CLUB FINANCE

PROFITABILITY OF A PRIVATE EQUITY INVESTMENT IN POWER PLANTS IN WESTERN EUROPE

LES ÉTUDES DU CLUB

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Cette étude a été réalisée par Noémie Peiffer (HEC 11) sous la direction de Jean-Michel Gauthier, Professeur à HEC Paris

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Master Thesis

Under the supervision of Mr. Jean-Michel Gauthier

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EXECUTIVE SUMMARY

This paper is aimed at analysing the profitability for a Private Equity fund to invest in the conventional power sector in Europe and more precisely in a gas-fired power plant in Italy, a coal-fired power plant with Carbon Capture and Storage ("CCS") in Germany, a nuclear power plant in France, and an hydro power plant in Sweden[1].

In view of the increasing electricity needs in Europe, it is uncertain whether utilities will be able to face the investment requirements alone. Private Equity funds could provide additional funds either in operating power plants to free up some capital of the utilities or in new power plants projects. However, since the beginning of the liberalisation process in Europe, Private Equity funds have not been very active in conventional power generation whereas they have been very active in the US or in the renewable generation in Europe. Therefore, this paper helps understand why such investments have not been carried out so far by Private Equity funds and if they are likely to happen in the future.

First, we have carried out a quantitative analysis to understand the type of profitability Private Equity funds could get from such investments. We have built four financial models (one per power plant) on the basis of the data on electricity generation costs presented in the 2010 edition of the OECD publication *Projected Costs of Generating Electricity* ("EGC study"). "The study contains data on electricity generating costs for almost 200 power plants in 17 OECD member countries and 4 non-OECD countries. It was conducted under the supervision of the Ad hoc Expert Group on Electricity Generating Costs, which was composed of representatives of the participating OECD member countries, experts from the industry and academia as well as from the European Commission and the International Atomic Energy Agency (IAEA). Experts from Brazil, India and Russia also participated."[2] Based on the financial models, we have carried out a sensitivity analysis showing the impacts on the Internal Rate of Return ("IRR") of key underlying factors such as electricity prices, fuel prices and carbon prices, load factors and Operation & Maintenance costs ("O&M costs"). Then, we have gone deeper in the analysis through a qualitative discussion on factors that cannot be captured in the financial model but can also impact the investment decision such as the market structure both at a European level and a national level, the regulatory risks, the current electricity prices, fuel prices and carbon prices as well as their possible evolution.

The results of this quantitative analysis show that investing in conventional power generation in Europe and more specifically in the four above-mentioned assets is highly challenging and sensitive to the evolution of demand and competition. Therefore, it is impossible to make any general recommendation on which asset a Private Equity fund should invest into given the very specific risk/return profiles of each asset and the fast evolution of demand and competition. However, the sensitivity analysis highlights that among the four assets analysed, the gas investment is probably the first one (among the four) a Private Equity fund willing to make an investment should analyse because it is likely to be the most flexible investment. Indeed, the gas investment is the one for which the IRR can be the most easily improved either through higher revenues or through cost improvement (decrease in fuel prices or carbon prices or

[1] Please note that in this paper, we have extended the term "conventional" to hydro

[2] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 5

improvement of operational performance). Nevertheless, it is also the one that requires the highest market prices to breakeven and to be dispatched. Therefore, it is the most sensitive to demand and prices forecasts - either electricity prices forecasts or gas prices forecasts – and to the competition structure. The qualitative analysis reinforces the conclusion by highlighting that the market structure in Western Europe[3] is not the most favourable to Private Equity investments in power generation.

In the future, these trends are unlikely to change and Private Equity investments are more likely to be observed in the transmission networks rather than in the generation sector.

[3] Please note that, in this paper, we include Italy and Sweden in the generic term "Western Europe"

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INTRODUCTION

Since 1996 with the European Commission's first Electricity Market Directive, Europe has engaged into the liberalisation of its electricity market. The first countries that applied the directives of the European Union and the most liberalised nowadays are the UK and the Nordic countries. It has then spread to the rest of Europe not without difficulty. Nowadays, power generation is liberalised, power exchanges have emerged and are increasingly liquid.

However, heritage from the past remains heavy in European countries and has slowed down the liberalisation process, especially in Western Europe. Indeed, Western European markets have always been very concentrated and integrated around major utilities such as EDF, E.ON, Enel, RWE, etc. Now referred to as the "Incumbents", these utilities are still dominant players in their national markets and have taken advantage of the liberalisation process to expand to other European countries through merger and acquisition activities reinforcing the overall concentration of the European electricity market. Moreover, although the liberalisation process has forced the Incumbents to unbundle network activities from sales and generation activities, most Incumbents remain present in both the generation segment and the retail segment. New actors in the generation segment would therefore find themselves competing with their own customers (Mr. D'Argenio, 2011). Finally, although the EU directives have increased the transparency of the electricity market, the Incumbents benefit from a strong position giving them access to up-to-date market knowledge reinforcing their competitiveness.

Overall, it is still very hard for third parties to compete with the Incumbents. It explains why although the liberalisation process has been accelerating, we have not seen many new strong actors emerging in the electricity market. New corporates have emerged mostly on the retail segment and have developed their generation infrastructures to gain independence from the Incumbents. However, unlike in the US, financial investors have not been very active in power generation since liberalisation started.

Another obstacle for financial investors is the increasing uncertainty that characterizes Western European energy markets. The future of the EU-ETS market, the biggest carbon market in the world developed to meet the Kyoto requirements, is uncertain after the end of the Kyoto Protocol in 2012. Europe has decided to maintain this market until at least 2020 but the future prices of the CO2 ton are likely to evolve after the end of the Kyoto Protocol. The future of nuclear is at stake in some countries such as Germany after the Fukushima disaster in March 2011. The profile of demand is changing with a quicker increase of peak demand vs base demand (Mr Delorme, 2011).

