 26 Breakdown cost of the wind farm in Argentina

4.3.4 Revenues and operating costs

The sole source of revenues for the wind farm is the sale of electricity. It is considered that all the electricity produced by the power plant will be sold to the grid at 56,06 €/MWh[13]. Therefore, the source of revenue of the project is assured while the wind farm produces electricity. The capacity factor of the wind farm is 50,6% (P50), which results in an annual production of 439,5 GWh. Thus, taking into account the losses and the parasitic consumption (i.e. the consumption of the equipment used within the wind farm), the total electricity sold to the grid is equal to 408,375 GWh. It is estimated that this production will remain until the fourth year of operation, then it will be considered some losses

[13] Electricity price in €/MWh, using the average exchange rate in 2017 (1€-0,911497)

in generation equal to 0,2%. These losses in electricity generated are caused by the degradation of the equipment over the years. Some of the factors that affect these losses are: hysteresis due to wind gust; degradation, soiling and freezing of the blades; overload or failure in the electrical network; and machine downtime (Gómez *et a*l., 2010). Consequently, after applying this degradation coefficient the electricity sold to the grid the last year will be 395,8 GWh.

Regarding the operating expenses of the wind farm, it has been estimated that the annual cost will be equal to 45€/kW (Wiser et al., 2016; Rehfeldt et al., 2013). Within this cost is included the lease of the land, insurance, administrative cost and maintenance and replacement of equipment. The unscheduled replacements caused by breakages are not included within this cost. Thus, the operating expenses will be incremented annually by 1% in order to account for the unexpected replacement of equipment.

4.3.5 Financing

The wind farm is financed by the company (shareholders) and by a loan. In order to calculate the expected return of the project, it has been used the real WACC determined by the *Ente Nacional Regulador de la Electricidad* (ENRE). This entity through the regulatory files Nº 0493/2016; Nº 79/2017 has defined the real rate of return of the companies in the electricity business in Argentina. This rate is considered, according to the Law Nº 24.065, similar to the average rate within the industry. Therefore, the real rate of return after taxes considered for the base case scenario is equal to 8,04%. Moreover, this value has been compared with other real discount rates used in other South American countries (Table 27).

Country/Company	Real WACC after taxes	Real WACC after taxes
Uruguay	8,8%	13,5%
Colombia	8,6%-9,3%	13,0%-13,9%
Brazil	8,1%	12,3%
Peru	8,4%	12%
Chile	8,3%	10%

Table 27 Real WACC before and after taxes for different countries in South America and Argentinean Companies
Source: *Propuesta para la tasa de retribución del capital*, 2016

Although 8,04% will be the real discount rate employed in the calculation of the profitability of the project in the base case scenario, it will be analyzed how different rates affect the profitability of the project in the sensitivity analysis.

4.3.6 Externalities

In this case study, it is not calculated the avoided social cost associated with the production of electricity with the wind farm because there is not any carbon pricing system implemented in Argentina.

4.3.7 Input values

The input data employed for the calculation of the base case scenario of the wind farm in Argentina are summarized in the following table.

Inputs	Units	Symbol
Installation type	-	Onshore wind
Capacity installed	kWp	99.000
Electricity generated	kWh	439.500.000
Annual degradation rate (after 4th year)	%	0,2
Useful life	years	20
Price of electricity consumed	€/kWh	-
Price of electricity sold	€/kWh	0,05606
Initial investment	€	121.894.494
Start operations	year	2
Operating expenses (Year n)	€	4.356.000
Annual increase in operating expenses	%	1
Corporate tax rate	%	35
WACC	%	-
Real discount rate	%	8,04
Inflation	%	-
Investment subsidies	€/kWp	0
CO_2 avoided	$kgCO_2/kWh$	-
Social cost of CO_2	$€/kgCO_2$	-

Table 28 Input data of the wind farm in Argentina

5 Discussion of the results

Within this chapter the financial parameters of the different case studies are presented. Moreover, a sensitivity analysis is performed in order to analyze the variability of the profitability parameters when the input data varies in a certain range. This analysis is performed in order to assess different possibilities due to uncertainty in some input data like electricity generation, the price of electricity or O&M cost. And also to assess how some factors (e.g. installation cost, structure of financing, etc.) affect the output parameters of each project. The sensitivity analyses consider variations within the range from -50% to 50%, with 10% increments. It is calculated the influence of these factors over the NPV, IRR and LCOE.

5.1 Discussion case 1

The results obtained in the base case scenario of the PV system installed in Portugal are summarized in Table 29. The inflows and outflows of the project during its serviceable life are included in the annex. From these results, it is obtained a NPV equal to 5.812,61 €, which means that future net cash flows worth more than the initial investment making the project profitable. Another value that clearly states the profitability of the project is the IRR, which value in nominal terms (20,24%) is far above the nominal rate of return demanded by the investor (3,5%).

Parameter	Output
Installation type	(2) PV system with no batteries nor compensation from the grid
NPV	5.812,61 €
Real IRR	18,47%
LCOE	0,067 €/kWh
LCOE (externalities)	0,062 €/kWh

Table 29 Results of the financial and economic analysis of the base case scenario of the PV system in Portugal

Furthermore, the total cost of producing 1 kWh of electricity over its serviceable life is equal to 0,067 €. Nevertheless, this cost is calculated over the total electricity produced by the system and not over the total electricity consumed. Thus, the total cost of consuming 1 kWh of electricity over its useful life is equal to 0,074 €. This value still far below the price paid for each kWh of electricity consumed (0,2018 €). The difference between these two values is what makes the PV installation profitable because the owner is saving almost 12,7 c€ each kWh consumed from solar energy. Moreover, it has been calculated the LCOE including the positive externalities of avoiding CO_2 emissions, which value is 0,062 €/kWh.

In Figure 19 are presented the cumulative cash flows during the operating lifetime of the project. Thus it can be appreciated the moment in which the sum of cash inflows overcomes the initial investment of the project. This occurs during the sixth year of operation of the PV system, which represents the discounted pay back period of the project. During the year 13th it can be appreciated a change in the tendency of the cumulative cash flows, it is caused by the reinvestment in the inverter.

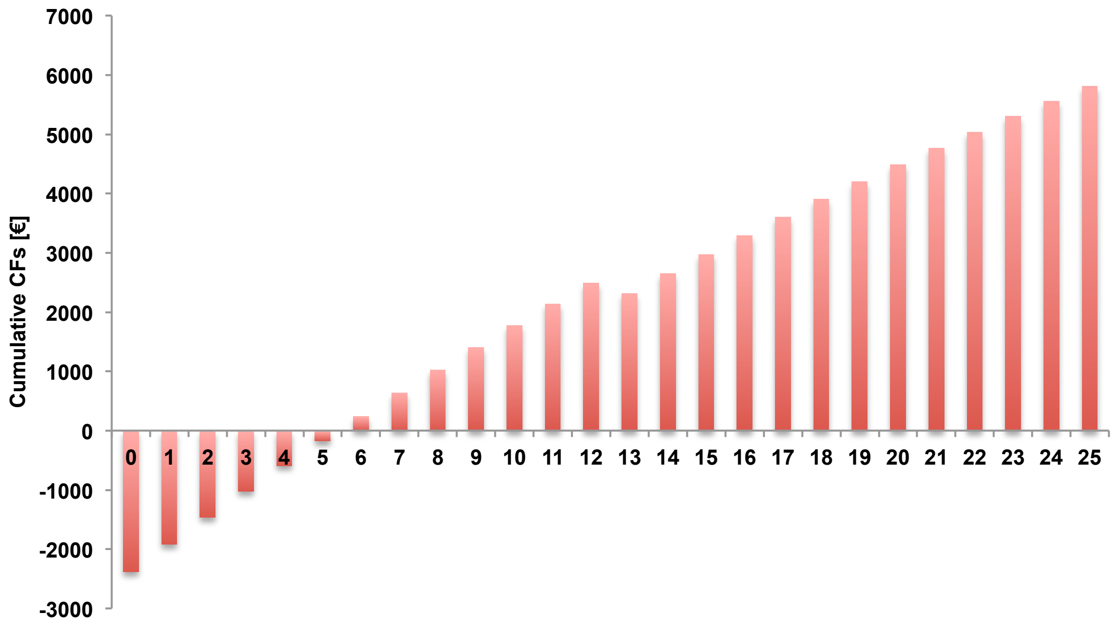


Figure 19 Cumulative cash flows of the residential PV system in Portugal

Regarding the sensitivity analysis performed within this project, the following variables have been considered: percentage of financing that is debt, installation cost, electricity price, electricity production and O&M cost. Although the installation cost and financing of the project are clear because the installation is already constructed, it has been considered important to see how the project would have been affected by these factors. The rest of variables considered in the sensitivity analysis have been selected because its unpredictable nature (i.e. these values might change due to variations in weather, regulation, technology performance…). Thus it is important to analyze the possible results under such scenarios. The weight of each factor on the financial results varies widely.

The first factor analyzed is the installation cost. It has been defined a range of variation from 1.191,2 € to 3.573,6 €. The results obtained are shown in Figure 20. If the overnight cost of the installation were increased by 50% the project would be profitable with a NPV of 4.102,4€ and a nominal IRR of 12,21%, a value significantly above the opportunity cost of capital. Moreover, the LCOE varies between 0,034 and 0,101 €/kWh (Figure 21) when there are relative percentage variations of -50% and 50% of the installation cost.

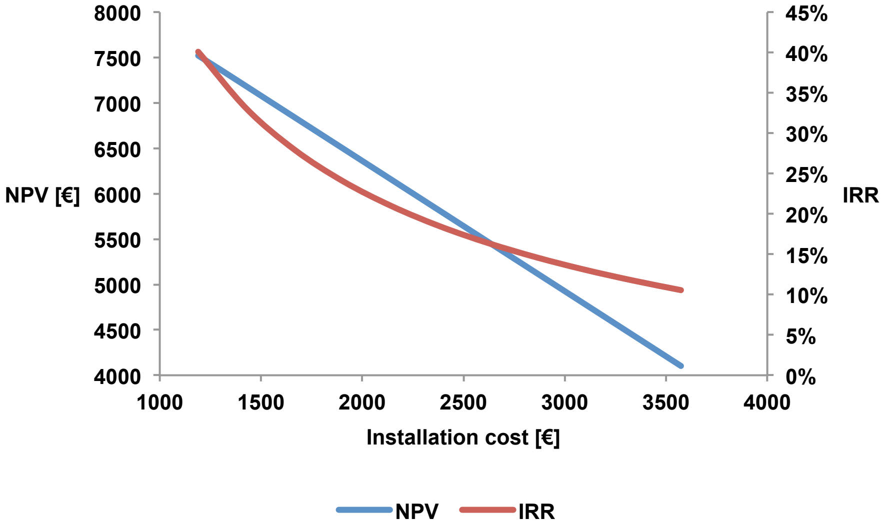


Figure 20 Variations of the NPV and IRR with the installation cost in the PV system of Santarém

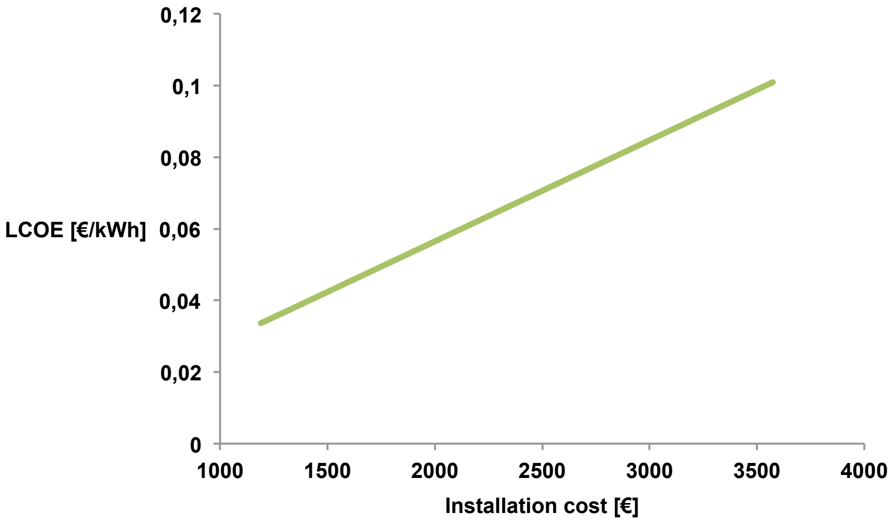


Figure 21 Variations of the LCOE with the installation cost in the PV system of Santarém

In order to analyze the impact of the electricity price over the financial results of the project, it has been computed the model for different prices of electricity. The prices considered ranged from 0,101 to 0,303. These fluctuations in the price of electricity might be caused by several factors like variations in the fuel cost of the technologies feeding the grid, higher implementation of the renewables, etc. Accordingly, it has been analyzed the variations of NPV and IRR with the electricity price (Figure 22). It is remarkable that even when the electricity price is reduced by 50%, the project remains profitable with a NPV equal to 1.216 € and IRR of 6,23%. This result is mainly explained by the small investment required, 1,53 € per watt installed, and the high solar resource in the location (1700 kWh/kWp year). Both combined together provide good profitability indexes under a wide range of conditions. In fact, the electricity price below which it would make the project unprofitable is 0,0743 €/kWh, which is a reduction of 63% from the BCS. Moreover, the variation of the LCOE is not performed because the changes in electricity price do not affect the LCOE calculations (i.e. the LCOE remains constant).

