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THE APPLICATION OF REAL OPTIONS TO THE ECONOMIC EVALUATION OF ELECTRICITY GENERATION INVESTMENTS

by

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ABSTRACT

The main objective of this study is the application of the Real Options Approach (ROA) on the evaluation of an electricity generation project from renewable sources, demonstrating its advantage over the application of traditional methods. Thus, it was conducted an extensive literature survey, that proves that due to the uncertainties and specific characteristics of these projects, the traditional methodologies for evaluating investments have limitations in the feasibility analysis of these investments. The traditional methods ignore the irreversibility, uncertainty and management flexibility. As an alternative to these methodologies, it was performed an analysis of investment through the ROA for a mini-hydro, using the binomial tree method developed by Cox, Ross and Rubinstein (1979) for the option to defer the project. This analysis proves that the project evaluated through ROA has a higher value than with an Net Present Value(NPV) evaluation, due to the flexibility of decision. When considering the option of deferral, the investor can get better information and reduce uncertainty, thus avoiding loss and achieving greater returns with the project. In addition, while investment by NPV and Internal Rate of Return(IRR) evaluation neglects the uncertainty on electricity prices, considering them constant throughout the life of the investment, the ROA takes into account these and other uncertainties, giving investors a more complete and realistic information. However, given that ROA assessment starts by calculating NPV, when analyzing the investment through the ROA, the traditional evaluation methods are not abandoned, since this new approach complements and refines the traditional NPV rule. This study provides a deep analysis of the major gaps of the evaluation of electricity generation projects, and it contributes to a better understanding of the ROA usefulness.

Key-words: Energy, Investment Analysis, Real Options

This dissertation exceeds the 50 pages usually suggested. The reason why this happens is twofold: instead of introducing most figures and schemes, some of them rather large, in appendix, we have kept them along the text as they make it easier to follow; the same applies to the extensive data concerning the case study. We apologize for the length of this study.

RESUMO

Este estudo tem como objectivo a aplicação da Abordagem das Opções Reais (AOR) na avaliação de um projecto de geração de electricidade de origem renovável, demonstrando as suasvantagens face à aplicação dos métodos tradicionais. Neste sentido, foi realizada uma extensa pesquisa bibliográfica, que demonstra que devido às incertezas e características específicas destes projectos, as metodologias tradicionais de avaliação de investimentos apresentam limitações na análise de viabilidade dos mesmos. Estes métodos ignoram a irreversibilidade, a incerteza e a flexibilidade de gestão. Assim, como alternativa a estas ferramentas, foi realizada uma análise de investimento através da AOR a uma mini-hídrica, utilizando o método da árvore binomial desenvolvida por Cox, Ross e Rubinstein (1979) para a opção de adiamentodo projecto. Esta análise comprova que o projecto com a ROA apresenta maior valor do que com a avaliação pelo Valor Actualizado Líquido (VAL), devido à flexibilidade de decisão. Ao considerar a opção de adiamento, o investidor pode obter melhores informações e diminuir as incertezas, evitando perdas e obtendo maiores retornos com o projecto. Além disso, enquanto a avaliaçãodo investimento pelo VAL e pela Taxa Interna de Rentabilidade (TIR) negligencia a incerteza face aos preços de electricidade, considerando-os constantes ao longo de período de vida útil do investimento, a AOR permite ter em consideração essa e outras incertezas, dando ao investidor uma informação mais completa e realista. Contudo, dado que a análise das opções reais se inicia a partir do cálculo do VAL, ao analisar o investimento por meio da AOR não se abandonam os métodos tradicionais de avaliação ou seja esta abordagem complementa e refina a regra do VAL tradicional.Este estudo fornece uma análise profunda das principais falhas da avaliação dos projectos de geração de electricidade, e contribui para uma melhor compreensão da utilidade da AOR.

Palavras-Chave: Energia, Análise de Investimentos, Opções Reais

Esta dissertação excede as 50 páginas sugeridas. Existem duas razões fundamentais: em vez de introduzir figuras e esquemas em apêndice, mantiveram-se ao longo do texto, uma vez que facilita o seu seguimento. O mesmo se aplica aos dados extensos sobre o caso de estudo. Pedimos desculpa pela dimensão deste trabalho.

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INTRODUCTION

The electricity market liberalization significantly influenced investments within this sector. The introduction of competition into the generation and supply segments of the electricity value chain brought new constraints to investment decisions related to aggravated risk and uncertainty (IEA, 2003).

Prior to the market liberalization, electricity companies were vertically integrated in a legal natural monopoly. Investment decisions were made taking into account the supply systems optimization as a whole, or in other words, minimizing the total system costs, instead of simply evaluating the profitability of a single plant. Today, due to liberalization, the framework for investment decisions changed dramatically, since the decisions and risks passed from the State and consumers to investors. Thus, revenues depend on the volatility of electricity prices while costs depend on the capital invested and operational costs.

Due to the introduction of competition, there are now not only the standard incumbent firms but also an increase of new entrants in the market. This will result in more or less significant changes in market structure, altering electricity prices and increasing uncertainty. In a competitive market, consumers can not only choose their suppliers, but can even select, in certain cases, the kind of energy source they want. Thus, competition means increased risk for companies in the liberalized branches which, as refereed by Damodaran (2001), has to be perceived "through the eyes of investors in the firm".

Electricity market liberalization brings not only uncertainty over demand but also regulatory risk. Like other risks, regulatory risk can have a chilling effect on investment by increasing risk premium demanded by investors. In these cases, the government has an essential role to provide a credible and clearly defined regulatory framework, applying changes to regulation whenever necessary to support a strong policy of diversification and security on energy supply. Even in a phased process, changes in regulatory conditions may influence investment evaluation throw its viability, for

example the changes to feed-in tariff, introduction of building permits, network authorizations and transfer price systems.
In investment decisions the fuel prices volatility for the electricity generation sector are also a key factor. If the investment analysis is too influenced by low fuel prices, instead of taking into account the main factor that is the efficient level of future prices, it may lead to wrong decisions, especially considering the high capital costs and long life cycle of projects.

Beyond efficiency, security of supply and diversification of sources of power generation are some of the objectives in liberalizing the electricity market. They seek above all to encourage electricity generation from renewable sources. Indeed, renewable energy sources and climate change mitigation – thus, the climate and energy policy– was agreed as a “package” by the European Parliament and Council in December 2008 and became law in June 2009.

Notwithstanding, in the framework of the investment analysis of renewable projects this favourable environment may be sending false signals since there can be changes to the current regulation.

Investments in power generation also feature long life cycles and sunk costs, i.e., its assets have a high degree of specificity, which implies that once the expenses are undertaken they cannot be reversed. This irreversibility involves high opportunity costs, so it has to be properly incorporated in its economic and financial assessment. Moreover, a long lifetime of the investment involves a greater uncertainty regarding projects constraints.

The constant technological innovation inherent to these projects is also a key feature in energy generation investments, particularly when regarding technologies of renewable energy generation. Most of these technologies still have a low degree of maturity which means that they are constantly subject to new developments for their improvement. In this sense, technologies cannot compete with more mature ones due to the high level of investment. However, supporting technologies can quickly become mature and competitive, therefore reducing their prices and making past technology obsolete and undervalued. On the other hand, the diffusion of renewable energy technologies is affected by the high level of uncertainty that characterizes the liberalized electricity market (price and demand for electricity) so investors have to evaluate their options under high level of uncertainty (Kumbaroğlu et al, 2008).

Therefore, when evaluating these projects one has to adopt valuation methodologies that proper capture and assess their specific characteristics, going beyond the traditional decision-making approaches. The most traditional method used in evaluating investment opportunities is the Net Present Value (NPV), but for situations where flexibility is one of the features of the project, this method consistently underestimates the value of investment, due to the fact that it does not take into account that actions such as expansion or contraction could be an option (Johansson, 2010). Moreover, these traditional methods require forms of accounting issues of irreversibility and high risks without undermining the projects value.

This investment evaluation by traditional methods, is even more inadequate in power generation investments from renewable sources, because of their high degree of uncertainty, both in technology (technologies with low degree of maturity and more expensive than conventional technologies) and regulatory risk. Many authors (for example, Dinica (2006) argue that one of the barriers to the diffusion of renewable energy technologies are the inadequate methods used to assess the costs of energy projects. The traditionally methods of valuation used in electricity investments are outdated and make projects of renewable energy technology seem more expensive (Awerbuch, 1996). Engineers and managers use arbitrary discount rates for fuel costs and operating expenses when calculating the levelised electricity generating costs, not taking into account the true financial risks associated with the cost of electricity projects, which leads to a systematic overestimation of the cost of renewable based electricity.

Thus, Real Options Approach (ROA) proves to be an important tool to evaluate these possibilities and characteristics of generating electricity projects. When dealing with uncertainty and irreversibility, ROA offers a useful approach for assessing the uncertainty over time. The main feature of this methodology is precisely the ability to account value inherent flexibility to change (e.g., contraction, expansion, delay) of an irreversible investment in the future (Kumbaroğlu et al, 2008).

Given the large gap in assessing renewable generation investments, and their high uncertainty and irreversibility, this dissertation is an opportunity not only to improve the assessment of these investments, but also to identify the best way of incorporating the ROA in the current investment evaluation practices in institutions.

The main objective of this dissertation is the implementation of the ROA on the evaluation of an electricity generation project from renewable sources, showing if there is a benefit in applying this method over the application of traditional methods of NPV and IRR. To achieve the above, this work is divided in two more specific objectives:

- To understand and identify the reasons for the failure of traditional methods in the evaluation of these projects;
- To analyze a case study of a mini-hydro project through the ROA, comparing the results obtained with the traditional analysis of NPV and IRR.

Therefore, the methodology for this work is defined as follows:

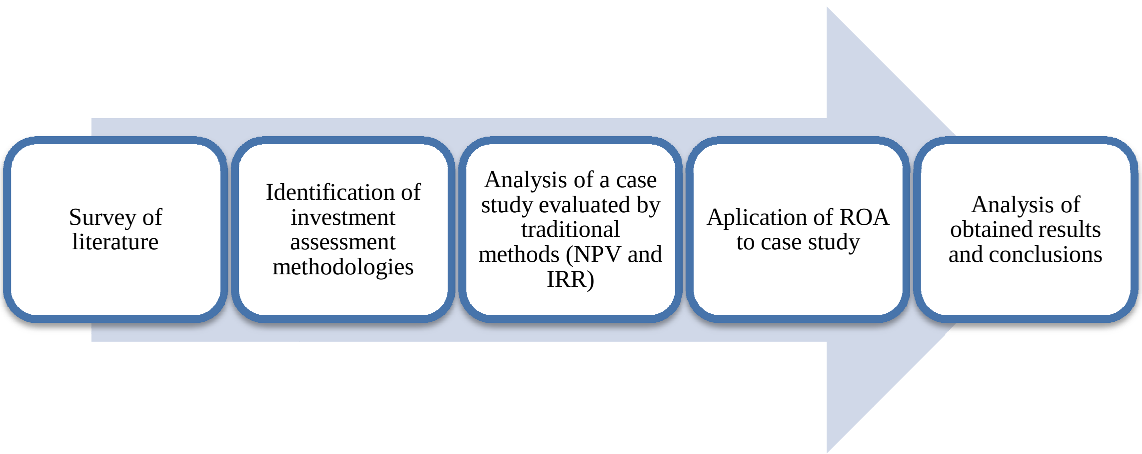

Figure 1 - Methodology of Dissertation
Source: Elaborated by the author

The literature review will serve to identify key uncertainties and characteristics of electricity generation projects, and understand the main, indicated by several authors, in assessing the projects. From this, the study proceeds to the analysis of an investment evaluation by NPV and IRR applied to an electricity generation project from renewable sources. Finally, the ROA is applied to the same case study were the obtained results are analyzed and compared.

Thus, the first chapter identifies the main uncertainties of an electricity generation investment in a liberalized market, performing an extensive literature review. The second chapter presents the methods for evaluating investments, referring the most relevant studies on energy assessment. The third chapter identifies the main characteristics of renewable energy investments and describes the methods of assessment that are considered in their decision process. The fourth chapter explains the method of the ROA. Chapter five presents the application of ROA to a mini-hydro, also making a critical analysis to the traditional evaluation of NPV and IRR. Finally, chapter six includes the conclusions and limitations of this work.

1. COMPETITION AND INVESTMENT IN A LIBERALISED MARKET

The liberalization of the electricity market significantly influences investment decisions in electricity generation. Issues as fuel and electricity prices, uncertain demand and regulatory risks, technological development, open markets to new entrants and high investment capital costs, may dramatically change the approach to investment decisions in new electricity generation projects. On the other hand, electricity generation projects have certain characteristics, such as irreversibility and high level of uncertainty that enhances the relevance of these issues when choosing investment assessment tools.

Previous to the liberalization of the electricity market, in the traditional regulatory framework, and since risk is assumed by costumers, investors have a guaranteed payback in their investments. Moreover, energy prices were not equal to energy costs within this scheme in most countries as prices were directly or indirectly (through cross-subsides) subsidized. Henceforth, within the new regulatory framework, risk is assumed by investors and energy prices tend to represent private costs (IPTS, 2000).

This change makes electricity generation companies dependent from the volatility of energy markets. In this new scheme, companies must manage risks related to daily operation (short term) and also long term operations. Accordingly, market-based methodologies must be used to plan their generation capacity, to assess investment opportunities and to maximize asset value. Thus, there will be a strong demand by electricity generation investors for protecting tools against financial risks (*hedging*), and appropriate strategic investment evaluation methods.

Even though these risks affect all generation technologies, it does so in different ways. Technologies with higher specific investment in capacity, such as renewable technologies, in spite of having a lower fuel cost are the most affected by this risk, due to their lower response capacity. So, technologies with high capital costs and low fuel costs can probably be competitive in the short term and therefore be chosen to as an investment option. However, if there is a continuous decline in the electricity market prices, companies supported on these technologies could face serious financial problems. (IEA, 2003)

The analysis of different risks and uncertainties related to electricity generation investments in a liberalized market is crucial not only to the decision process, but also to the improvement of planning. In doing so, there will be a detailed analysis about main risks and uncertainties related to the liberalized electricity market and their influence on investment decisions.

1.1. Uncertainty in electricity prices

In the framework previous to electricity market liberalization, the price changes were minimal and heavily regulated by state or by the sector regulator. With market liberalization, the price increases significantly, stimulating the development of new contracts, with physical or financial exercise, and with electricity as an underlying asset which allows the practice of *hedge* against the risk associated to the high price volatility by agents.

The restructuring and liberalization of the electric market have been based, in most markets, in *spot* price theory. Schweppe et al (1998), developed the theory that spot price in an electricity market in perfect competition is determined by the intersection between demand and supply curves, which in turns, equals them to marginal costs of electricity generation. As demand changes, also spot prices alter, sending economic signals to market participants, in order to effect a better management of their resources.

On the other hand, Deb et al. (2000) argues that in an electricity competitive market, the spot prices are not determined exclusively based on cost. Rather, they are defined on the basis of competitive rational behaviour of market participants, and its objective is to maximize income from all available markets, including auxiliary services and markets of emissions allowances. Traditional production-costing models do not represent the multi-commodity electricity market, since they ignore transmission constraints and neglect volatility, not being adequate models for the emerging competitive electricity market.

The inability of electricity storage combined with a demand peak, may cause sudden price increases, denominated *spikes*. Kanamura and Ohashi (2004) argue that deregulation of electricity markets has caused electricity price *spikes*, and the associated risk, affects energy companies positively and negatively, according to transaction type. On the one hand, price spikes can provide profitable opportunities for companies that are trading in the *spot* market to high prices, but on the other hand price spikes may be a burden if companies have electricity supply contracts with very low predetermined prices.

In most commodity markets, price effects are mitigated by surplus storage. In contrast, most electricity systems have a gap in storage. The volatility in the electricity market happens hourly, daily and seasonally, associated with fundamental physical and market drivers for generating and distributing electricity, which creates a great need to correctly predict these variations (Deb et al., 2000).

Schindlmayr (2005) shows that *spot* market behaviour is essentially characterized by three conditions, which were not usually observed in other financial markets. The first condition relates to the seasonality in electricity spot prices that present seasonal pattern in different scales of time (annual, weekly, daily), which reflect the typical patterns in electricity demand. The second condition is Spikes, since spot prices may exhibit extreme price peaks in times of high electricity demand (for example, cold or hot weather) and limited generation capacity (for example, central outages). Finally, there is no cash-and-carry arbitrage relation between spot and future prices, since electricity is not efficiently storable, and thus, forward curve can has a very complicated seasonal pattern.

Besides these, Skantze *et al* (2000) suggest other factors that underlie the electricity price formation related to the demand and supply characteristics. On the one hand, the demand characteristics that influence electricity prices are:

- Demand Elasticity: The elasticity electricity demand / price is low, since the liberalization process of electricity market is still very recent and changing habits means that consumers are less sensitive to electricity price movements.
- Mean Reversion: It is the tendency of a given variable which, in this case, is electricity price in return to its long-term average value. When it observes temporary *spikes* in electricity demand, levels achieved by demand in these situations are not sustainable, so the demand eventually returns to previous levels.
- Stochastic Growth: The demand growth is directly correlated with economic evolution. The forecast of this growth is difficult when looking in long time horizons, and therefore, should be considered stochastic.

On the other hand, Skantze *et al.* (2000), still suggest main supply characteristics that influence electricity prices:

- Supply Elasticity: The Supply elasticity related price is high. The generators are the mainly responsible by price formation through their bid into the market. In spite of operational costs are dependent on technology used in generation, the market power exercise and strategies used in sale offers execution, influences the form of the aggregated bid sales curve, and consequently, the market price.
- Stochastic Availability of Generation: Generators can be offline from time to time, due to unexpected equipment failure or planned maintenance. This can significantly influences availability of supply on the market-clearing price.
- Fuel Costs: The uncertain fuel costs, especially for oil and gas, impact the generation costs, and consequently, on generators bid into the market.
- Unit Commitment: Nonlinear characteristics of generator cost function, such as start-up costs and minimum run times, have an influence on their dispatch, and consequently, on market price.

- Import/Export: The generators and consumers participation in external markets may involve changes in sale and purchase strategies, respectively, influencing market price.

Due to all these constrains, electricity prices are difficult to predict, which carries a very high risk for electricity generation investments. Additionally, market liberalization has yet a greater level of uncertainty due to the introduction of new competitors and to the possibility of consumer's choice. Newberry (2002) argues that defenders of the old structure of electricity industry defend that integrated vertically monopolies with regulated final prices, are the only politically sustainable structure, which is needed to ensure an adequate capacity to avoid shortages and/or high prices. The cost of failed liberalization has already been demonstrated (by high prices and by impact on economic activity in case of energy outage) to an unacceptable high level, and undermines the whole electricity liberalization process.

Furthermore, Gross (2010) argues that the influence of risks associated to electricity price volatility in investments differs by technology. The low electricity prices represent a revenue risk for the technologies that cannot influence these prices. In contrast, This author also said that "price makers", who define marginal prices, are largely able to pass fuel price increases to costumers, obtaining "hedge" against fuel and electricity price fluctuations.

With the liberalized electricity market, price fluctuations and financial risk associated assume a growing importance, particularly, because it is estimated that in the next few years the volatility of energy prices will probably increase due to several issues such as: the intermittent power from renewable energy sources, the growing scarcity of fossil fuels and the increase in speculative trading in energy commodities. Therefore, price volatility will become a key factor to consider for investment decisions (Kienzle and Andersson, 2009). Similarly, Green e Newbery (1992) in their article about initial problems of high market power and concentration in England and Wales, show that electricity prices in the liberalized market are closely related to the number of players and tightness of the market, i.e., the supply and demand balance. The combination of low price elasticity of demand and a low number of competitors means that market prices can easily deviate from competitive levels (Jamasb and Pollit, 2005).

Neuhoff and Vries (2004), argue that spot prices theory suggests that energy spot markets will provide sufficient incentives for generation capacity investment. This result still remains in the presence of uncertainty. However, in the absence of a sufficient volume of long-term contracts or similar mechanism, the result cannot be sustained, if investors or end-consumers are risk-averse. These authors identified various uncertainty types, which induces risk-averse investors to reduce the balance volume of generation capacity relative to risk-neutral investors. On the other hand, if risk-averse consumers can sign long-term contracts or invest directly in electricity generation, they develop a greater volume of electricity generation capacity than risk-neutral investors or consumers. This suggests that electricity price risk vary not just by technology but also by the type of investor and their risk aversion. Moreover, these authors argue that high inter-annual price uncertainty in the electricity markets can encourage regulators to intervene during periods of high prices, which limit expected revenues, and consequently, decrease the incentives for generation capacity investments. Due to the fact that the construction of electricity generation plants is characterized by a long lead-time and long economic life, incomplete information about future demand and supply increases investment risk. The limited predictability of future electricity prices induces generation companies to rely more on current prices to make their investment decisions.

Neuhoff and Vries (2004), prove that electricity prices are higher and more volatile, if investments are financed through revenues from the spot market. High inter-annual price volatility results in higher risk premium on capital. If this risk premium does not derive from underlying fundamentals, but is caused by flaws in the market design, then it biases investment towards less capital-intensive technologies, which represents a barrier to renewable technologies that tend to have the highest ratio between capital and operating costs.

The report of IEA (2003) concludes that electricity price uncertainty exposes projects with long lead-time and long construction time to additional risks. Scale economies favour large electricity generation projects compared to smaller projects. However, the combination of a long lead-time of projects, the uncertain growth in electricity demand and electricity prices, and uncertainty in total costs of construction financing, increases the risk for major investments. Moreover, large projects, which should actually be built as a single large plant, are more vulnerable to this risk than projects which development can be phased while smaller power plants respond to market conditions.

Given this situation, electricity generation investors need financial tools that allow hedging against price volatility in the *spot* market. In order to answer this necessity, in some electricity markets were introduced derivatives markets that trade contracts whose underlying asset is electricity. These markets, besides having an important role hedging against price volatility in the spot market, allow the elimination of credit risk and the increase of liquidity in the market (Peixoto, 1995). The derivatives markets transact, among others, *forward*, future and option contracts.

Forward contracts are bilateral contracts, in which both parties, mutually, agree on specific transaction details (price, quantity, date and place of delivery) with payment and goods delivery on a future date (Peixoto, 1995). Since the price is fixed at the outset, the parties mitigate risks, but also limit potential gains. In these contracts, the seller holds a short position, and the purchaser holds a long position. The price defined in *forward* contracts, is designated as *delivery price* (Azevedo, 2007).

There is a clear distinction between markets *over-the-counter* and bilateral markets. In *over-the-counter* markets, the contracts are established through an intermediary or broker, while in bilateral markets, the contracts are set, freely, between parties, without the intervention of any intermediary. In both markets, traded contracts include the existence of physical delivery of electricity, having to be subject to approval by the System Operator (Azevedo, 2007).

Future contracts are contracts traded on organized markets, commonly, referred to as exchanges, where the long position holder (buyer) assumes the obligation to buy the underlying asset, under established conditions (price, quantity, place and date of delivery) and the short position holder (seller) assumes the obligation to sell the underlying asset in the same conditions (Peixoto, 1995).

Options contracts are negotiable contracts, made in organized markets or not, in which a seller, in exchange for a monetary counterpart (premium), gives a buyer the right to buy him (call option) or sell (put option), until a certain date (expiry date), an asset (base asset), under standard conditions at a predetermined price (exercise price) (Peixoto, 1995).

Although, in their essence, *options contracts* are bilateral contracts, the *options* are fundamentally different from *forward* and *future* contracts. The *options contracts* give to their holder the right to buy (call option) or sell (put options) the base asset until expiration date. However, the *option* holder is not obliged to exercise that right. By contrast, in *forward* and *future* contracts, both parties make a commitment, which necessarily have to result in a buy / sell action. To hold a position in a *future* or *forward* contract, the costs for the buyer are null, except for margin requirements, while to hold a position in an *option*, the buyer has to make an advance payment, denominated *premium* (Azevedo, 2007).

These long-term bilateral contracts reduce risk, but also reduce the possibility of receiving the benefits of efficiency gains, while short-term contracts are more flexible, but more risky. Moreover, these bilateral contracts also have reduced transaction costs (IPTS, 2000).