The goal of this paper is therefore to analyse the potential of Private Equity investments in the power generation sector in Europe. In view of the major differences from one country to another regarding the heritage from the past, regulation, power plants cost structure, we have chosen to concentrated on four types of power plants in four countries:

- Gas-fired power plant in Italy – CCGT
- Coal-fired power plant with CCS in Germany
- Nuclear power plant in France
- Hydro power plant in Sweden

Our analysis is based on two pillars: first, a quantitative analysis based on a financial model that measures the sensitivity of the IRR a financial investor could get from an investment in one of the four power plants mentioned above and second, a qualitative analysis that covers factors that cannot be covered with the financial model but are likely to impact the investment decision.

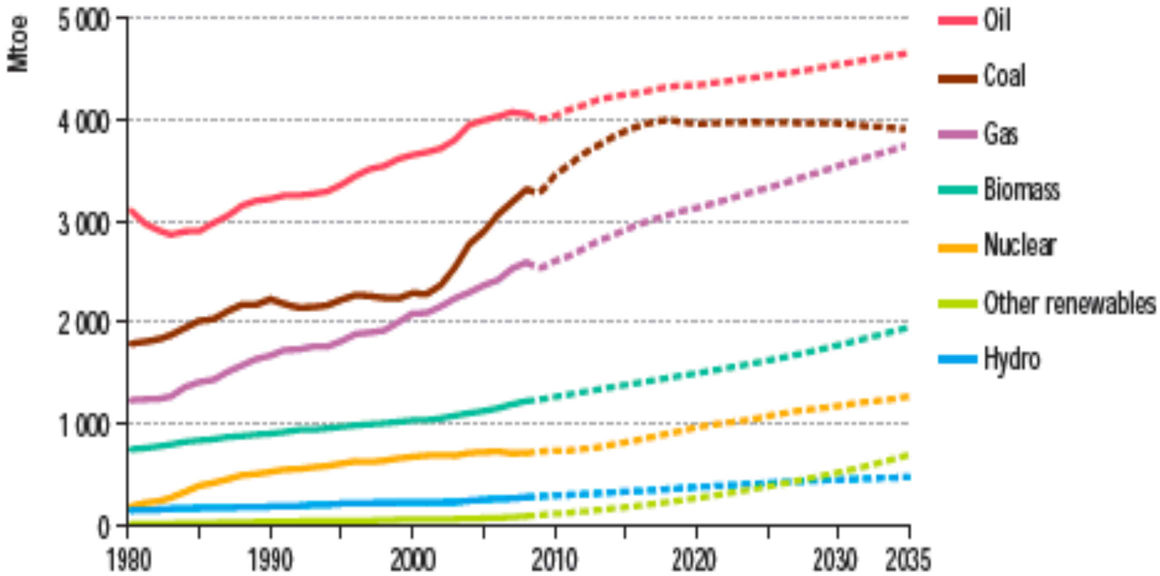
First, we offer a macro view of the subject through the presentation of the future of the energy and the power markets in the world and in Europe and we draw a typology of the financial investors targeted by such a study. Then, we present the methodology of the quantitative analysis and more specifically the structure of the model as well as the steps of the sensitivity analysis. Finally, we develop the investment case starting with the results of the sensitivity analysis and wrapping up with an in-depth analysis of the four electricity markets with a special focus on the structure of the market, competition, regulatory risks and market prices of fuel and electricity.

I Macro analysis

1 Overview of the energy and the power sectors

1.1 Significant investment are required to meet increasing demand

By 2035, world primary energy demand should increase by 36% with oil, coal and natural gas accounting for more than 50% of this increase. Additionally, global electricity demand will grow by 2.2% per year from 16 819 TWh in 2008 to 30 300 TWh in 2035 with 20% of this increase coming from OECD countries. These are the latest forecasts issued by the International Energy Agency ("IEA") under its New Policies Scenario[4], which take into account existing government policies as well as declared intentions.



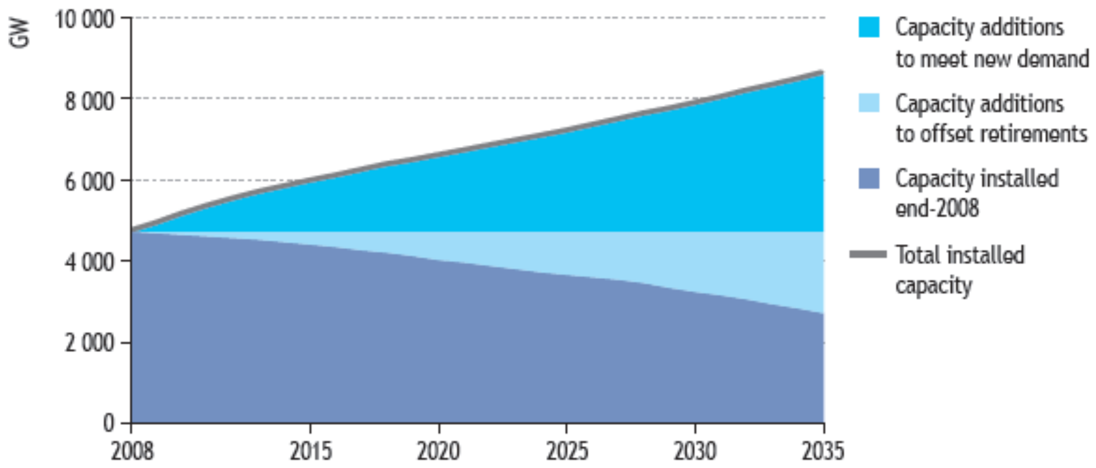
1) World primary energy demand by fuel in the IEA New Policies Scenario[5]

To answer this increase in energy demand, sizeable investments in energy-supply infrastructures will be needed worldwide. By 2035, the IEA forecasts a global need for $ 33 trillion investments. Out of the $ 33 trillion, $ 16,6 trillion will be dedicated to the power sector with 60% of this amount being poured into new power plants and plants refurbishment and the remaining 40% into transmission and distribution

[4] IEA, World Energy Outlook 2010, 2010 edition, p. 81 & 217

[5] IEA, World Energy Outlook 2010, 2010 edition, p. 84

infrastructure[6]. Altogether, 5 900 GW of additional power generation capacity shall be built between 2010 and 2035 (from 4 722 GW in 2008 to 8 600 GW in 2035) with 40% installed by 2020[7].