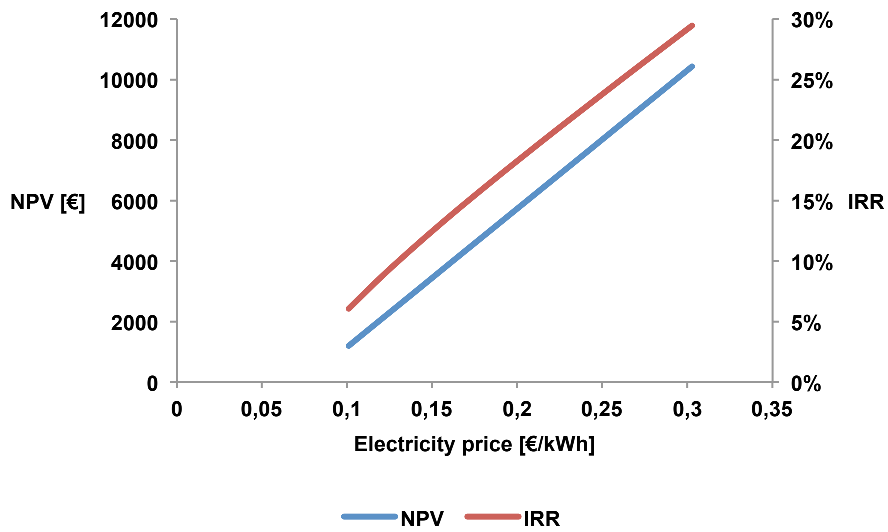


Figure 22 Variation of the NPV and IRR with the electricity price in the PV system of Santarém

Likewise, it has been performed the same sensitivity analysis for electricity production. The electricity production is affected by external conditions like irradiance, temperature and dust (see Chapter 3.1.1), resulting in unpredictable amounts of electricity produced. The variations of NPV and IRR are not presented because the results obtained are equal to the ones presented above (Figure 22). Thus, electricity price and electricity production affect equally to the NPV and the IRR of the project. Meanwhile, variations in the electricity output affect the LCOE, Figure 23 shows the parabolic reduction of the LCOE with the increase in electricity production. As expected, the profitability of the project would be compromised if the electricity production is reduced below 1010 kWh (in year 1), which corresponds again to a reduction of 63% from the BCS.

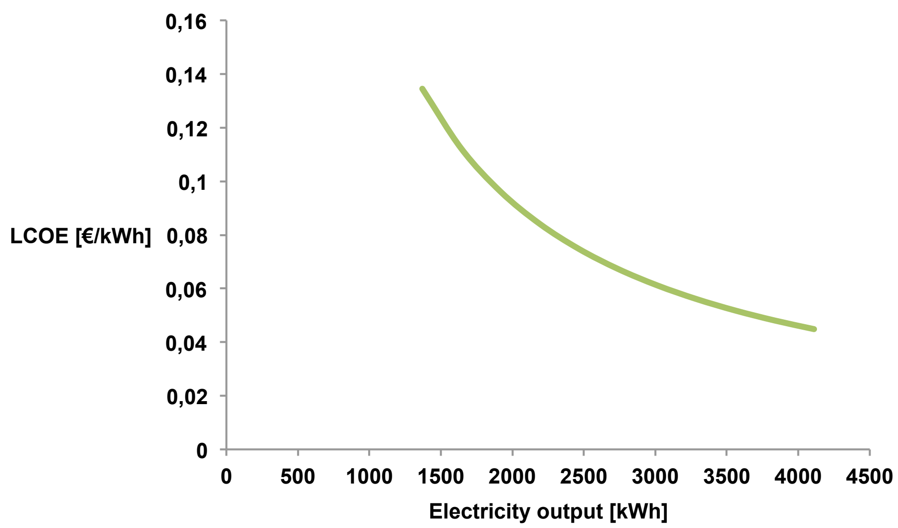


Figure 23 Variation of the LCOE with the electricity production of the PV system in Santarém

Regarding the O&M cost of the installation, it has been assumed a 1% of the overall cost of the installation, which is reasonable for roof top installations. However, this value might increase due to unexpected circumstances (breakage of machinery, intensive cleaning due to dust deposition, etc.). Therefore, it has been performed an analysis for a range of O&M cost from 7,64 €/kW to 22,91 €/kW. The results obtained slightly affect the financial parameters (Figure 24). Likewise, the LCOE suffers smooth variations with the operating expenses (Figure 25).

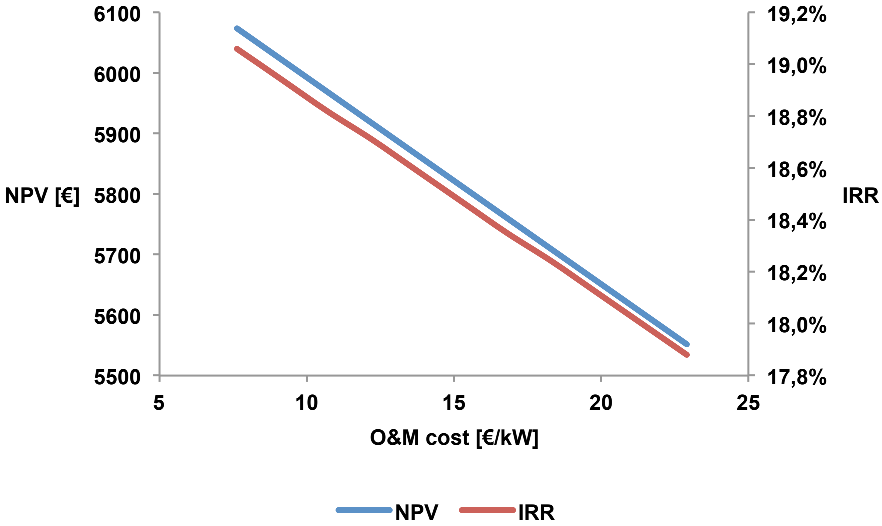


Figure 24 NPV and IRR variations with the O&M cost of the PV system in Santarém

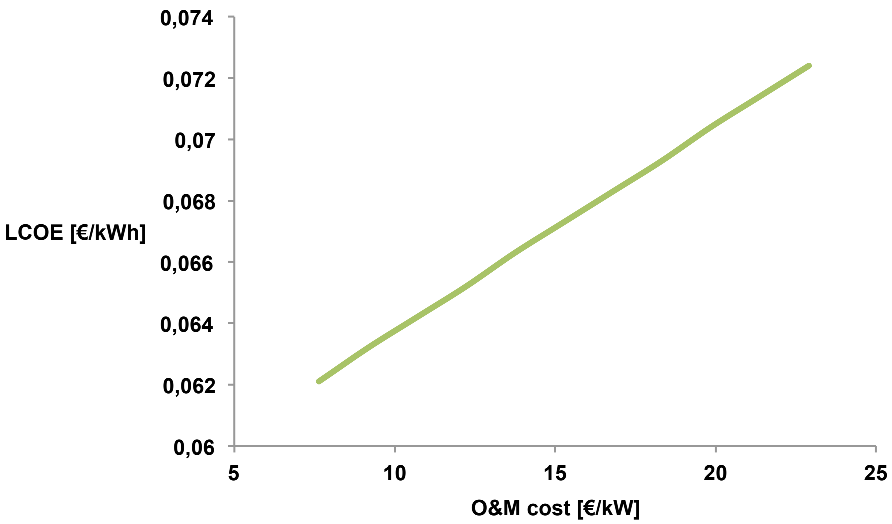


Figure 25 LCOE variations with the O&M cost in the PV system of Santarém

Finally, it has been analyzed how the financial outputs vary with the percentage of financing that is debt, from 0% to 100% debt is represented in Figure 26. Regarding LCOE variations, the values are linearly increased with the percentage of debt, achieving its maximum value around 0,08 €/kWh when the project is completely financed by debt. On the contrary, the NPV has reduced accordingly with the increase of debt. The financial parameters suffer slight variations with the percentage of financing that is debt. This is because by varying the percentage of financing that is debt, it is being modified the nominal rate between 3,5% and 5,89% (i.e. from 0% to 100% debt). Thus, this range is still far below the nominal IRR (20,44%).

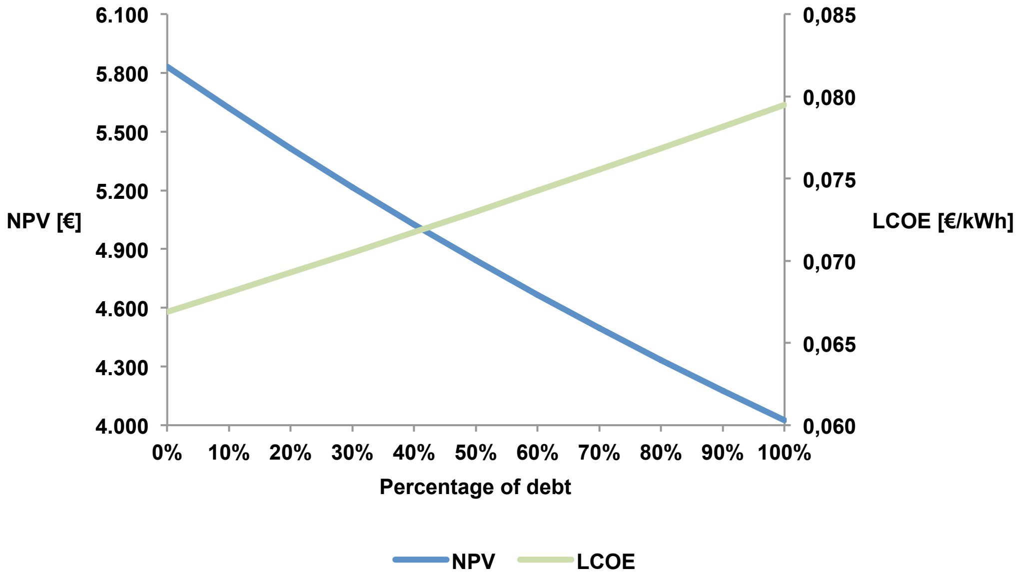


Figure 26 Variation of the NPV and LCOE with the percentage of financing that is debt in the PV system of Santarém

Therefore, it is unlikely that the profitability of the PV installation in Santarém will be affected by variations in energy output, electricity price or O&M costs. Moreover, it can be concluded that installation cost, electricity output and electricity price have the greatest influence over the profitability and cost indexes. The NPV is more affected by variations in the electricity price and electricity output, resulting in relative percentage variations up to 79%. Meanwhile, the IRR is more influenced by the installation cost, which entails relative percentage variation up to 117%. Regarding LCOE variations, electricity output entails the strongest influence with relative changes up to 100%.

5.2 Discussion case 2

The results of the financial and economic analysis of the base case scenario of the residential PV system located in Valencia are presented in the annex and summarized in Table 30. It can be concluded that under these conditions, it would be profitable to invest in the project because it yields a NPV equal to 6.884,8 €. However, it would be necessary to compute a sensitivity analysis over some variables because the difference between the nominal IRR (7,92%) and the WACC of the project (4,23%) is small, thus changes in the electricity output, installation cost and cost of financing will affect the profitability of the project. The main reason behind the smaller profitability indexes obtained in the project is the small difference between the cost of the electricity consumed (0,1507 €/kWh) and the price of the electricity consumed (0,193 €/kWh).

Parameter	Output
Installation type	(1) PV system with batteries and no compensation from the grid
NPV	6.884,8
Real IRR	6,33 %
LCOE	0,146 €/kWh
LCOE (externalities)	0,144 €/kWh

Table 30 Results of the financial and economic analysis of the base case scenario of the PV system in Spain

Regarding the calculation of the LCOE, when the externalities are not included in the calculation the cost of producing 1 kWh over its useful life is equal to 0,146 €. This value is slightly larger than the LCOE including the externalities, 0,144 €/kWh. The difference between these two parameters is small due to the relatively low emission factor in the Spanish system and little amount of electricity produced over its serviceable life. Finally, Figure 27 shows the cumulative cash flows during the length of the project. The investment is not recovered until the 19th year of operation, thus this project can be categorized as a risky investment. The swift from positive to negative cash flows experienced from the year 14th to 15th is due to the reinvestment in the Ampere Tower.

It is important to point out that within the financial analysis is not being considered the savings obtained due to the innovative function implemented in the Ampere Tower. This function allows buying and storing electricity from the grid when the price of electricity is cheaper. Thus, the financial parameters obtained in the project would be slightly better.

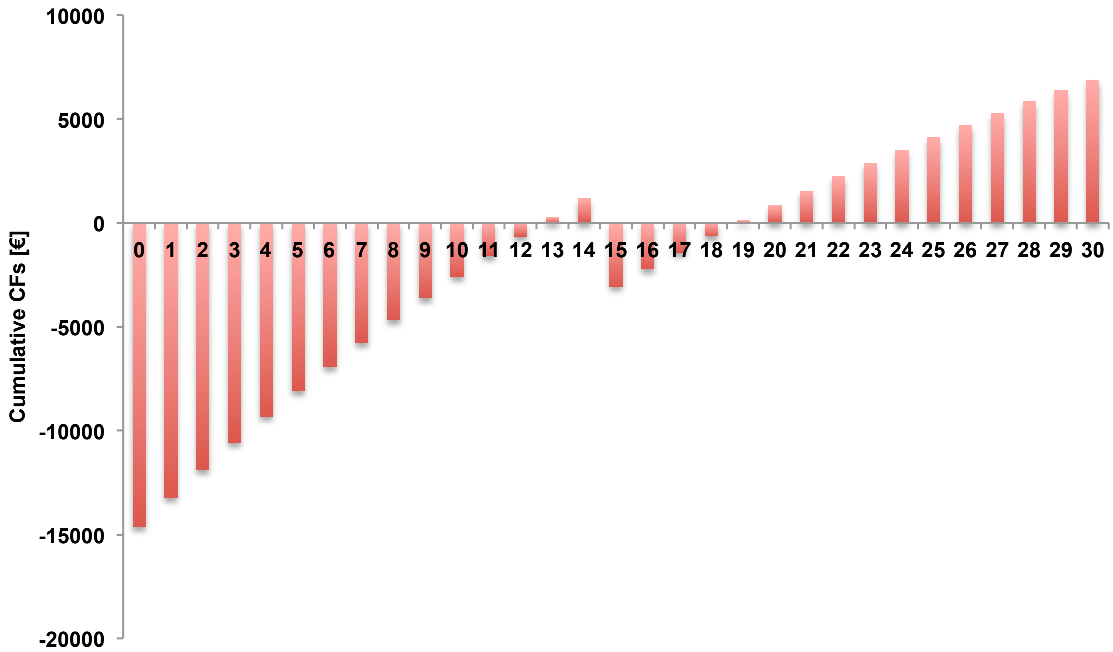


Figure 27 Cumulative cash flows of the PV installation in Valencia

As a consequence of the results obtained, it is necessary to elaborate a sensitivity analysis over the most likely values to suffer variations. Accordingly, it has been considered for the evaluation the following variables: installation cost, the percentage of financing that is debt, electricity production, operating expenses and electricity price. Regarding the installation cost and financing, it is not completely determined the initial investment and whether this cost will be completely paid by the owner or partially financed by a commercial bank. Thus, it becomes important to analyze the possible results under such variations. Likewise, electricity production, electricity price and operating expenses are values subjected to a certain degree of uncertainty, which can affect the profitability of the project.