Nevertheless, the report of IPTS (2000) identifies two main problems related to these contracts. On the one hand, this mechanism tends to benefit large players, since there is an information asymmetry under this scheme. This effect may be greater in oligopolistic industries, and can mean an inefficient allocation of risk for small companies. On the other hand, energy prices can reflect only private costs, given that bilateral contracts are essentially private arrangements (unless there is regulator intervention). Moreover, even though in perfect competition theory implies lower prices than in the regulated traditional framework, this scheme favours large players who could exercise their market power and therefore, increase prices. Furthermore, transaction costs are high for small players, which would see their total costs increase.

In fact, it is evident that while electricity *spot* markets attract much attention with their high visibility and frequent price changes, any company that depends on them takes a large risk. Most companies do much of their trading through long term contracts, but currently it does not imply that contracts last for decades, only years (or even one year). Green (2005) said that a combination of a bilateral contract and an appropriate set of bids in the market, allows a company to fix the cost of a given electricity volume, to respond to margin of spot market price. Once the contracts reduce the importance of the spot price for company's profits, they can act as a mean of mitigating market power.

A problem for contract markets is that if investors in electricity generation projects use these contracts to finance investments in new electricity plants, the contracts will need to vigour for several years (Green, 2005). Retailers may be willing to sign contracts if they are reasonably certain that they can pass on the costs to their consumers, and this was the case when retailers had monopoly franchises. Thus, given that retail markets are opened to competition, retailers face risk of retail prices due to their close connection to the current wholesale price. If there is a drop in the wholesale market prices, the retail companies will not be able to pass the cost of their contracts to consumers, which make them reluctant to sign long term contracts with investors in electricity generation (Green, 2005) (Joskow, 2006).

1.2. Uncertainty in fuel prices

The fuel prices strongly influence investment decisions in electricity generation due to the fact that, technologies with a high proportion of fuel costs in their total production costs are more exposed to the risk of price variation with high impact in net income. It should be noted that the effect of this kind of risk varies with the type of technology used in electricity generation, since it is more relevant in electricity plants that use fossil sources and not so important when dealing with renewable electricity plants. In this way, given that fuel costs are the most relevant variable cost in electricity generation from fossil fuel, fuel prices volatility is an important risk factor to take into account in the investment assessment of these plants (NETL, 2010).

In doing so, when evaluating important issues of investment decisions in electricity generation within a liberalized market, it is important to analyse the level and development of the difference between electricity prices and fuel costs used in electricity generation - “spark spread” (IEA,2003). The importance of the “spark spread” depends on the type of plant and its estimated usage. As a result, for base load electricity plants that work for a large number of hours, is desirable a favourable “spark spread” so they can operate in full thus recuperating from high capital costs. For peak-load plants, with higher fuel costs, the capital costs should be recover over a lower number of hours. This way, the flexible generation plants will be able to take advantage whenever “spark spread” is favourable (IEA,2003).

The “spark spread” may vary depending on the kind of fuels used and can also be different in plants that use the same fuel (NETL, 2010). However, it is important to note that this value must be positive for the operating plant, otherwise the plant contribution would be negative leading to an operational stop, due to profit losses. In the long-term, “spark spread” must be high enough so that investors have the expected return of their investments.

On the other hand, fuel costs will not only have isolated effects on investment viability, but also contribute extensively to the formation of a plant production costs, since they represent a significant part of the variable costs and thus influencing electricity prices.

The fuel prices and plant efficiencies for the system marginal plants establish the short-term electricity price in wholesale market (NETL, 2010). This means that fuel prices volatility is reflected in electricity prices, and thus possible fuel price increases can be transferred to wholesale consumers, giving investors some degree of natural "hedge" against fuel price variations.

The fuel prices impact in electricity prices happens, partly due to the fact that fuels are used as an input for electricity generation from fossil fuels, which still represents a large proportion of total electricity generation. On the other hand, the market movements of these commodities as the oil case, constantly causes impacts in all the economy, being the electricity market no exception. Besides that, in many cases, these fuels are electricity substitutes in consumer choices in energy markets. At last, under market-based pricing, electricity prices should, in part, reflect fuel costs at least in the long-term, whereas under cost-based pricing it should reflect a mark-up over average or marginal costs (Mohammadi, 2009).

However, it is not sufficient to expect that in a liberalized market the sale prices of their output covers input costs, due to the existence of large price volatility and a high variety of conditions that quickly change market movements. In this way, to mitigate risks of uncertainty associated with fuel prices, investors seek to establish long-term contracts that result in a diversity of trading activities and contract structures, including forward contracts and more complex financial derivatives contracts, which support management risks (NETL, 2010).

Henriques and Sadorsky (2010), consider that environmental sustainability in a company may be another form of risk management in energy prices, leading to a competitive advantage through lower operating costs and lower business risk. In this article, is proven that the increase of environmental sustainability can lead to a reduction in risk exposure of companies in terms of energy price. Furthermore, environmental sustainability also offers a way to address the issues of energy security and climate change, since both of these issues contribute to the risk of energy price.

In response to the risk in energy prices, companies have invested in alternative energy technologies that do not depend on fossil fuels which are highly volatile in market.

Economic theory suggests that higher oil prices induce the development of alternative energy sources. Sadorsky and Henriques (2007) found, however, that the shocks in oil prices have not a significant impact on the price of alternative energy. They suggest that governments should support the emergence of these technologies, with a clear energy policy.

Bernanke (1983) demonstrates that when there is greater uncertainty about the future price of oil, it is ideal for companies to postpone irreversible investment execution, since the uncertainty increases the option value of waiting to invest. While waiting for new information about the uncertainty of oil prices, the company improves its chances of making the correct investment decision.

The risk of fuel costs can influence dramatically the expected return on investments, thus it is important to assess properly the uncertainty in order to obtain reliable results. Even with risk mitigation long-term contracts, markets are excessively volatile, which difficult the prediction of future movement fuel prices.

1.3. Uncertainty in Demand

In the traditional system prior to electricity market liberalization, there was an monopolistic supplier whose responsibility was to ensure an efficient generating capacity for all consumers, being that the prices were regulated, and therefore, somewhat little influenced by demand and supply trends. In liberalized market, the function of balancing supply and demand is made in real time, usually through electricity wholesale market, where information about the balance between supply and demand is signalized by electricity prices. The electricity buyers in wholesale or retail markets, finally, can finally have an option in the choice of their supplier, making demand a higher risk to investment, not only by traditional determinants, such as electricity and substitute fuel prices, weather conditions, income or changes in economic, politic and social conjuncture, but also by the upcoming uncertainty derived from power of consumer choice.

Kirschen (2003), argues, however, that consumers have little influence on the design of electricity markets, this is justified by the fact that these small consumers do not have financial incentives and necessary skills to contribute effectively to a task so complex and lengthy. Consequently, due to this lack of representation, most of the electricity markets do not consider consumers as a truly genuine demand able to make rational decisions, but simply as a load that needs to be satisfied in all conditions.

According to Joskow (2006) in a long-term investment perspective, the electricity demand depends of the average level of electricity future prices, substitute fuel prices, replacement rate of appliances and equipment and also on the level and composition of aggregated economic activity. He also asserts that in short-term, electricity demand is particularly sensitive to weather conditions since the climate changes lead to large variations in demand for heating and cooling, being the price and income elasticity's very low in the short-term.

Changes in electricity demand are also conditioned by issues of behaviour due to environmental concerns. This case reveals to be highly favourable for the proliferation of renewable technologies. Since some consumers, groups and companies value the potential of low carbon electricity, these are crucial in driving the transition to renewable electric system, helping to push necessary innovation and increasing political acceptability of the company (Laing and Grubb, 2010).

In this way, given the variations in electricity demand and since it cannot be stored, is necessary to plan availability of supply in accordance with highest prediction demand and error margin. If this is not done, supply interruptions in form of falls and blackouts would be common, causing considerable economic damage. Thus, it is essential to ensure continued supply of electric energy.

Moreover, Holmberg and Newberry (2010) defend that electricity has specific characteristics such as too expensive storage, and high variation in demand and supply over the day and season, both subject to sudden shocks, which causes gaps in the provision, either in terms of generation or in terms of availability of line. Therefore, it is essential to have a system operator to balance supply and demand and ensure that the energy flow through the transmission lines does not exceed security limits.

The need to ensure electricity supply establishes that the investment planning in new plants is primordial activity, which must be undertaken in a systematic way. For this, responsible entities must anticipate, as safely as possible, the electricity demand in a more or less distant future, so they can make a planning decision about plant types to be implemented, its size and timing to achieve investments. The long-term forecast in electricity demand is therefore crucial in the analysis of any investment, and it should be performed with utmost rigor. Incorrect previsions can not only mean a generating capacity constrain, but also a key error in investment viability analysis.

Economic theory suggests that electricity consumers will increase demand to the point where the marginal benefit of electricity consumption is equal to the price they are willing to pay. But, according to some studies, the empirical evidence suggests that the price elasticity of demand of electricity in small in the short-term (Kirschen, 2003).

According to Kirschen (2003), there are three main reasons for this elasticity to be low. First, the cost of electricity represents only a small part of the total production cost or the cost of living for most families. At the same time, electricity is essential in manufacturing and is considered essential to the quality of life, therefore most industrial consumers will not reduce production to avoid a small increase in their electricity costs, since that in the short term, the savings can be more than compensated by the loss of profit. Similarly, most residential consumers probably will not reduce their comfort and convenience to reduce their electricity bill by a few percentage points. The second factor that explains this low elasticity is partly historical, since the early days of commercial electricity production, electricity has been marketed as a commodity that is easy to use and always available. This convenience is installed in such a way that very few people make a cost / benefit analysis each time they use electricity. This author also shows two main consequences of this low elasticity. On the one hand causes high price spikes, and on the other hand, facilitates the exercise of market power by generation companies.

Joskow (2006) explain that in investment perspective, with the traditional model of regulated monopolies, the planning of generating capacity reflected long-term uncertainty in demand and supply, establishing reserve margins beyond the expected level of electricity demand peak. These reserve margins were based on forecast demand peak and capacity levels, assuming that full capacity would be available at the time of system peak. The reserve margin can, typically, include contracted demand response that the system operator can control, but does not assume that demand would respond to fast changes in real-time prices. On the other hand, in a short-term operating perspective, the amount scheduled generating capacity to electrical energy supply incorporates capacity applied for frequency regulation[1], operating reserves and replacement reserves.

This author also argues that with market liberalization, there is no longer a static role of operating reserve margins in electricity systems. In normal operations, the generating capacity is now scheduled by the system operator to supply energy, through wholesale energy and operating reserves markets. In the moment that the level of operating reserves cannot be maintained, because there is no additional generation or demand response available for the system operator to appeal, an "operating reserve emergency" or "operating reserve shortage will be declared. As a result, the capacity constraints are actually achieved when generating capacity available for the system operator falls below 110% of current demand. Therefore, a more realistic characterization of capacity constraints should include operating reserves in total capacity required to respond to any demand level.

[1] Frequency is number of times for second that alternating current is transmitted over electrical grid, being necessary to regulate this frequency to ensure that devices operate as expected. To do this, utilities must balance electricity generation with load at all times. This balancing act on short-term scales is known as frequency regulation.

The issue of capacity planning of electricity generation is crucial for the viability results of these investments. Since electricity generation is characterized by scale economies, combined with its irreversibility, an error in determining the dimension of capacity generation with the available demand can be decisive in turning the project completely unfeasible. With the electricity market liberalization, determination of demand future movements brings higher uncertainty level, given a higher variety of suppliers and the unpredictable choices of consumers.

The increasing uncertainty in electricity demand brings other main issues for energy generation investments. For example, in case of a demand decline, investors should manage the risks associated with uncertainty with the expectation of when there will be a demand recovery, which will be the strength of this recovery and the response time of market for this increased demand. This situation adds risks that investors have to manage in terms of ideal timing and location of new investments (NETL, 2010).

In addition, an economic recession with a negative impact on electricity demand, reducing the need of additional generating capacity, can influence the new electricity generation investments to be delayed or cancelled, depending on the strength and duration of this reduction impact. An electricity demand decline, leads to a decrease in dispatch and energy price projections, affecting project returns, since it can reduce its cash-flows and therefore, change their economic viability. If this decline is long-lasting, the potential returns of electricity generation investments may prove to be unsatisfactory, increasing risks for investors, leading to an increase of financing costs and investment delay.

For Holmberg and Newberry (2010) electricity prices are volatile because electricity is not adequate for large-scale storage and in the short-term, supply and demand are very inelastic. Thus, to cover the risks inherent to these factors, market participants can buy and sell various derivative contracts, for example, futures and forward contracts, which bind the conditions of buying and selling.

1.4. Regulatory Risk

An electricity generation plant investor faces considerable regulatory risks, not only in terms of the electricity market design, but also in terms of environmental regulations (for example, polices against climate changes). Unless there is liquidity in the long-run markets, where the investors can recover from their financial risks, these uncertainties can significantly reduce investment in new generation capacity.

Neuhoff and De Vries (2004), argue that normative changes can increase the risk of investment and, therefore, create a negative impact on the willingness to invest. Moreover, they argue that a second source of regulatory uncertainty is caused by a possible lack of regulatory commitment.

The implemented polices affect the risk of investment in several ways. The governments can create incentives and support schemes, but these policy changes may influence the markets, especially if political parties have a different view of energetic policies. When governments introduce changes in the regulation, there are impacts on electricity prices, more market volatility and increased risk. Gross et al., (2010), defend that the approach in which regulators will assume market governance influences market structure and price volatilities. Market power can reduce this volatility, but the fear of regulatory intervention may also depress certain investments. Furthermore, these authors claim that policies or electricity regulation related to issues such as the difficulty of securing planning permits, grid authorizations and transmission system pricing, affect the viability of investments.

This regulatory risk related to apparent stability of environmental policy will influence the financial cost of an investment. However, such policy can also create markets through a variety of supports or incentive mechanisms to increase returns or decrease risks, such as feed-in tariffs, fixed premium or green certificates.

Fuss et al. (2008) proved that policy uncertainty induces the producer to wait and see if the government will continue to engage with the climate policy. In other words, if the wait to obtain more information about the government's commitment is more valuable than investing in carbon neutral technologies immediately, the option value of waiting exceeds the value of the technology and investment will be postponed. This can lead to a shortage of supply and a limited diffusion of technologies that are less carbon intensive.

Changes are common in market and institution regulations, since they impose new regulatory restrictions or influence market prices, which generates large levels of uncertainty on future public polices and creates a barrier to new investments. This is especially problematic in electricity markets, because a large portion of net revenue, necessary to compensate investors for the capital invested, relies on very high spot market price that only takes place during few hours each year (Joskow, 2006). The potential opportunity for market rules and regulatory actions to keep prices bellows satisfactory levels, even a few hours each year, when efficient price levels would be high, may seriously damage investment incentives (Joskow, idem).

On the other hand, these technologies reveal substantial economies of scale as a consequence of high construction costs and relatively low operation costs, frequently restricting the number of companies which can efficiently operate (CEC, 2007). Accordingly, the policy makers can substantially reduce regulated tariffs or investor returns through other policy changes, knowing that, while operational costs are covered, owners will still continue to operate (Holburn et al, 2009).

Moreover, the services provided by the utility sector are consumed by the general public, who often regards them as essential services and “natural” rights. For this reason, prices of public utili**ties** become highly sensitive, providing an opportunity for governments to often act with political interests, trying to please the public opinion (Holburn et al, 2009). This issue may imply that any time the public entities can, for example, decrease incentives given to energy generation investments, causing serious problems in its economic viability.

Holburn et al. (2009) argues that these regulatory risks also vary according to the adopted technologies. Comparing the renewable technologies with traditional technologies from fossil sources, we can see that renewable technologies have a higher average cost of electricity production. In doing so, there are regulatory policies that seek to encourage electricity generation through renewable sources making these technologies more competitive than the ones. These instruments can be, for example, incentives for their development or even establishing fixed tariffs, which compensate for the gap relative to generation costs. Consequently, a change in economic priorities or polices can create pressures to slow the commitment progresses of renewable generation and turn them a little less competitive than the traditional technologies.

On the other hand, Fuss et al. (2008) concluded that the capital intensive energy sector is particularly vulnerable to political uncertainties that affect the revenue stream from (irreversible) investment. The future control of emissions is a key risk to the economic viability of investments in the sector that the policy seeks to regulate.

Holburn et al. (2009) also believe that the rapid technologic progress on renewable energies can also lead governments in changing their policies, supporting certain technologies, especially, if costs decrease significantly. However, despite the costs of these more matures technologies, such as wind, biomass or solar, have decreased, their future costs are still very uncertain. Besides these uncertain costs, there can be unforeseen costs that may make investments in these technologies less attractive. Thus, as relative costs of renewable technologies change over time, governments may be tempted to alter the relative subsidy levels, updating their policy objectives, reducing or increasing subsidies to specific technologies. Obviously, according to those authors, this causes big uncertainty for investors, and may even originate situations of non-viability of their investments, since they consider a favourable conjuncture of supports that may not match the expected period. As a result, it is crucial that an investment analysis seeks to analyse the various possibilities inherent to regulation changes.

Furthermore, the electricity generation from renewable sources typically operates on smaller scale than traditional generation technologies. **T**his kind of electricity generation is geographically dispersed, often in different jurisdictions, which means that investors have greater uncertainties in the expected return on their investment, since indirect costs are amortized by small dispersed plants over a period of several years (Holburn et al, 2009).

Burns and Riechmann (2004), in their article about the influence of the regulation instruments on investment performance, argue that, depending on how the parameters of the regulatory regime are set, the incentive based regulation can lead to an excess or insufficiency of investment, too high or too small output provision, distorted input usage and distorted investment timing and efficiency gains. The authors suggest, therefore, a movement towards an output-based regulation, where the output also includes quality indicators that have been ignored for a long time. The regulator can choose a combination of price and non-price incentives to ensure that output provision is settled in a socially acceptable range.

1.5. Technological progress

Uncertainty related to technological progress is highly important for investment decisions in electricity generation since they affect their viability. Obviously, also in this uncertainty type, their interest varies according to the technology used, i.e., more mature technologies, such as the case of fossil-fired technologies, will have lower technological risk, since their progress is relatively stable. On the other hand, less mature technologies, such as renewable technologies, are still suffering large technological advances that can obsolete the current technologies, being this the greater concern when assessing this uncertainty.

Kenneth Arrow (1962) questioned Schumpeter's view that firms with monopoly power would be primarily responsible for business innovation, particularly due to higher human, financial and organizational resources. Arrow noted that, while it is true that innovation activity is often risky and resource consuming, it is even more important that who initiates and fosters innovating activities has the right incentives to do so. The monopolists are those who have less incentive, since the innovation, either because they introduce new products or because they develop more efficient processes, are just "replacing themselves" (replacement effect). Thus, the monopoly companies may have the resources, but will not have the necessary incentives for innovation. As a corollary, Arrow argued that are the more competitive environments that have higher incentive for innovation.

Since we are currently facing a growing demand for low carbon electricity, innovation is needed across a range of technologies. However, Laing and Grubb (2010), argue that the electricity sector has suffered from a lack of innovation and investment in research and development (R & D). The intensity of R & D in the electricity sector is only a small fraction of the most innovative sectors (pharmaceuticals, software and computer services). A large part of the current technology incorporated in generation, transmission and distribution is based on technology used a century ago.

Laing and Grubb (2010), pointed out some of the main reasons for the lack of innovation in this sector. One of these reasons can be related to the scale and technological risk associated with the heavy engineering involved in converting large amounts of power. Furthermore, although it was expected that liberalization would injected more innovation, in terms of operational practices, there has been a collapse of new R & D, due to the fact that investors are seeking quick returns.

Moreover, electricity is a homogeneous good, which means that there is little product differentiation in the electricity sector, and generally, electricity consumed is identical and has the same price. This lack of product differentiation reduces the incentive to innovate. A new electricity generation source is forced to compete against incumbent technologies, that have beneficiated from decades of development, economies of scale and adaptation of regulation, exclusively within prices. Renewable technologies can be supported by carbon price, but that differential price, driven and limited by politics, is the only basis on which innovation can recover all the costs and risks of its R & D.

Compared to other uncertainties, studies show that technological progress is considered like a risk for electricity generation investment, since it is unclear the intensity degree of technological innovation and when it happens. For example, Murto (2003), in his article about "Timing of investment under technological and revenue related uncertainties", through the Real Options Approach (ROA), states that revenue uncertainty is different from technological uncertainty in terms of concept, i.e., a characteristic property of technological progress is that it moves in only one direction. Thus, innovations can only improve the best-available technology, not worsen it. Consequently, when referring to uncertainty in technological progress, one refers to the speed at which technology improves, not the direction in which it moves.

The same author presents some conclusions related to revenue and technological progress uncertainties. On the one hand, in the absence of revenue uncertainty (i.e., when the volatility of revenue process is set to zero), the technological uncertainty has no implications for the project. The investor can act as if the stochastic process for the investment cost was replaced by its expected path. Nevertheless, when revenue uncertainty is added in the model, the technological uncertainty starts to have also importance. Therefore, maintaining the expected path of investment fixed cost, the higher the uncertainty in the process, more reluctant the investor is investing. It is concluded that the effect of technological uncertainty depends crucially on whether the revenue stream is deterministic or stochastic.

Fuss and Szolgayová (2010) also relate the technological progress with another type of uncertainty, namely, fuel prices uncertainty, placing great importance in comparing fossil-fuel-fired and renewable technologies. This author argues that, despite the fact that less carbon-intensive modern technologies, being still too expensive, they maybe submitted to improvements due to technological future progress, making them more attractive, especially if the fossil fuel price volatility of traditional technologies become riskier. At the same time, the authors conclude that technological progress has a high uncertainty level, particularly, associated with the progress in renewable technologies, which leads to investment delay. Even with the simultaneous inclusion of stochastic fossil fuels prices in the same model, renewable energy is not competitive with fossil-fuel-fired technology in the short-run.

Technological progress uncertainty is also related with the fact that the investments in these technologies are irreversible, which makes this uncertainty more significant in determining the viability of electricity generation (Murto, 2003, Farzin et al, 1998). Therefore, it becomes essential to seek tools that properly assess the impact of technological innovation in these investments, determining, which technology should be adopted and when it should be adopted. The importance of technological uncertainties becomes more clear, when we see that the company's decisions about when to adopt innovations, depends on how fast and how technology will advance over time (Farzin et al, 1998).

In several studies about this subject, it is considered that the process of technological innovation is a stochastic process, such that in general there is not only uncertainty about the velocity in which new technologies become available for adoption, but also about the extent of efficiency gains of new technologies relative to the current state of the art (Farzin et al, 1998, Murto, 2003, Fuss and Szolgayová, 2010).

In doing so, Farzin et al (1998), argues that when there is fast technological change, there is little chance of recovering the capital cost invested in any new chosen technology such that, the choice of technology becomes largely irreversible. Under such circumstances, the technology adopter should consider two kinds of costs among themselves, on the one hand, the mistake cost of adopting too early (as the sunk costs cannot be recovered for reinvestment, should a more efficient technology become available later on) and, on the other hand, the opportunity costs of waiting in expectation of better future technologies (such as potential benefits that will be foregone during the waiting period).

Murto (2003) also considers that even if the technological improvements, after investment, does not affect the values of existing generating units, the investor decision to hold an project now, or perhaps later, must take into account the fact that the postponement of investment could allow the project execution later with improved technology. For projects with payback horizons extending over many decades, such considerations may be very important. The history of wind energy production supports this view.

Farzin et al (1998), in his article about how the optimal timing of technology adoption is affected by uncertainties inherent in the process of technological innovation, namely, uncertainty about arrival velocity and extent of efficiency improvement of new technologies, also concludes that even in the absence of other types of uncertainties, for example, uncertainty about market conditions, the optimal timing for a company to adopt new technologies is greatly influenced by technological uncertainties. Interestingly, the comparative static results indicate that some effects are in stark contrast to what common intuition might at first suggest. Specifically, it was found that here, contrary to what happens with the method of the conventional net present value:

- the higher discount rate, the lower the trigger efficiency level of technology and thus faster the timing of adoption;
- the slower the expected pace at which more efficient technologies arrive, or the shorter the expected maximum improvements in future technologies, the lower the trigger efficiency level of technology;
- innovation adoption will be slower for companies that are already at the forefront of technological efficiency.