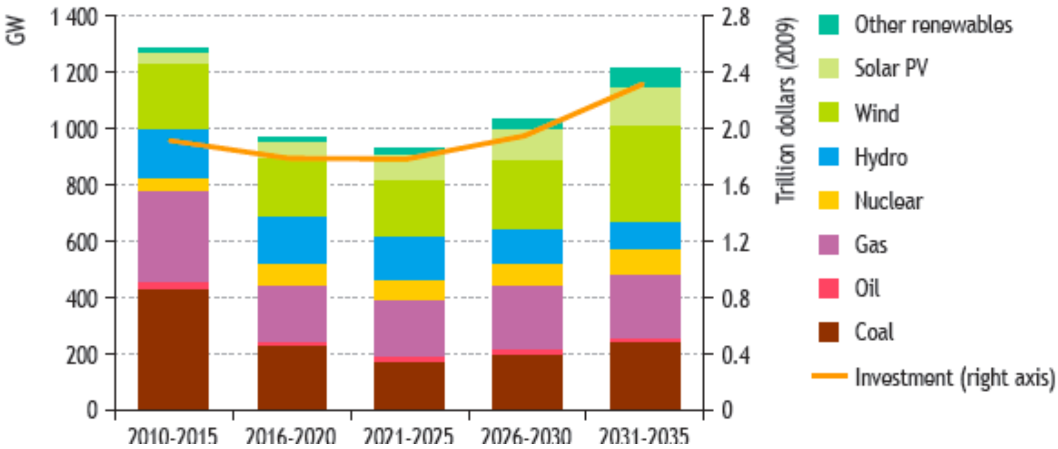
2) *World installed power-generation capacity by type in the IEA New Policies Scenario*[8]

[6] IEA, World Energy Outlook 2010, 2010 edition, p. 227

[7] IEA, World Energy Outlook 2010, 2010 edition, p. 225

[8] IEA, World Energy Outlook 2010, 2010 edition, p. 229

When looking more precisely at the power generation sources, it is clear that coal and gas remain the most predominant sources of energy.



3) *World power-generation capacity additions and investments in the IEA New Policies Scenario*[9]

As far as coal is concerned however, investments are likely to come under high scrutiny from governments, NGOs and the population especially in OECD countries because of their high carbon footprint. Carbon reducing technologies such as the Carbon Capture and Storage ("CCS") technology are likely to be promoted in the future. However, according to the IEA, the deployment of these technologies is likely to be slow given the extensive performance tests that need to be carried out at a commercial scale first and the need for a proper regulation. Thus, the IEA forecasts the CCS technology to be deployed at a very limited scale by 2035 - from zero nowadays to 1,5% of total generation in 2035 - and mostly on demonstration power plants in OECD countries[10]. Europe is currently very active in this area thanks to the development of a subsidy scheme that will be presented later on in the report.

Regarding renewable power generation, a strong push is to be expected. Although hydro is not likely to be the bulk of the renewable investments, the IEA expects hydro to remain the basis of renewable power electricity generation worldwide given that it is "the most mature renewable energy technology"[11]. According to the IEA New Policies Scenario, total investments in power generation from renewable sources will amount to $ 5.7 trillion by 2035 with $ 1.5 trillion for large hydro projects and $ 176 billion for small hydro projects. These investments should bring an additional gross power capacity of 2 800

[9] IEA, World Energy Outlook 2010, 2010 edition, p. 225 & 230

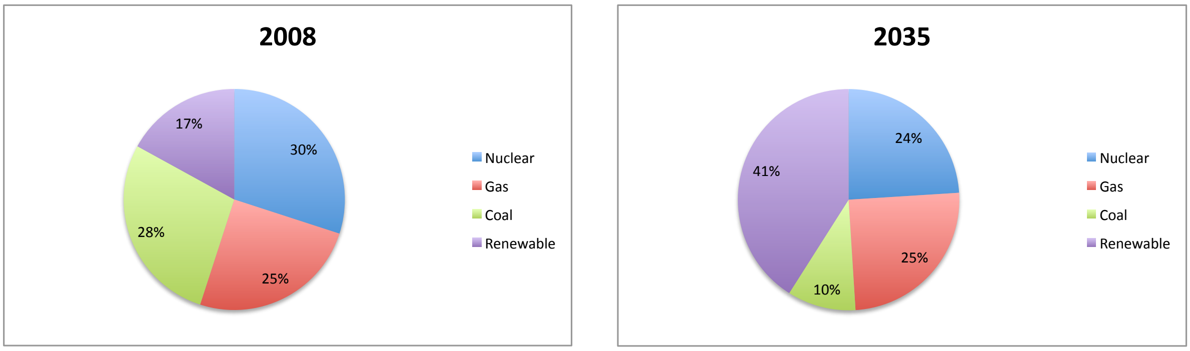
[10] IEA, World Energy Outlook 2010, 2010 edition, p. 220

[11] IEA, World Energy Outlook 2010, 2010 edition, p. 299

GW. Europe will be very active in this sector given the binding 20-20 target they defined in 2009: achieving 20% share of renewables in the gross final energy consumption by 2020[12].

As far as nuclear is concerned, the future of the technology has become highly uncertain since the Fukushima disaster in March 2011 and it is still too early to draw any conclusions on the potential long-term impact of this disaster on nuclear investments.