The first parameter analyzed is the overnight cost of the installation. Consequently, it has been defined a range of variation from the BCS. The results obtained are shown in Figure 28. It can be concluded that if the overall installation cost is increased by 30% (18.993,5 €) the profitability of the project will be compromised, yielding a negative NPV and a nominal IRR of 4,21%, below the expected rate of return of the investor (4,23%). On the contrary, if the installation cost is reduced by 50% the IRR and NPV will be increased up to 19,09% and 18.437,2 € respectively. Regarding the LCOE, its range of variation ranged from 0,077 €/kWh to 0,215 €/kWh (Figure 29).

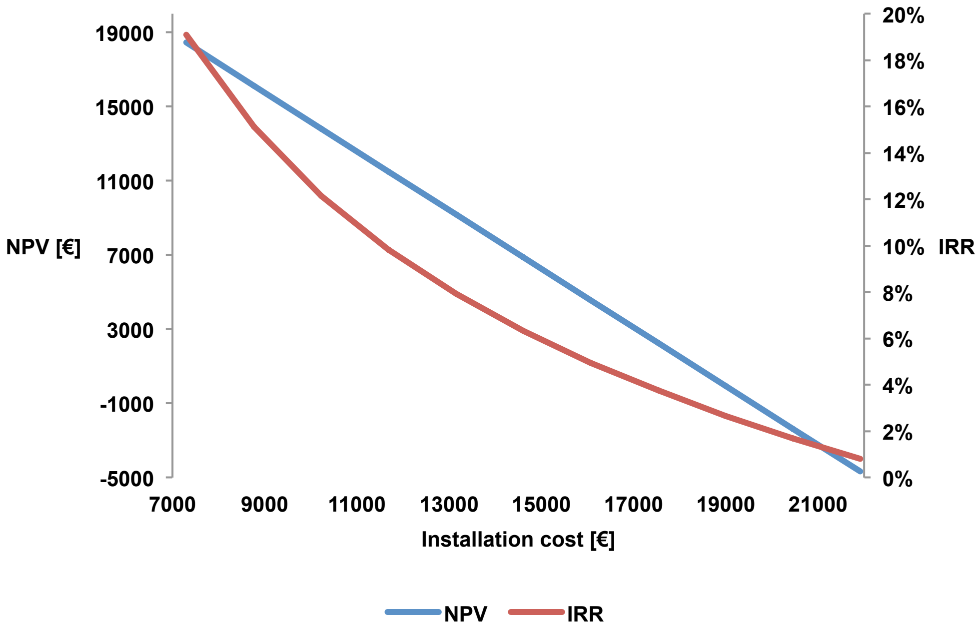


Figure 28 Variation of the financial parameters with the installation cost in the PV system of Valencia

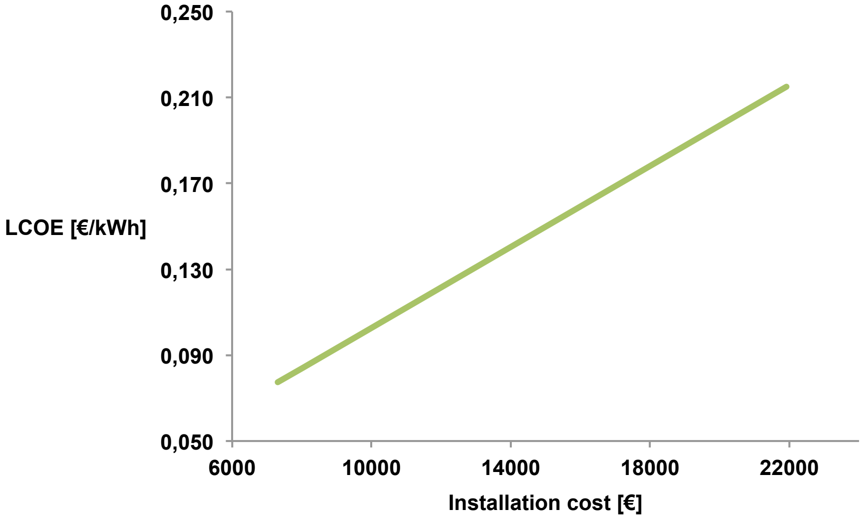


Figure 29 LCOE values with the variation of the installation cost in the PV system of Valencia

The annual electricity output is another important variable in the study of the economic viability of a project. Thus, it has been analyzed the variation of the NPV, real IRR and LCOE when the annual electricity production varies from the BCS. It has been defined a range of variation between 4.370 and 13.110 kWh. The results obtained for the different cases are summarized in Figure 30 and Figure 31. It can be concluded that the variation of the electricity production remarkably affects the financial parameters of the project. In fact, if the electricity production is reduced by 30% the project will be already unprofitable with a NPV and a real IRR equal to -2.532,61 € and 1,16%, respectively. Moreover, the LCOE (0,209 €/kWh) is above the electricity price.

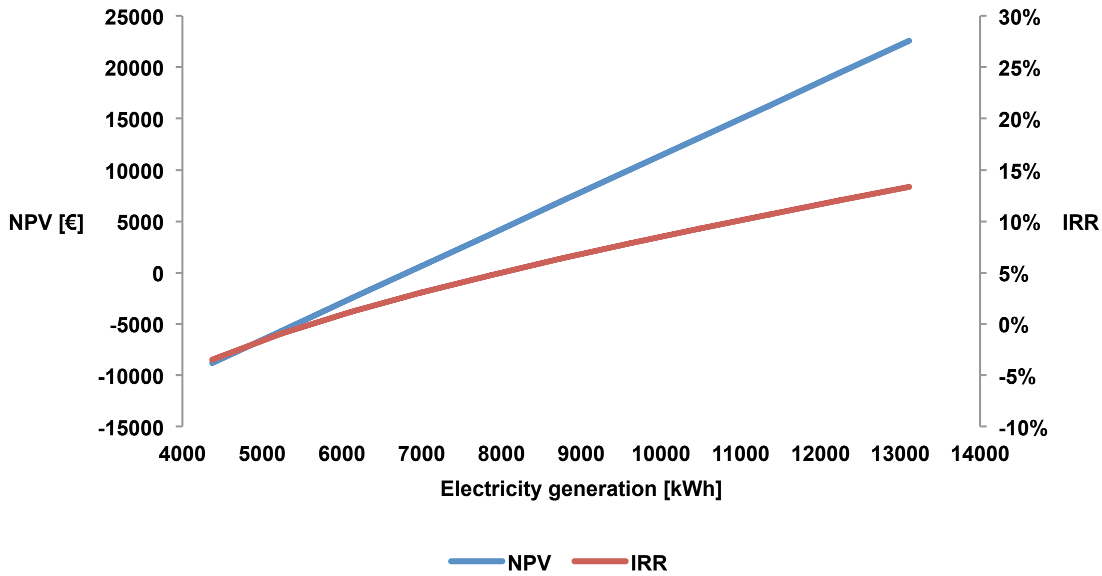


Figure 30 Variation of the NPV and IRR with the electricity generation in the PV system of Valencia

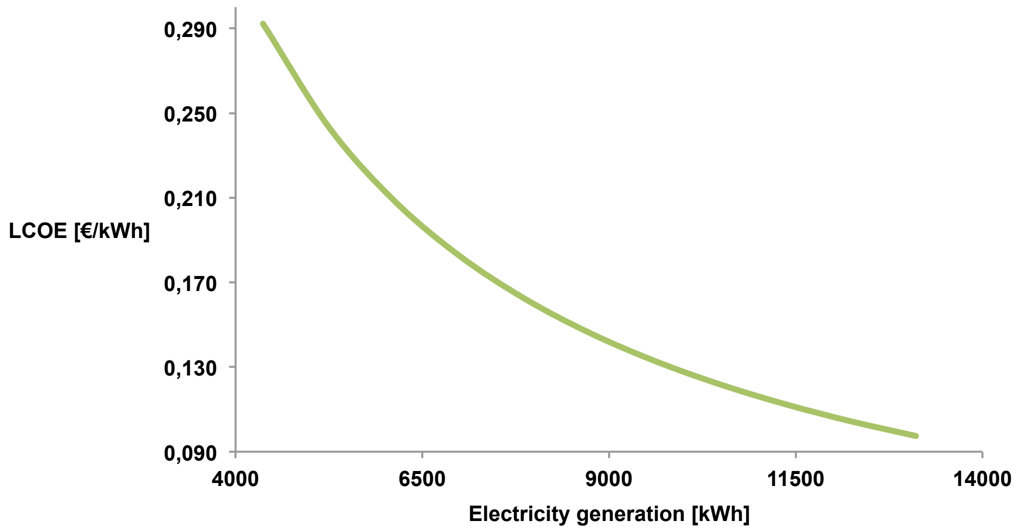


Figure 31 Values of the LCOE with the variation of the electricity output in the PV system of Valencia

Although the owner of the household wants to completely finance the project, it has been considered a possibility to finance the initial investment with a loan. Consequently, it has been analyzed the profitability parameters resulted from the variation of the project debt (Figure 32). The cost of debt considered within the calculations is 7,18%. The results conclude that the project remains profitable even if the project is completely financed. However, the financial parameters are significantly reduced. Therefore, it is strongly recommended for the investor to either finance the project by equity or find better conditions from the moneylender.

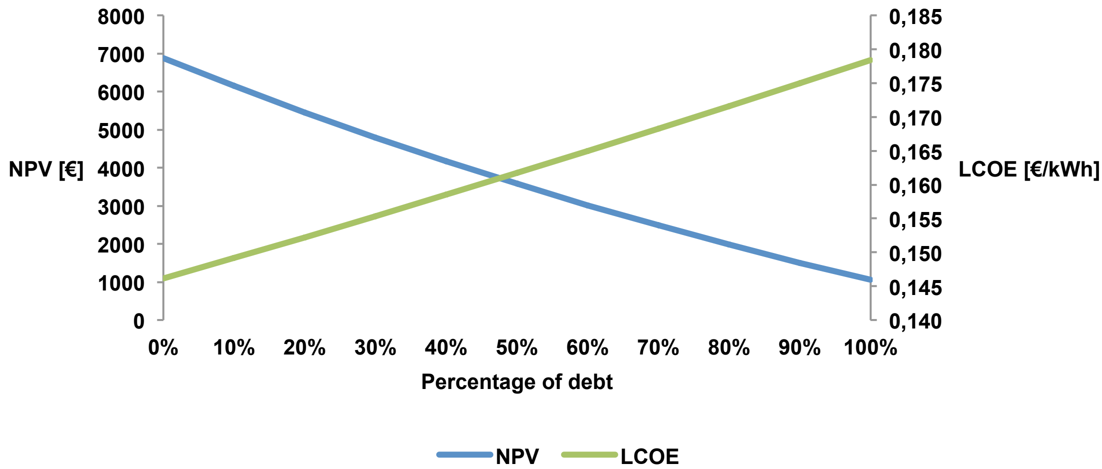


Figure 32 NPV and LCOE over the percentage of financing that is debt in the PV system of Valencia

Finally, it has been evaluated the financial results with the variation of the operating expenses. This factor slightly affects the financial indexes (Figure 33). In fact, the NPV remains positive when the operating expenses are increased by 50%. Meanwhile, the nominal IRR is above the opportunity cost of capital. Regarding the LCOE, small variations result from the variation of the operating expenses (Figure 34).