Zon and Fuss (2006), discovered in their article about irreversible investment under uncertainty in electricity generation, that the incorporation of technological change, combined with the expectation of future change to another technology, may actually reduce investment in this current technology (while temporarily increases current investment in competing technologies). This allows rational investors, that are risk-averse, to maximize their productivity gain, while waiting for the technological change to take place and then investing more heavily in newest vintages associated with this technology.

With liberalized electricity markets, investors in electricity generation are facing higher competition and need to internalize and cover a large number of uncertainties. These can be volatile fuel prices risks, or uncertainties about how renewable technologies will actually develop in terms of their efficiency. Zon and Fuss (2006) argues that due of these technological uncertainties and high capital costs, investors in the electricity sector may still be reluctant to adopt renewable technologies on a large scale, although, by doing so, they may have to expose themselves to a higher degree of fuel price risk. Nevertheless, by composing a portfolio of technologies with different (co-)variances in the price changes and rates of technical progress, producers can effectively hedge these types of uncertainties. This implies that producers will opt for a combination of technologies, including technologies that are not yet fully developed.

Other studies show that when new companies introduce innovation, reflected in the improvement of a given technological process, the incumbent companies, that use technology not yet incrementally developed, will evaluate the economic costs of technology change and only tend to invest in innovation if the costs are low or the earnings potential is high. Otherwise they will tend to maintain the current technology, since the cost of entry is already internalized in their cost function - the effect of sunk cost. For the entering firm, the investment decision of entry into the market considers the possibility of adopting a new technology that can give an initial advantage. For this reason, the propensity to innovation of entering firms is higher than the company that is already installed.

1.6. New entrants

The process of electricity market liberalization originated the emergence of new players in electricity generation, thus increasing competition in this sector, and giving consumers a more active role, since they have the ability to choose their supply entity. This path is based on a perfect competition market structure in a traditionally monopolistic industry.

From a theoretical point of view, the perfect competition relies on the assumption of entry and exit free of market players, but empirically, these entry conditions will differ depending on the type of industry (Kwoka, 2008). The electricity sector, given its characteristics that potentiated a monopolistic market structure, is a very specific case in liberalization process and this enhances some entry barriers to new entrants.

The perfect competition model is based in the following conditions:

a) – the product is homogeneous, i.e., they are perfect substitutes;
b) – there are a large number of buyers and sellers;
c) – the information is perfect;
d) – all new and established companies in the industry, have equal access to technology and inputs;
e) - there are no barriers to entry or exit of market.

These assumptions also require that companies and consumers are rational "price takers", and companies can enter and exit the market instantly and without costs. Satisfied these conditions the fundamental theorem of economy proves that markets are perfectly efficient in production and consumption.

The entry of companies into the market without costs is illustrated in Figure 2, with initial market curves of demand and supply represented by D1 and S1, respectively. Prices and quantities of equilibrium are given by P1 and Q1. When demand will change from D1 to D2, arises a situation of demand excess over the existing supply, consequently raising the market price to P2. This represents the need for increased production capacity in the long-term, also signalled by additional profits (shaded area) above the additional costs.

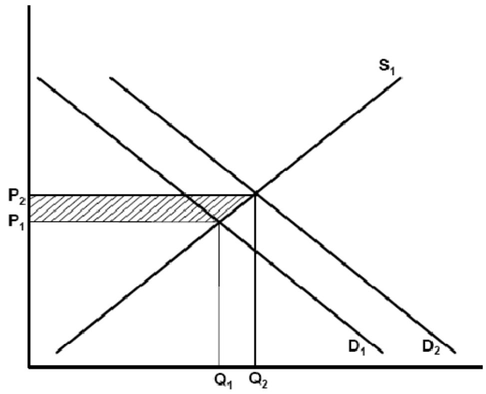

Figure 2 - Conditionsfor entry into the market under perfect competition
Source: (Kwoka, 2008)

As shown in Figure 3, the entry of new players into the market has an increase in the amount offered, restoring market equilibrium (P1 and Q3).

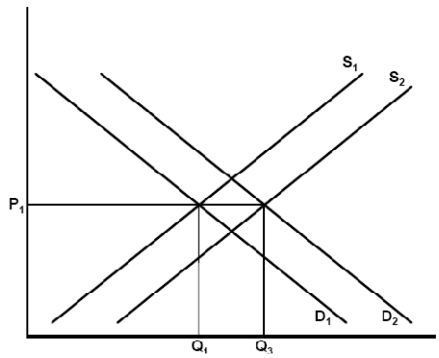

Figure 3: Entry of new players on the market under perfect competition
Source: (Kwoka, 2008)

Despite this, there may be certain factors, designated as entry barriers that, while not preventing the entry of new players into the market, may actually difficult it. In the electricity sector, these barriers exist, and despite the liberalization process, the strategic and structural barriers, sometimes are an obstacle for new players in electricity generation.

According to Porter (1986), scale economies, product differentiation, capital requirements, switching costs, access to distribution channels, disadvantages of scale independent costs and government policy are the main entry barriers. On the other hand, authors as Kwoka (2008) point some economic barriers, regulation and uncertainty sources, as the main obstacles to new player's entry into this sector.

This author argues that traditional economic barriers are different for each type of technology. For example, nuclear plants are expensive, with large dimension, and require long lead times, while gas fired plants have a much more modest capital cost and efficient size. Moreover, renewable technologies such as hydroelectric plants require considerable time and capital for construction, while wind technologies are capital intensive, but with shorter time horizon.

Scale economies in the electric sector are not only present in technologic innovations, but also in the introduction of new organizational processes and business management, from the maximizing return perspective on capital from investors.

When referring to distribution channel access, in some cases the entry of new players into electricity generation require new transmission facilities, or even a new distribution plan to ensure market access. In doing so, for viable agent entry, increased investment is need, which can represent an entry barrier, requiring more capital, more know-how and possibly much longer time limits for entry into the "two market" (generation and transmission) (Kwoka, 2008).

Another obstacle relates to the cost disadvantages non related to scale to new competitors, since, for example, incumbent firms have the best location for installations of power stations, that cannot be replicated by new firms, either by environmental and regulatory issues, or other (Kwoka, 2008). Moreover, usually, incumbent firms have a learning curve or experience more favourable, which, Porter (1986) argues that experience effects reflect on cost reductions. The difference between incumbent cost and the cost that the entering firm must to pay represents a competitive advantage for companies already installed (Kwoka, 2008).

The product differentiation is related to the identification of companies brand, either through the service to costumer, differences in products, the publicity effort, or by having entered first in industry, which develop a sense of loyalty within their buyers. Depending on the market, in the case of electric energy, this loyalty can be an entry barrier, given that new entrants are forced to invest heavily in breaking the established ties between costumers and existing companies.

High capital needs can be one major entry barrier, which is worsened by sunk costs, long lead times and still uncompetitive technologies, beyond the large uncertainties associated with these projects that increase dramatically financial costs.

The high uncertain degree of these projects is also mentioned as a barrier to entry. The uncertain demand and project costs and regulatory risks are the main barriers. Projects with long time horizons, inevitably involve high market risks, particularly for those projects that depend on very specific input as fossil fuels (Kwoka, 2008). In this case, investors will require a much greater compensation for financing these projects, which difficult the entry of new investments.

Furthermore, regarding electricity generation, costs are almost totally sunk, aggravating uncertainty level. When analysing by types of technologies, uncertainties related to electricity generation investments from fossil fuel, are essentially derived from market due to its fuel price volatility and environmental issues. On the other hand, if we analyze renewable technologies the major uncertainty level comes from the weather (Kwoka, 2008).

The entry barriers can also be strategic, i.e., obstacles deliberately created to difficult the entry of new firms. Newberry (1998), on a study related to competition, contracts and entry in electricity market, proves that if the new plant is identical to the existing company and the incumbent firm has insufficient generation capacity, the entry will occur. However, if the new plant has lower variable costs, then the incumbent firm may act to stop the entry into the market.

This last situation can be happen in the form of a strategic barrier by capacity excess, i.e., incumbent firms may create a capacity excess, denying the possibility to new firms to enter the market (Kwoka, 2008). However, if industry has enough capacity, incumbent firms can sell sufficient contracts to decrease prices to a level that detain the entry of new competitors (Newberry, 1998). The relative prices practiced by incumbent firms have become a strategic issue for hinder market entry (Otero and Price, 2009).

Neuhoff and Vries (2004) claim that long-term contracts between producers and retailers, ensure sufficient revenue for new investment, but on the other hand, if new entrants in the market know that high prices are a consequence of market power of incumbent firms, rather than actual shortage of supply, they may hesitate to enter the market, as increased competition could cause prices to fall. Moreover, as the market power is exercised in times of full capacity, it is difficult to assess whether high prices are caused by market power or scarcity. Incumbent firms of electricity generation can benefit from barriers to entry, making it more difficult for new entrants to provide new generation capacity. The installation of new capacity will be more beneficial in areas already occupied by other units where there is often space for an additional unit (for example, the local of a dismantled old unit). In addition, the cost of a new plant is lesser if it is built in a place where electricity, fuel and cooling systems infrastructures are already present. Finally, large established companies can obtain the necessary capital more easily. If the entry is restricted, then Von der Fehr (1997) shows that incumbents can limit capacity investments to increase spot prices.

Newberry (1998), proves that even if existing capacity in the market is not sufficient (taking into account the number of companies) the incumbent firms can not reduce prices enough to prevent an excessive entry of new competitors, in which case, these will only be able to hinder the entrance if new projects have a lower marginal cost than the existing capacity, and only after the realization of all necessary investments. Besides this, if new capacity has the same variable costs than the existing capacity, it will play the same role as the incumbent firm in fixing prices, offering contracts with lower price, being able to enter into the market and increasing the competition degree.

When analyzing the data relative to the competition increase in electricity market at the European market level, studies show that there is still a high concentration in electricity market, revealing high market shares by the major national generators. For example, Malta and Cyprus, have only one power company that dominates national production, and other countries show a concentration above 80% (Greece (91.8%), Estonia (90%), France (87.3%), Latvia (87%) and Slovakia (81.7%)) (Eurostat, 2011).

During the last decade (2000-2009), we observe (based on market shares of 21 EU member states that provided information provided on this indicator during this period) that the average size of the largest electricity generators decreases by about 10% (Eurostat, 2011). This shows that although the largest companies of electricity generation still have a high market share, these values tend to decrease, which demonstrates a greater degree of market competition (Table 1).

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Belgium	92.3	91.1	92.6	93.4	92.0	87.7	85.0	82.3	83.9	80.0	77.7
Bulgaria	:	:	:	:	:	:	:	:	:	:	:
Czech Republic	71.0	69.2	69.9	70.9	73.2	73.1	72.0	73.5	74.2	72.9	73.7
Denmark	40.0	36.0	36.0	32.0	41.0	36.0	33.0	54.0	47.0	56.0	47.0
Germany*	28.1	34.0	29.0	28.0	32.0	28.4	31.0	31.0	30.0	30.0	26.0
Estonia	93.0	91.0	90.0	91.0	93.0	93.0	92.0	91.0	94.0	96.5	90.0
Ireland	97.0	97.0	96.6	88.0	85.0	83.0	71.0	51.1	48.0	45.6	37.0
Greece	98.0	97.0	98.0	100.0	100.0	97.0	97.0	94.6	91.6	91.6	91.8
Spain	51.8	42.4	43.8	41.2	39.1	36.0	35.0	31.0	31.0	22.2	32.9
France	93.8	90.2	90.0	90.0	89.5	90.2	89.1	88.7	88.0	87.3	87.3
Italy	71.1	46.7	45.0	45.0	46.3	43.4	38.6	34.6	31.3	31.3	29.8
Cyprus	99.7	99.6	99.6	99.8	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Latvia	96.5	95.8	95.0	92.4	91.0	91.1	92.7	95.0	86.0	87.0	87.0
Lithuania	73.7	72.8	77.1	80.2	79.7	78.6	70.3	69.7	70.5	71.5	70.9
Luxembourg	:	:	:	:	80.9	80.9	:	:	:	:	:
Hungary	38.9	41.3	39.5	39.7	32.3	35.4	38.7	41.7	40.9	42.0	43.1
Malta	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Netherlands	:	:	:	:	:	:	:	:	:	:	:
Austria	21.4	32.6	34.4	:	:	:	:	:	:	:	:
Poland	20.8	19.5	19.8	19.5	19.2	18.5	18.5	17.3	16.5	18.9	18.1
Portugal	57.8	58.5	61.5	61.5	61.5	55.8	53.9	54.5	55.6	48.5	52.4
Romania	:	:	:	:	:	31.7	36.4	31.1	27.5	28.3	29.3
Slovenia	:	:	:	50.7	50.3	53.0	50.1	51.4	82.0	53.0	55.0
Slovakia	83.6	85.1	84.5	84.5	83.6	83.7	83.6	70.0	72.4	71.9	81.7
Finland	26.0	23.3	23.0	24.0	27.0	26.0	23.0	26.0	26.0	24.0	24.5
Sweden	52.8	49.5	48.5	49.0	46.0	47.0	47.0	45.0	45.0	45.2	44.0
United Kingdom	21.0	20.6	22.9	21.0	21.6	20.1	20.5	22.2	18.5	15.3	24.5
Norway	30.4	30.6	30.7	30.7	30.7	31.2	30.0	30.9	32.5	27.4	29.5
Croatia	:	:	:	:	82.0	86.0	87.0	83.0	84.0	85.0	92.0
Turkey	79.0	75.0	70.0	59.0	45.0	39.0	38.0	:	:	:	:

Table 1 - Market share of the largest electricity generator in the market, 2009 (in %)
Source: Eurostat (online date code: nrg_ind_331a)

This increased levels of market competition in electricity generation result in a greater uncertainty level for existing companies, in terms of their market share levels, which in turn tend to complicate entry of new firms as noted above. The structural and strategic entry barriers are present in this industry, complicating the possibility of new investments by new entrants.

One of the most important financial consequences of increased competition is the reduction of expected return on investments. Szabó and Jager-Waldau (2008), argue that this reduction has a significant influence on investment decisions. Firstly, the difference in the NPV of investments with different cash-flows decreases. When, on the other hand, similar cash-flows differentiated by relative weight of initial cost, which are characterized by upfront, become more competitive when lower discount rate is used to evaluate the project. This gap of NPV reduction eliminates barriers that disadvantage renewable electricity technologies from conventional generation. The second effect in the decline of return in investments is that it decreases willingness to invest in this industry, seeking invest in projects which require less initial capital.

Studies also show a strong relation between the competition increase and the proliferation of investment in electricity generation from renewable sources. Szabó and Jager-Waldau (2008), for example, they reveal that polices intended for expanding renewable technologies and competition reinforcement in electricity markets, have mutually reinforcing effects, i.e., more competition may reduce the financial burdens of existing schemes to support renewable technologies, and thus contribute to achieve the established aim for these technologies. This study also proves that more competitive financing can effectively distribute financial burdens, resulting from electricity generation investments from renewable source, between the pool of physical and financial investors and consumers. The physical investors can synchronize the physical payment of cash-flows generated by the project. The co-financing institutions are willing to provide more competitive financing due to risk reduction. The consumers can choose different levels of contribution (additional green tariffs or feed-in tariffs system).

The fundamental requirement in the design basis for sustainable policies to support renewable technologies is the achievement of lower capital costs needed to create conditions of equality with technologies of traditional electricity generation, which implies a more competitive market structure (Szabó and Jager-Waldau, 2008).

1.7. Capital Cost

With the liberalization of the electricity market, there are certain risks that require a more efficient management from investors of electricity generation, since this has implications in determining the rate of return required for generation investments. The access to funding and support of national policies for individual technologies intended to reduce financing risks (such as feed-in tariffs, loan or price guarantees), are susceptible of playing an important role in determining the final choices in energy generation (IEA, 2010).

The increase in uncertainty due to the electricity market liberalization leads to a strategic behaviour and an increase of capital costs that, on the one hand, reduces investments and entry in the short-term, and on the other hand, generates less innovation in the long-term (Jamasb and Pollit, 2005).

Capital cost is associated with the return that a certain investment must deliver, and the minimum return required by investors is defined taking into account the risk premium of business. At company level, capital cost is related to investors decisions when choosing between assets to invest and the way to finance them, maximizing company value.

From the investors viewpoint, with the disappearance of monopolies in the electricity generation sector, there is a greater risk of loss of market share and lower profits from these investments. Thus, investors will require higher interest and return rates and tend to be reluctant about making new investments, since the capital is more expensive than it used in monopoly conditions (Markard et al, 2001).

In an intensive capital and liberalized market such as the electricity market, this issue becomes particularly important due to the fact that, with market liberalization, there will only exist investment projects which ensure at least equal returns that are provided by market for investments with similar risk, i.e. the appropriate rate is the cost of capital.

For companies to be attracted to invest it is necessary fair returns on invested capital, taking into account the business risk. For this reason, risk and uncertainty associated with market liberalization will have to be taken into consideration when determining the capital cost of an investment. When investing in a particular project, the risk does not represent a negative sign for its viability, since taking calculated risks is the way that companies use when seeking profits above its capital cost (Blytha et al, 2007). However, an additional risk increases the capital cost of investment and can change decisions of investors.

Debt and equity are fundamental for total capital cost and level of expected return of an investment. Gross et al. (2010) show that due to the lower cost of capital associated with debt, investors will aim to obtain as much debt financing as they can. On the other hand, increasing debt also increases the default risk, leading lenders to raise interest rates and/or limit the gearing rates. Thus, the level of debt depends on the type of projects and perceived risk profile. In a riskier project, equity that assumes a higher risk has a larger role so the project returns must be sufficiently high to sustain the high financing costs.

The issue of low cost debt compared to equity arises because lenders (debt) are the first to receive the company sales, while investors (equity) receive the remaining sales. The amount paid to lenders is fixed according to the loan terms, while the amount paid to investors varies according to the company's profitability. The extent of these variations depends strongly on the extent of funding, because the residual income will be more volatile if there is a high level of fixed costs in debt repayments scheme (Gross et al, 2010).

The cost of capital for producers depends on a number of factors: the balance between debt and equity financing, market conditions, and risk and uncertainty related to investment returns. Laing and Grubb (2010) analysing this issue within low-carbon investments, claim that investment return in electricity generation of these technologies depends on the price of electricity, in conjunction with policies for additional support. In competitive wholesale electricity markets, such as UK, the price is set by the marginal unit of generation. In the UK, this is predominantly gas or coal.

Basically, this means the price at which an investor of low carbon electricity generation can sell their product has little or no relation to their own costs. In turn, it depends on the volatility of coal, gas and carbon prices faced by producers of fossil fuels (Roques, Nuttal et al. 2006). In economic terms, zero carbon sources are infra-marginal, but in the absence of other measures will receive a fixed price at the margin on which they have no control and very little foresight. This potentially increases the capital cost, raising total costs and reducing incentives to invest in various sources which are vital to the future of low carbon generation (Laing and Grubb, 2010).

Another important issue is to analyse forms of financing these investments. An electricity generation plant is financed mainly through "*Project Finance*" and "*Corporate Finance*" (Gross et al, 2010). *Project Finance,* in a general way can be defined as "investment finance in the independent capital that shareholder company separate of their assets and obligations of general purpose" (Wynant, 1980). In *Project Finance* the risk and return are accounted exclusively at the project level to invest (Gross et al, 2010). On the other hand, in *Corporate Finance* case the company incorporates the new investment in its global activities portfolio and evaluates the marginal impact on the company's overall risk and return characteristics (Gross et al, 2010).

Theoretically, the choice of financing method should make no difference to the marginal cost of capital needed to finance a project with a specific risk profile. For example, it is easy to think that riskier projects may be financed with low capital costs, if they are carried out by a company with a set of "safe" assets and access to cheap capital, but in theory this is not possible, because the capital cost for the company as a whole should reflect the entire project portfolio (Gross et al, 2010). Thus, this situation would lead to higher capital costs for the company, since it began investing in riskier projects, which implies an increased risk of default on debt payments. In practice, the ability to handle these risks through the inclusion or exclusion of projects in the balance sheets depends on the accounting rules that the company is subject to.

Accordingly, if there is no flexibility in the company's accounting, *Project Finance* represents an important advantage, because it keeps the debt off the balance, which is beneficial, since the funding for new projects will not affect the current conditions of debt shareholders of different companies (spreads, commissions and other fees) (Comer, 1996).

On the other hand, there is a consensus that *Project Finance* as a longer time span to finalize, is more expensive and leads to a loss of flexibility in management. For example, a transaction in accordance with *Project Finance* principles is more complex, since the only guarantee of the new project are the estimated cash-flows, thus is fundamental a more correct estimation of future cash-flows (Comer, 1996).

Although, investments in large-scale of energy plants are often financed with a high degree of *Corporate Finance*, there are at least two features of corporate debt that are unfavourable. The first inconvenient is that if the project fails, creditors can claim all assets of the firm, even those not related to their debt. The second feature is the incorporation of corporate debt on the balance sheet of the company, which will increase their indebtedness level that can translate into difficulty in raising finance by debt in the future (Comer, 1996).

In contrast, in terms of *Project Finance*, the exposure of a project to return risks limits the amount of debt that can be achieved, increasing the need for more expensive equity finance (Gross et al, 2010).

When regarding different technology types of electricity generation, capital costs also vary between them, since certain technologies are more affected by rises of this cost due to liberalization. Laing and Grubb (2010), claim that the electricity sector liberalization has been very effective in reducing costs and prices associated with existing operating systems, but less effective in attracting new investment. In the analysis of renewable technologies like wind power, almost all the costs are related to capital costs of turbines building, and once the turbines are built, costs become lower, due to the fact that there is no fuel only operation and maintenance (O & M).

Current data of different technologies levelised costs shows that with a lower discount rate (5%) the more capital-intensive and low carbon technologies, as nuclear power, are the most competitive solution in comparison with coal plants without carbon sequestration and natural gas. For renewable technologies like wind and solar are not very competitive and have higher investment costs (See Figure 4).

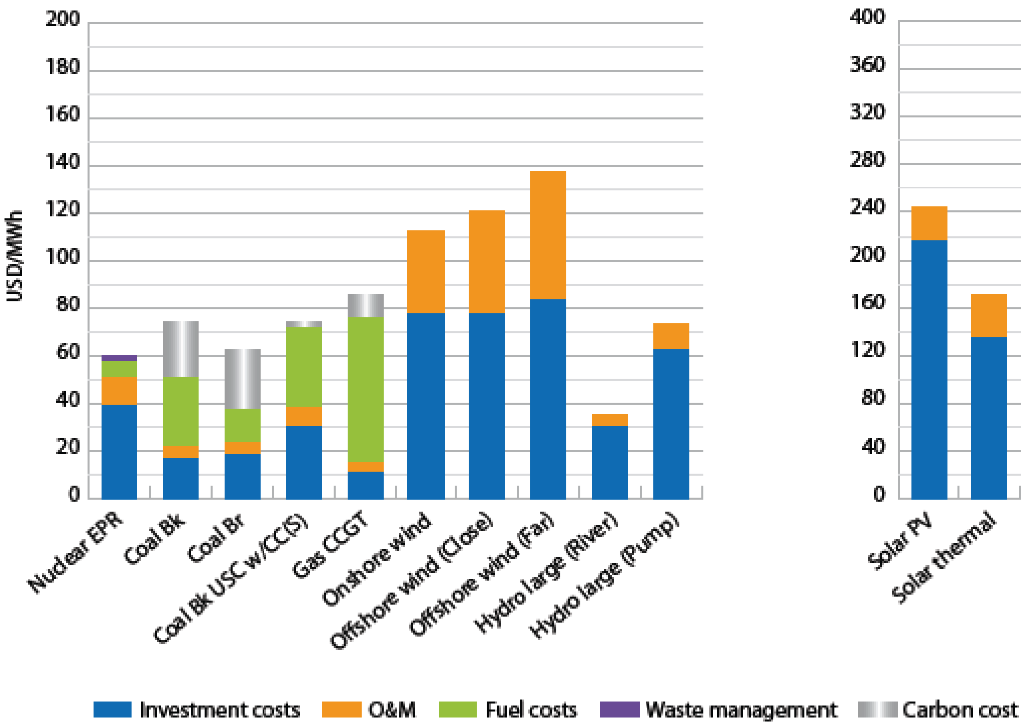

Figure 4 - Eurelectric / VGB levelised costs of electricity (at 5% discount rate)
Source: IEA, 2010

Comparatively, under a higher discount rate (10%) coal without carbon capture equipment followed by coal with carbon capture equipment, combined cycle gas turbine (CCGT) and hydroelectric technologies are cheaper to generate electricity (See Figure 5).