In Europe, total investments in power generation should reach $ 1,7 trillion between 2010 and 2035. The generation mix should change as follows:



4) Europe: evolution of the power generation mix between 2008 - 2035[13]

1.2 Who will finance such investments needs?

The Private Equity experts interviewed in the context of this master thesis agree on saying that utilities will face huge investment challenges in the future and may require some restructuration. However, they insist on saying that the power sector is not a piece of cake for Private Equity funds.

Although some funds have developed a strong presence in the conventional power sector in some countries such as the United States, electricity markets are so specific from one region to another that they cannot necessarily replicate their strategy in other countries.

The economics of the power markets are difficult, especially for conventional power that rarely benefit from feed-in tariffs unlike renewable. The volatility of electricity prices and fuel prices are the most obvious obstacles for financial investors. However, they only are the top of the iceberg. First, unlike the other industries, the power industry presents a great deal of internal disparities: the economics of a nuclear plant have little in common with the economics of a gas-fired power plant for instance. Second, given the strategic importance of electricity for each country, political and public interference are

[12] IEA, World Energy Outlook 2010, 2010 edition, p. 310 - 313

[13] IEA, World Energy Outlook 2010, 2010 edition, p. 230 - 231

commonplace and regulations are constantly evolving. Third, conventional power investments or hydro plants are under pressure regarding their social and environmental impacts and face a great deal of uncertainty regarding the evolution of environmental policies. Finally, competition is difficult to comprehend. Indeed, there is first the domestic competition to understand and the competition from neighbouring countries, which is increasing with the development of certain mechanisms such as market coupling[14]. In November 2009 for instance, the coupling of the Nordpool spot market and EPEX was launched[15].

All in all, it is difficult for financial investors to get at ease with the fundamentals of power markets and to compete with other players, especially in Western Europe where the market is highly concentrated around the Incumbent. Indeed, unlike in the US where the market is highly fragmented with a great number of private actors, deregulation in Europe has been carried out slowly and has mostly benefited to the Incumbents. They have seized the liberalisation opportunity to go out of their historical borders and grasp new market shares in neighbouring countries reinforcing their horizontal concentration and leaving few opportunities for new entrants (Mr. Halbout, 2011). Additionally, Private Equity experts pointed out the lower cost of capital of utilities that give them a strong competitive advantage compared to Private Equity funds and Infrastructure funds (Mr. Halbout and Mr. Kalthöfer, 2011).

Supporting these views, we can highlight that investments in power generation in Western Europe are very seldom. Most of these investments are concentrated in the renewable sector, mostly favoured by feed-in tariffs.

Therefore, answer the question “Would financial investors be willing to invest in the conventional power sector in Europe?”, requires first a good understanding of the investment criteria of the financial investors and second to carry out an extensive profitability and feasibility analysis.

2 Typology and strategy of financial investors

2.1 Risk – Return profiles

So far, we have talked about Private Equity funds in general. However, the term “Private Equity fund” covers different types of investors. Indeed, it is common to include Infrastructure funds in this term. However, as underlined by the industry experts interviewed, Private Equity and Infrastructure funds have different investment strategies.

Private Equity funds target higher IRR than Infrastructure funds and have different investment horizons. Indeed, Private Equity funds target a minimum IRR around 20% - 25% over a 5-7 period whereas Infrastructure funds target a minimum IRR of 10% - 15% and have much longer holding periods around 10-15 years (Mr. D’Argenio, Mr. Kalthöfer and Mr. Robberts, 2011).

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14 Definition of market coupling from Belpex website: “Market coupling is a method for integrating electricity markets in different areas. […] It means that the buyers and sellers on a power exchange benefit automatically from cross-border exchanges without the need to explicitly acquire the corresponding transmission capacity. […] one exchange will export to another for as long as the marginal offered price in one is lower than the marginal bid price in the other, until the point that prices converge or available cross-border capacity is exhausted.”

15 Nordpool Spot website

They do not consider projects with the same risk profile. Infrastructure funds look at projects with low risks. They are keen on taking infrastructure risks such as traffic risk and volume risk but are unlikely to accept commodity price risk. Private Equity funds are likely to accept more risks – which explains the higher IRR target. Then, they can hedge the risks if necessary bearing in mind that the costs of any hedging strategy will impact the IRR.

Given these risk profiles, Infrastructure funds tend to look at assets with steady cash flows and therefore, invest mostly in regulated assets such as transmission and distribution networks or quasi-regulated assets such as renewable with feed-in tariffs whereas Private Equity funds look at companies or technologies for which there is a clear potential to improve operational efficiency and are more present in deregulated sectors (Mr. Kalthöfer and Mr. Schubert, 2011).

Of course, these above described risk profiles are standard risk profiles. Each fund will undertake a careful risk analysis to know what type of risk it can bear. For instance, an Infrastructure fund could well decide to invest in a generation project in which the fuel risk is mitigated by a long-term supply contract if it deems the implied counterparty risk to be acceptable.

Talking about Infrastructure funds, Jim Dillavou, U.S. leader of Deloitte & Touche LLP's Merger and Acquisitions Energy and Resources Industry practice said:

"That is a different profile than the historical Private Equity investment because of the long-term horizon for the investment […] The investor is trying to take assets that historically have earned a steady but sleepy return, and increase the return from additional leverage with relatively low-cost, long term debt and add-on investments. The return is enhanced by the management fees and the ability to profitably sell down its ownership interests in the fund over time."[16]

2.2 Value creation levers

Power generation assets are in the middle of these two strategies. Indeed, they are deregulated assets and present a risk profile that seems to better suit Private Equity funds. However, they also are assets for which improving operational efficiency can be difficult when considering a single power plant. The question of value creation levers is therefore critical. Where does the value creation come from? Are the value creation levers the same as in other Private Equity investments or will the value creation only come from a "market timing strategy"[17] (Mr. Hege, 2011)?