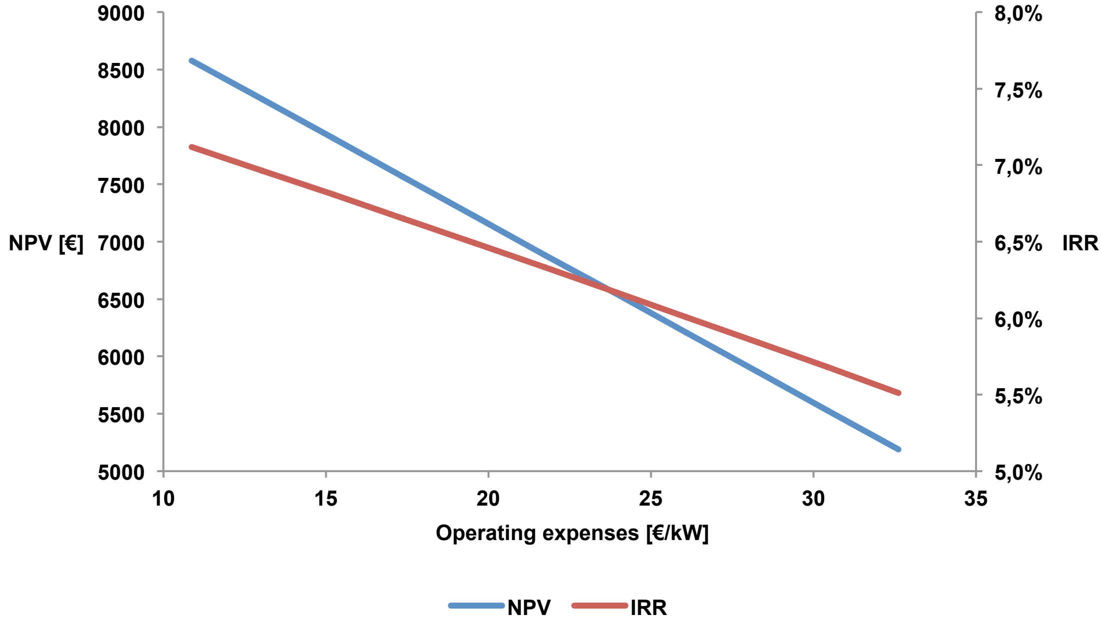


Figure 33 Financial parameters over the annual operating expenses in the PV system of Valencia

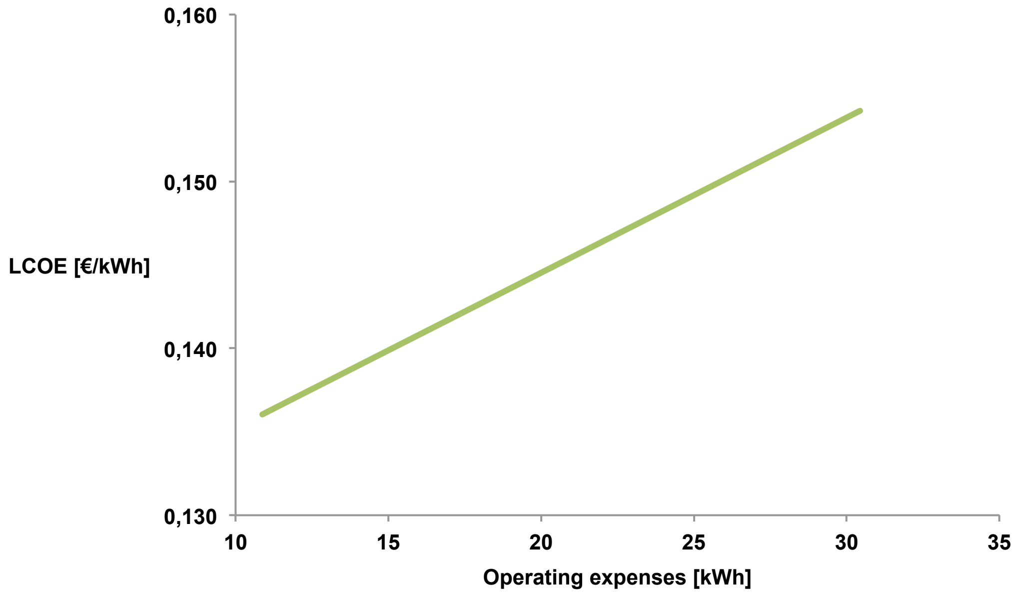


Figure 34 LCOE variation with the operating expenses in the PV installation of Valencia

Therefore, the project is likely to become unprofitable if any of the main factors involved in the project suffers variations. Electricity output and price exercise the greatest influence over the NPV and LCOE. Meanwhile, the IRR is more affected by relative percentage variations of the installation cost.

5.3 Discussion case 3

The inflows and outflows of the project through its useful life are presented in the annex. Table 31 shows the results calculated within the model for the base case scenario of the wind farm in Argentina. Although the positive value obtained for the NPV, 10.297.211,88 €, the small difference between the real IRR (9,22%) obtained and the real WACC used for the project (8,04%) draw attention to the possibility of unfavorable financial results if some of the variables change. Consequently, it would be necessary to perform a sensitivity analysis over the variables that are subjected to some uncertainty like electricity production, installation cost operating expenses and the rate of return used for discounting future cash flows. In this case, the price received for the electricity production will remain constant because is the bidding price agreed in the tender.

Parameter	Output
Installation type	(5) Onshore wind
NPV	10.297.211,88 €
Real IRR	9,22%
LCOE	0,040 €/kWh
LCOE (externalities)	- €/kWh

Table 31 Results obtained from the financial and economic model of the wind farm in Argentina (BCS)

Furthermore, it is possible to calculate the profits the company is making for each kWh feed into the grid by calculating the cost of each kWh sell to the grid. This value is equal to 0,04294 €, which is slightly higher than the LCOE because within its calculation the parasitic electricity and other losses are not included in the total electricity produced over its serviceable life. Therefore, the company is earning 1,312 c€ for each kWh sell to the grid. This profit is enough to make the project profitable. Nevertheless, the investment will be recovered almost at the end of the project lifetime (Figure 35).

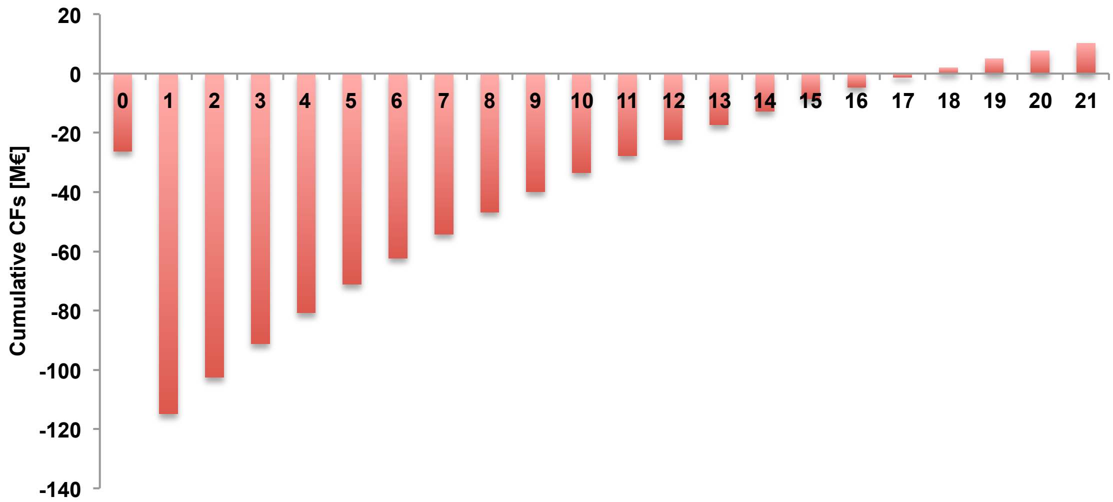


Figure 35 Cumulative cash flows of the wind farm in Argentina

The first factor analyzed in the sensitivity analysis is the installation cost. As a consequence of the size of the project and the many partners involved in the construction, it might increase the final cost of the installation due to problems during the construction (e.g. halts in component supply). Therefore, the profitability indexes are calculated over the installation cost varying between 60.947.247 € and 182.841.741 €. Figure 36 shows a linear negative tendency of the NPV with the installation cost, which value equals 135,1 M€ when the NPV is equal to zero. Thus above 10,8% of the base installation cost, the project becomes unprofitable. Likewise, IRR present a parabolic (negative) variation with the installation cost. Its range of variation with such factor is between 19,7% and 5%. On the contrary, higher installation cost results in larger LCOE for the project, which as shown in Figure 37 vary between 0,027 and 0,059 €/kWh.

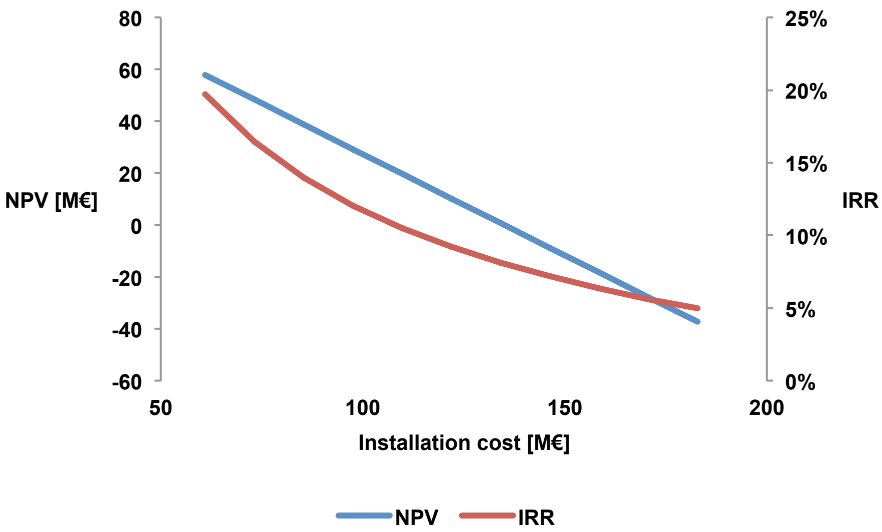


Figure 36 NPV and IRR values over the installation cost variation in the wind farm of Argentina

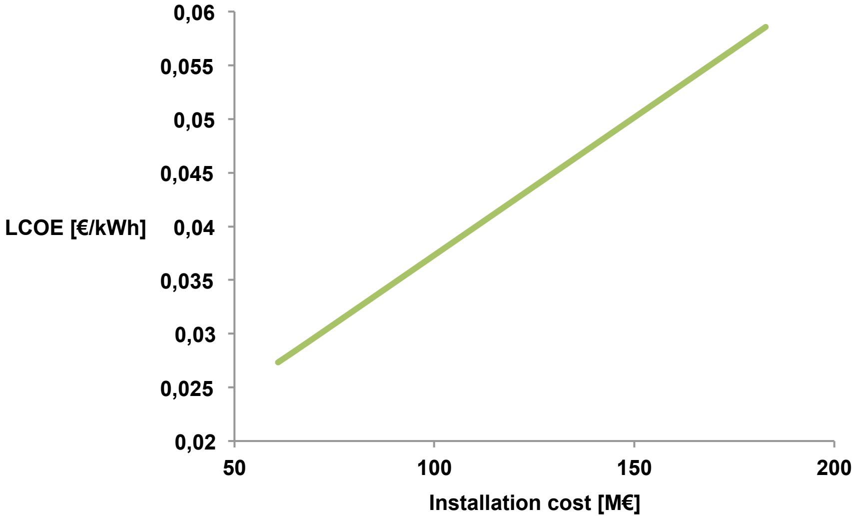


Figure 37 Variation of the LCOE with the installation cost in the wind farm of Argentina

The electricity output of the installation is also a relevant factor in the calculation of the profitability of the installation. Thus, it has been calculated the value of the NPV and IRR when the electricity output varies between 200 GWh and 600 GWh (Figure 38). The NPV is equal to zero when the electricity output is decreased 7,7% (405,5 GWh). Thus, below this production of electricity, the real IRR (8,04%) is under the real interest rate of the project. The LCOE draws a parabolic (negative) variation with the electricity production. The values ranged from 0,086 to 0,029 €/kWh.

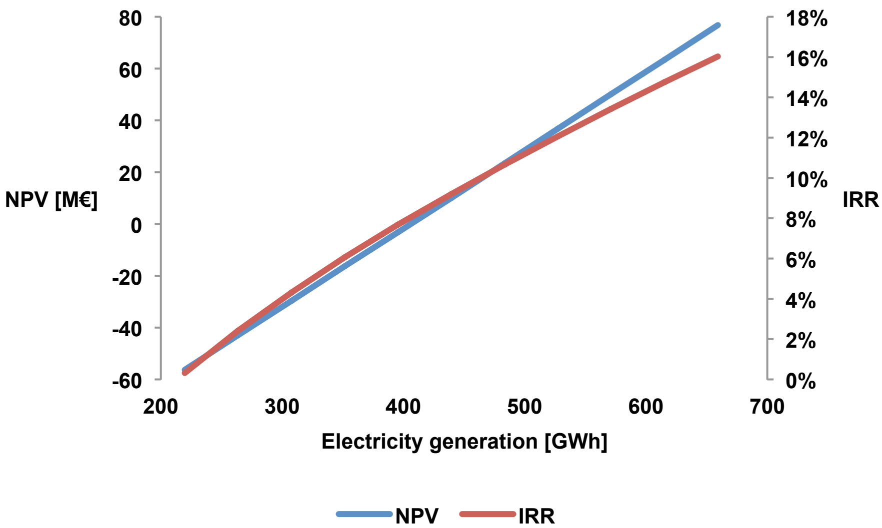


Figure 38 NPV and IRR values according to the electricity generated by the wind farm of Argentina

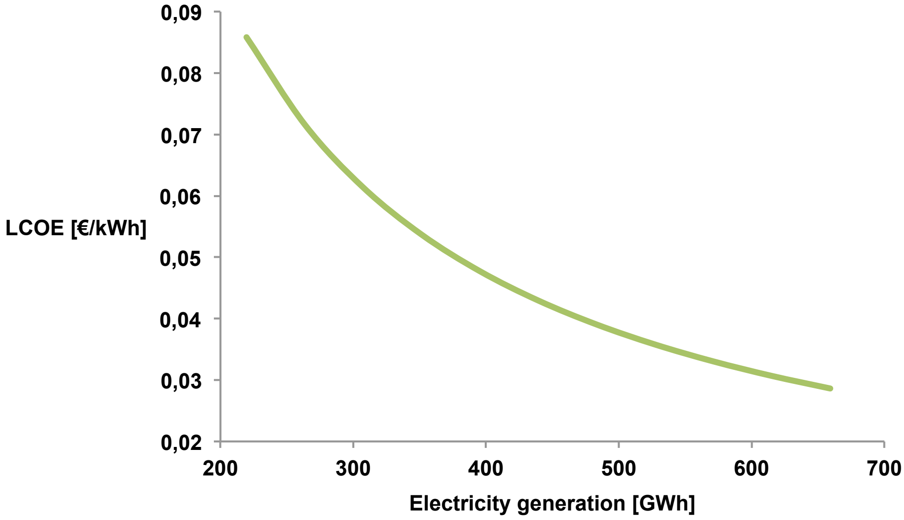


Figure 39 LCOE variations over the electricity generated in the wind farm of Argentina

Figure 40 represents the NPV over the variation of the rate used to discount the future cash flows. The NPV present a parabolic (negative) variation with the real WACC after taxes, which varies between 4,02% and 12,06%. The value at which the profitability of the project is compromised is when the discount rate equals the real IRR of the project (9,22%).