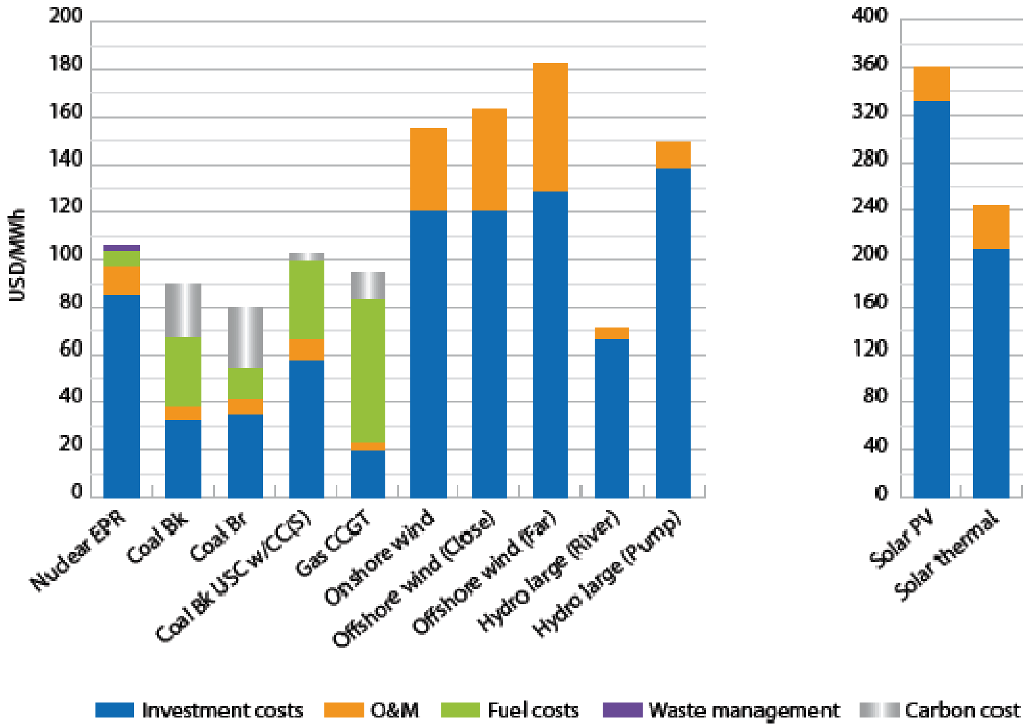

Figure 5 -Eurelectric /VGB levelised costs of electricity (at 10% discount rate)
Source: IEA, 2010

The average costs and relative competitiveness of different technologies for power generation in each country are highly sensitive to discount rate, and a bit less but still very sensitive to the projected price for natural gas, coal and CO2 (IEA, 2010).

The significant impact of discount rates on total production costs for most technologies can still be seen in Figure 6 with a sensitivity analysis performed for rates that vary from 2.5% to 15%.

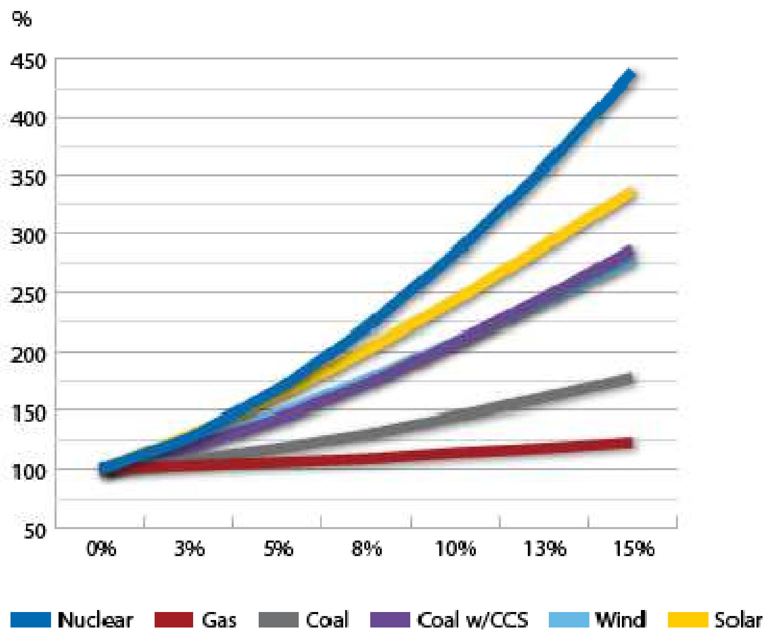

Figure 6: Levelised costs of electricity as a function of the discount rate
Source: IEA, 2010

Logically, with an increase in capital cost, the total cost of generation for all technologies increases. The first observation is the relative stability of energy costs for gas, and therefore, its insensitivity to changes in the discount rate. At the other extreme, nuclear power, despite having a lower ratio of investment cost than renewable technologies, is the technology more sensitive to changes in the discount rate, due to higher building time than any other technology (IEA, 2010). Thus, the structure and cost of financing has a great importance when investing in nuclear capacity.

From the ratio of investment cost and total costs of the different technologies represented in Figure 7, it appears that the proportion of investment costs of nuclear energy in total costs rise faster than the wind or solar power in response of increases in the discount rate, although renewable technologies, initially, have a much higher investment cost in relation to the total cost. Indeed, the capital ratios on total cost for solar and wind power are relatively insensitive to changes in the discount rate compared to other technologies, even for gas-fired plants, for which capital costs represent only a very minor proportion in total cost. This happens because renewable technologies have a substantially construction time less than any other technology (IEA, 2010).

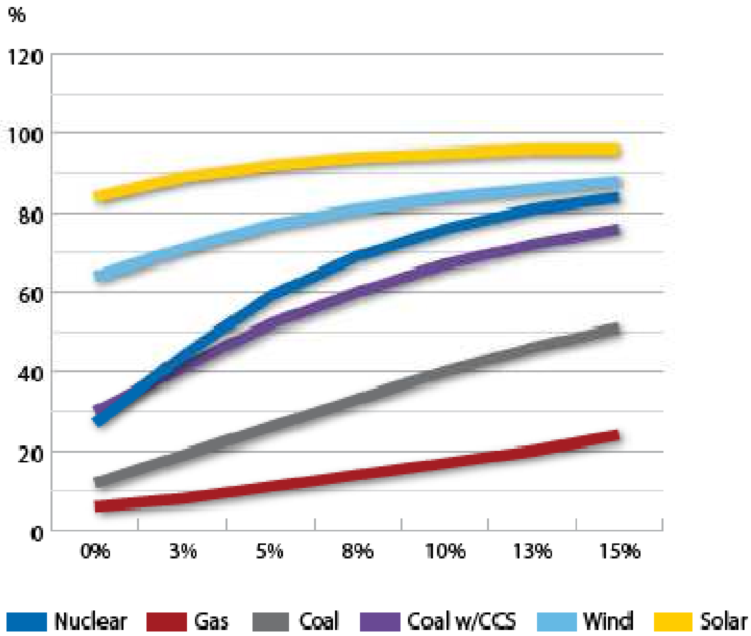

Figure 7 - The ratio of investment cost to total costs as a function of the discount rate
Source: EIA, 2010

These last two figures confirm that with doubling of capital costs (discount rate) from 5% to 10%, the total cost of capital-intensive technologies, such as wind or nuclear, increase to a much greater proportion than conventional technologies. But when analysing the influence of discount rate increases in proportion of investment costs in the generation total costs, it is concluded that renewable technologies do not change in their capital cost, though these continue to be higher than conventional technologies.

Another important conclusion relates to the competitiveness of technology, that with a rate of 5%, the nuclear power can be competitive against, for example, gas and coal, but at a rate of 10% it ceases to be profitable when comparing with these technologies, which is shown in the sensitivity analysis of total costs compared to increases in the discount rate.

2. THE ECONOMIC EVALUATION OF ENERGY INVESTMENTS: A LITERATURE SURVEY

Several methods of investment evaluation are used to analyse the viability of energy investments. Many authors have used different methods, as a way to achieve an assessment as accurate as possible, taking into account the risks and uncertainties inherent of these projects.

2.1. Net Present Value

The Net Present Value (NPV) is the evaluation criteria favoured by almost all the manuals for projects financial evaluation, it constitutes an expectation of gain to be obtained from investment beyond the minimum return required by investors for their capital, i.e., that results from applying a discount rate previously accepted. In analytical terms is the algebraic sum of investment with a set of costs and revenues associated with the project and discounted with a previously accept rate i, or in other words, the sum of discounted cash-flows.

The NPV is defined by:

$$NPV = \sum_{t=1}^{n} \frac{NR_t}{(1+i)^t} - \sum_{t=0}^{n-1} \frac{I_t}{(1+i)^t} \qquad \textbf{(1)}$$

Where:

NR_t: Net revenues

I_t: Investment

According to this criterion a project is profitable when the NPV is positive for a chosen discount rate. All projects with NPV> 0 are implementable according to the criteria and all projects with NPV <0 are rejected. The value of NPV is the function of *i* rate and varies in its inverse proportion, i.e., their values are inversely proportional (see Figure 8).

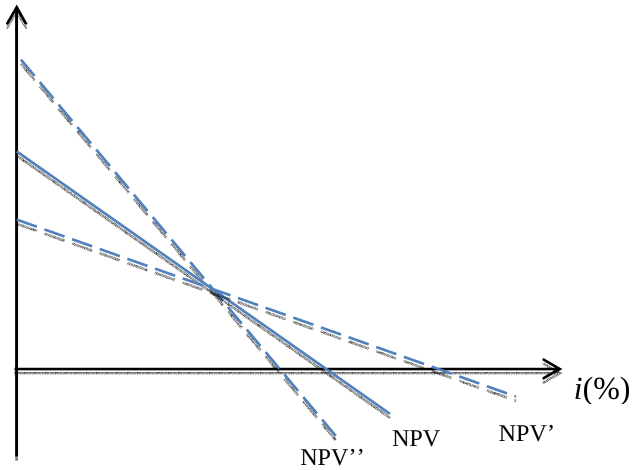

Figure 8- Relation between rate i and NPV

Source: elaborated by the author, based on Araújo (2003)

In case of two or more mutually exclusive investment opportunities, the optimal choice is the opportunity with the highest NPV (Brealey and Myers, 2003).

- *Cost of Capital and Weighted Average Cost of Capital*

The investors or companies require higher return rates for riskier projects. When considering projects where cash-flows are known in advance, the rate of return associated to others investments without risk, such as bank deposits, is the basis for the discount rate to be used in NPV calculations (Kvalevåg, 2009). When cash-flows are uncertain, as the case of oil and gas fields, they are usually represented by their expected values and the return rate is calculated in function of Capital Asset Pricing

Model (CAPM) in order to overcome possible undesirable results (Aven and Vinnem, 2007).

The capital cost, also known by opportunity cost of capital, can be defined as the minimum required return on that capital, given the risk involved. According to Gitman (2007), the CAPM is a model that links the non-diversifiable risk to the return of all assets. The equation of CAPM is:

$$\boldsymbol{k_e = R_f + \left[\beta * \left(R_{market} - R_f\right)\right]} \tag{2}$$

Where:

k_e: Cost of equity;

R_f: Risk-free interest rate

β: Relative measure of non-diversifiable risk (Gitman, 2007). It indicates the degree of return variability of an asset in response to a change of market return. It can also be understood as the systematic risk of shares

R_{market}: Expected return of market portfolio

$(R_{market} - R_f)$: Market risk premium

The risk-free interest rate is the amount received by investing in securities considerable free of credit risk. The *beta* of assets measures how much the company's share price moves in relation to the market as a whole. If *beta* is greater or less than one, the company's share price moves more or less than the market, respectively.

2.2. Internal Rate of Return (IRR)

The Internal Rate of Return (IRR) represents the discount rate that equates NPV value to zero. Thus IRR must satisfy the following condition:

$$\sum_{t=1}^{n} \frac{NR_t}{(1+IRR)^t} - \sum_{t=0}^{n-1} \frac{I_t}{(1+IRR)^t} = 0 \quad \textbf{(3)}$$

The IRR equals the operating cash-flows to investment cash-flows, offsetting NPV. Graphically we have:

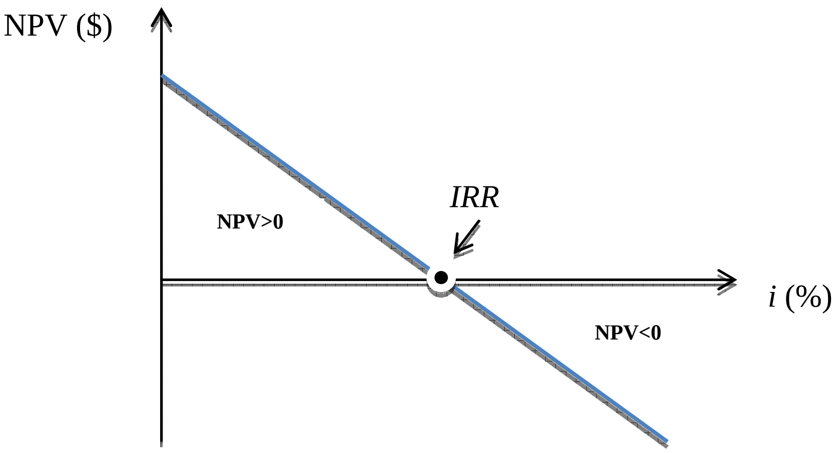

Figure 9 - Graphical representation of the IRR
Source: elaborated by the author, based on Ross et al., (2002)

This decision criterion consists in the implementation of a project when its IRR exceeds the reference interest rate (Ross et al., 2002). The IRR, as a decision criterion, always requires a reference interest rate, which is usually the opportunity cost of invested capital.

If there is profit excess, the IRR will be higher than risk-adjusted discount rate, in other words, going beyond the normal or competitive rate of return. Moreover, if a project is partially supported by debt and partly by equity and the cost of debt is smaller than the IRR for the project, then the effective rate of return on equity in the project will be greater than the overall IRR project (Pindyck, 2001).

Brealey, Myers and Allen (2003) mention four disadvantages of the IRR method. The first relates to the challenges associated with the fact that this approach does not distinguish lending or borrowing. If a project offers positive cash-flows followed by negative cash-flows, NPV can increase as the discount rate is increased. The second disadvantage, relates to projects with cash-flows that change the sign more than once. In this case, project may have several or no IRRs. The third disadvantage refers to the fact that IRR is not able to classify projects of different scale, and the inability to classify projects with different patterns of cash-flows over time. The last disadvantage pointed out by the authors stems from the possibility of the capital cost to the short-term cash-flows are different from capital cost to the long-term cash-flows. The IRR rule requires the comparison between projects IRR and opportunity cost of capital. Sometimes, this cost of capital varies over time, and there can be no simple criterion for evaluating the IRR of the projects.

2.3. Return on Investment (ROI)

The ROI indicates how many units of net revenues are generated by each unit of invested capital. In this case the weighted average rate of return to equity and borrowed funds, or capital structure to which the investor can have, is the discount rate of net cash-flow.

The ROI is defined by:

$$ROI = \frac{\sum_{t=1}^{n} \frac{NR_t}{(1+i)^t}}{\sum_{t=0}^{n-1} \frac{I_t}{(1+i)^t}} \tag{4}$$

ROI = 1 means that for every unit invested (discounted) one obtains precisely one unit (discounted). ROI=1 is equivalent to NPV=0

Brealey, Myers and Allen (2003) say that ROI is often seriously biased by measures of true profitability, for example, they argues that book ROIs are generally too low for new assets and too high for old ones.

2.4. Payback Period

Given the net cash-flow of an investment project discounted with a previously accepted rate i, the Payback period of total investment is equal to the number of years that results from applying the following formula:

$$P = \frac{\sum_{t=0}^{n-1} \frac{I_t}{(1+i)^t}}{\frac{\sum_{t=1}^{n} \frac{NR_t}{(1+i)^t}}{n}} \qquad \textbf{(5)}$$

Based on the rule of payback, an investment is acceptable if its calculated payback period is less than a pre-specified number of years (Ross et al., 2002).

As a tool for investment analysis, the payback has drawbacks. It does not take into account the cash-flows that occur after the recovery is achieved and therefore does not measure long-term value of an investment (Brealey, Myers and Allen, 2003; Ross et al., 2002). In addition, it treats all cash-flows in the same way, whether they occur in year 1 or in year 5. In terms of finance return it ignores the time value of money (Brealey, Myers and Allen, 2003; Ross et al., 2002). Ross et al. (2002) considers that the biggest problem of the payback method is the subjective pre-specified number of years that are considered minimum for recovery of an investment, since there is no objective basis in doing so.

2.5. Benefit-Cost Ratio

The Benefit-Cost analysis aims to identify, quantify and weigh the benefits and costs of investment projects designed to improving the welfare of society as a whole.

The Benefit-Cost Ratio is defined by:

$$B/C = \frac{\sum_t \frac{R_t - C_t}{(1+i)^t}}{\sum_t \frac{I_t}{(1+i)^t}} \quad \textbf{(6)}$$

Where:

$R_t - C_t$: Operation cash-flows

I_t: Investment cash-flows

With this criterion the condition for that a project is profitable, is that the B/C must be greater than 1.

2.6. Levelised Costs approach

The calculation method of levelised costs takes into account an annual level of all costs and an annual amount of energy produced. This model is useful to compare energy generation technologies with different characteristics and life times.

The expression that gives the value of levelised costs is:

$$\mathbf{LC} = \frac{\mathbf{c_I + c_{O\&M} + c_c + c_d}}{\mathbf{E_{act}}} \quad \textbf{(7)}$$

Where:

c_I: Present Investment cost

$c_{O\&M}$: Present value of Operation & Maintenance costs

c_c: Present value of fuel costs

c_d: Present value of various annual costs

E_{act}: Present cumulative value of energy production

2.7. Real Options

Authors like Trigeorgis (1993), Lopes (2001) and Minardi (2004) claim that since the investments are composed of sceneries of great uncertainty and require significant flexibility, it should rephrase the NPV for it to be able to capture the value of these flexibilities. Thus, they proceed with the following equation which reflects the flexibility component incorporated into a strategic NPV:

$$NPV_{expanded} = NPV_{tradtional\ or\ static} + Value_{management\ flexibility} \tag{8}$$

As seen previously, for a project to be accepted by the NPV analysis, it must be positive (NPV>0), but for it to be accepted by Real Options method, the project must be profitable enough due to the options flexibility.

2.8. The economic evaluation of energy projects: a survey of literature

For this study **it** is very important to understand how these methodologies are applied to each project type. In this case, the actions undertaken as an attempt to assess environmental or energy resources have a particular importance.

There have been many studies, by authors, to identify the best evaluation methods for natural resources. The traditional static methodologies have been losing importance in economic analysis, since they do not account uncertainty and management flexibility of energy projects. According to Dixit and Pindyck (1994), the large changes in the economic environment, where the uncertainty reigns in almost all the markets, have made traditional techniques insufficient to capture certain features of investment projects, which often leads to serious errors.

According to Emhjellen and Alaouze (2003), the method of net cash-flow is still the most common valuation method used by oil companies. When analysing energy industries as the case of oil, it appears that despite several decades, the most common form of asset valuation has been the discount cash-flows analysis. Over the past years, a growing number of institutions and organizations have adopted other approaches of assessment to overcome some limitations imposed by this method (Schiozer and Suslick, 2004).

Jood and Boots (2005) claim that the risks can be incorporated more effectively in these static methods when considering different scenarios or sensitivities, such as the future development of electricity prices or using a scope of discount rates. These components are discounted according to their degree of risk, using a probabilistic assessment (expected value) of the key uncertainty factors. The NPV static method assumes irreversible investment decision, which tends to depend on a simple estimate of fuel and electricity prices. These authors consider that when regarding issues of management flexibility, e.g., can an investment be delayed until there is more information, the ROA is the most appropriate method to assess these different conditions.

Kvalevåg (2009) argues that the analysis of discounted cash-flows is an important rule within financial theory with many applications, especially in the evaluation, providing a systematic and logical framework for making investment decisions. The method takes into account the costs, revenues, time and risk. This approach not only encourages decision makers to consider all relevant factors in a project, but also enables the understanding of the possible outcomes of each one. The author also states that this analysis is well understood and easy to communicate to both decision makers and to other stakeholders.

Tourinho (1979) assesses the oil reserves through option pricing techniques. Brennan and Schwartz (1985) apply techniques of choice for evaluating irreversible natural resource assets. Paddock et al. (1988) evaluated offshore oil concessions. Bjerksund and Ekern (1990) showed that it is possible to ignore two options of abandonment or temporary suspension in the presence of the option to delay the initial investment for development of oil fields. Suslick and Schiozer, (2004) make a risk analysis applied to an exploration and production of oil by the method of real options. These authors consider that the traditional methods based on discounted cash-flows are always based on static assumptions.

Brennan and Schwartz (1985) with the concern to improve the way of these investment evaluation, present a study about assessment of investments in natural resources using the theory of pricing stock options, using as an example the copper mines of Chile. These authors argued that management flexibility should increase the value of a project. They considered three options: production (when prices are high enough), the temporary stop (when they are lower), and the permanent closure (when prices fall too long). They found the threshold price of copper which is ideal to close a mine temporary or to open one that had been disabled.

Dickens and Lohrenz (1996) used the Black-Scholes option pricing model to assess the value of oil and gas assets in the Gulf of Mexico and compared these values with traditional assessments of NPV. The main conclusion is that the evaluation by the option method leads to higher values than the NPV assessments. Thus, the analysis of option valuation would lead to "accept" decisions more often. As financial assets, the assets of oil and gas are full of uncertainties that strongly affect their values.

Grafström and Lundquist (2002) examined if the value of an oil field is affected by the use of real options evaluation. These authors use a numerical method to estimate the option value, which is compared with the value of the discounted cash-flows, also considering the option to delay investment in an oil field undeveloped in the North Sea, where its development is being planned. In this study is concluded that the value of an oil field in the North Sea is different depending on whether the method is applied to real options valuation or assessment of discounted cash-flows.

Rothwell (2006) in his study on the feasibility of a new nuclear plant, models the NPV of building an Advanced Boiling Water Reactor in Texas using a ROA to determine the risk premium associated with uncertainty of net revenue. This paper uses a ROA to determine risk-adjusted of capital cost (and therefore the NPV) for an asset that has the uncertainty of net revenue similar to a new nuclear plant in the U.S..

Yun and Baker (2009) did a study about investment opportunities for both types of power-generating base load with two types of technologies that use different fuels, such as coal and uranium under the trading mechanism of allowances. These authors apply the ROA to evaluate investment opportunities depending of at least two underlying assets, characterizing evolution of different prices. For this, they adopted a mean reversion model for the evolution of electricity prices to include its characteristic of seasonality, and the model of geometric Brownian motion for the allowance of CO_2 and cost of building the power plant. In order to approximate the values of investment, they still used the Monte Carlo approach to overcome a limitation of the analytical approach and achieve adequate results.

Fleten and Erkka (2010) in their article Gas-Fired Power Plants: Investment Timing, Operating Flexibility and abandonment, use the ROA to evaluate the investment. In addition, they analyze investments in plants under stochastic prices of natural gas and electricity. They used a two-factor model for price processes, enabling the analysis of the value of operational flexibility, the opportunity to leave the capital goods, and funded the limits for energy prices for which it is ideal to proceed with the investment.

Other methods such as levelised costs are still heavily used for evaluating energy investments. This approach is a special case of NPV analysis, which reserves the process: given the target of zero economic profit, the annual income required is calculated so that present value of all revenues exactly balances the present value of all project costs (Roques , Nuttall and Newbery, 2006).