Although answering such questions on a general basis is difficult and requires to take a regional approach as well as a closer look at the asset itself, the Private Equity experts interviewed agree on the following:

- Unlike in the US, creating value through boosting operational efficiency is not common in Europe. Indeed, unlike the US where power generation is a fragmented market between

[16] Knowledge@Wharton. Private Equity Firms Discover Electricity — and Lead the Charge for Energy Investment. 2007. p.13

[17] Definition of Market Timing Strategy from InvestorWords.com website: "Attempting to predict future market directions, usually by examining recent price and volume data or economic data, and investing based on those predictions."

smaller private actors making it easier to outperform competitors, power markets in Wester Europe are dominated by the Incumbents in front of which competition is extremely hard

- For Private Equity funds an effective way to make high returns is to take a “differential commodity price view relative to the market” (Mr. D’Argenio, 2011) and therefore have a successful market timing strategy

2.3 Preferred investment stage

Regarding the preferred stage of investment - development, construction or operation – there is no clear-cut answer according to the Private Equity experts interviewed.

There have been examples of Private Equity funds investing in both green-field and brown-field projects. As underlined by Private Equity experts, “it really depends on the situation and whether there is a meaningful cost benefit from pursuing brown-field. Private Equity funds will transition from construction to existing operating plants depending on points in the cycle and valuations. Sometimes when markets are tight it makes more sense to build new capacity. Other times you can buy existing capacity cheaper than new construction. Most times it is difficult to sell a plant in the secondary market for equal to or more than it costs to build the plant.” (Mr. D’Argenio, 2011). Nevertheless it is worth noting that green-field investments present a number of additional risks that can jeopardize the IRR of a fund such as construction costs overruns that would force a fund to inject additional funds.

Private Equity experts also pointed out that “most investors are not in the business of "developing" assets - they buy into business plans and already permissioned projects. So irrespective of green- vs. brown-field, they would likely only invest after the planning and permissioning phase has been concluded positively or has significant chance of getting permission.” (Mr. Kalthöfer, 2011)

In view of the above, we have decided for the purpose of our analysis to focus on an investment in an operating power plant by a Private Equity fund with a holding period of 7 years.

	INFRA FUND	PE FUND	POWER PLANT
RISK LEVEL	Low Ok for volume / traffic risk	High	Fuel price risk Volume risk (hydro) Electricity price risk Environmental policy risk
FAVOURED TYPE OF ASSET	Regulated	Deregulated	Deregulated in the four countries considered
CASH FLOWS	Stable	Perspective of improvement	Difficult to forecasts Difficult to improve (as demonstrated in the paper)
IRR	10%-15%	20%-25%	See later in the paper
HOLDING PERIOD	5-7 years	10-15 years Can be even longer	

5) Summary of the differences between Infrastructure funds and Private Equity funds[18]

3 Rationale of the subject

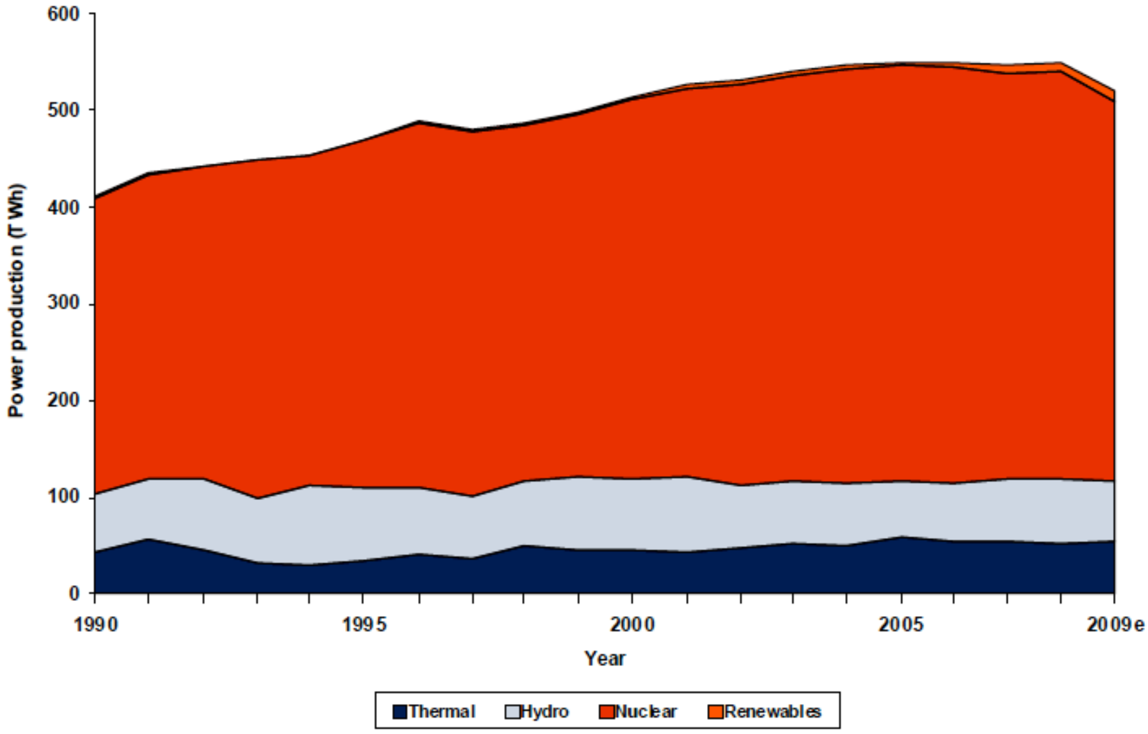
As previously stated, the chosen technologies and countries for this profitability analysis are the following:

- Gas-fired power plant in Italy (CCGT)
- Coal-fired power plant with CCS in Germany
- Nuclear power plant in France
- Hydro power plant in Sweden

We had to be specific in the choice of the assets given the great disparity of operation (and construction) costs from one technology to another and from one country to another as highlighted in the EGC study.