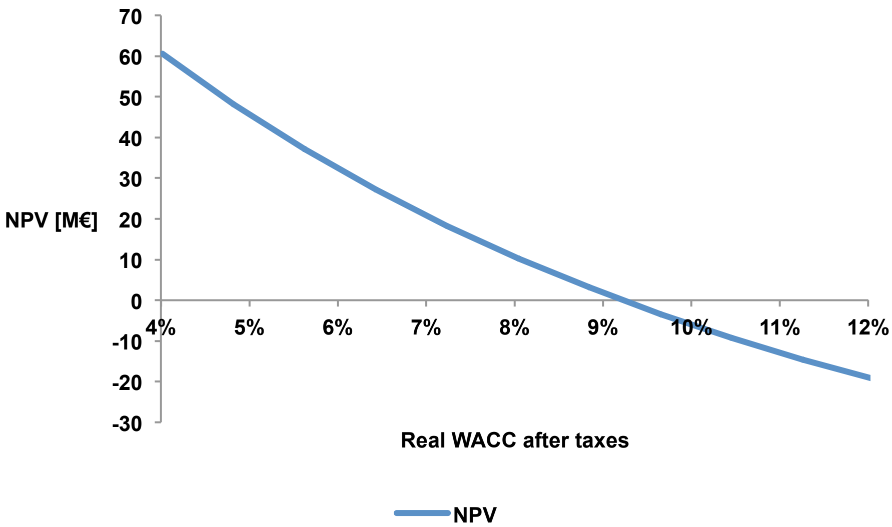


Figure 40 NPV over the real WACC after taxes in the wind farm of Argentina

Finally, it has been analyzed the results obtained when the O&M cost is varied from the BCS, from 22 €/kW to 66 €/kW (Figure 41). The NPV turns to negative values for O&M cost above 60,3 €/kW, which represents a 37% increase from the BCS. Meanwhile, the IRR varies between 7,6% and 10,73%. According to the LCOE, when the lowest value of operating expenses is analyzed the cost of 1 kWh equals 0,037 €. On the contrary, this price is increased up to 0,049 € when the O&M cost is 66 €/kW. Thus, LCOE presents a linear tendency with the operating expenses (Figure 42).

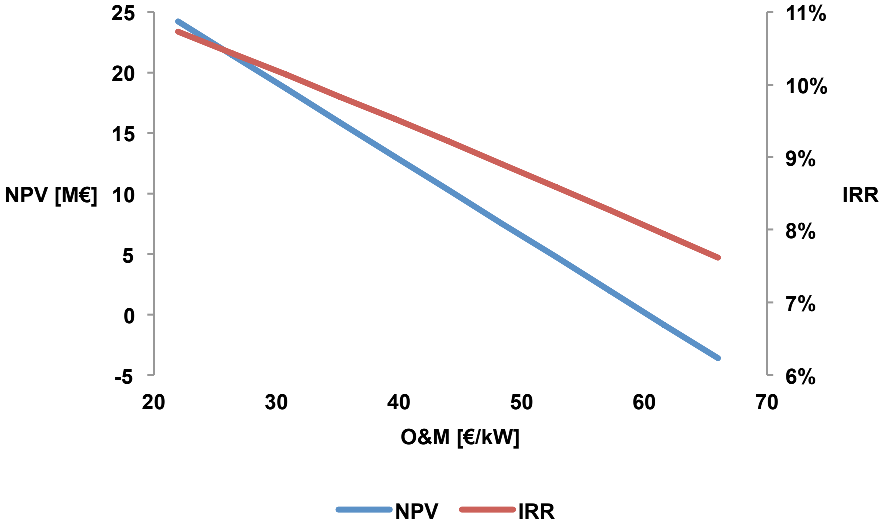


Figure 41 NPV and IRR variations with different values of O&M cost in the wind farm of Argentina

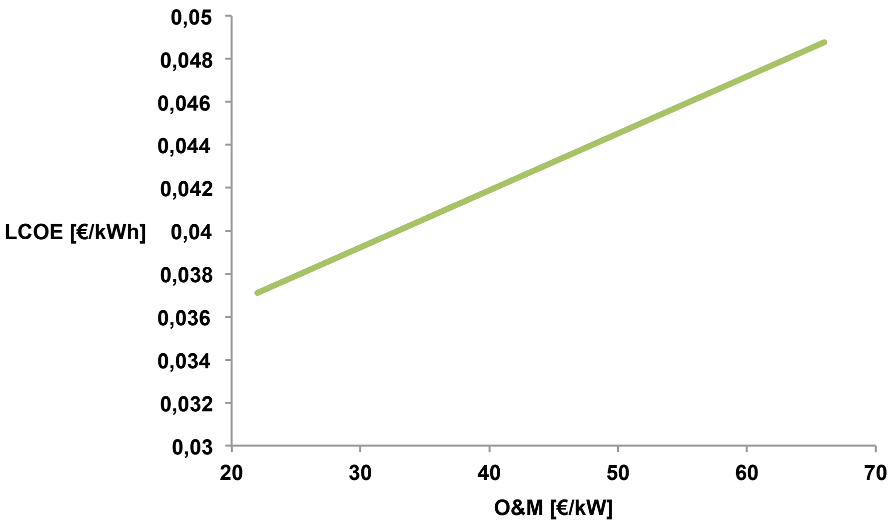


Figure 42 LCOE variations over the operating expenses in the wind farm of Argentina

From the analysis presented, it is clear that the electricity output has the strongest influence over the financial and cost parameters, NPV, IRR and LCOE presented the largest variations when the electricity output is altered. The installation cost and the discount rate have less influence over these parameters. Finally, changes in operating expenses entail the smallest influence over the financial and cost parameters.

5.4 Comparison between the cases

Both wind and PV cases have been presented in order to show the differences between the technology regarding the data and methodology employed. Wind projects produce larger amounts of electricity yearly per kWp installed. Table 32 shows the electricity output of each project, which states the great difference between the technologies. Moreover, PV technologies are subjected to stronger degradation of its main component, thus experiencing a greater reduction of electricity output during its serviceable life. Whilst, the wind farm presents a yearly degradation rate of 0,2% after the fourth year of operation, the PV installations decrease annually their electricity output by 0,5% after the first year of operation. The installation cost also favors the wind farm case, which presents a lower installation cost. On the contrary, the operating expenses of the solar systems are considerably lower compared to the wind farm. Whereas the PV installations present a mean value of 18,5 €/kW, the wind farm operating expenses are 44 €/kW. Al these factors combined together result in a generally lower LCOE for the wind projects compare to PV systems. In the cases analyzed, the LCOE values are 0,067, 0,146 and 0,043 €/kWh for the PV installations in Santarém and Valencia and the wind farm in Argentina, respectively. Although this trend has characterized the panorama of both technologies until now, the advancements in technology and reductions in cost of the PV industry and the difficulty to access good wind locations (i.e. availability to constant and strong wind speeds and lack of construction constraints) are resulting in equalizing the LCOE of both technologies.

Factor	Santarém solar PV	Valencia solar PV	Argentina wind farm
Installation cost [€/W]	1,53	2,17	1,23
Electricity output [kWh/kWp year]	1756,4	1300,6	4439,4
O&M cost [€/kW]	15,27	21,7	44
Electricity price [€/kWh]	0,2018	0,193	0,056
LCOE	**0,067**	**0,146**	**0,043**

Table 32 Comparison of the input data of the three cases

Moreover, the differences in the methodology used for investments in projects under the private owner and the company perspective are also distinguished. On the spreadsheets of the different projects presented in the annex, it clearly states the difference between the cases evaluated. Under the perspective of the company (wind case), taxes have to be paid for the gain obtained after selling electricity to the grid. Therefore, companies incur in tax liabilities based on the tax laws (e.g. a utility company in Argentina has to pay 35% taxes). In the case of an installation for self-consumption, these concepts are not considered within the calculation. Another difference between these perspectives is the calculation of the WACC, which is more complicated to calculate for companies due to the larger sources of financing considered, as aforementioned in chapter 4. Besides the different approach calculating the WACC, the wind farm discount rate (8,04%) is significantly larger than in the Portuguese (1,97%) and Spanish (2,69%) PV projects. This directly affects the results of the NPV and LCOE. The demand for a larger rate of return is a consequence of the riskiness of an investment. In the Argentinian case, the high inflation and the political turbulence of the country, which may affect the project outputs, motivate such rate of return. In the PV cases there is no such uncertainty, thus the rates of return are considerably low. Furthermore, exists a great difference between the price of the electricity between the wind and PV cases. Whilst the PV cases present a mean electricity price of 0,197 €/kWh, the value used in the wind case is considerably lower (0,056 €/kWh). Therefore, the results of the financial parameters for each case (Table 33) are a consequence of the differences between the factors employed for each case.

Financial index	Santarém solar PV	Valencia solar PV	Argentina wind farm
NPV	5.812,61 €	6.884,80 €	10.297.211,88 €
IRR	18,47%	6,33%	9,22%
DPBP [years]	6	19	18

Table 33 Results of the financial parameters of each case for the base case scenario

The influence of each factor over the profitability indexes varies between cases. Table 34 and Table 35 presents the relative percentage variations of the profitability indexes from the results obtained in the base case when the installation cost and electricity output are varied from the values defined in the base scenario. In the PV installation of Santarém, a 10% decrease in the installation cost from the base case scenario results in an increase of the IRR and NPV of 13,5% and 5,88%, respectively. Such reduction in the installation cost of the PV system in Valencia results in an increase of 34% and 25% of the NPV and IRR respectively. In the wind case, if the installation cost is reduced by 10% the NPV and IRR results in an increase of 92% and 14%. Regarding electricity output, a 10% increase in the Portuguese installation results in a relative percentage increase of the NPV and IRR equal to 15,88% and 12,16%. In the Spanish installation, such increase in the electricity output results in larger relative variations from the base case scenario, 46% for the NPV and 24% for the IRR. In the wind project, if the electricity output is increased 10% from the base case, the NPV is increased by 129% and the IRR by 16%. Same results are obtained for the NPV if the electricity price is increased 10% from the values of the base case scenario. It can be concluded that the highest sensitivity of the NPV for all the cases is caused by the electricity production. Regarding IRR, it is more influenced by the installation cost in the PV cases, whereas electricity generation entails larger influenced over the IRR over the wind case. Although it is not presented, the relative percentage variations of the profitability indexes with the relative variation of the operating expenses entail the smallest influence among the factors presented. Moreover, the percentage of financing that is debt (in the PV cases) and discount rate (in the wind farm) variations have more influence than the operating expenses over the profitability of the project.

$\Delta x/x$	Santarém PV		Valencia PV		Argentina wind	
	NPV	**IRR**	**NPV**	**IRR**	**NPV**	**IRR**
-50%	29%	117%	168%	201%	462%	114%
-40%	24%	79%	134%	139%	369%	78%
-30%	18%	51%	101%	92%	277%	52%
-20%	12%	30%	67%	55%	185%	31%
-10%	6%	14%	34%	25%	92%	14%
BCS	0%	0%	0%	0%	0%	0%
10%	-6%	-11%	-34%	-22%	-92%	-12%
20%	-12%	-21%	-67%	-41%	-185%	-22%
30%	-18%	-29%	-101%	-58%	-277%	-31%
40%	-24%	-36%	-134%	-73%	-369%	-39%
50%	-29%	-43%	-168%	-87%	-462%	-46%

Table 34 Relative percentage variations of the profitability indexes (IRR and NPV) for the three cases, as a function of the relative percentage variation of the installation cost

$\Delta x/x$	Santarém PV		Valencia PV		Argentina wind	
	NPV	**IRR**	**NPV**	**IRR**	**NPV**	**IRR**
-50%	-79%	-67%	-228%	-155%	-647%	-97%
-40%	-64%	-52%	-182%	-115%	-517%	-74%
-30%	-48%	-38%	-137%	-82%	-388%	-53%
-20%	-32%	-25%	-91%	-52%	-259%	-34%
-10%	-16%	-12%	-46%	-25%	-129%	-17%
BCS	0%	0%	0%	0%	0%	0%
10%	16%	12%	46%	24%	129%	16%
20%	32%	24%	91%	46%	259%	31%
30%	48%	36%	137%	68%	388%	46%
40%	64%	48%	182%	90%	517%	60%
50%	79%	59%	228%	110%	647%	74%

Table 35 Relative percentage variations of the profitability indexes (NPV and IRR) for the three cases, as a function of the relative percentage variation of the electricity output

Specifications regarding the technology used and the perspective considered to analyze a project are relevant in order to define the parameters used and the methodology followed. However, projects using the same technology and analyzed under the same perspective also present differences in the results. The comparison between the residential PV cases analyzes such differences. Albeit both systems are profitable under the conditions of the base case scenario, the results obtained for the Portuguese case are considerably better. Although the Spanish project requires an initial investment 6,13 times larger, the difference between the NPV is small (only 1,18 times larger). Likewise, the real IRR of the Portuguese case (18,47%) is larger than in the Spanish case (6,33%). A big difference on the IRR was also presented by Swift (2013) in a research study of 4 PV installations located in the US, from -8,27% to 31,60%. Swift concluded that the main reasons behind the difference in the IRR among locations were the following factors: electricity prices, variation in state incentives and level of solar irradiation. In this case, electricity price did not affect greatly the financial results because the difference between both projects is below 1,0 c€/kWh. On the contrary, the electricity output and the different regulation between countries resulted as an important parameter. Moreover the installation cost and operating expenses, which are directly affected by the regulatory framework of the location and the system chosen, also contributed obtaining such difference in the results. The difference between the cases regarding the normalized installation cost is mainly due to the device used to store electricity, which price (7600 €) increases considerably the final installation cost. Whilst the Portuguese installation cost is equal to 1,53 €/Wp, the Spanish one is equal to 2,17 €/Wp. Additionally, the Spanish system presents higher normalized operating expenses (almost double) because more equipment is used and taxes paid due to the storage system. Regarding electricity production, the Portuguese installation performs more efficiently because the lack of structural constraints (i.e. PV panels face to the south).