The report of IEA (2003) shows that this approach was well adapted to evaluate energy investment before liberalization, because it reflects the reality of long-term financing, passing costs to customers.

But in a liberalized electricity market, what matters for investors is the return on investment against the risk to capital invested. The risk level expected by an investor in a electricity plant, will be reflected in the level of expected return on investment. The higher the risks of investment, the higher the required return. It is difficult for levelised costs methodology to incorporate risks and uncertainties effectively (Roques, Newbery and Nuttall, 2006). In order to assess the risks, different scenarios or sensitivities are usually calculated, which often give only a limited assessment of the risks involved.

Rode et al. (2001) consider that the probabilistic approach is the most complete assessment when accounting for a wide range of uncertainties. The authors of a case study of a nuclear power plant project used the Monte Carlo simulation and related techniques to solve many of the limitations of decision analysis (and sensitivity analysis). The Monte Carlo approach consists in characterizing the uncertainty in model results by allocating probability distributions of inputs, and to simulate the distribution of outputs by repeated sampling. This method allows simulating the impact of uncertainty in costs and technical parameters to obtain a probabilistic evaluation of risks and revenues of different generation technologies. The uncertainty of input parameters is usually modelled by a probability distribution and a simulation is run multiple times for different values of uncertain parameters, generating a probability distribution of NPV (Roques, Nuttall and Newbery, 2006).

Feretic and Tomsic (2005) provide a probabilistic analysis of lifetime discounted costs of electrical energy if produced in coal gas and nuclear plants, to start operation in Croatia in 2010.

Sevilgen et al (2005), intended to determine the best technologies for the generation of additional power given an increased demand in Turkey. They determined the economic parameters that affected the level of levelised annual costs. The levelised annual costs of alternative plants for more probable values of economic parameters in Turkey were transferred to the load duration curve. As a result, the more convenient plant, between alternative plants, has been determined with the value of the load factor.

On the other hand, Roques, Nuttall and Newbery (2006), analysed the limitations of the traditional approach of levelised costs, taking into account the risks and uncertainties to evaluate different technologies for power generation. For this, the authors introduce a probabilistic valuation model of investment in three basic technologies (gas turbine combined cycle (CCGT), coal plant and nuclear power plants), along with simple sensitivity analysis, which served as an intermediate step useful for identifying the key parameters to be modelled by probability distributions in the Monte Carlo simulation. Thus, the authors demonstrate through three case studies as a probabilistic approach provides investors a much richer analytical framework to evaluate energy investments in liberalized markets. This study also analyzes the combined impact of multiple uncertainties about the value of alternative technologies, the value of the operational flexibility of central managers, and the value of mixed portfolios of different production technologies.

Galli et al. (1999) conducted a study about suitability of three methods used for project evaluation, such as option pricing, decision trees and Monte Carlo simulation. In this paper, the authors compare their similarities and differences from three viewpoints: how they deal with uncertainty in the values of key parameters, such as stocks, oil prices, and costs; as they incorporate the value of money in time; and if they allow management flexibility. All three approaches seek to determine the expected value (or maximum expected value) of the project, however, they consider different assumptions about the underlying distributions, the variation with time of input variables, and correlations between these variables. Another important difference is how they deal with the value of money in time. Decision trees and Monte Carlo simulations use the traditional discount rate, and the option pricing uses the concept of financial risk-neutral probabilities. One of the difficulties in estimating the project value is that it is usually a nonlinear function of input variables (e.g., the tax is treated differently in years with a profit than in years with a loss).

The methods of evaluating investments in the energy sector have been the subject of numerous studies, mainly due to its irreversibility and its high uncertainty degree that strongly influences the results of investments. The decision of these projects is not to choose between investing now or never, accounting for only a few risks and uncertainties, easily observed in the market, but rather to asset difficulty to stock, surrounded by economic, technical and regulatory uncertainties difficult to predict and with little available information.

Thus, the evaluation method chosen for the analysis projects viability, must not only be easy to use, but also, must consider all their specificities.

3. RENEWABLE ENERGY PROJECTS: THE DECISION MAKING PROCESS

The energy investments have particular characteristics that are essential to take into account both when choosing the appropriate methods to perform analysis of its viability, and within the process of valuing.

Four general characteristics can be identified in energy investments.

1. First, they are partially or completely irreversible, so once applied the cost of capital, these can be considered unrecoverable. Irreversibility usually arises, because the capital of industry is very specific, i.e. it cannot be used productively in a different sector or by a different company (Pindyck, 1989)
2. Uncertainty is always present in the definition of future returns and costs. Thirdly, the investment may occur in flexible time. In other words, the investment can take place today, if expected returns are high enough to recover all costs, or can be postponed in order to obtain better information. Investors have the opportunity or option, but not the obligation, to invest in a project over a period of time.
3. Finally, in decision-making several different technologies can be chosen for power generation, depending on the available technologies and their associated uncertainties (Lundmark and Pettersson, 2007).

Some studies about energy investments, as the case of oil industry, have some of these characteristics that, according to several authors, determine the investment in this sector. The irreversibility and uncertainty are the most debated issues, in addition to long periods of maturation and the high degree of specificity of the assets of these industries. Postali and Picchetti (2008) state that these two features make the investment in this sector highly irreversible, and that investment irreversibility involves opportunity costs in the decision to develop an oil field, and should therefore be properly incorporated in the assessment of the project.

The issue of irreversibility in energy investments and their sunk costs is even more critical when combining the high uncertainty that involve these projects, such as market, technical and regulatory uncertainties. The work developed by Dixit and Pindyck(1994) tries to relate these two issues. These authors show that an investment under uncertainty, the company should have a smaller capacity than a situation with complete information and no uncertainty. This implies that the ideal capacity or number of utilities should be less with uncertainty. The model says the opposite of what has been the prevailing view in the regulatory regime, i.e., a large capacity is needed in case of unexpected events. One explanation for this is the error of not including the option value of future investment opportunities, which may result in over-investment. The reason is that uncertainty also increases the value of the company investment options. The investment criterion is to invest if the price is higher than the long-term marginal costs, plus the option value of waiting to invest.

Dixit and Pindyck (1994) show that in cases of modest average growth of the industry and uncertainty in demand, the required rate of return for a risk-neutral firm can be significantly higher than the real interest rate. This implies that the price may exceed the industry average cost of long-term for a long period in a competitive industry without stimulating the entry**.**

Uncertainty and irreversibility of these investments makes the issue of management flexibility an important factor in implementing these projects. Thus, when assessing energy investments, the traditional static methods are not suitable to quantify this flexibility, since they presuppose that investments are "now or never." Within an investment analysis one must consider the possibility of investing immediately if the conditions are favourable, or to postpone the start date of the capital application to a more propitious time in the future. This ability to wait (*defer option* or *option to wait*) should be assessed, preferably through models based on Option Pricing Models (Trigeorgis, 1999).

This flexibility is necessary so that investors do not make wrong investment decisions and do not completely lose all the capital invested. The choice of technology, the right time to invest, uncertainty and irreversibility reveal the need to apply valuation methods that can contemplate these issues.

3.1. Renewable energy investments: main features

Electricity generation projects from renewable sources are characterized by their irreversible investment, high degree of uncertainty, need for management flexibility and choice of different generation technologies. However, these issues are even more important when added to other relevant characteristics of renewable technologies, especially the intermittency of electricity generation and low maturity of the technologies.

In fact, compared to conventional technologies, renewable energies have the advantage not to suffer significantly the uncertainty regarding to fuel price for generation, but on the down side, their viability is highly determined by fluctuations in natural resources that affect operation. In this case, the choice of technology can be decisive, since the intermittency, for example, in a hydropower plant is not as immediate as in wind or solar power station, given that river levels do not drop suddenly, while the sun and wind are much more unpredictable (Wan and Parsons, 1993). On the other hand, a particular feature of the electricity sector is the commitment to provide electricity to consumers at a specified price at any time to any level of demand.

The issue of intermittency relates mostly to the uncertainty of energy produced by a given technology, reducing its value compared with the use of energy from traditional sources. Thus, it is essential to perform a correct prediction of the energy produced and to make an appropriate choice of location. Unfortunately, this choice depends on geological constraints and the best sites for raising funds are far away from consumption centres, which require new distribution systems to avoid losses. This obviously involves an increase in investment costs.

Another important feature of these investments is technological innovation, since such technologies are not yet in full state of maturity, which makes them uncompetitive compared to traditional technologies of fossil fuels. Many studies have proven that this lack of maturation promotes a postponement of investment, given their high cost (eg, Fuss and Szolgayová, 2010).

Moreover, since the technological changes in the renewable energy generation happen quickly, there is little chance of recovering the cost of capital invested in any new chosen technology, so that this choice becomes largely irreversible. Under such conditions, the adopter of technology can on the one hand, accept the cost of making a mistake by adopting too early, or, on the other hand, can choose to accept the opportunity cost of waiting in expectation of better future technologies (Farzin et al, 1998).

Another particularly important characteristic of these projects is the regulatory uncertainty, which strongly affects investment decisions and may influence the viability of investments in a negative way, if any regulatory changes alter the favourable conditions for these projects. Rapid technological progress in renewable energy and changes in economic or political priorities can create pressure to slow the progress of commitments to renewable generation, leading governments to change their policies in terms of support for certain technologies (Holburn et al, 2009).

All these uncertainties strongly influence the viability of investments, which require an economic assessment can account for the options of flexibility in managing projects.

3.1.1. Which is the best evaluation method?

There are many studies about evaluation of renewable energy investments that try to incorporate these features with the use of traditional methods, which include scenario and sensitivity analysis to account for the uncertainties and flexibility of these projects.

Kosugi and Sik Pak (2003), make an economic evaluation of solar thermal hybrid H2O turbine power generation systems, using the method of levelised costs considering the uncertainty of future fuel cost and capital cost of the solar collector.

The benefit-cost method is also commonly used to evaluate projects of energy production by renewable sources. Moran and Sherrington (2006), use this method to evaluate a project of a wind farm power generation in Scotland including externalities. This study makes an assessment, not only of monetary costs and benefits but also costs and benefits that are not based on market transactions, such as carbon emissions avoided by the project and costs of the visual impact (measured by willingness to pay of habitants), carbon released during reforestation, manufacturing and construction. Other studies of renewable energy projects, such as Henriques et al. evaluate three technologies for power generation using municipal solid waste with the methodology of the cost-benefit analysis considering their potential for obtaining credits for carbon emissions avoided.

Tsukamoto et al. (2006) makes an economic assessment of a wind farm project, considering the analysis of various scenarios. For these authors, the NPV method allows them to measure and evaluate all items of a common standard as cash-flow, and realized scenario and sensitivity analysis in different situations, so that they can evaluate projects from many viewpoints.

Other assessment methods are being used in these projects, even serving as a complement between them, in order to achieve a reliable feasibility analysis. Nagaoka et al. (2007), in his study on the economic viability of cogeneration of electricity in a sugarcane central with objective of trading excess, under risk conditions, use the Monte Carlo method and cost-benefit combined with the NPV, Payback and IRR analysis.

Kai and Tiong (2008), present a case study about recent developments of a hydro power plant with carbon finance option in central Vietnam, using the IRR. In summary, the IRR will be calculated taking into account the benefits and economic costs. Economic costs have two components, i.e. non-tradable and tradable costs. Tradable goods, are valued at border price in the exchange rate. Non-tradable commodities are valued by using the shadow price conversion factor and the standard conversion factors specific to different sectors.

Alves (2010), makes an investment analysis and study of economic and financial viability of building a small hydroelectric plant on different scenarios for the variables that affect the project. For each scenario developed is found a minimum price in energy auction in the regulated market that enables to assess the feasibility of the project from an economic viewpoint. It is also calculated the NPV and IRR of a small hydroelectric power according to the sale value of energy obtained by the entrepreneurs in the last auction of alternative energy to the captive market.

Muneer et al.(2011), in their study of the *Large-scale Solar PV Investment Models, Tools and Analysis: The Ontario Case*, also uses the NPV method to evaluate this project, since it is believed that this method incorporates the entire life cycle of the project and the value of money over time. Thus, the NPVs are calculated for all proposed projects, and the project with the highest NPV is selected.

These projects, that are typically evaluated based on static evaluation tools and neglect the issue of flexibility, often lead to undervalued investments (Willis and Scott, 2000). This flexibility refers to the ability of managers to modify the projects according to the evolution of uncertainty, in order to improve the value of investments. However, with the traditional methods this hypothesis is easily ignored (Martínez-Cesena and Mutale, 2011).

The importance of this flexibility and its calculation has been studied by several authors such as Kulatilaka (1998), Trigeorgis (1999), Wang and Neufville (2004), Dixit and Pindyck (1994) and Bengtsson (2001). Thus, the ROA is indicated as the most effective method to take into account the flexibility, and for the evaluation of renewable energy projects. According to Martínez-Cesena and Mutale, (2011) the flexibility captured by this method can increase the value of these projects. Traditional methods even with the application scenario analysis still focus on the question of whether or not to invest in a project and do not say which is the best time to invest (Yang and Blyth, 2007).

Roques et al. (2006), for example, assume a model where investment decisions are made at intervals of five years, and also based on the NPV. The model can be used to evaluate two different timings of investment behaviour. First, it assumes that the investment takes place during the first period of time that has a positive NPV and uses technology that has the highest positive NPV. If the NPV for all technologies is negative, further evaluation will occur in the next period of time. If we never have a positive NPV then no investment is made. This approach produces an investment timing and technology choice pattern. However, it can be used to find the optimal timing of investment.

The ROA is the extension of financial options theory for the evaluation of real assets. A real option can be defined as the right but not the obligation, to make an investment decision on real assets (i.e., delay, construct, abandon, alter, change, etc.). This flexibility can increase the value of projects (Dixit and Pindyck, 1994). In contrast to financial options, a real option is not negotiable - for example, the owner of a factory cannot sell the right to expand the facility to the other party, as only he can make this decision (Blyth and Yang, 2007).

According to Botterud and Korpas (2004), in the ROA, investment projects with uncertain future cash-flows can be considered as options, if the investment decision is irreversible and the investment timing is flexible. This is usually the case when investing in new power generation plants. The ROA states that the optimal timing of an investment does not occur until the value of the project itself is equal to the option of investing in the future. Figure X illustrates the situation where is optimal to invest until the net cash-flow of the project reaches V *, i.e., when the NPV of the project itself, N (V), reaches the value of having the option to invest F (V). The static evaluation of the NPV in Figure 10 recommends investing when the N (V) is positive, i.e., when the NPV of the project exceeds the investment cost, I. The ROA provides a more restrictive investment strategy, since the value of waiting for information about the uncertain future trends that affect the project's cash-flow, A (V), is explicitly taken into account in project evaluation.

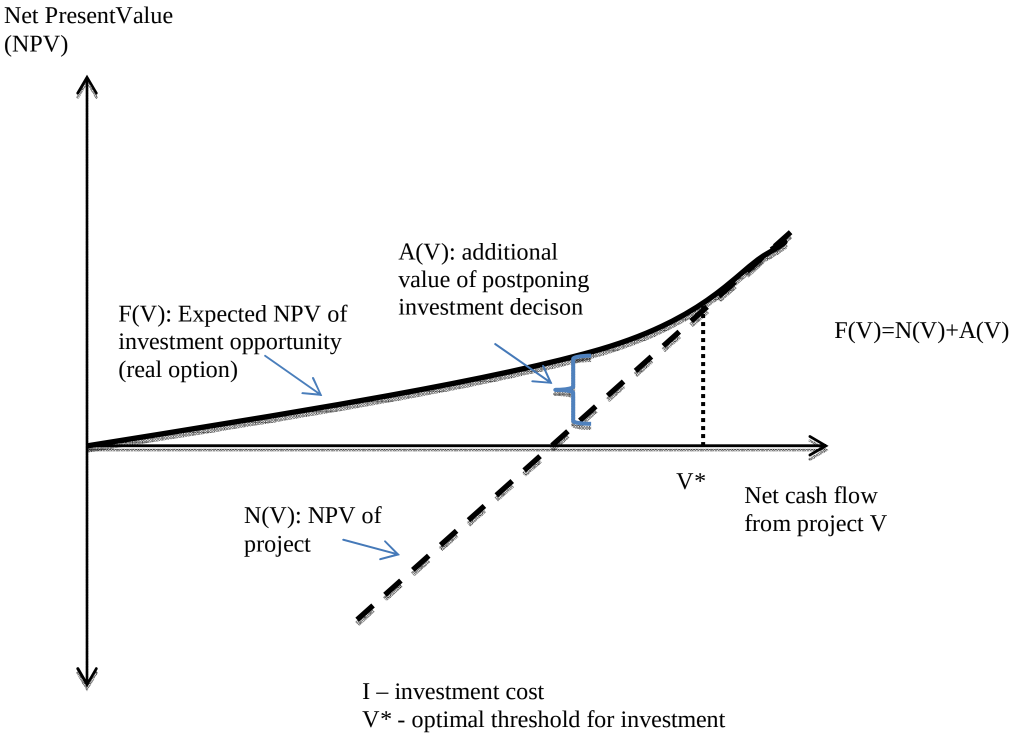

Figure 10 - Illustration of the real options approach

Source: elaborated by the author, based on Botterud and Korpas (2007)

According to Bracher (2003), the traditional evaluation of projects knows the risk of a project, but ignores the fact that management actions could mitigate these risks, and thereby, maintain or even, increase the value of the project. On the contrary, real options analysis combines uncertainty and risk with the flexibility of the evaluation process, considering the volatility as a potential positive factor, attributing value to the project.

Regarding the issue of evaluation of environmental resources, according to Pindyck (1999), for investment projects involving natural resources, there are certain peculiarities involved: 1) the irreversibility of investment, 2) the possibility of postponement of the investment decision and benefits of waiting, 3) the timing for optimal use of environmental good. The presence of these three aspects suggests that evaluating these projects with the techniques that traditionally have been used is inconsistent, which implies the use of the ROA.

The ROA is a methodology for evaluation of real assets, which takes into account the operational and managerial flexibility over the lifetime of the project. Its dynamic characteristic differs from traditional techniques, like NPV, and therefore, leads to more realistic results. A real option is the flexibility that a manager has to make decisions about real assets. As new information is developed and the uncertainty about the cash-flow is revealed, the investor can make decisions that positively influence the final value of the project.

As previously discussed the irreversibility of power generation projects, the high degree of technical, economic and regulatory uncertainty, as well as the need for management flexibility, require an investment evaluation capable of taking into account these issues, that the project is not under-estimated. The determination of the viability of projects by traditional methods are able to assess the risk, but do not examine all the uncertainties and flexibility required for their proper implementation. Thus, the ROA will fill these gaps through the incorporation of management flexibility allowing investors of project power generation from renewable sources, to make the right decisions by obtaining better information for their execution.

4. THE REAL OPTIONS APPROACH

4.1 – Real Options Approach

The Real Options Theory is perceived as the only method of assets valuation that recognizes the interaction between the three factors that characterize the nature of investments: irreversibility, uncertainty and flexibility in timing (Dixit and Pindyck, 1994).

In a context of uncertainty and flexibility, the evaluation of an investment must take into account the possibility of response to future operating conditions. The technical evaluation of real options has the capability to account for this investment flexibility (Soares et al., 2008). The following figure represents a matrix that relates the uncertainty and flexibility with the methodologies that evaluate risk and uncertainty in project analysis.

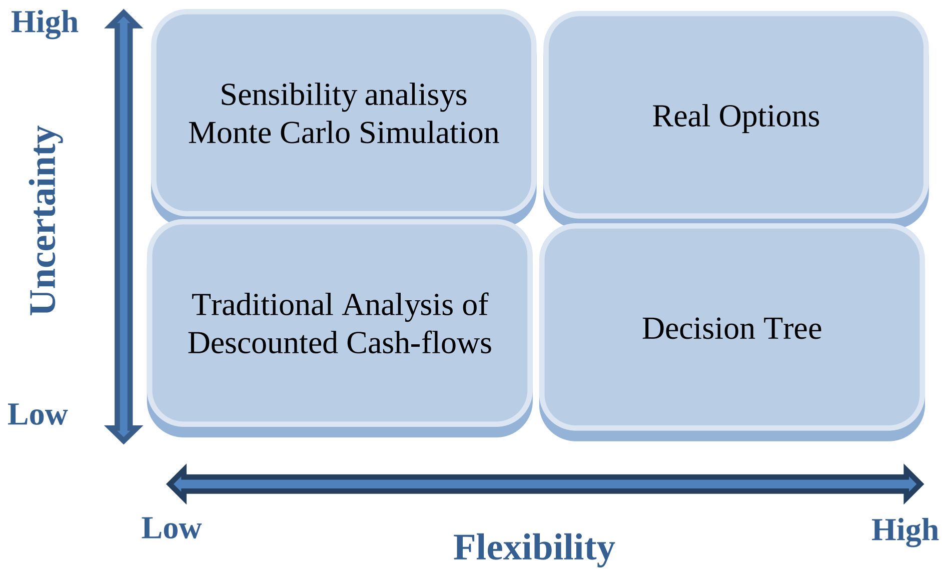

Figure 11 - Uncertainty and Flexibility

Source: Elaborated by the author based on Soares et al., 2008

As it has been claimed in this paper, this matrix shows that the ROA is the best method of investment evaluation when flexibility is incorporated into the investment and there is a high level of uncertainty.

The ROA results from developments in studies of Financial Options. Thus, for explaining the application of Real Options, it is necessary to establish theoretical concepts that also resulted in Financial Options.

4.1.1. Financial Options and Real Options

A financial option is an asset that gives the holder the right but not the obligation, to buy (call option) or sell (put option) a certain amount of a particular asset (underlying asset), to a pre-determined fixed price (exercise price), within a certain period or established date (Soares et al., 2008).

In 1973, Miller-Fisher Black and Myron Scholes derived the first mathematical formula for pricing options of purchase shares (call options) of the european type (Black and Scholes, 1973). In their article, Black¬Scholes start from a non-arbitrage premise (proposed by Modigliani and Miller) to develop an equilibrium model that involves a risk-free portfolio, whose return could be represented by risk-free rate.

The Black-Scholes model (1973) takes into account the following assumptions:

1. The risk-free rate is known and constant over time;
2. The asset pays no dividends;
3. The option can only be exercised at the time of maturity (Option of European type);
4. There are no transaction costs when buying or selling an asset or derivate;
5. It is possible to invest any fraction of assets or derivates to the risk-free interest rate;
6. There are no penalties when making short-selling;

7. The model derives from the concept that asset price of an option has a continuous stochastic behaviour in the form of Geometric Brownian Motion (GBM) according to the following equation:

$$\frac{dS}{S} = \mu dt + \sigma dz \quad \textbf{(9)}$$

Where:

dS: Variation of S (underlying asset price) at time dt;
μ: A mathematical expectation of the instantaneous return rate of the underlying asset;
σ: The instantaneous standard deviation of return on the underlying asset;
dz: A standard process of Gauss-Wiener[2].

The Black-Scholes equation for European call option is:

$$c = SN(d_1) - Ke^{-r\tau}N(d_2) \quad \textbf{(10)}$$

Where:

$$d_1 = \frac{\ln\left(\frac{S}{K}\right) + \left(r + \frac{\sigma^2}{2}\right)\tau}{\sigma\sqrt{\tau}} \quad \textbf{(11)}$$

and,

$$d_2 = d_1 - \sigma * \sqrt{\tau} \quad \textbf{(12)}$$

Where:

$N(d)$: Function of Cumulative normal distribution;

[2]**Wiener Process:** A stochastic process $W_t = \{W(t), t \geq 0\}$ defined in a probability space (Ω, F, P) is a Wiener process if:
1. for $s \geq 0$ and $t > 0$, the random variable $W_{t+s} - W_s$ has a normal distribution N(0,t);
2. for $n \geq 1$ and $0 \leq t_0 \leq \cdots \leq t_n$, the random variable $W_{tr} - W_{tr-1}$ is independent;
3. $W_0 = 0$;
4. W_t is continuous for $t \geq 0$.

ln: Natural logarithm;

S: Stock price;

K: Exercise price;

r: Risk-free rate with continuous capitalization;

τ: Time to expiration;

σ: The volatility of underlying asset.