[18] Own analysis based on information provided by Private Equity experts

Moreover, we have decided to choose the main power generation sources in each of the four countries analysed: gas for Italy, coal for Germany, nuclear for France and hydro for Sweden as shown by the following charts.

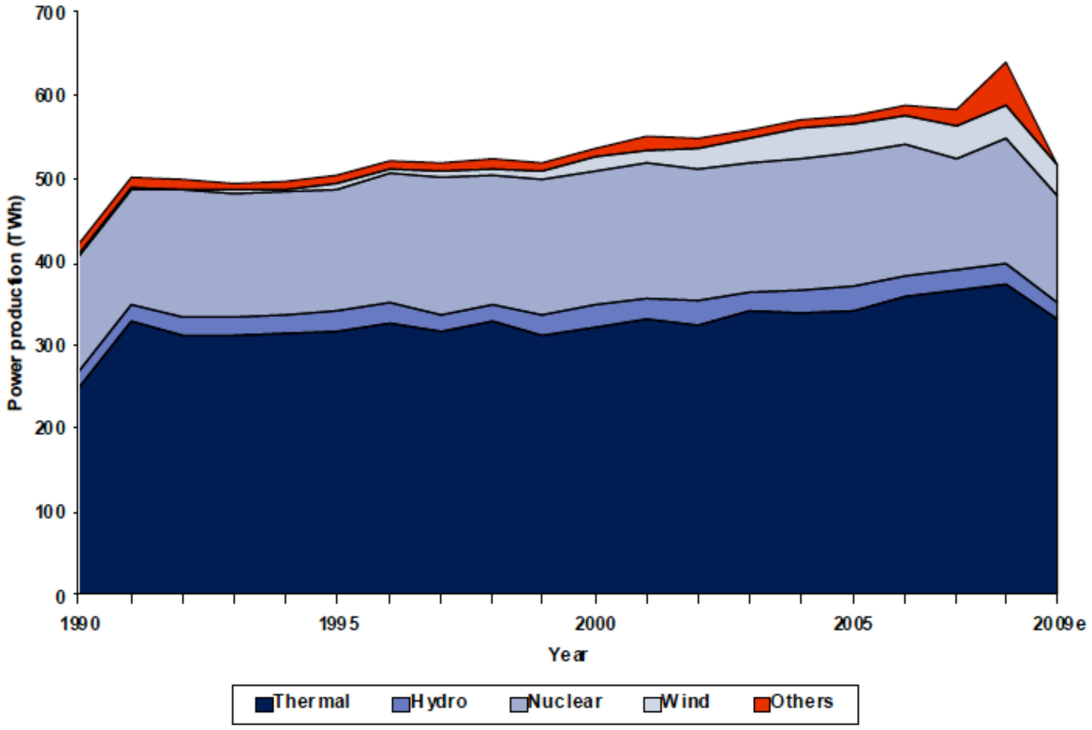


6) France, Power production by fuel input[19]

In France, three-quarter of the electricity generated come from nuclear power plants. According to the ParisTech Review of May 2011[20], although the Fukushima disaster triggered a shift in the public acceptance of nuclear power plants in France (57% of the French population want a nuclear phase-out after Fukushima vs 55% in favour of the nuclear programme before Fukushima), French people are not ready to pay the price of a switch from nuclear to other generation sources given that the majority of French people refuse to pay higher electricity prices necessary to finance the way out of nuclear.

[19] Business Insights, The Western European Electricity Market Outlook 2010, 2010 edition, p. 57

[20] ParisTech Review, L'énergie nucléaire dans un monde post-Fukushima, May 2011, p.2



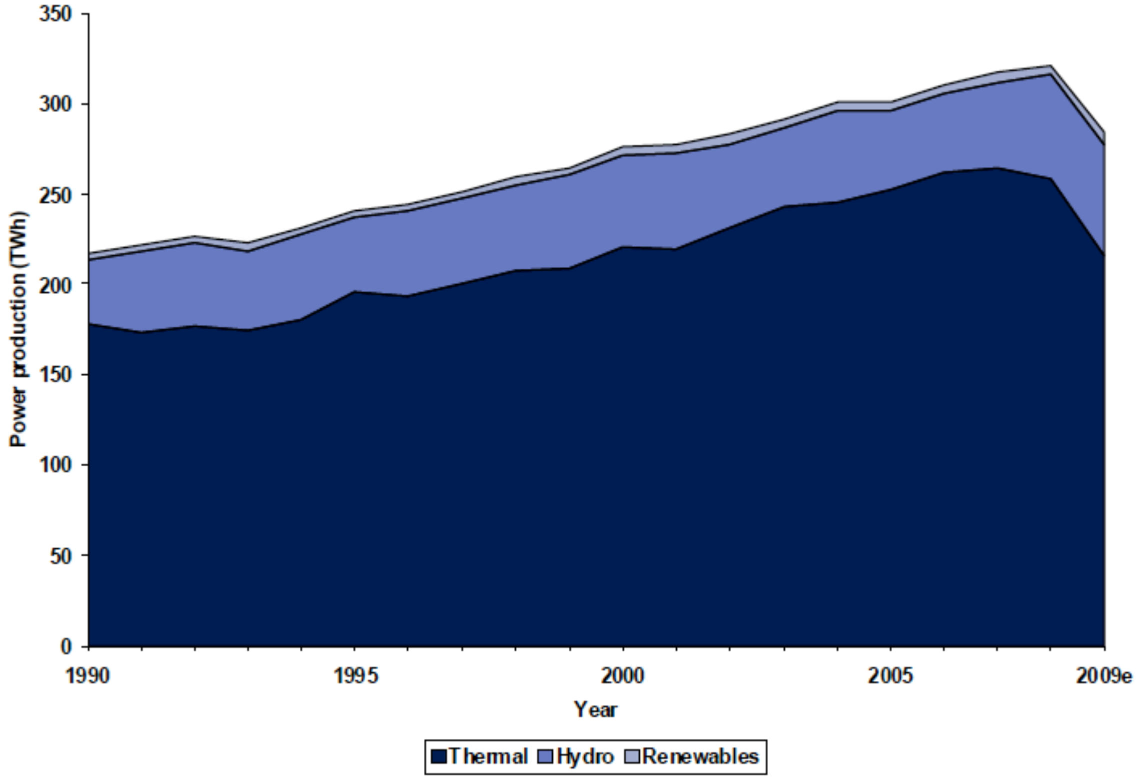
7) Germany, Power production by fuel input[21]