The immediate consequence of the differences among these factors is reflected in the cost of producing 1 kWh in each system, which is also affected by the discount rate employed in each case. The discount rate is higher in the Spanish case because the risk free interest rate (rate of return of bonds) in Spain (2,957%) is larger than in Portugal (2,23%). Accordingly, the Portuguese PV installation presents a LCOE of 0,067 €/kWh while the Spanish doubles it with 0,146 €/kWh. Such values are slightly decreased when considering the positive externality of reducing the emitted CO_2. The reduction is greater in the Portuguese scenario because both the carbon tax and factor of electricity generation –CO_2 emission intensity are larger in Portugal than in Spain. Therefore, considering that the price of the electricity consumed by the households slightly differs (below 1,0 c€/kWh), the great difference in the financial results obtained is a consequence of such disparity on the LCOE. Furthermore, the Portuguese investment is less risky because the money is recovered sooner. Whilst the Portuguese owner recovers the money in the 6th year after the initial investment, the Spanish one has to wait almost until the end of the project life (19th year).

6. Conclusions

The advancements in solar PV and wind technologies, together with cost reductions have increased the competitiveness of such installations in the power sector. Currently, the cost of generating electricity with both technologies is in a vertiginous downward trend, especially for the PV systems. Therefore, everyday is more economically attractive for companies and individual owners to invest in such installations because they are becoming profitable without any government support. The aim of this dissertation has been to provide a useful tool to assess the profitability of solar PV and wind energy projects by elaborating a financial and economic model. This research also presents the main advancements during the last decades of the PV and wind industry. Finally, the presentation of three real cases provides an overview of the state of the art of the performance and cost of PV and wind systems.

The development of the solar PV and wind industries has been driven by technology improvements, government support and experience acquired. All these factors combined together are making these technologies competitive in the power sector by continuously decreasing their cost of generating electricity. Although these technologies have already achieved grid parity in some locations without any support, there are still many locations that need a favorable regulatory framework in order to make it profitable. Thus, the right regulation is essential in order to provide a favorable environment for investing in solar PV and wind projects. A stable government support and a reliable regulatory framework in the renewable energy sector boost investments in the industry by reducing the perception of risk (e.g. Law 27.191 supports the use of renewable energies in Argentina). Additionally, more investment results in technology advancements and diminishing costs, the right virtuous circle. On the contrary, unfavorable regulation (e.g. RD 900/2015 for self-consumption systems in Spain) negatively affects the financial indexes of a project (e.g. the PV installation in Valencia).

The results obtained from the application of the model to the three cases conclude that all the cases are profitable under the conditions of the base case scenario. The PV installation in Santarém yields an IRR of 18,45%, which is considerably larger than the opportunity cost of capital (1,97%). Meanwhile, in the PV system in Valencia, the difference between the IRR (6,33%) and the opportunity cost of capital (2,69%) is significantly smaller, although being significant. This difference is even smaller in the wind farm in Argentina, where the IRR is 9,22% and the WACC is 8,04%. Such differences in the results are a consequence of the factors considered for each case. Each factor entails a different degree of influence over the profitability indexes. The sensitivity analyses performed for the three cases provide evidence that installation cost, electricity output – electricity price and operating expenses can be classified from highest to lowest in terms of their influence over the IRR.

Therefore, it is clear that wind and PV solar projects are profitable in some locations without any support thanks to the improvements in technology performance and reductions in costs achieved through the years. Such level of development has been possible thanks to the right regulatory framework provided by certain countries, which have resulted in large investments in research, development and innovation in both industries. Consequently, it is important to keep the path of technology improvements and cost reductions in order to completely assure the profitability of the wind and solar PV projects worldwide, which will be achieved by implementing the right regulation in each particular country.

7. References

Associação de Energias Renováveis (APREN). (2017). Estatísticas rápidas – nº147 – janeiro de 2017. Retrieved 10 May from http://www.apren.pt/fotos/newsletter/conteudos/estatisticas_rapidas-renovaveis_janeiro_2017_dgeg_1491321550.pdf

Bakos, G. C. (2009). Distributed power generation: a case study of small scale PV power plant in Greece. *Applied Energy*, *86*(9), 1757-1766.

Bang, D., Polinder, H., Shrestha, G., & Ferreira, J. A. (2008, March). Review of generator systems for direct-drive wind turbines. In *European Wind Energy Conference & Exhibition, Belgium* (pp. 1-11).

Barbose Galen L., Darghouth Naïm R. (2016). Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States. Retrieved 5 April 2017, from https://emp.lbl.gov/sites/default/files/tracking_the_sun_ix_report.pdf

Berkeley Lab, National Renewable Energy Laboratory (NREL) and International Energy Agency (IEA) wind. (2016). Forecasting wind energy costs and cost drivers. LBNL—1005717. Retrieved 30 March 2017, from https://www.ieawind.org/task_26_public/PDF/062316/lbnl-1005717.pdf

Bhattacharya, M., Paramati, S. R., Ozturk, I., & Bhattacharya, S. (2016). The effect of renewable energy consumption on economic growth: Evidence from top 38 countries. Applied Energy, 162, 733-741.

Branker, K., Pathak, M. J. M., & Pearce, J. M. (2011). A review of solar photovoltaic levelized cost of electricity. Renewable and Sustainable Energy Reviews, 15(9), 4470-4482.

Byrd, S., Radcliff, T., Lee, S., Chada, B., Olszewski, D., Matayoshi, Y., Gupta, P., Rodrigues, M., Joanas, A., Mackey, P. J., Curtis, M., Walsh, P. R., Campbell, R. & Gosal, D. (2014). Solar Power and Energy Storage: Policy Factors vs. Improving Economics. Blue Paper, Morgan Stanley Research, Washington, DC. Retrieved 12 April 2017, from https://forms.greentechmedia.com/Extranet/95679/Morgan%20Stanley%20Solar%20Power%20&%20Energy%20Storage%20Blue%20Paper%20July%2029%202014.pdf

Candelise, C., Speirs, J. F., & Gross, R. J. (2011). Materials availability for thin film (TF) PV technologies development: A real concern?. Renewable and Sustainable Energy Reviews, 15(9), 4972-4981.

Chandel, M., Agrawal, G. D., Mathur, S., & Mathur, A. (2014). Techno-economic analysis of solar photovoltaic power plant for garment zone of Jaipur city. *Case Studies in Thermal Engineering*, *2*, 1-7.

China Energy Portal. (2017). Retrieved 18 May 2017, from http://chinaenergyportal.org/en/2016-detailed-electricity-statistics/

Decree-Law 153. (2014). 20 of October. *Cria os regimes jurídicos à produção de electricidade destinada e autoconsumo e ao da venda à rede eléctrica de service public a partir de recursos renováveis, por intermédio de Unidades de Pequena Produção*

Department of Energy. (2016). 2015 Wind Technologies Market Report. Energy Efficiency & Renewable Energy. Retrieved 12 April, from: https://energy.gov/sites/prod/files/2016/08/f33/2015-Wind-Technologies-Market-Report-08162016.pdf

Dominguez-Ramos, A., Held, M., Aldaco, R., Fischer, M. and Irabien, A. (2010). Carbon footprint assessment of photovoltaic modules manufacture scenario. Retrieved 8 April 2017, from https://www.researchgate.net/profile/Angel_Irabien/publication/259190237_Carbon_footprint_assessment_of_photovoltaic_modules_manufacture_scenario/links/5477b9380cf293e2da280ad2/Carbon-footprint-assessment-of-photovoltaic-modules-manufacture-scenario.pdf

Eikelboom, J. A., & Jansen, M. J. (2000). Characterisation of PV modules of new generations. *Results of tests and simulations*.

El-Shimy, M. (2009). Viability analysis of PV power plants in Egypt. *Renewable Energy*, *34*(10), 2187-2196.

Energiewende, A. (2015). Current and future cost of photovoltaics–long-term scenarios for market development system prices and LCOE of utility-scale PV systems. *Report by Fraunhofer Institute for Solar Energy Systems on behalf of Agora Energiewende. Retrieved 6 May 2017, from http://www.fvee.de/fileadmin/publikationen/weitere_publikationen/15_AgoraEnergiewende-ISE_Current_and_Future_Cost_of_PV.pdf*

European Investment Bank (EIB). (2013). The Economic Appraisal of Investment Projects at the EIB. pp 15-44, 107-112 Retrieved 6 June 2017, from http://www.eib.org/attachments/thematic/economic_appraisal_of_investment_projects_en.pdf

European Wind Energy Association. (2009). *The economics of wind energy*. EWEA.

Fraunhofer Institute for Solar Energy Systems (ISE). (2016) Photovoltaics Report, Retrieved 1 March 2017, from https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/Photovoltaics-Report.pdf

Fraunhofer Institute for Solar Energy Systems (ISE). (2017). Power generation in Germany – assessment of 2016. Retrieved 12 May 2017, from https://www.ise.fraunhofer.de/content/dam/ise/en/documents/publications/studies/power-generation-from-renewable-energies-2016.pdf

Gardner, P., Garrad, A., Jamieson, P., Snodin, H., & Tindal, A. (2009). Wind Energy–The Facts. Technology", Part I. Retrieved 17 May 2017, from https://www.wind-energy-the-facts.org/

Girard, A., Gago, E. J., Ordonez, J., & Muneer, T. (2016). Spain's energy outlook: A review of PV potential and energy export. *Renewable Energy*, *86*, 703-715.

Goetzberger, A., Luther, J., & Willeke, G. (2002). Solar cells: past, present, future. *Solar energy materials and solar cells*, *74*(1), 1-11.

Gómez D., Murcia J., Nieto E., González de Velandia. (2010). *Proyecto EOS. Project Finance de un parquet eólico*. Retrieved 30 May 2017, from http://biblioteca.cunef.edu/gestion/catalogo/doc_num.php?explnum_id=1530

Goossens, D., & Van Kerschaever, E. (1999). Aeolian dust deposition on photovoltaic solar cells: the effects of wind velocity and airborne dust concentration on cell performance. *Solar Energy*, *66*(4), 277-289.

Hammond, G. P., Harajli, H. A., Jones, C. I., & Winnett, A. B. (2012). Whole systems appraisal of a UK Building Integrated Photovoltaic (BIPV) system: energy, environmental, and economic evaluations. *Energy Policy*, *40*, 219-230.

Harrabin R, Solar panel costs 'set to fall', BBC News; Retrieved 20 March 2017, from http://news.bbc.co.uk/2/hi/science/nature/8386460.stm

Hernández, C. V., Telsnig, T., & Pradas, A. V. (2017). JRC Wind Energy Status Report 2016 Edition. Retrieved 30 March 2017, from https://setis.ec.europa.eu/sites/default/files/reports/wind_energy_status_report_2016.pdf

Iea.org. (2014). IEA–Report. Retrieved 3 May 2017, from http://www.iea.org/statistics/statisticssearch/

International Energy Agency. (2013). Technology Roadmap – Wind energy. 2013 Edition. IEA Retrieved 4 May 2017, from: https://www.iea.org/publications/freepublications/publication/Wind_2013_Roadmap.pdf

IEA-ETSAP, IRENA. (2016). Wind Power – Technology Brief. International Energy Agency – Energy Technology System Analysis Programme, Inter International Renewable Energy Agency. Retrieved 15 March, from http://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP_Tech_Brief_Wind_Power_E07.pdf

IEA, NEA. (2015). Projected Costs of Generating Electricity–2015 Edition. International Energy Agency and Nuclear Energy Agency, France. Retrieved 6 May 2017, from https://www.oecd-nea.org/ndd/pubs/2015/7057-proj-costs-electricity-2015.pdf

IRENA. (2016). Innovation Outlook: Offshore Wind, International Renewable Energy Agency, Abu Dhabi. Retrieved 23 May 2017, from https://www.irena.org/DocumentDownloads/Publications/IRENA_Innovation_Outlook_Offshore_Wind_2016.pdf

IRENA. (2016). Letting in the Light. Abu Dhabi. Retrieved 25 April 2017, from: https://www.irena.org/DocumentDownloads/Publications/IRENA_Letting_in_the_Light_2016.pdf

IRENA (2017), Renewable capacity statistics 2017, International Renewable Energy Agency. Abu Dhabi. Retrieved 18 April 2017, from http://www.irena.org/DocumentDownloads/Publications/IRENA_RE_Capacity_Statistics_2017.pdf

IRENA. (2012). Solar Photovoltaics. Retrieved 10 March 2017, from: https://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-SOLAR_PV.pdf

Islam, M. R., Mekhilef, S., & Saidur, R. (2013). Progress and recent trends of wind energy technology. Renewable and Sustainable Energy Reviews, 21, 456-468.

Jäger-Waldau, A. (2016). PV Status Report 2016. EUR 28159 EN. doi:10.2790/682995. Retrieved 16 May 2017, from http://publications.jrc.ec.europa.eu/repository/bitstream/JRC103426/ldna28159enn.pdf

Jäger-Waldau, A. (2017). Snapshot of Photovoltaics—March 2017. *Sustainability*, *9*(5), 783.

Jones-Albertus, R., Feldman, D., Fu, R., Horowitz, K., & Woodhouse, M. (2016). Technology advances needed for photovoltaics to achieve widespread grid price parity. Progress in photovoltaics: research and applications, 24(9), 1272-1283.

Jordan, D. C., & Kurtz, S. R. (2013). Photovoltaic degradation rates—an analytical review. Progress in photovoltaics: Research and Applications, 21(1), 12-29.