The Black-Scholes equation for European put options is easily deduced from the previous equation through "put-call parity[3]". Considering that p is the value of the put option of an asset in time t, we have:

$$\boldsymbol{p = Ke^{-r\tau}N(-d_2) - SN(d_1)} \qquad \textbf{(13)}$$

While European options can only be exercised at maturity date, the American options can be exercised at any time until the maturity date of an option. These American and composed options require for their valuation, the use of numerical methods, such as binomial tree developed by Cox, Ross and Rubinstein (1979). According to these authors, this development comes from a simple and efficient procedure for options evaluation, allowing by essence of its construction, the optimal premature exercise of an option. For these options, we must decide at every instant, which of two actions is most beneficial: exercise option in advance or wait for maturity date.

In this model it is assumed that the period to an option maturity can be divided in discrete periods, whose dimension will be represented by Δt, assuming in each period a given behaviour for the underlying asset price. Each time interval Δt, the underlying asset price is multiplied by an random coefficient μ or d. This random coefficient is the

[3]The ***put-call parity*** is resulted by (Soares et al., 2008):

- a composed portfolio by a *long position* in an unit of underlying asset;
- a *short position* in a call option (meaning it had sold the asset without owning, that is sold to uncovered);
- and a *long position* in a put option,

In maturity date of the options is always has the value of exercise price. Therefore, in the absence of arbitrage opportunities, the portfolio value at any point in time is the value of the exercise price discounted by risk-free interest rate.

rate of variation price in the underlying asset, which can be ascending (μ) or descending (d), reflecting the favourable and unfavourable conditions in the market. These multiplicative factors depend on volatility (σ) and size of time interval (ΔT). The **Figure 12** is a binomial tree of evolution for the underlying asset price, where the nodes on the right represent the distribution of possible future values for the underlying asset in option maturity.

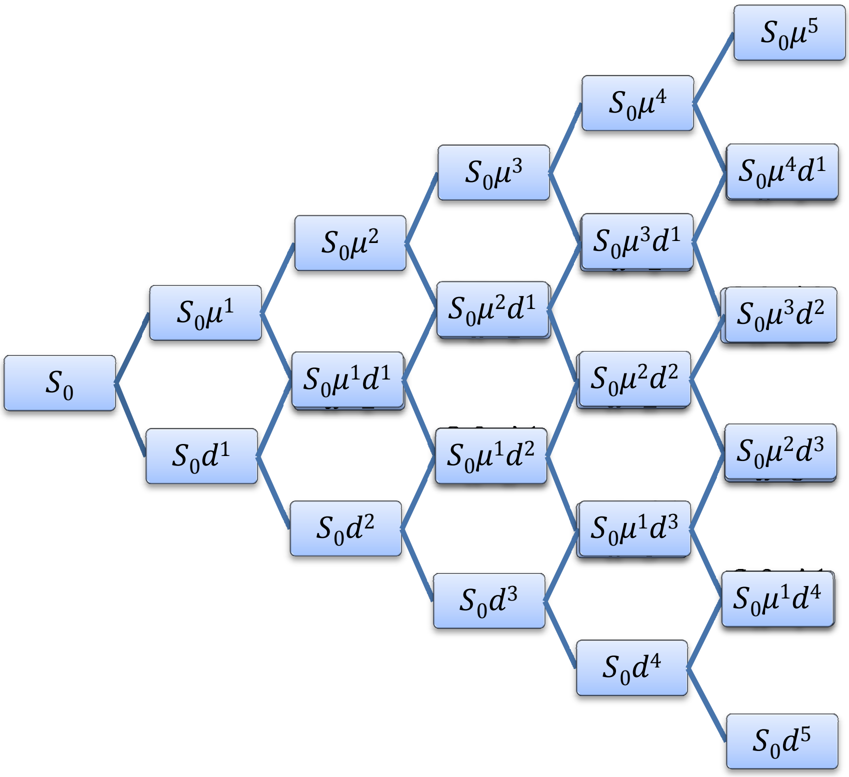

Figure 12 - Binomial tree of evolution for the underlying asset price
Source: Elaborated by the author based on Soares et al., 2008

The ascent and descent coefficient values of the stock in each time interval, d, respectively, are given by:

$$\mu = e^{\sigma\sqrt{\Delta t}} \quad \textbf{(14)} \quad \text{and} \quad d = e^{-\sigma\sqrt{\Delta t}} \quad \textbf{(15)}$$

The probability of stock price increase or decrease is given by risk-neutral measure by p and $q = 1 - p$, respectively. This probability is given by the following equation:

$$\boldsymbol{p} = \frac{e^{r_f \Delta T} - d}{u - d} \qquad \textbf{(16)}$$

When these parameters are determined, it is possible to get values for each option through an option evaluation tree. In this tree is represented each obtained gain for stock price. In the case of a call option, this value is given by the maximum difference between value of the underlying asset and exercise price and zero, i.e., *max (S-K,0)*, while in the case of a put option, the value corresponds to the maximum difference between exercise price and stock price and zero, i.e., *max (K-S,0)*. From the option value in the right nodes of the tree, it is calculated the other values applying the neutral probability on each pair of values vertically adjacent, represented mathematically by the following equation:

$$\boldsymbol{c_t} = \frac{p {c_\mu}^{t+1} + (1-p) {c_d}^{t+1}}{e^{r\tau}} \qquad \textbf{(17)}$$

From the current stock price we determine the different trajectories that it can follow in time until it reaches maturity. For the option value it is adopted an opposite route, from right to left, based on the prices defined in each node.

Identically to financial options, the real options are the right but not the obligation to take an action that affects a real physical asset, at a pre-determined cost, during a pre-established time (Soares et. al., 2008). Therefore, the following figure represents the real and financial options determinants:

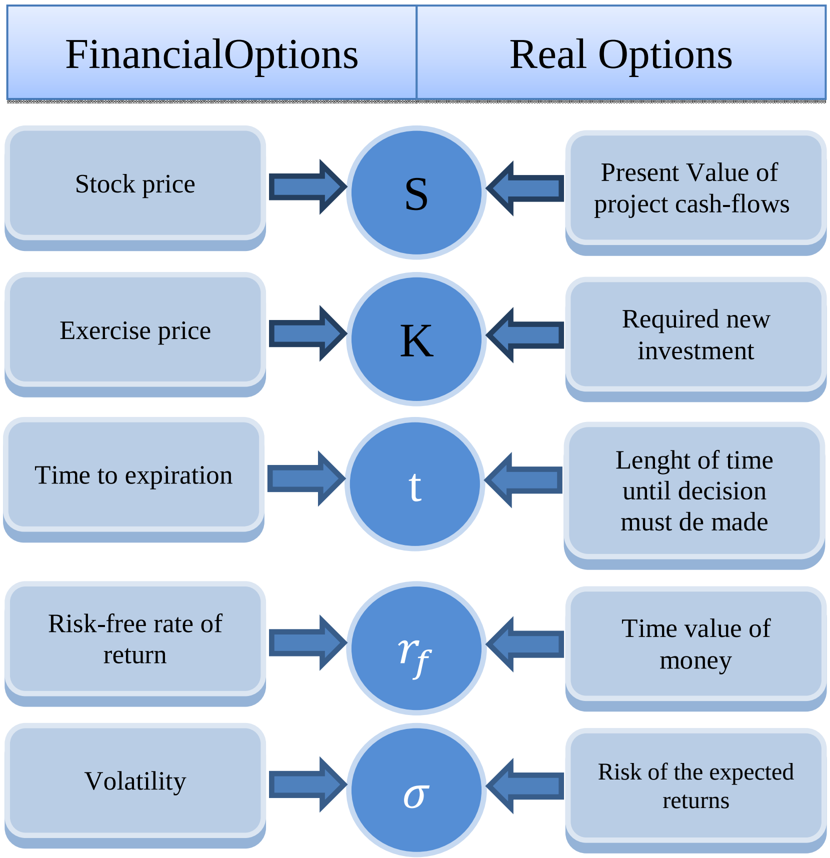

Figure 13- Correspondence in the Valuation Models

Source: Elaborated by the author based on Sanisio, 2002

4.2. Real Options typologies

When dealing with an investment project several options can be exercised, like the option to defer investment, cancel new steps of investment, change the scale of production (expand, contract, temporarily shut down, restart), abandon by residual value of the project, change uses (inputs and outputs) and growth options (Trigeorgis, 1995). These typologies of real options can be classified by flexibility offered in accordance with the following taxonomy:

Table 2 - Types of Real options

Delay Option	It is an American call option found in most projects where exists the possibility to postpone the beginning of investment
Abandon Option	The abandon option of a project for a fixed price (even if that price declines over time) is formally an American put option
Contraction Option	The contraction option (reduce size) of a project, by selling a fraction of this project for a fixed price, is also an American put option
Option for growth and expansion	The expand option of a project, paying more to increase it, is an American call option
Compound Options	There are also options on options, called composited options. The investments planned in phases fall into this category. In these cases it is possible to stop or delay the project in the end of each phase. Thus, each phase is a contingent option to previous exercise of other options: an option on options.

Source: Elaborated by the author

4.2.1. Delay Option

The option to delay a project provides a right, but not an obligation to its holder, to make the investment in the next period, and only performed if the value of investment of the next period exceeds the necessary investment on the current date.

In other words, this option corresponds to an American option, allowing the postponement of an investment decision during a given time. Since, the investment decision implies not exercising the option of waiting, this value of option loss is similar to an additional opportunity cost, which justifies investment only when the NPV exceeds the value of the deferral option (Trigeorgis, 1995).

The delay option confronts the gains of uncertainty resolution and obtaining of additional information, with the costs from project deferral. These costs are reflected, on the one hand, in competitive position, since the deferral may cause partial or total loss of investment value due to the actions of competitors; and on the other hand, loss of positive cash-flows generated by an investment that was not undertaken (Soares et al., 2008).

4.2.2. Abandon Option

In an unfavourable situation for project viability, the abandon option can be exercised in order to give additional value to the investment when there is liquidation of its assets (Soares et al., 2008).

The first option type happens when an investment is divided in such a way that it can be abandoned at any time, since the costs are not concentrated in one period. In this case, it is a situation of sequential investment, in which are determined a series of options on options called Compound Options.

The second type of option consists in the complete abandonment of the project, only getting the amounts for capital expenditures that have not been realized or its residual value.

According to Brealey and Myers (2003), the abandonment of project provides a partial insurance against investment failure. This option is equivalent to an American put option, in which the exercise price corresponds to the liquidation value of investment assets.

4.2.3. Contraction Option

If the conditions are unfavourable in a given market conditions, it is possible to reduce the production scale, reserving part of the planned investment expenditures. This capability is similar to a put option on part of the project, with an exercise price equal to the potential costs saved.

4.2.4. Option for growth and expansion

Contrary to the previous points, this option is exercised in cases of favourable market conditions for the project. This option is identical to an American call option to acquire an additional part of the project, requiring an accompaniment cost (exercise price) ((Trigeorgis (1995).

This option allows promoting pilot-projects for new technologies, which even with negative NPV, should be performed, because these projects can put on the market new successful products or processes. In other words, in these cases, the projects that were initially rejected by traditional assessment methods should be implemented (Soares et al., 2008).

5. CASE STUDY: APPLICATION OF REAL OPTIONS TO A SMALL HYDRO INVESTMENT PROJECT

5.1. Small hydro investments

The term mini-hydro plant differs from large hydro plant, since the first, due to its small environmental impact, is considered a renewable technology. As for the second, although, it uses a renewable resource, it produces non-negligible effects on the environment, which make their classification as a renewable resource technology problematic.

Mini-hydro plants use the following classification recommended by UNIPEDE relatively to installed capacity and height of fall:

Table 3- Classification of hydro plant by installed Capacity

Designation	*P(MW)*
Small-hydropower plant	<10
Mini-hydropower plant	<2
Micro-hydropower plant	<0,5

Source: Elaborated by the author based on UNIPEDE, 2009

Table 4 - Classification of hydro plant by height fall

Designation	*H(m)*
Low fall	2-20
Average fall	20-150
High fall	>150

Source: Elaborated by the author based on UNIPEDE, 2009

The mini-hydro plants are very criticized for their impact on the ecosystem. First, they avoid the connection between upstream and downstream of the installation, having negative consequences, such as the block of passages and protection for fishes, interruption of sediment transport and impact on the landscape in areas little explored.

Systems of mini-hydro plants convert the potential and kinetic energy of water in electricity movement, using a turbine that drives a generator. As the water runs from a high point to a lower zone, as in rivers and waterfalls, the energy is transported that can be exploited by the system of mini-hydro plant.

A constant flow of water is critical to the success of a project for a mini-hydro. The energy available from a turbine is proportional to the amount of water that passes through the turbine per unit of time (i.e., flow), and the vertical difference between the turbine and the water surface to water inlet. Like most of the cost of a project for a mini-hydro results from construction expenses and purchase of equipment, this investment can generate large amounts of electricity with very low operational costs and modest maintenance costs for 50 years or more (RETScreen International, 2005).

Comparatively with other technologies from renewable sources, these plants have a high technological efficiency, due to their maturity level, which reduces significantly the technological risk. Relatively to intermittency of generation, this technology has variation rates and low intermittency, with small variations from day to day. Moreover, as mentioned earlier, their resource (water) is easily predictable, which reduces the uncertain amount of energy generated.

The following figure shows the main components of a mini-hydro plant:

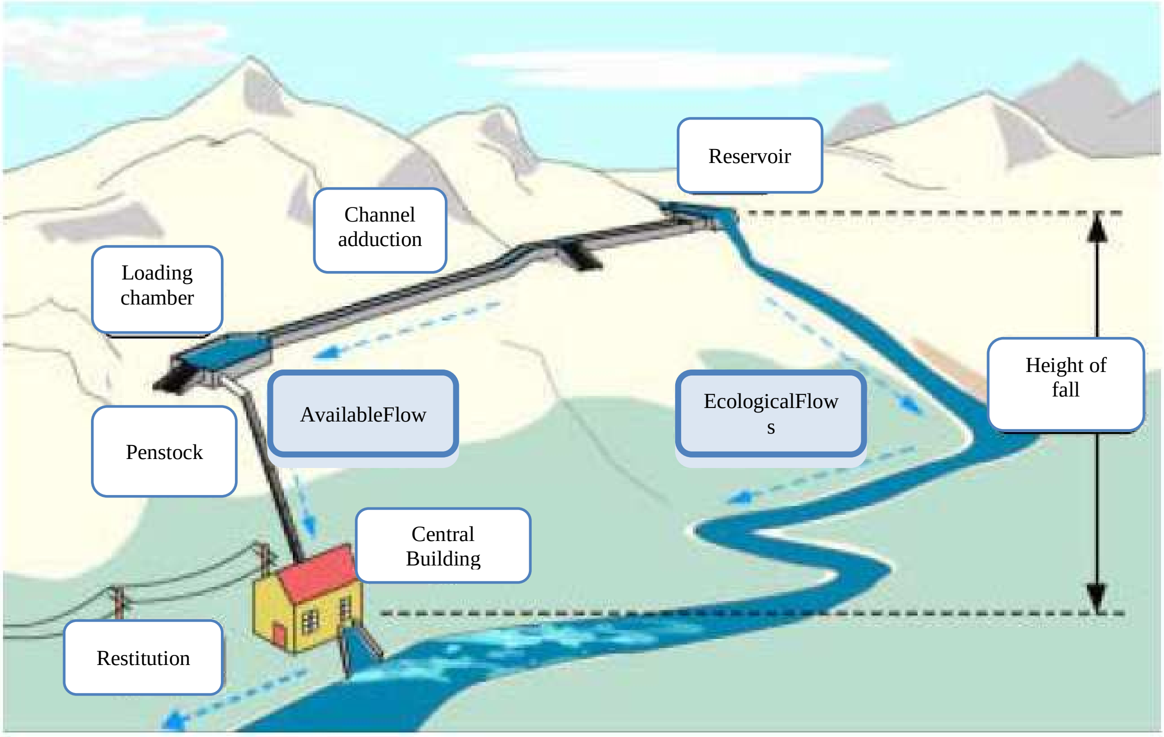

Figure 14 – Components of Mini-hydro plant
Source: Camus and Eusébio (2006)

According to the report of analysis of clean energy projects RETScreen International (2005), some authors, usually consider four stages of engineering work required to develop a project for a hydroelectric plant. These steps of project are represented in the following figure:

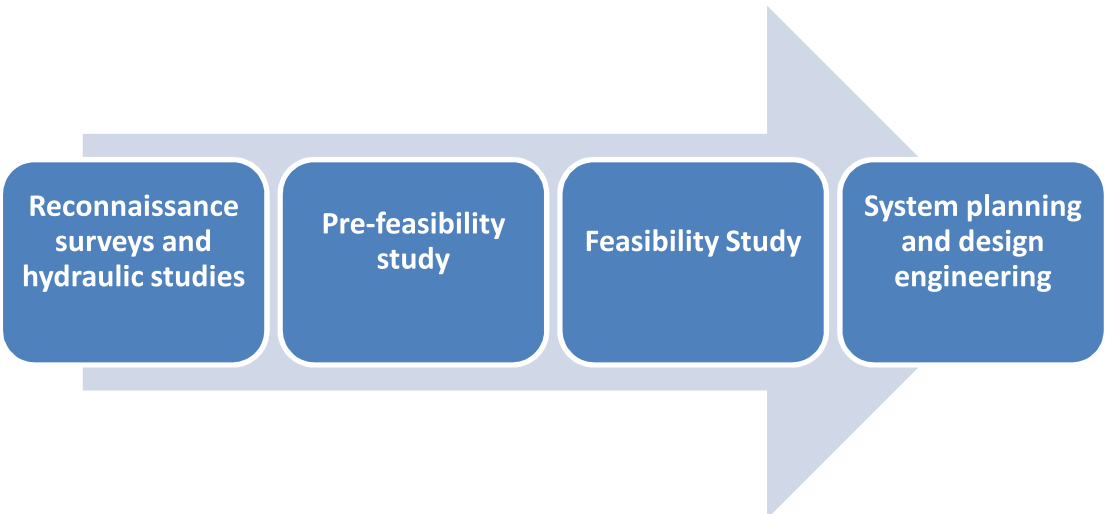

Figure 15 - Main stages of hydropower projects

Source: elaborated by the author

Reconnaissance surveys and hydraulic studies: This first phase of work usually covers numerous sites and includes: map study, delineation of drainage basins; preliminary estimates of flow and flooding; and one day visit to each location (by an engineer and project geologist or geotechnical engineer); preliminary layout; cost estimates (based on formulas or computer data); a final classification of sites based on the energy potential, and a cost index.

Pre-feasibility study: Work on chosen site or sites include: mapping the location and geological investigations; recognition for a suitable borrow areas (eg, sand and gravel); a preliminary layout based on known materials to be available; primary selection of characteristics of main project (installed capacity, type of development, etc.); a cost estimate based on major amounts; identification of possible environmental impacts; and elaboration of a single report on each site.

Feasibility Study: Work continues on the selected site with a major program of foundation investigation; design and testing of all borrow areas; estimate of deviation, design, and probable maximum flood; determination of energy potential for a range of heights dams and installed, determining the project design earthquake and maximum credible earthquake; design of all structures in sufficient detail to obtain quantities of all items that contribute more than about 10% to the cost of individual structures; determination of the dewatering sequence and project plan; optimizing the layout of the project, water levels and components; production of a detailed cost estimate; and finally, an economic and financial evaluation of the project, including an assessment of the impact on the existing electrical wiring, along with a feasibility report.

System planning and design engineering: This work should include studies and final design of the transmission system; transmission system integration; integration of the project to the power grid to determine the precise mode of operation; production of tender drawings and specifications; reviewing proposals and detailed design of the project; production of detailed construction drawings and review of drawings of the equipment manufacturer.

However, for a mini-hydro, the engineering work is often reduced to three stages, with a lower level of detail in order to reduce costs. Generally, a preliminary investigation is conducted, which combines the work involved in the first two phases described above. While reducing the engineering work, increases the risk of the project not being financially viable, which can usually be justified, due to the reduction of costs associated with smaller projects (RETScreen International, 2005).

5.2. Case study: a brief description

In this point it will be analysed a former investment valuation on a hydroelectric plant where were used traditional methodologies of project valuation and then, proceed to a practical application of the ROA to this case study. Thus, the phases of the mentioned project will not be assessed in this study, since they have been already finished. Only the phases related directly to the economic viability of the project, such as the economic and financial data and production estimates, will be in the scope of this study.

The case study represents an investment project of a mini-hydro plant with an installed capacity of 500 kW, resultant to a capture usage of low dropout (10.5 m), with a plant built on river margins, besides the concrete reservoir. The lifetime of the project is 50 years, which corresponds to the lifetime of the turbine and generator. The lifetime of the transformer is 25 years.

This project presents the following characteristics:

Table 5- Characteristics of the mini-hydro plant

Turbine Type	Kaplan with vertical axis
Nº of turbines	1
Generators	Asynchronous three-phase 400V
Nº of generators	1
Income generator	95%
Transformers	400V/15kV
Nº of transformers	1
Income of transformers	90%
Capacity of each turbine (kW)	500
Capacity of project (kW)	500
Interconnection line (km)	line de 15Kv with 10 km
Average annual generation (kWh)	1.332.808

Source: elaborated by the author

The project begun in 2006, and the start-up was the end of that year.

At the time of the economic assessment, the project costs were assumed to be following:

Table 6 - Investment Cost (%)

Investment Costs	***Percentage of Total***
Transformers	14,46%
Generators	10,24%
Turbines	10,24%
Electromechanical equipment	14,46%
Construction	24,10%
Line of 15kv	12,05%
Study and Project	2,41%
Cost of land and expropriation	12,05%

Source: elaborated by the author

Table 7 - Operating and Maintenance Costs (%)

Operating & Maintenance Costs (Annual)	*Percentage of total*
Years 1 a 50	2,48%
Maintenance year 10	4,97%
Maintenance year 20	4,97%
Maintenance year 30	4,97%
Maintenance year 40	4,97%
New transformers after 25 years	77,64%

Source: elaborated by the author

Regarding the financing of the project, there is an incentive program that funds 40% of the investment, being financed up to 1000 €/ kW. The equity of the company support is 25% of the investment and the remaining 35% are obtained by use of bank credit. The first 300 €/kW of incentive are not refundable, and the remainder must be repaid, without interests, in nine years with a waiting period of 3 years (i.e. from the 4th to the 9th year in annual constant payments). The bank financing is a 10 year credit, repayable through constant annual payments, with a 6.5% interest rate, from the date of entry to the operation of the plant. The opportunity cost of capital is considered 10%.

5.3.The economic evaluation of the project under a traditional approach: critical analysis

In this subchapter, it will be undertaken a critical analysis of the assessment made, focusing the following points:

- Calculation of energy produced;
- Value of the energy sales/year;
- Inflation rate;

- Depreciations;
- Rate of capital cost;
- NPV, IRR e Payback.

This project has been assessed from three main traditional methods: NPV, IRR and Payback. The main results obtained with this analysis were the following:

Table 8 - Results of project

Energy Produced (kWh/year)	1.332.808
Remuneration of energy (€)	9.6672
NPV (€)	51.371
IRR (%)	11,22%
Payback (years)	35

Source: Elaborated by the author

- **Energy produced**

The hydrological study was conducted for flow distribution based on the values of the monthly average flow, measured in a hydrological station located 1000m upstream of where is installed the mini-hydro, with a catchment area of 200 km2.