Coal-fired generation is the largest source of power in Germany and accounts for more than half of production. Coal is likely to remain one of the biggest sources of power. Indeed, Germany phased-out 7 nuclear reactors in the aftermaths the Fukushima disaster. Therefore, coal is likely to be crucial to meet the country electricity needs, even if Germany plans to seize this phase out opportunity to become “the first major industrialised country that achieves the transition to renewable energy” as announced by Mrs Merkel at the end of May 2011.

However, considering the increasing environmental pressure and the “20-20” target, we decided to focus on a coal-fired power plant equipped with CCS. Indeed, Germany needs to consider investments reducing the CO2 emissions from coal-fired power plants and the CCS technology is an option promoted by the government. Although the level of public acceptance of the CCS technology is still low, as explained later in this report, Germany has decided to launch a couple of pilot & demonstration CCS projects. Vattenfall commissioned the first small-scaled 30 MW pilot power plant in the middle of 2008. This plant, located at Schwarze Pumpe near the board with Poland, is used as a test before launching bigger demonstration projects such as the Jänschwalde project. Vattenfall plans to refurbish the existing power plant at Jänschwalde and install a CCS system. The storage site is still under study. The 1.7 Mtpa of CO2 captured are to be transported through a 60 to 300 km pipeline and should be stored in

[21] Business Insights, The Western European Electricity Market Outlook 2010, 2010 edition, p.66

onshore deep saline formations. The commissioning date is scheduled in 2015[22]. Another demonstration plant, sponsored by RWE, was planned but has been delayed[23]. At the end of 2009, E.ON and Siemens also announced a partnership to develop a CCS pilot project. The first tests were completed at the end of 2010[24]. In addition to that, there is a also a research project coordinated by GFZ – German Research Center for Geosciences –aimed at analysing the effect of injecting CO2 into a reservoir[25].



8) Italy, Power production by fuel input[26]

[22] Vattenfall website

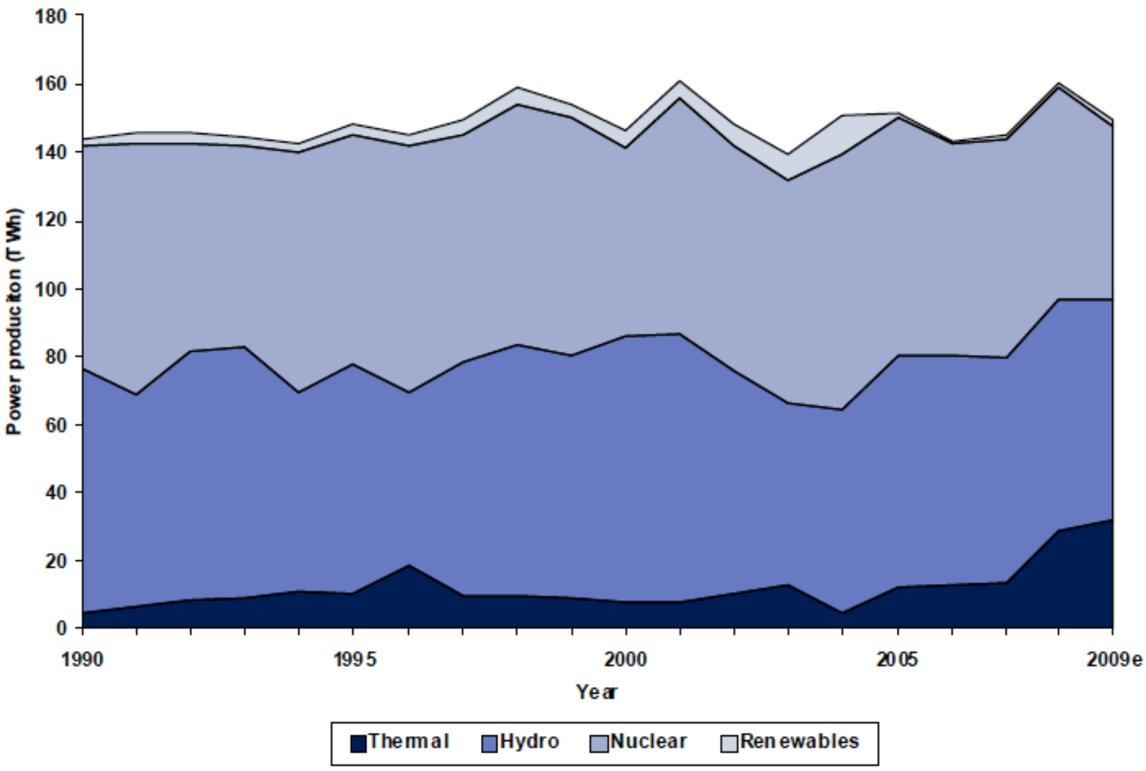
[23] Global CCS Institute, The Global Status of CCS 2010, 2011, p. 188

[24]Carbon Capture Journal, Siemens announces CO2 capture test results, November 2010

[25] Institute for European Environmental Policy, Review of the public participation practices for CCS and non-CCS projects in Europe, 2011, p.23 & 53

[26] Business Insights, The Western European Electricity Market Outlook 2010, <source HEC database laquelle ?>

As shown in the above graph, thermal plants are the primary source of power in Italy, with gas accounting for most of it.