Kaldellis, J. K., & Zafirakis, D. (2011). The wind energy (r) evolution: A short review of a long history. Renewable Energy, 36(7), 1887-1901.

Kic Innoenergy. (2016). Future renewable energy costs: solar photovoltaics. Retrieved 4 April 2017, from http://www.innoenergy.com/wp-content/uploads/2016/01/KIC-InnoEnergy-Solar-PV-anticipated-innovations-impact.pdf

Kumar, R., & Rosen, M. A. (2011). A critical review of photovoltaic–thermal solar collectors for air heating. *Applied Energy*, *88*(11), 3603-3614.

Kumar, Y., Ringenberg, J., Depuru, S. S., Devabhaktuni, V. K., Lee, J. W., Nikolaidis, E., Andersen, B., & Afjeh, A. (2016). Wind energy: trends and enabling technologies. *Renewable and Sustainable Energy Reviews*, *53*, 209-224.

Lacal, R. (2013). JRC wind status report. JRC Scientific and Policy Reports. Retrieved 20 April 2017, from https://setis.ec.europa.eu/system/files/JRC_wind_status_report_0.pdf

Lacal, R., Corsatea, T., & Suomalainen, K. (2014). JRC Wind Status Report-Technology, Market And Economic Aspects of Wind Energy in Europe. European Commission, Joint Research Centre, Institute for Energy and Transport: NL-1755 LE Petten, The Netherlands. Retrieved 20 April 2017, from https://setis.ec.europa.eu/system/files/2014JRCwindstatusreport_EN_N.pdf

Lacal, R., Corsatea, T., & Suomalainen, K. (2012). JRC wind status report. European Commission: Petten, The Netherlands. Retrieved 20 April 2017, from https://setis.ec.europa.eu/system/files/LDNA25647ENN_2012_JRC_wind_status_report_FINAL.pdf

Law 24.065. *Generación, Transporte y distribución de la electricidad*

Law 27.191. (2015). 21th of October. *Uso de fuentes renovables de energía – Producción de enrgía electrica*. "Promotion of renewable energy usage"

Live CO2 emissions of electricity consumption. (2017). Electricitymap.org. Retrieved 6 July 2017, from https://www.electricitymap.org/?wind=false&solar=false&page=country&countryCode=ES

Magyari, S. (2017). Solarplaza 30 lowest solar PPAs worldwide. Solarplaza.com. Retrieved 10 July 2017, from https://www.solarplaza.com/channels/top-10s/11647/global-pv-prices-show-continuous-decline/

Moné, C., Stehly, T., Maples, B., & Settle, E. (2014). 2014 Cost of Wind Energy Review (No. NREL/TP-6A20-64281). National Renewable Energy Laboratory (NREL). Retrieved 15 May 2017, from: http://www.nrel.gov/docs/fy16osti/64281.pdf

Morthorst, P. E., Auer, H., Garrad, A., & Blanco, I. (2009). The economics of wind power. Wind Energy: The Facts, Part Three. Retrieved 20 May 2017, from https://www.wind-energy-the-facts.org/

NREL. (2016). Rooftoop Solar Photovoltaic Technical Potential in the United States, A Detailed Assessment. Retrived 25 May 2017, from http:// http://www.nrel.gov/docs/fy16osti/65298.pdf

NREL. (2017). Photovoltaic Degradation Rates – An Analitical Review. Retrieved 10 April 2017, from http://www.nrel.gov/docs/fy12osti/51664.pdf

Nrel.gov. (2017). Photovoltaic Research. NREL. Retrieved 14 May 2017, from https://www.nrel.gov/pv/

Overview of electricity production and use in Europe. (2017). European Environmental Agency. Retrieved 2 July 2017, from https://www.eea.europa.eu/data-and-maps/indicators/overview-of-the-electricity-production-2/assessment

Peng, J., Lu, L., & Yang, H. (2013). Review on life cycle assessment of energy payback and greenhouse gas emission of solar photovoltaic systems. *Renewable and Sustainable Energy Reviews*, *19*, 255-274.

Progress in Photovoltaics: Research and Applications. Solar Cell Efficiency Tables. Version 1-46

Realini, A. (2003). Mean time before failure of photovoltaic modules. *Final Report (MTBF Project), Federal Office for Education and Science Tech. Rep., BBW*, *99*.

Red Eléctrica de España (REE). (2016). *El sistema electric español. Avance 2016*. Retrieved 25 May 2017, from http://www.ree.es/sites/default/files/downloadable/avance_informe_sistema_electrico_2016.pdf

Rehman, S., Bader, M. A., & Al-Moallem, S. A. (2007). Cost of solar energy generated using PV panels. *Renewable and Sustainable Energy Reviews*, *11*(8), 1843-1857.

Renewable Energy Policy Network for the 21st century. (2016). Global Status Report. 2016 Edition Retrieved 12 March 2017, from http://www.ren21.net/wp-content/uploads/2016/06/GSR_2016_Full_Report.pdf

Renewable Energy Institute (2016), Comparing Prices and Cost of Solar PV in Japan and Germany – The Reasons Why Solar PV is more Expensive in Japan, pp. 5-8 Retrieved 6 June 2017, from https://www.renewable-ei.org/en/images/pdf/20160331/JREF_Japan_Germany_solarpower_costcomparison_en.pdf

Resolution Ente Nacional Regulador de la Electricidad (ENRE) 494. (2016). 29th August.

Resourceirena.irena.org. (2017). IRENA REsource. Retrieved 4 June 2017, from http://resourceirena.org/gateway/

Royal Decree Law 900. (2015). 10 of October, Energy self-consumption Royal Decree Law. BOE, 10 October 2015, num. 243, p. 94874-94917.

Royal Decree-Law 1. (2012). 27 of January. *Suspensión de los procedimientos de preasignación de retribución y a la supresión de los incentivos económicos para nuevas instalaciones de producción de energía eléctrica a partir de cogeneración, fuentes de energía renovables y residuos*. “Suspension of renewable energy subsidies”.

Rubin, E. S., Azevedo, I. M., Jaramillo, P., & Yeh, S. (2015). A review of learning rates for electricity supply technologies. Energy Policy, 86, 198-218.

Şahin, A. D. (2004). Progress and recent trends in wind energy. Progress in energy and combustion science, 30(5), 501-543.

Sampaio, P. G. V., & González, M. O. A. (2017). Photovoltaic solar energy: Conceptual framework. *Renewable and Sustainable Energy Reviews*, *74*, 590-601.

Sarver, T., Al-Qaraghuli, A., & Kazmerski, L. L. (2013). A comprehensive review of the impact of dust on the use of solar energy: History, investigations, results, literature, and mitigation approaches. *Renewable and Sustainable Energy Reviews*, *22*, 698-733.

Serrano‐González, J., & Lacal‐Arántegui, R. (2016). Technological evolution of onshore wind turbines—a market‐based analysis. *Wind Energy*.

Short, W., Packey, D. J., & Holt, T. (1995). *A manual for the economic evaluation of energy efficiency and renewable energy technologies* (No. NREL/TP--462-5173). National Renewable Energy Lab., Golden, CO (United States). Retrieved 12 March 2017, from http://www.nrel.gov/docs/legosti/old/5173.pdf

Sollarcellcental.com. (n.d.). Solar In-depth: From Sun to Nanoparticles To Electricity. Retrieved 4 June 2017, from http://solarcellcentral.com/solar_page.html

Soares J.O., Fernandes A.V., Março A., Marques J.P. (2006), "Avaliação de Projectos de Investimento na Óptica Empresarial", Edições Sílabo, 2ª edição.

Sun Power- United States. (2017). SunPower Solar Module Verified 24,1 Percent Efficient. Sun Power Solar blog . Retrieved 4 April 2017, from https://us.sunpower.com/blog/2016/06/26/sunpower-solar-module-verified-241-percent-efficient/

Swift, K. D. (2013). A comparison of the cost and financial returns for solar photovoltaic systems installed by businesses in different locations across the United States. *Renewable Energy*, *57*, 137-143.

Talavera, D. L., Muñoz-Cerón, E., De La Casa, J., Ortega, M. J., & Almonacid, G. (2011). Energy and economic analysis for large-scale integration of small photovoltaic systems in buildings: The case of a public location in Southern Spain. *Renewable and Sustainable Energy Reviews*, *15*(9), 4310-4319.

Talavera, D. L., Nofuentes, G., & Aguilera, J. (2010). The internal rate of return of photovoltaic grid-connected systems: a comprehensive sensitivity analysis. *Renewable energy*, *35*(1), 101-111.

Tegen, S., Hand, M., Maples, B., Lantz, E., Schwabe, P., & Smith, A. (2012). 2010 Cost of Wind Energy Review (No. NREL/TP-5000-52920). National Renewable Energy Laboratory (NREL), Golden, CO.. Retrieved 15 May 2017, from http://www.nrel.gov/docs/fy12osti/52920.pdf

Theologitis, I. and Masson, G. (2015). Potential for cost reduction of PV technology – Impact of cheetah research innovations. Belgium. Retrieved 20 May 2017, from http://becquerelinstitute.org/wp-content/uploads/2015/10/7DV.4.23-Potential-for-Cost-Reduction-of-PV-Technology.pdf

Tyagi, V. V., Rahim, N. A., Rahim, N. A., Jeyraj, A., & Selvaraj, L. (2013). Progress in solar PV technology: research and achievement. *Renewable and sustainable energy reviews*, *20*, 443-461.

U.S. Energy Information Administration (EIA). (2017). Retrieved 15 May 2017, from https://www.eia.gov/electricity/monthly/

Weaver, T. (2012). Financial appraisal of operational offshore wind energy projects. *Renewable and Sustainable Energy Reviews*, *16*(7), 5110-5120.

Wind Europe. (2016). Making transition work. Retrieved 12 April 2017, from https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Making-transition-work.pdf

Wiser R. and Bolinger M. (2016). Wind Technologies Market Report 2015. U.S. Department of Energy (DOE). Retrieved 22 April 2017, from https://energy.gov/sites/prod/files/2016/08/f33/2015-Wind-Technologies-Market-Report-08162016.pdf

Wohlgemuth, J. H., & Solar, B. P. (2003, March). Long term photovoltaic module reliability. In *NCPV and solar program review meeting* (pp. 179-183).

Woldometers. (2017). Woldometers – real time world statatistics. Retrieved 3 June 2017, from http://www.worldometers.info/world-population/

Wong, J. H., Royapoor, M., & Chan, C. W. (2016). Review of life cycle analyses and embodied energy requirements of single-crystalline and multi-crystalline silicon photovoltaic systems. *Renewable and Sustainable Energy Reviews*, *58*, 608-618.

World Energy Council. (2016). World Energy Resources Report. 24th Edition. (pp) 4-37 Retrieved 28 February 2017, from https://www.worldenergy.org/wp-content/uploads/2016/10/World-Energy-Resources-Full-report-2016.10.03.pdf

Wu, L., Tian, W., & Jiang, X. (2005). Silicon-based solar cell system with a hybrid PV module. *Solar energy materials and solar cells*, *87*(1), 637-645.

Annex

SANTAREM PV CASE

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Investment CFs	- 2.382,40 €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Revenues	- €	497,64 €	495,15 €	492,67 €	490,21 €	487,76 €	485,32 €	482,90 €	480,48 €	478,08 €	475,69 €	473,31 €	470,94 €
O&M	- €	23,82 €	24,06 €	24,30 €	24,55 €	24,79 €	25,04 €	25,29 €	25,54 €	25,80 €	26,06 €	26,32 €	26,58 €
EBITDA	- €	473,81 €	471,09 €	468,37 €	465,67 €	462,97 €	460,28 €	457,61 €	454,94 €	452,28 €	449,63 €	446,99 €	444,36 €
D&A	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT	- €	473,81 €	471,09 €	468,37 €	465,67 €	462,97 €	460,28 €	457,61 €	454,94 €	452,28 €	449,63 €	446,99 €	444,36 €
Tax	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Incomes after taxes	- €	473,81 €	471,09 €	468,37 €	465,67 €	462,97 €	460,28 €	457,61 €	454,94 €	452,28 €	449,63 €	446,99 €	444,36 €
Depreciation	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Operation CFs	- €	473,81 €	471,09 €	468,37 €	465,67 €	462,97 €	460,28 €	457,61 €	454,94 €	452,28 €	449,63 €	446,99 €	444,36 €
Total CFs	- 2.382,40 €	473,81 €	471,09 €	468,37 €	465,67 €	462,97 €	460,28 €	457,61 €	454,94 €	452,28 €	449,63 €	446,99 €	444,36 €
DCFs	- 2.382,40 €	464,66 €	453,06 €	441,74 €	430,70 €	419,93 €	409,43 €	399,18 €	389,19 €	379,44 €	369,93 €	360,65 €	351,60 €
ACFs	- 2.382,40 €	- 1.917,74 €	- 1.464,68 €	- 1.022,94 €	- 592,24 €	- 172,31 €	237,12 €	636,30 €	1.025,49 €	1.404,93 €	1.774,85 €	2.135,50 €	2.487,10 €