The monthly average flows presented are:

Table 9- Monthly average flow (m^3/s)

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SET
"1966/67"	7,8	9,2	3,2	6,5	23	9,1	2,9	9,5	1,8	0,38	0,15	0,2
"1967/68"	0,4	2,9	1,1	0,87	21,75	5,7	8,9	1	1,4	0,24	0,06	0,72
"1968/69"	1,06	14	20	32	29	57	6,4	11	3,9	1,1	0,22	1,1
"1969/70"	0,83	2,2	1,6	8,5	7,2	2,7	1,6	4	1,3	0,19	0,05	0,02
"1970/71"	0,1	1,1	1,28	12,32	5,25	3,85	14,67	10,67	7,13	5,54	2,09	0,69
"1971/72"	1,31	0,73	0,91	4,74	37,44	11,66	3,99	1,84	0,76	0,15	0,04	0,17
"1972/73"	2,83	6,18	14,58	22,21	5,3	2,06	0,57	9,85	2,61	0,71	0,28	0,24
"1973/74"	1,72	1,75	3,02	20,98	20,08	4,6	2,4	2,29	10,36	2,46	0,37	0,34
"1974/75"	0,37	2,26	1,55	4,26	7,71	13,81	2,92	1,59	0,89	0,22	0,04	0,45
"1975/76"	1,3	1,24	1,98	1,19	4,86	2,44	2,06	1,63	0,38	0,58	0,19	0,53
"1976/77"	6,37	6,52	8,79	22,38	45,19	10,38	5,46	1,97	1,71	0,37	0,15	0,11
"1977/78"	2,31	1,59	39,3	12,03	61,98	23,97	4,68	6,96	1,84	0,39	0,07	0,04
"1978/79"	0,44	1,32	39,3	24,05	72,96	23,45	15,64	3,51	1,6	0,53	0,09	0,05
"1979/80"	5,16	3,16	4,62	5,52	10,18	7,82	5,54	5,59	1,83	0,31	0,11	0,07
"1980/81"	0,35	1,69	1,06	0,82	1,23	3,75	5,76	5,72	1,62	0,14	0,03	0,15
"1981/82"	3,13	0,58	23,76	14,92	7,26	3,2	1,59	0,98	0,8	0,11	0,04	0,65
"1982/83"	1,78	6,74	9,43	3,09	10,17	4,47	14,39	22,21	3,37	0,84	0,71	0,27
"1983/84"	0,28	6,09	19,7	6,57	5,28	7,08	8,01	3,42	2,23	0,43	0,06	0,13
"1984/85"	5,2	28,05	13,06	23,58	45,81	9,7	9,76	3,25	4,21	0,67	0,21	0,07
"1985/86"	0,16	1,37	14,49	10,25	21,28	8,79	3,31	1,9	0,41	0,06	0	3,43
"1986/87"	0,68	3,5	3,24	7,25	15,84	6,32	7,79	2,15	0,75	0,59	0,06	2,71
"1987/88"	6,77	3,99	13,81	31,47	27,02	3,69	4,44	10,08	4,18	2,69	0,34	0,14
"1988/89"	1,08	1,71	1,44	1,15	2,71	4,2	5,07	2,32	2,99	0,2	0,11	0,05
"1989/90"	0,14	13,36	72,21	14,1	15,11	3,33	4,42	1,65	0,64	0,17	0,1	0,12

Hydrological studies provide the probability of flows (usually daily mean values) during the year. It is necessary an analysis of records over several years in order to calculate the water resources during the life of the mini-hydro (Camus and Eusebio, 2006).

It can be supplied data relative to daily and monthly average flows to calculate: the average energy produced; flows in dry, wet and normal years to study scenarios; flood flows, for the design of water retaining structures and spillways; ecological flows, to calculate the available flow (Camus and Eusebio, 2006).

The primary objective of the hydrologic analysis designed to support feasibility studies of hydroelectric power plants is, therefore, to obtain the call duration of the flow-duration curve. This curve is a mean curve supported by observations made over several years and its significance will be greater, the longer the time period required for its construction (Castro, 2002).

This way, the values considered for the period 1966 to 1990, used to calculate a forecast of production for a project that started in 2006, may not be enough. Given the climatic changes over the past 40 years, it is important that these values were updated, at least until the beginning of the twenty-first century. Moreover, it is recommended that these data matches 30 to 40 years (Eusebius and Camus, 2006; Castro, 2002).

- **Value of energy sold annually**

The tariff calculation is performed based on assumptions and does not take into account the true values of each part of the tariff. The remuneration value of generated energy is calculated using the following formula:

$$VRD_m = [KMHO_m * [PF(VRD)_m + PV(VRD)_m] + PA(VRD)_m * Z] * \frac{IPC_{m-1}}{IPC_{ref}} * \frac{1}{(1-LEV)} \quad \textbf{(18)}$$

Where:

VRD_m:Monthly remuneration applicable to central of Renewable Producers;
$KMHO_m$: It is a coefficient that modulates the values of$PF(VRD)_m$, $PV(VRD)_m$ and $PA(VRD)_m$as a function of time in which electricity has been provided;
$PF(VRD)_m$: Fixed portion of remuneration (capacity) applicable in the month m;
$PV(VRD)_m$: Variable portion of remuneration (energy) applicable in month m;
$PA(VRD)_m$: Environmental portion of remuneration in month m;
Z: Additional coefficient that reflects the characteristics of the resource and technology used;
IPC_{m-1}: Consumer price index, excluding housing, on the Continent, in the month m;
IPC_{ref}: Consumer price index, excluding housing, on the Continent, in the month prior to the start of power supply;
LEV: Losses in transmission and distribution avoided by the renewable central.

When reviewing the calculation of the first part of the equation (KMHO), the value is considered equal to 1. However, although in the licensing process, the renewables have the possibility to decide if they prefer or not the tariff modulation translated by the coefficient KMHO, the hydro plants have obligatory modulation. Thus, the value should not be considered 1, but should be calculated based on the assumption of legislation and the following formula:

$$KMHO = \frac{KMHO_{pc} * ECR_{pc,m} + KMHO_v * ECR_{v,m}}{ECR_m} \quad (19)$$

Where:

$\boldsymbol{KMHO_{pc}}$**:** Factor that represents the modulation corresponding to full and peak hours, which have the value of 1.15 for the hydro plants;

$\boldsymbol{ECR_{pc,m}}$ $(\boldsymbol{kW/h})$**:** Renewable electricity produced by the plant in full and peak hours and end of month *m*;

$\boldsymbol{KMHO_v}$**:** Factor that represents the modulation corresponding dumped hours, which have the value of 0.80 for the hydro plants;

$\boldsymbol{ECR_{v,m}}(\boldsymbol{kW/h})$***:*** Renewable electricity produced by the central in dumped hours of the month *m;*

$\boldsymbol{ECR_m}(\boldsymbol{kW/h})$***:*** Renewable electricity produced by the plant in the month *m.*

The fixed part $\boldsymbol{PF(VRD)_m}$is associated to the remuneration related to capacity guarantee provided by the renewable plant, and it is calculated by following equation:

$$\boldsymbol{PF(VRD) = PF(U)_{ref} * COEF_{pot,m} * POT_{med,m}} \quad \textbf{(20)}$$

Where:

$\boldsymbol{PF(U)_{ref}}$is the unit value of reference for $PF(VRD)$, which:

- Must correspond to the monthly investment unit cost in new production facilities, which construction is avoided by a renewable energy plant, that ensures the same level of capacity that would be provided by a new production facility;
- It’s value is 5,44 € (kW/h);
- It will be used, in each plant, during all periods in which the remuneration set by VRD is applied.

$\boldsymbol{COEF_{pot,m}}$: Dimensionless coefficient that reflects the plant contribution of renewable in the month *m* to guarantee capacity provided by the public network.

$\boldsymbol{POT_{med,m}}$: Average capacity available (declared) by renewable plant to the public network in month *m*, expressed in kilowatts.

The variable part of remuneration $\mathrm{PV(VRD)_m}$ is linked to the energy delivered by PRE-R, and is calculated as follows:

$$\boldsymbol{PV(VRD)_m = PV(U)_{ref} * ECR_m} \tag{21}$$

Where:

$\boldsymbol{PV(U)_{ref}}$ is the unit value of reference for $PV(VRD)$, which:

- Must correspond to the operation and maintenance costs that would be needed to exploit the new production facilities, which construction is avoided by the renewable plant;
- It's value is €0,036 kW/h;
- It will be used, in each plant, during all periods in which the remuneration set by VRD is applied.

The environmental part $\mathrm{PA(VRD)_m}$ values the environmental benefits provided by the renewable plant, and it is calculate by the following formula:

$$\boldsymbol{PA(VRD)_m = ECE(U)_{ref} * CCR_{ref} * ECR_m} \tag{22}$$

Where:

$\mathbf{ECE(U)_{ref}}$ is the reference unit value for avoided carbon dioxide emissions by the renewable plant, which:

- Must correspond to a unit value of carbon dioxide that would be emitted by a new production facility, which construction is avoided by the renewable plant;
- It's value is 2*10 – 5 EUR/g;
- It will be used, in each plant, during all periods in which the remuneration set by VRD is applied.

$\boldsymbol{CCR_{ref}}$:is the unit amount of emissions of carbon dioxide from the reference plant, which takes the value of 370 g / kilowatt-hour, and it will be used in each plant, during all periods in which the remuneration set by VRD is applied.

The parameter $\boldsymbol{LEV}$ for this project with a capacity less than 5 MW, takes the value of 0,035.

The factor **Z** is the technology used in production. The value for the mini-hydro is 4,5 and not 4,2 as indicated in the analysis.

$\frac{\boldsymbol{IPC_{m-1}}}{\boldsymbol{IPC_{ref}}}$ was calculated taking into account the IPC of 2005 (the year preceding the project) and updated by inflation.

The following table represents the values determined for all parcels, together with the return of energy to the month and year:

Table 10 - Results of energy remuneration

KMHOm	*1*
IPCm-1/IPCref	1
LEV	0,035
PF(VRD)m	323,63
PV(VRD)m	3998,42
PA(VRD)m	821,90
Z(mini-hydro)	4,2
VRDm	**8.056 €**
VRDa	**96.672 €**

Source: Elaborated by the author

Another important note about the value of remuneration is the period of support. In this investment analysis it is considered that the energy generated will be paid during all the life of the project in this amount, however, this support has only the durability of 20 years, renewable for another five years, i.e. has a total 25 years of provision. Obviously, due to simplicity reasons in the calculation it is assumed that the revenues will be generated according to this value during the 50 years of the project, but this is not correct, since that in the middle of the project, energy will be sold according to market conditions, which provides a highest uncertainty and increases the risks for investment.

- **Inflation rate**

The inflation rate is assumed to be equal to 3%. However, this is only applied when calculating the remuneration of the energy produced, but it is not accounted for the remaining components of cash-flows, i.e. the cost of the project. As a result, this evaluation indicates that the projects revenues are growing over the years, but in return, the costs remain, which over-evaluates the NPV, benefiting positive results of project.

The inclusion of inflation in investment analysis is not consensual. Some authors argue that it only justifies to realize an evaluation at current prices if the inflation rate is very high and unstable, if not, a constant price analysis is best (Barros, 1991). This is common in studies of investment assessment, since it is considered that inflation affects in the same way all the revenues and costs. This situation happens due to the fact that many analysts, for simplicity, consider identical values of inflation for all components (Barros, 1991, Soares et al., 2008). This assumption is not realistic, since each component has different values of inflation, by types of products or sectors.

The inflation has an impact on cash-flows on investment projects at three levels (Soares et al. 2008):

- In nominal incomes, which increase;
- In nominal expenditures, they also increase;
- In the interest and charges relating to debt, which also increases.

For this reason, if this assessment considers inflation in revenues, it should also consider it in costs and in interest rates related to debt.

It is also important to note that the differentiated application of inflation is difficult to achieve and can lead to substantial errors. By analysing, for example, the replacement value of the transformer after 25 years, it is calculated based on weak assumptions, since it considers that it will cost five times more than its cost in the initial investment.

Regarding the choice between the evaluation at current or constant prices, the costs and profits reflect equally the impact of inflation, both investment analysis are equivalent, being the impact of inflation neutral. However, depreciations are determined by the underlying assets. Given that, these are accounted and remain at historical cost in corporate balance sheets, depreciation is a constant proportion of that cost, so it should not suffer the effect of inflation on an analysis at current prices. As depreciation is a cost that is not affected by price increases, but incomes reflect this growth, the impact of inflation will be an increase in net income before taxes and, by extension, a real increase in paid taxes. The real profitability of the company is reduced by the transfer of wealth from the company to the Government through higher taxes (Barros, 1991; Soares et. al., 2008).

In the case of determining the cash-flows at current prices, also the opportunity cost of capital, must be updated with inflation. Thus, the estimation of the discount rate, adjusting the effect of inflation, is the following relationship:

$$\boldsymbol{i_{Nominal} = i_{Real} + \pi + i_{Real} * \pi} \qquad \textbf{(23)}$$

Where:

$\boldsymbol{i_{Nominal}}$:Rate of capital cost at current prices

$\boldsymbol{i_{Real}}$:Rate of capital costs at constant prices

π: Inflation rate

- **Depreciations**

In this evaluation is used a method of depreciation of constant quotas. However, there is some inconsistency about how it is applied. The following table represents the depreciation calculated:

Table 11- Depreciations by year

Year	*Assets*	*Depreciation*	*Accumulated depreciation*	*Net Value*
Start	810.000 €			
End of 2006	710.000 €	16.200 €	16.200 €	693.800 €
End of 2007	710.000 €	16.200 €	32.400 €	677.600 €
End of 2008	710.000 €	16.200 €	48.600 €	661.400 €
End of 2009	710.000 €	16.200 €	64.800 €	645.200 €
End of 2010	710.000 €	16.200 €	81.000 €	629.000 €
End of 2011	710.000 €	16.200 €	97.200 €	612.800 €
End of 2012	710.000 €	16.200 €	113.400 €	596.600 €
End of 2013	710.000 €	16.200 €	129.600 €	580.400 €
End of 2014	710.000 €	16.200 €	145.800 €	564.200 €
End of 2015	710.000 €	16.200 €	162.000 €	548.000 €
End of 2016	710.000 €	16.200 €	178.200 €	531.800 €
End of 2017	710.000 €	16.200 €	194.400 €	515.600 €
End of 2018	710.000 €	16.200 €	210.600 €	499.400 €
End of 2019	710.000 €	16.200 €	226.800 €	483.200 €
End of 2020	710.000 €	16.200 €	243.000 €	467.000 €
End of 2021	710.000 €	16.200 €	259.200 €	450.800 €
End of 2022	710.000 €	16.200 €	275.400 €	434.600 €
End of 2023	710.000 €	16.200 €	291.600 €	418.400 €
End of 2024	710.000 €	16.200 €	307.800 €	402.200 €
End of 2025	710.000 €	16.200 €	324.000 €	386.000 €
End of 2026	710.000 €	16.200 €	340.200 €	369.800 €

End of 2027	710.000 €	16.200 €	356.400 €		353.600 €
End of 2028	710.000 €	16.200 €	372.600 €		337.400 €
End of 2029	710.000 €	16.200 €	388.800 €		321.200 €
End of 2030	710.000 €	16.200 €	405.000 €		305.000 €
End of 2031	710.000 €	16.200 €	421.200 €		288.800 €
End of 2032	710.000 €	16.200 €	437.400 €		272.600 €
End of 2033	710.000 €	16.200 €	453.600 €		256.400 €
End of 2034	710.000 €	16.200 €	469.800 €		240.200 €
End of 2035	710.000 €	16.200 €	486.000 €		224.000 €
End of 2036	710.000 €	16.200 €	502.200 €		207.800 €
End of 2037	710.000 €	16.200 €	518.400 €		191.600 €
End of 2038	710.000 €	16.200 €	534.600 €		175.400 €
End of 2039	710.000 €	16.200 €	550.800 €		159.200 €
End of 2040	710.000 €	16.200 €	567.000 €		143.000 €
End of 2041	710.000 €	16.200 €	583.200 €		126.800 €
End of 2042	710.000 €	16.200 €	599.400 €		110.600 €
End of 2043	710.000 €	16.200 €	615.600 €		94.400 €
End of 2044	710.000 €	16.200 €	631.800 €		78.200 €
End of 2045	710.000 €	16.200 €	648.000 €		62.000 €
End of 2046	710.000 €	16.200 €	664.200 €		45.800 €
End of 2047	710.000 €	16.200 €	680.400 €		29.600 €
End of 2048	710.000 €	16.200 €	696.600 €		13.400 €
End of 2049	710.000 €	16.200 €	712.800 €	-	2.800 €
End of 2050	710.000 €	16.200 €	729.000 €	-	19.000 €
End of 2051	710.000 €	16.200 €	745.200 €	-	35.200 €
End of 2052	710.000 €	16.200 €	761.400 €	-	51.400 €
End of 2053	710.000 €	16.200 €	777.600 €	-	67.600 €
End of 2054	710.000 €	16.200 €	793.800 €	-	83.800 €
End of 2055	710.000 €	16.200 €	810.000 €	-	100.000 €

Source: Classes of Investments of Renewable Energy

In this context, the depreciations were calculated only for the tangible assets, taking into account the total value of the initial investment, with the exception of the components studies and projects, divided by the life time of the investment.

Meanwhile, some aspects deserve a special attention. First, it is assumed that all components of the investment are depreciated in the same way, which is not correct since, for example, the building has not the same lifetime tax of equipment. Thus, according to the rules of depreciation, it would be more appropriate to draw a map with the different amortization allocations for each component. Second, the component corresponding to land and expropriations is not depreciable, being only the value of the building included. Third, the studies and projects were not considered in the amortization map. However, although they represent intangible assets, these are amortized over three years. The following table presents an alternative to the amortization map:

Table 12 - Depreciations by components of investment

Components	*Depreciation (years)*	*Depreciation rates[4] (%)*
Equipment (Transformers, Generators, Turbines, Electromecanic Equipment)	16	6,25
Construction	30	3,33
Line of 15kV	20	5,00
Study and Project	3	33,33

Source: elaborated by the author

In addition, the component relative to equipment suffers a change in its value, due to the replacement of a transformer at the end of 25 years, which will increase both the value of fixed assets and depreciation in that year.

[4]According to **Decreto Regulamentar n.º 2/90 de 12 de Janeiro**

- **Rate of Capital costs**

The rate of capital costs considered corresponds to 10%. This rate should be calculated according to the Weighted Average Cost Of Capital (WACC), determined as follows:

$$\boldsymbol{WACC = K_S * W_S + W_D * K_{D*} * (1 - T)} \qquad \textbf{(24)}$$

Where:
$\boldsymbol{K_S}$**:** Rate of return required by shareholders, promoters of the project;
$\boldsymbol{W_S}$**:** Weight of equity;
$\boldsymbol{W_D}$**:** Weight of debt;
$\boldsymbol{K_D}$**:** Nominal interest rate;
$\boldsymbol{T}$**:** Tax rate on profits

The WACC indicator shows the composition in terms of funding sources. The data for its calculation can be based on the historical balance sheets of the company or market values, being theoretically more correct the use of market values (Mithá, 2009). In the specific case of determining the Beta for the cost of equity, one of the major problems is that it is not possible to determine this value for companies not publically traded and, for this reason, the solutions given are for the use of the Beta of comparable companies; use average Beta of business related (*bottom-up*); use Beta of the listed companies with which there is strong correlation of activities (customers, suppliers, business sector).

- **NPV, IRR e Payback**

The results are a reflection of the assumptions taken into account in evaluating this investment. The value of NPV is low, considering the high investment, the payback is 35 years and the IRR is only 1% above the rate of capital cost considered.

Issues, such as not changing the depreciation values when the new equipment is incorporated in the mid-life of the project, not updating properly all investment components and the determination of little founded assumptions, makes these results less realistic.

One of the facts to comment in these results relates mainly to the calculation of the IRR. This project has non-conventional cash-flows, with signal change in more than one moment of its life time, which involves multiple IRR's and not just one, as shown. In this case, the solution in multiple IRR's is calculating the Modified IRR (IRRM) (Soares et. al., 2008).

First, it should upgrade to the invested capital for the time 0 (t0), to cost of capital. Then capitalize the successive operating cash-flows for the end of the life of the project (tn), to reinvestment rate that the company believes to have strong chances of getting, or ultimately, to a rate equal to the cost of capital. Finally, updates to the sum of the capitalized cash-flows for the time t0 at a rate (MIRR) that allows equals them to investment (Soares et al., 2008). Analytically, we have:

$$\frac{\sum_{t=1}^{n} \boldsymbol{OCF_t}(\mathbf{1}+\boldsymbol{R_2})^{\boldsymbol{n-t}}}{(\mathbf{1}+\boldsymbol{IRRM})^{\boldsymbol{n}}} = \boldsymbol{CI_0} \tag{25}$$

Where:

$\boldsymbol{OCF_t}$**:** Operating cash-flow at the end of year *t*;

$\boldsymbol{R_2}$**:** Reinvestment rate of operating cash-flows;

$\boldsymbol{MIRR}$: Modified Internal Rate of Return.

$\boldsymbol{IC_0}$: Sum of investments in the project updated to rate of capital costs.

Using the MIRR is very useful in cases like these, it only allows associating a measure of profitability to a set of cash-flows (Soares et al., 2008).

Concluding this chapter, this analysis assumes three key assumptions that strongly affect the results of the evaluation:

1 - *The plant will produce to full capacity and all the energy produced will be sold during the life of project.*

The fact that it will produce at full capacity over 50 years is optimistic but also unrealistic, since these predictions are based on hydrological studies, considering the average annual water flow. The failure to consider the uncertainty in this case can be a mistake that could put the viability of the project at risk.

2 –Energy *remuneration is constant over 50 years of life.*

It does not seem reasonable to assume that the price of electricity will not change over 50 years. Even though, it is considered that the government will keep a constant remuneration for the energy produced, but this will only be valid for a maximum of 25, and not 50 years.

3 - *The rate of discount of 10% is assumed deliberately without consideration of funding sources.*

The discount rate definition is not normally consensual. However, in this case to assume a discount rate without any relation with the composition of funding sources is not correct. As mentioned in previous points, the discount rate has influence on the results of the NPV, thus, assuming rates that do not correctly evaluate the data for the project will produce incorrect results.

5.4. Methodology for Real Options application

To accomplish this evaluation through the ROA will be followed the following steps:

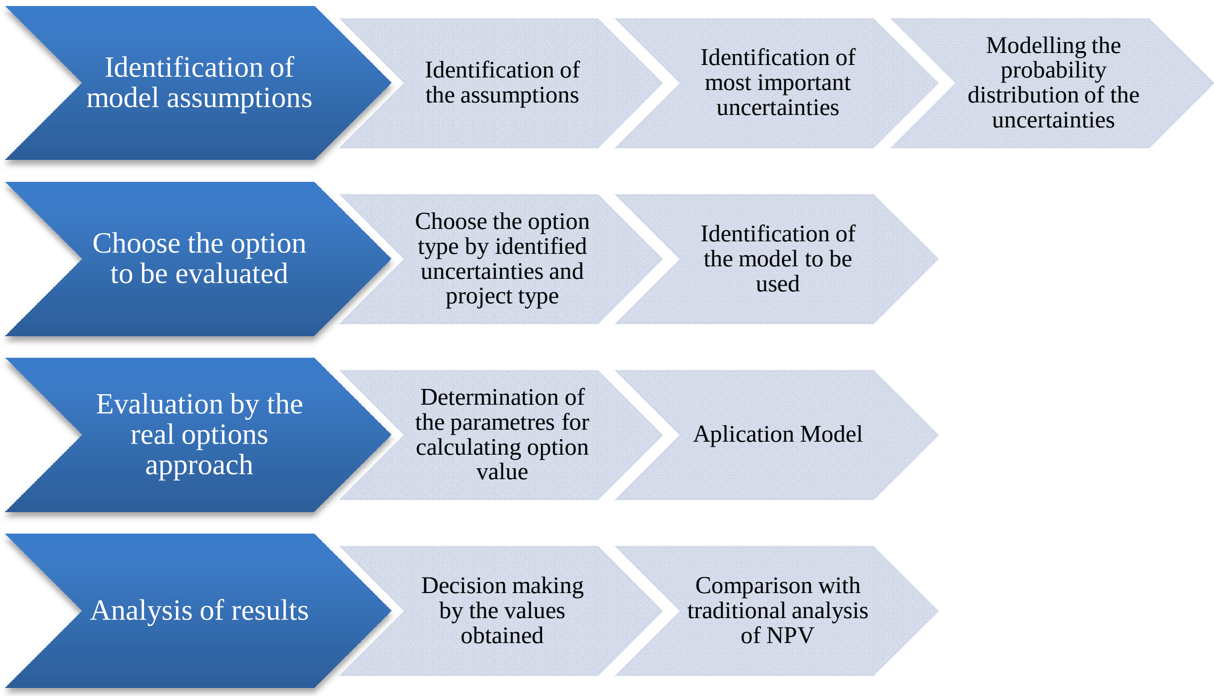

Figure 16 - Steps for Real Options Analysis
Source: Elaborated by the author

5.4.1. Assumptions

For development of investment analysis through ROA, it will be considered the following hypotheses:

Assumption 1 – All data provided by the traditional evaluation model and the results obtained are considered.

For the application of ROA, we assume the data provided by the project. This case study does not intend to alter any assumptions made by the traditional approach. Even being detected some weakness in this model, the objective of this study is to compare the traditional methods of project evaluation and the ROA. In addition, it would not be possible to make corrections accurately, because it is not possible obtain the necessary data to do these.

Assumption 2 – Considering the uncertainty about electricity prices

In spite of uncertainty dynamics that affect these projects, it will be only considered uncertainty of electricity prices, since in the case of mini-hydro investments, the operating costs are not affected by high levels of uncertainty. For example, in these cases, fuel costs have not a considerable influence on production costs. With regard to other uncertainties (technological change, environmental policies, among others), for simplicity case, they will not be included in the analysis.

For the modelling of this uncertainty, it will be considered the electricity price in long-term contracts in OMIP (the Iberian Power Derivatives Exchange) observed over four years.

In evaluation of long-term project of power generation, current spot price is not the most desirable for calculation of volatility project, because it may be strongly influenced by short-term factors (climate, availability of short-term production capacity, among others). In these situations, the uncertainty about time-average price over the lifetime of mini-hydro projects is more relevant.

Therefore, to calculate the volatility of investment return, it will be followed the premises of a GBM for modelling the probability distribution of long-term electricity prices. Pindyck (2001) discusses the evaluation of long-term commodity prices, and argues that for long-term investments related to energy (as the case of mini-hydro projects), the use of GBM will lead to small errors.

5.4.2. Modelling of uncertainties and Monte Carlo analysis

For project volatility assessment was applied a consolidated approach of uncertainty, defined by Copeland and Antikarov (2001), where all considered uncertainties on the assets value are combined into one uncertainty**:** the percentage of the project present value change over time, i.e., the investment return.

In the presented approach, the authors rely on the assumption that present value of cash-flows without flexibility is the best estimation of project market value, being for this reason considered as its market price. This value is used as an input in the binomial tree.

Copeland e Antikarov (2001) base their work on the theorem developed by Paul Samuelson (1965), which proves that the return rate of an asset follows a random trajectory, independently of the cash-flows generated in future, i.e., the current asset value already reflects all the information contained in the historical sequence of this asset. This implies that any deviation in the trajectory of future cash-flows will be given by random events, and consequently, the deviations on the rate of return will also be random.

Based on the ideas of Paul Samuelson, Copeland and Antikarov resorted to the method of Monte Carlo to combine several uncertainties in a single uncertainty, i.e., in volatility of return. The application of Monte Carlo simulation for calculating volatility of project return is represented as follows:

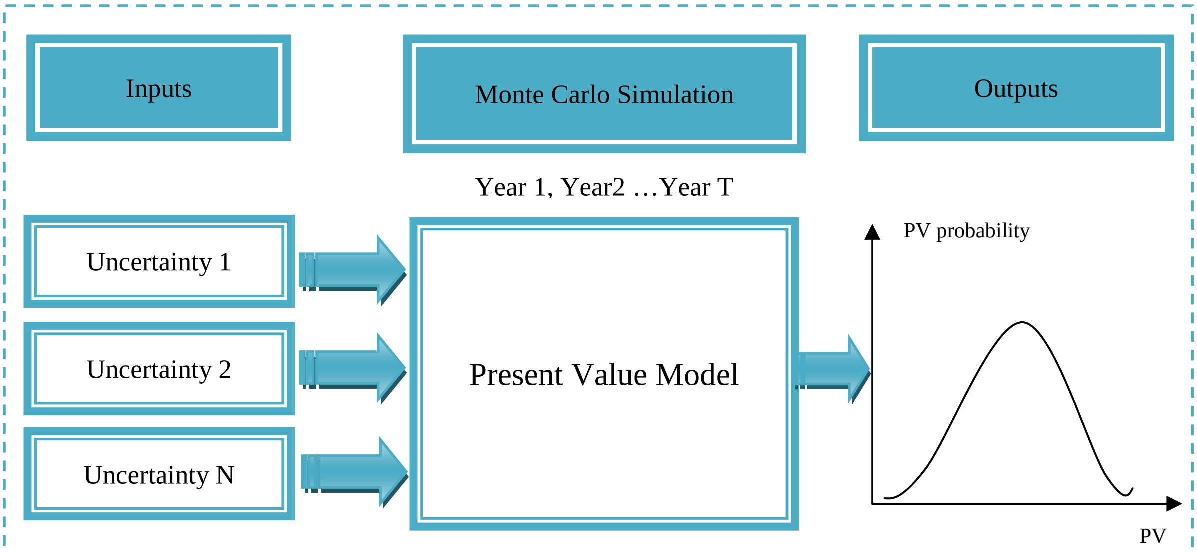

Figure 17 - Monte Carlo Simulation for calculating volatility of project return

Source: Elaborated by the author based on Copeland e Antikarov, 2001

These authors consider that the volatility of the project corresponds to the volatility of its returns. Thus, the values obtained in the simulation can be converted in a return rate by the following equation:

$$\boldsymbol{rt = \ln\left(\frac{PV_t}{PV_0}\right)} \qquad \textbf{(26)}$$

Where:

PV_t: Present value at time t;

PV_0: Present value at time zero;

rt: Rate of return.

The value of future cash-flows are estimated for two dates, and given that the rate of return is constant over time, it is considered that *t* assumes the value one (*t=1*). Thus, the percentage change the project value of one period to the next can be calculated using a logarithmic scale as follows:

$$\boldsymbol{z = \ln\left(\frac{PV_1+FCF_1}{PV_0}\right)} \qquad \textbf{(27)}$$

Where:

PV_1: Present value of project at time 1;

FCF_1: Free cash-flow at time 1;

PV_0: Present value of project at time 0.

The present value of the project at date 0 and date 1 can be calculated using the equations **(28)** and **(29)**, respectively:

$$\boldsymbol{PV_0 = \sum_{t=1}^{T} \frac{FC_t}{(1+WACC)^t}} \qquad \textbf{(28)}$$

$$\boldsymbol{PV_1 = \sum_{t=2}^{T} \frac{FC_t}{(1+WACC)^{t-1}}} \qquad \textbf{(29)}$$

The probability distribution of the "z" values is obtained through the Monte Carlo simulation, thought the usage of the Crystal Ball software. During the simulation the denominator of the equation **(27)** $(\boldsymbol{PV_0})$ remains fixed, only varying $PV_1 + FCF_1$according to the uncertainties defined as *Assumption*. The project volatility is defined as the standard deviation of "z" in the following equation:

$$\boldsymbol{\sigma = desv.pad\,(z)} \qquad \textbf{(30)}$$

In this case, the values are: $VP_0 = [WACC; FC_1\!: FC_9] = 881.371€$ and $VP_1 = [WACC;\ FC_2\!: FC_9 = 851.422€]$. As a result, the value of *z* will be 9,53%.

As mentioned in the model assumptions, it was considered uncertainty on electricity prices in the Iberian market (OMIP) of long-term contracts. The price, because it cannot be negative, follows a lognormal distribution, being one of the premises of GBM. For this distribution, were defined the following values in the confidence interval of 5% to 95%: 21.90€ and 77.91€, corresponding to the lowest and highest price obtained in market over four years. The mean and standard deviation were calculated automatically by the program, giving values of 44.50 and 17.2 respectively. The following figures represent this procedure:

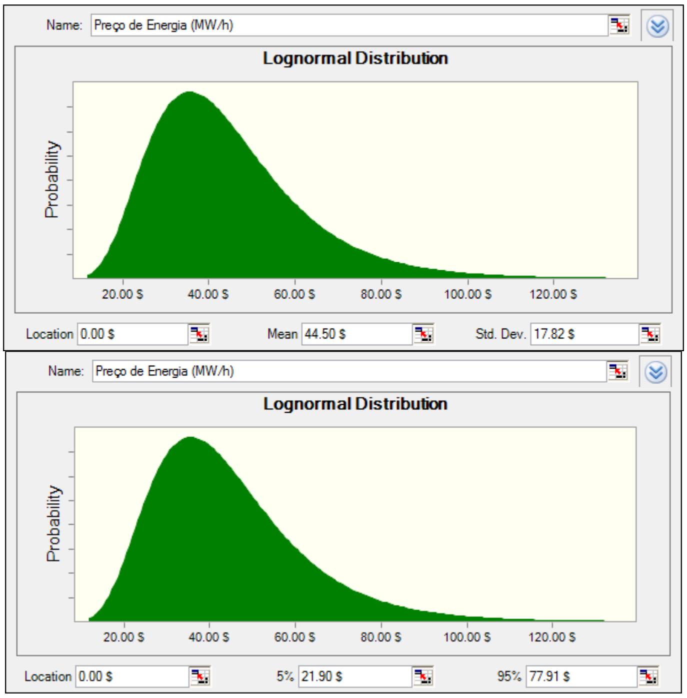

Figure 18 - Distribution of electricity prices
Source: Elaborated by the author using Crystal Ball software

Then, it was defined the value of z as *Forecast*, and proceeded to a Monte Carlo simulation with 5000 iterations, obtaining a standard deviation of project returns of approximately 40%, which corresponds to the volatility of the project (see **Figure 19**).

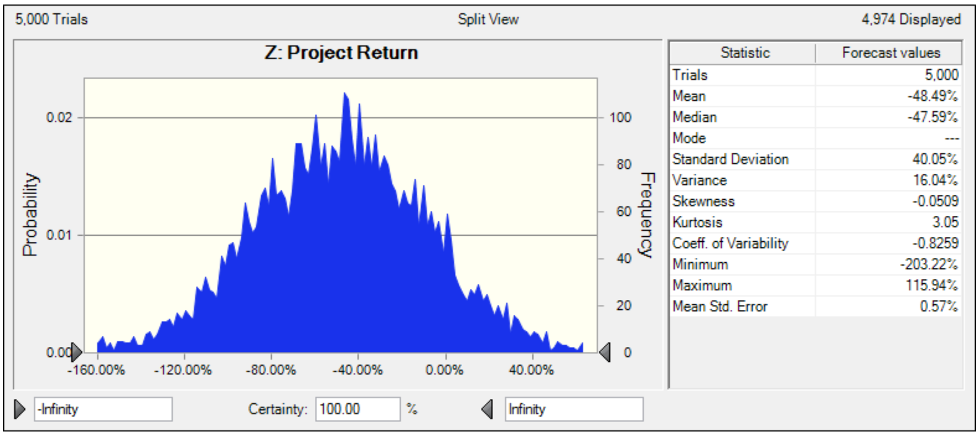

Figure 19 - Forecast of project returns
Source: Source: Elaborated by the author using Crystal Ball software

5.4.3. Modelling Real Options

It is important to emphasize that the investment on a mini-hydro, with exception of the study phase, is not implemented in phases. In other words, once the project starts, it is unlikely to hold an option to interrupt the plant (Fenolio and Minardi, 2008).

Therefore, in this case study, it will be studied the option of deferring the project within five years. This hypothesis of postponement is justified by the high uncertainty on regulatory change that may arise. In other words, given the current economic crisis, the government believes that the support given to electricity generation from renewable sources is no longer a priority and that the legislation could be changed in the coming years, conditioning the feasibility of these projects. Thus, the remuneration of the new plants would no longer have a constant remuneration, being subject to the uncertainty of electricity prices on the open market.

Given this uncertainty, it will be evaluated through the ROA, the option of delaying construction for a maximum period of five years for to obtain better information about new legislation and price evolution, and the option of investing now.

Thus, as presented in the previous point, a deferral option corresponds to an American call option, in which the decision to invest now will be taken if the NPV of the project exceeds the value of the option to defer.

In this case, it is applied the binomial tree method developed by Cox, Ross and Rubinstein (1979), in which the parameters found for the construction of the tree are represented in the following table:

Table 13- Parameters for binomial tree construction

Stock Price (S)(€)	881.371
Exercise price (k)(€)	830.000
Time to option expiration (days) (T)	1.825
Volatility(σ)	0,40
Risk-free rate (rf)	0,07
Number of steps (n)	5
ΔT=(T/365)/n	1
μ=exp(σ√ΔT)	1,49
d=1/μ	0,67
exp(rf*ΔT)	1,07
p=(exp(rf*ΔT)-d)/(u-d)	0,49

Source: Elaborated by the author

As previously stated, the stock price represents the cash-flows of an investment and exercise price is the investment required to implement the project. The time to maturity of the option to defer is 5 years and the volatility of investment returns found by the method of Monte Carlo simulation is approximately 40%.

The risk-free rate of return considered represents the rate of return on Treasury bonds to 10 years. The coefficients of ascent and descent of the underlying asset's values μ and *d* (Equations (14) and (15))assume values of 1.49 and 0.67, respectively. Finally, the value of probability of the underlying asset price increases is 49%, while the probability of decreasing assumes a value of 51%.

Determined these variables the tree is constructed with the possible evolutions of the underlying asset price from left to right, being placed in the node on extreme left the current price of the underlying asset. At each time interval, the price can increase or decrease depending on the coefficients μ and *d*, respectively. The last column of the binomial tree represents the possible values of the underlying asset at the maturity of the option.

After, it is elaborated an evaluation tree of the option from right to left. Given that the abandon option is a call option, from the values of the last column of the underlying asset is subtracted to each one of these values the exercise price (investment on the project), and this result takes the max value between *S*-*K* and *0*. To determine the remaining values of the evaluation of the call option, it is applied the neutral probability to each pair of vertically adjacent values.

5.4.4. Results

The main issue of this evaluation is to determine if the investment of this mini-hydro should be performed immediately, or if it should be deferred up to five years for to obtain better information about changing the remuneration of these plants. Thus, if the value obtained for the project with the option to delay is greater than the value derived from the investment without considering flexibility, the decision more advisable will be to exercise the option.

The results obtained in the binomial tree in relation to the future underlying asset values and values of the project with the option of postponing are represented in the upper and lower values, respectively, in each node in the following figure:

Steps	0	1	2	3	4	5
						6.512.498
						5.682.498
					4.365.458	
					3.591.571	
				2.926.254		2.926.254
				2.204.687		2.096.254
			1.961.527		1.961.527	
			1.314.526		1.187.640	
		1.314.851		1.314.851		1.314.851
		763.591		647.461		484.851
	881.371		881.371		881.371	
	433.659		343.632		221.323	
		590.800		590.800		590.800
		178.808		101.029		0
			396.025		396.025	
			46.117		0	
				265.464		265.464
				0		0
					177.946	
					0	
						119.281
						0

Legend: Underlying asset / Project value of delay

Unit: Euros

Figure 20 – Evolution of underlying asset and project value of delay
Source: Elaborated by the author

The calculated value of the project with the option to delay is €433.659, much higher than the static NPV, which was €51.371. The option value of delay is obtained from the equation (8), i.e. the difference between static NPV and expanded NPV, resulting in a value of €382.289. Therefore, it is appropriate to postpone the project, because the option value of delay is much higher than the NPV of investing immediately.

With the investment and current revenues constrained by the electricity price (S = € 881,371) and a volatility of 40% (σ = 0.4), the option to postpone the investment has value and should be exercised. For this reason, there is value in waiting for more favourable conditions for investment.

This conclusion is based on the premise that, since the investment decision involves a loss of opportunity to defer this decision, the investment should be undertaken only when its NPV exceeds the value of the deferral option (Soares et al., 2008). This happens because investing now implies that there is a missed opportunity to wait for more information about the evolution of electricity remuneration, which corresponds to the value of the option to defer. Therefore, it is not enough that the value generated by the project covers the investment, but it also should be sufficiently high to cover the option of delaying the project. Under this assumption and since that this assessment is realized in continuous time and the option to invest now or delay can be taken at any time during the interval of five years, it is determined the following decision tree from the values found:

Steps	0	1	2	3	4	5
						Invest
					Invest	
				Invest		Invest
			Invest		Invest	
		Invest		Delay		Invest
	Delay		Delay		Delay	
		Delay		Delay		Do not invest
			Delay		Delay	
				Delay		Do not invest
					Delay	
						Do not invest

Figure 21 - Decision Tree
Source: Elaborated by the author

As empathized by Dixit and Pindyck (1994), the option to defer an investment for a time t +1 can be seen as the opportunity cost of investment. Investing in time t, means that we are throwing away the option to defer and the company must pay the opportunity cost and also the initial investment. Thus, for that project to be accepted at time *t*, it is not enough that the present value of the cash-flows are positive, as established in the traditional NPV rule, but it also has to be sufficiently positive to exceed the initial investment in an amount equal to the opportunity cost.

Therefore, as shown in the decision tree (**Figure 21** - Decision Tree), in each time interval can be assessed which option maximizes the value of the project, by looking at the upward or downward trend of the underlying asset. This decision is based on maximum value between the static NPV and the option value of delaying the project for each node. As we can seen, for higher values of the underlying asset, the best option is to invest now, and for lower values of the underlying asset, the option value of postponing the project for the next period is more valuable.

In other words, since the underlying asset value depends mainly on the electricity price, the investor will choose to invest if the evolution of energy remuneration is sufficient to overcome the investment costs and the opportunity cost of not postponing the project.

In this particular case, the project despite having a positive outcome, presents a low static NPV, given the high investment and lifetime of the project. In other words, is necessary to invest € 830.000 to implement the project now obtaining € 51.371 after 35 years. Thus, even intuitively, any investor would prefer to wait for more information and minor uncertainty. This decision tree shows that even when the static NPV is positive the project is delayed, because the value of the deferral option is superior.

In the last year (step 5), the investor will no longer be able to postpone the project, so he must to decide if the conditions are favourable for investing in that moment, or if the project will not be implemented. At the end of the expiration of the deferral option, he will only invest if electricity prices are sufficiently high, otherwise, the investor will choose not to invest.

To postpone the project increases its value. This happens because during the waiting period uncertainty about the economy has been resolved, and this information allows a better decision. Obviously, delay also involves losses, in terms of cash-flows that are lost, and in terms of competition. For this reason, this type of analysis should be performed with special care, because in an uncertainty context, not to include losses of project postponement, could mean never investing in the project due to the gains of more information and consequent reduction of uncertainty.

For the traditional NPV analysis, not considering the value of flexibility, underestimates the project value. The assessment by the ROA gives the investor flexibility to re-evaluate the project in future stages, and from that information, redefine his strategy.

With the incorporation of Real Options in the analysis, it is possible to show that the NPV of the project increases in the considered period, confirming the premise that a project that can be delayed has more value than one without flexibility to delay, given that the investor has the option to defer the start of the project, taking into account the risks and the possibility of change.

6. CONCLUSION

The main objective of this dissertation is the assessment of an electricity generating project from renewable sources using the ROA. To achieve this objective we identified the main characteristics and uncertainties of these investments, which justify the use of this evaluation method in conjunction with traditional methods of analysis.

The electricity market liberalization brings an environment of greater uncertainty for investments in this sector, due to the fact that while in a monopoly context, uncertainties, such as electricity demand and price, entry of new competitors in the market and regulatory changes, were relatively stable. With the introduction of liberalization in the generation (and supply) segments of the value chain, these issues represent high levels of uncertainty in the decision to invest in a new plant.

These uncertainties do not affect all investments in the same way since their effects vary by type of technology used in electricity generation. In other words, while, for example, the technological progress uncertainty affects especially renewable energy projects with less mature technologies, the uncertainty on fuel prices affects with greater intensity the projects of electricity generation of fossil sources.

On the other hand, the increase in competition allowed consumers to have a more active role, being possible to choose a energy supplier. By analysing the European market, several reports and studies show that although there is still a high concentration of market power, these values tend to decrease. This question brings two important outcomes. On the one hand, increased competition leads to a higher level of uncertainty for existing firms by loss of their market shares, but on the other hand, these tend to create structural and strategic barriers to the entry of new competitors, complicating the possibility of new investments by new entrants.

From the perspective of the investors, with the disappearance of monopolies in this sector, there is a greater risk of loss in market share and lower profits on investments. Thus, investors will require higher rates of return and tend to be more reluctant about making new investments, which make their capital more expensive than it used to be under monopoly conditions.

Due to the irreversibility and high degree of uncertainty that characterize investments in electricity generation, the evaluation methods of projects have been subject to many studies. The electricity is a non-storable asset surrounded by technical, economic and regulatory uncertainties that are difficult to predict, due to the scarcity of information in the market. Given these specificities, the decision should not just be choosing to invest now or never, accounting some risks and uncertainties easily observed and determined in the market, in this case the evaluation method must include management flexibility, which allows to assess these uncertainties and to choose the best time to invest.

The traditional assessment methods, such as NPV or IRR, do not allow an investor to define the optimal timing to invest or capture the true value of the uncertainties of these projects, which may provide incorrect and insufficient information about their viability.

The ROA is a methodology for the evaluation of real assets, which takes into account the flexibility of management over the life time of a project. As new information appears, and the uncertainties are revealed, the investor can make decisions that positively influence the final value of the project. Thus, the ROA will maximize the gains in the favourable situation and minimize losses in unfavourable situations, because it allows an investor to have the flexibility of choice between options.

However, given that ROA assessment starts by calculating NPV, when analysing the investment through the ROA, it does not abandon traditional methods of evaluation. In this way, the new approach complements and refines the traditional NPV rule.

In the case of this study, it was found that according to the ROA, the project with the defer option allows the investor, during the five years, to analyse market conditions obtaining better information and reducing uncertainty. Thus, the investor avoids losses and obtains higher gains from the project.

The investment has a higher value with the option to defer, due to decision flexibility. Moreover, while the evaluation of the project by NPV and IRR neglected the uncertainty on electricity prices considering them constant throughout all the years of the project, the ROA allows considering these and other uncertainties, giving the investor more comprehensive and realistic information.

No single assessment method is considered absolute; neither the valuation of investments is an exact science. However, this does not mean that there is not a need to search for assessment methods that are able to interpret the characteristics of investment, uncertainties and management flexibility. The ROA, although being a method difficult to implement and uncommon in companies, it is the most current and appropriate method for these circumstances.

According to this, the purpose of this dissertation was to demonstrate that despite the ROA being more complex, it should be used as a support to traditional methods in order to compare results and taking into account greater management flexibility. The case study has very low returns for an investment too high, which proves that an analysis based on the traditional NPV rule is not sufficient, because small unfavourable changes in its return could automatically put viability at risk.

Thus, an analysis that assesses the various uncertainties over time, and include real options of projects, will support a more realistic decision-making process.

Limitations

This dissertation presents limitations that may serve for future developments in this research area. These limitations are mainly related to practical application and therefore can be improved and developed in other studies. The main weaknesses are:

- The evaluation considered in the case study by traditional methods was too simplified and had some weaknesses that have not been changed. In this case, it were only indicated correcting procedures, since that to make a better assessment of this case study, it would be required information that is not available, leading to intensive work that would not be aligned with the main objective of this dissertation. However, given that for the evaluation by the ROA is also needed an assessment by traditional methods, a study based on more realistic cash-flows will provide more solid results.

- For model simplification purposes and information gaps, in evaluating the case study it was considered only the uncertainty on electricity prices. There are other uncertainties in mini-hydro projects such as the generation level, construction costs, regulation, or even at the level of demand for electricity. Thus, other uncertainties for future works could be included in order to demonstrate the effectiveness of this method to combine all the uncertainties in one model.

- The postponement of the projects involves costs by loss of cash-flows not generated, and by the entry of competitor's new investments. These costs were not considered in the evaluation, due to limited information available. In order not to create arbitrary values that could be considered unrealistic, it was decided not to include these values. Thus, in future works of ROA implementation the way of accounting for these costs should be defined, so that its determination is not too subjective.

- This study developed a practical application of the ROA to a mini-hydro, but it would be interesting in future researches, to apply it to other projects of electricity generation from renewable sources, that present more significant levels of technical and economic uncertainty, for example, the case of solar or wind power.

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