SANTAREM PV CASE

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Investment CFs	- 664,83 €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Revenues	468,59 €	466,25 €	463,91 €	461,59 €	459,29 €	456,99 €	454,70 €	452,43 €	450,17 €	447,92 €	445,68 €	443,45 €	441,23 €
O&M	26,85 €	27,11 €	27,39 €	27,66 €	27,94 €	28,21 €	28,50 €	28,78 €	29,07 €	29,36 €	29,65 €	29,95 €	30,25 €
EBITDA	441,74 €	439,13 €	436,53 €	433,94 €	431,35 €	428,78 €	426,21 €	423,65 €	421,10 €	418,56 €	416,02 €	413,50 €	410,98 €
D&A	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT	441,74 €	439,13 €	436,53 €	433,94 €	431,35 €	428,78 €	426,21 €	423,65 €	421,10 €	418,56 €	416,02 €	413,50 €	410,98 €
Tax	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Incomes after taxes	441,74 €	439,13 €	436,53 €	433,94 €	431,35 €	428,78 €	426,21 €	423,65 €	421,10 €	418,56 €	416,02 €	413,50 €	410,98 €
Depreciation	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Operation CFs	441,74 €	439,13 €	436,53 €	433,94 €	431,35 €	428,78 €	426,21 €	423,65 €	421,10 €	418,56 €	416,02 €	413,50 €	410,98 €
Total CFs	- 223,09 €	439,13 €	436,53 €	433,94 €	431,35 €	428,78 €	426,21 €	423,65 €	421,10 €	418,56 €	416,02 €	413,50 €	410,98 €
DCFs	- 173,10 €	334,16 €	325,76 €	317,57 €	309,58 €	301,78 €	294,18 €	286,76 €	279,53 €	272,47 €	265,59 €	258,88 €	252,33 €
ACFs	2.313,99 €	2.648,15 €	2.973,91 €	3.291,48 €	3.601,06 €	3.902,84 €	4.197,02 €	4.483,78 €	4.763,31 €	5.035,78 €	5.301,37 €	5.560,24 €	5.812,57 €

VALENCIA PV CASE

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CFs Investment	- 14.610,40 €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Revenues	- €	1.391,21 €	1.384,25 €	1.377,33 €	1.370,44 €	1.363,59 €	1.356,77 €	1.349,99 €	1.343,24 €	1.336,52 €
O&M	- €	206,51 €	208,58 €	210,66 €	212,77 €	214,90 €	217,05 €	219,22 €	221,41 €	223,62 €
EBITDA	- €	1.184,70 €	1.175,67 €	1.166,67 €	1.157,67 €	1.148,69 €	1.139,73 €	1.130,77 €	1.121,83 €	1.112,90 €
D&A	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT	- €	1.184,70 €	1.175,67 €	1.166,67 €	1.157,67 €	1.148,69 €	1.139,73 €	1.130,77 €	1.121,83 €	1.112,90 €
Tax	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT after Taxex	- €	1.184,70 €	1.175,67 €	1.166,67 €	1.157,67 €	1.148,69 €	1.139,73 €	1.130,77 €	1.121,83 €	1.112,90 €
Depreciation	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Operation CFs	- €	1.184,70 €	1.175,67 €	1.166,67 €	1.157,67 €	1.148,69 €	1.139,73 €	1.130,77 €	1.121,83 €	1.112,90 €
Total CFs	- 14.610,40 €	1.184,70 €	1.175,67 €	1.166,67 €	1.157,67 €	1.148,69 €	1.139,73 €	1.130,77 €	1.121,83 €	1.112,90 €
DCFs	- 14.610,40 €	1.153,67 €	1.114,89 €	1.077,38 €	1.041,07 €	1.005,94 €	971,94 €	939,05 €	907,22 €	876,43 €
ACFs	- 14.610,40 €	- 13.456,73 €	- 12.341,84 €	- 11.264,46 €	- 10.223,39 €	- 9.217,46 €	- 8.245,51 €	- 7.306,46 €	- 6.399,24 €	- 5.522,81 €

VALENCIA PV CASE

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CFs Investment	- €	- €	- €	- €	- €	- 7.600,00 €	- €	- €	- €	- €	- €
Revenues	1.329,84 €	1.323,19 €	1.316,58 €	1.309,99 €	1.303,44 €	1.296,93 €	1.290,44 €	1.283,99 €	1.277,57 €	1.271,18 €	1.264,82 €
O&M	225,86 €	228,12 €	230,40 €	232,70 €	235,03 €	237,38 €	239,75 €	242,15 €	244,57 €	247,02 €	249,49 €
EBITDA	1.103,98 €	1.095,07 €	1.086,18 €	1.077,29 €	1.068,41 €	1.059,55 €	1.050,69 €	1.041,84 €	1.033,00 €	1.024,16 €	1.015,34 €
D&A	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT	1.103,98 €	1.095,07 €	1.086,18 €	1.077,29 €	1.068,41 €	1.059,55 €	1.050,69 €	1.041,84 €	1.033,00 €	1.024,16 €	1.015,34 €
Tax	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT after Taxex	1.103,98 €	1.095,07 €	1.086,18 €	1.077,29 €	1.068,41 €	1.059,55 €	1.050,69 €	1.041,84 €	1.033,00 €	1.024,16 €	1.015,34 €
Depreciation	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Operation CFs	1.103,98 €	1.095,07 €	1.086,18 €	1.077,29 €	1.068,41 €	1.059,55 €	1.050,69 €	1.041,84 €	1.033,00 €	1.024,16 €	1.015,34 €
Total CFs	1.103,98 €	1.095,07 €	1.086,18 €	1.077,29 €	1.068,41 €	- 6.540,45 €	1.050,69 €	1.041,84 €	1.033,00 €	1.024,16 €	1.015,34 €
DCFs	846,63 €	817,81 €	789,91 €	762,93 €	736,83 €	- 4.392,46 €	687,14 €	663,51 €	640,65 €	618,53 €	597,14 €
ACFs	- 4.676,18 €	- 3.858,38 €	- 3.068,46 €	- 2.305,53 €	- 1.568,70 €	- 5.961,16 €	- 5.274,02 €	- 4.610,51 €	- 3.969,86 €	- 3.351,33 €	- 2.754,19 €

VALENCIA PV CASE

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
CFs Investment	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Revenues	1.258,50 €	1.252,21 €	1.245,95 €	1.239,72 €	1.233,52 €	1.227,35 €	1.221,21 €	1.215,11 €	1.209,03 €	1.202,99 €
O&M	251,98 €	254,50 €	257,05 €	259,62 €	262,21 €	264,84 €	267,48 €	270,16 €	272,86 €	275,59 €
EBITDA	1.006,52 €	997,71 €	988,90 €	980,10 €	971,30 €	962,51 €	953,73 €	944,95 €	936,17 €	927,40 €
D&A	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT	1.006,52 €	997,71 €	988,90 €	980,10 €	971,30 €	962,51 €	953,73 €	944,95 €	936,17 €	927,40 €
Tax	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
EBIT after Taxex	1.006,52 €	997,71 €	988,90 €	980,10 €	971,30 €	962,51 €	953,73 €	944,95 €	936,17 €	927,40 €
Depreciation	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Operation CFs	1.006,52 €	997,71 €	988,90 €	980,10 €	971,30 €	962,51 €	953,73 €	944,95 €	936,17 €	927,40 €
Total CFs	1.006,52 €	997,71 €	988,90 €	980,10 €	971,30 €	962,51 €	953,73 €	944,95 €	936,17 €	927,40 €
DCFs	576,45 €	556,44 €	537,08 €	518,36 €	500,25 €	482,74 €	465,81 €	449,43 €	433,59 €	418,28 €
ACFs	- 2.177,74 €	- 1.621,31 €	- 1.084,23 €	- 565,87 €	- 65,62 €	417,12 €	882,92 €	1.332,35 €	1.765,94 €	2.184,22 €

ARGENTINA WIND CASE

	2017	2018	2019	2020	2021	2022	2023	2024
Investment CFs	- 26.187.309,20 €	- 95.707.184,80 €	- €	- €	- €	- €	- €	- €
Revenues	- €	- €	22.913.684,10 €	22.913.684,10 €	22.913.684,10 €	22.913.684,10 €	22.730.923,82 €	22.685.461,98 €
O&M	- €	- €	4.399.560,00 €	4.443.555,60 €	4.487.991,16 €	4.532.871,07 €	4.578.199,78 €	4.623.981,78 €
EBITDA	- €	- €	18.514.124,10 €	18.470.128,50 €	18.425.692,94 €	18.380.813,03 €	18.152.724,04 €	18.061.480,20 €
D&A	- €	- €	6.420.736,83 €	6.420.736,83 €	6.420.736,83 €	6.420.736,83 €	6.420.736,83 €	6.220.207,43 €
EBIT	- €	- €	12.093.387,27 €	12.049.391,67 €	12.004.956,11 €	11.960.076,20 €	11.731.987,21 €	11.841.272,77 €
Tax	- €	- €	4.232.685,54 €	4.217.287,08 €	4.201.734,64 €	4.186.026,67 €	4.106.195,52 €	4.144.445,47 €
EBIT after Taxex	- €	- €	7.860.701,72 €	7.832.104,58 €	7.803.221,47 €	7.774.049,53 €	7.625.791,69 €	7.696.827,30 €
Depreciation	- €	- €	6.420.736,83 €	6.420.736,83 €	6.420.736,83 €	6.420.736,83 €	6.420.736,83 €	6.220.207,43 €
Operation CFs	- €	- €	14.281.438,56 €	14.252.841,42 €	14.223.958,31 €	14.194.786,36 €	14.046.528,52 €	13.917.034,73 €
Total CFs	- 26.187.309,20 €	- 95.707.184,80 €	14.281.438,56 €	14.252.841,42 €	14.223.958,31 €	14.194.786,36 €	14.046.528,52 €	13.917.034,73 €
DCFs	- 26.187.309,20 €	- 88.584.954,46 €	12.234.967,07 €	11.301.802,83 €	10.439.559,37 €	9.642.862,70 €	8.832.050,68 €	8.099.434,22 €
ACFs	- 26.187.309,20 €	- 114.772.263,66 €	- 102.537.296,59 €	- 91.235.493,76 €	- 80.795.934,39 €	- 71.153.071,69 €	- 62.321.021,02 €	- 54.221.586,80 €

ARGENTINA WIND CASE

	2025	2026	2027	2028	2029	2030	2031	2032
Investment CFs	- €	- €	- €	- €	- €	- €	- €	- €
Revenues	22.640.091,05 €	22.594.810,87 €	22.549.621,25 €	22.504.522,00 €	22.459.512,96 €	22.414.593,93 €	22.369.764,75 €	22.325.025,22 €
O&M	4.670.221,59 €	4.716.923,81 €	4.764.093,05 €	4.811.733,98 €	4.859.851,32 €	4.908.449,83 €	4.957.534,33 €	5.007.109,67 €
EBITDA	17.969.869,46 €	17.877.887,06 €	17.785.528,20 €	17.692.788,03 €	17.599.661,64 €	17.506.144,10 €	17.412.230,42 €	17.317.915,54 €
D&A	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €
EBIT	11.749.662,02 €	11.657.679,63 €	11.565.320,77 €	11.472.580,59 €	11.379.454,21 €	11.285.936,67 €	11.192.022,98 €	11.097.708,11 €
Tax	4.112.381,71 €	4.080.187,87 €	4.047.862,27 €	4.015.403,21 €	3.982.808,97 €	3.950.077,83 €	3.917.208,04 €	3.884.197,84 €
EBIT after Taxex	7.637.280,32 €	7.577.491,76 €	7.517.458,50 €	7.457.177,39 €	7.396.645,24 €	7.335.858,84 €	7.274.814,94 €	7.213.510,27 €
Depreciation	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €	6.220.207,43 €
Operation CFs	13.857.487,75 €	13.797.699,19 €	13.737.665,93 €	13.677.384,82 €	13.616.852,67 €	13.556.066,27 €	13.495.022,37 €	13.433.717,71 €
Total CFs	13.857.487,75 €	13.797.699,19 €	13.737.665,93 €	13.677.384,82 €	13.616.852,67 €	13.556.066,27 €	13.495.022,37 €	13.433.717,71 €
DCFs	7.464.623,35 €	6.879.319,70 €	6.339.677,94 €	5.842.150,43 €	5.383.464,24 €	4.960.599,92 €	4.570.771,93 €	4.211.410,59 €
ACFs	- 46.756.963,45 €	- 39.877.643,74 €	- 33.537.965,80 €	- 27.695.815,37 €	- 22.312.351,14 €	- 17.351.751,22 €	- 12.780.979,29 €	- 8.569.568,70 €

ARGENTINA WIND CASE

	2033	2034	2035	2036	2037	2038
Investment CFs	- €	- €	- €	- €	- €	- €
Revenues	22.280.375,17 €	22.235.814,42 €	22.191.342,79 €	22.146.960,10 €	22.102.666,18 €	22.058.460,85 €
O&M	5.057.180,77 €	5.107.752,58 €	5.158.830,10 €	5.210.418,40 €	5.262.522,59 €	5.315.147,81 €
EBITDA	17.223.194,40 €	17.128.061,84 €	17.032.512,68 €	16.936.541,70 €	16.840.143,59 €	16.743.313,04 €
D&A	6.220.207,43 €	5.517.747,10 €	5.517.747,10 €	5.517.747,10 €	5.517.747,10 €	5.517.747,10 €
EBIT	11.002.986,96 €	11.610.314,74 €	11.514.765,58 €	11.418.794,60 €	11.322.396,49 €	11.225.565,94 €
Tax	3.851.045,44 €	4.063.610,16 €	4.030.167,95 €	3.996.578,11 €	3.962.838,77 €	3.928.948,08 €
EBIT after Taxex	7.151.941,53 €	7.546.704,58 €	7.484.597,63 €	7.422.216,49 €	7.359.557,72 €	7.296.617,86 €
Depreciation	6.220.207,43 €	5.517.747,10 €	5.517.747,10 €	5.517.747,10 €	5.517.747,10 €	5.517.747,10 €
Operation CFs	13.372.148,96 €	13.064.451,68 €	13.002.344,73 €	12.939.963,59 €	12.877.304,82 €	12.814.364,96 €
Total CFs	13.372.148,96 €	13.064.451,68 €	13.002.344,73 €	12.939.963,59 €	12.877.304,82 €	12.814.364,96 €
DCFs	3.880.145,38 €	3.508.757,90 €	3.232.208,12 €	2.977.324,15 €	2.742.416,83 €	2.525.928,21 €
ACFs	- 4.689.423,32 €	- 1.180.665,42 €	2.051.542,70 €	5.028.866,84 €	7.771.283,67 €	10.297.211,88 €