9) Sweden, Power production by fuel input[27]

On average, hydro accounts for almost 50% of power generation in Sweden.

4 Overview of the methodology of the analysis

In order to analyse the profitability of an investment by a Private Equity fund in one of the following assets:

- Gas-fired power plant in Italy
- Coal-fired power plant with CCS in Germany
- Nuclear power plant in France
- Hydro power plant in Sweden

[27] Business Insights, The Western European Electricity Market Outlook 2010, 2010 edition, p. 153

We have carried out a twofold analysis:

- **A quantitative analysis**: using a financial model built for the purpose of this master thesis, we have analysed the sensitivity of the profitability of an investment in the above-mentioned assets. In particular, we have carried out a sensitivity analysis of the IRR to market conditions such as electricity prices, fuel prices and carbon prices as well as to operating performance such as the load factor and the O&M costs

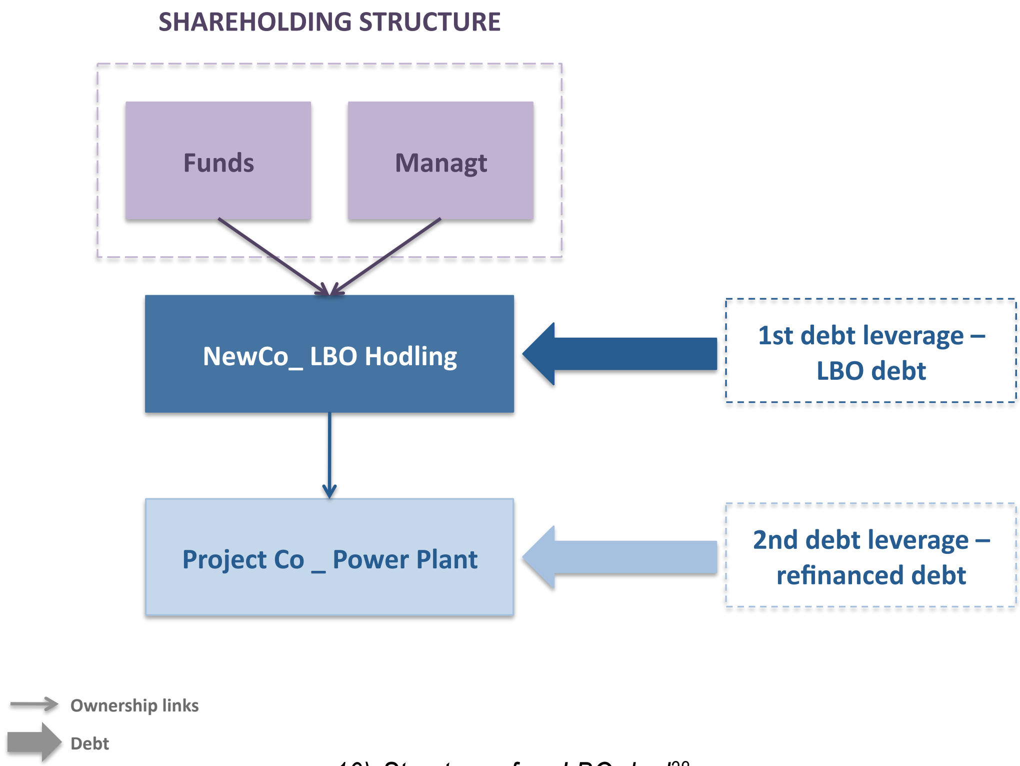
- **A qualitative analysis**: this qualitative discussion presents the factors that cannot be captured in the financial model but that can also impact the investment decision such as the market structure both at a European level and a national level, the regulatory risks and the current electricity prices and fuel prices as well as the possible evolution of these prices. "

II Methodology of the quantitative analysis

1 Structure of the financial models

In order to build the financial model to analyse the IRR of a fund's investment, we had to decide which financial structure would support the fund's investment.

According to the Private Equity specialists interviewed, funds tend to favour controlling positions unless they lack industry expertise. Leveraged Buy Out ("LBO") are common structures for controlling positions.



10) Structure of an LBO deal[28]

In such a structure, the fund acquires the power plant through a holding company called NewCo. The rationale of such a structure is twofold: first, it enables the fund to acquire a controlling position with a limited amount of equity (the rest being financed by debt), second, it optimises the level of debt in the acquisition and therefore, creates a leverage effect that should increase the IRR of the fund. Please note that the debt at the level of the Project Co - as shown in the above chart - is structured to refinance the existing debt in the Project Co: indeed, bank documentation usually states that existing debt should be refinanced in the event of a change of shareholding structure.

Given the significant amount of debt involved in a LBO deal, this structure is not suitable to acquire all types of companies. LBOs target companies with strong and recurrent cash flows, which is the case of an operating power plant. Indeed, as stated previously, we have chose to focus on operating power plants based on Private Equity experts' advice.

Moreover, to make the analysis more straightforward, the date of the LBO transaction is set after the ProjectCo has reimbursed all its initial debt. It has to be noted that this hypothesis enhances the IRR of the fund given the tax shield effect. Indeed, given that the ProjectCo leve has no debt to pay back, more cash flows are available for distribution to NewCo. Therefore, NewCo has the ability to borrow more and increase the tax shield effect. The consequence of this hypothesis is that the fund buys the power plant

[28] Own analysis

at an advanced stage of the plant's life. Therefore, it is to be kept in mind that given the finite life of the power plant, the closer to the end of the operation cycle and the beginning of the decommissioning period, the harder to sell the asset back - unless there are ways to extent the lifetime of the plant – and the lower the value of the plant. Therefore, although this absence of debt is attractive for a fund, the exit can be harder if close to decommissioning.

Furthermore, we want to stress out the fact that a LBO structure on a nuclear power plant in France is highly unlikely considering how strategic nuclear power plants are for EDF – owner of all the nuclear reactors in France. As explained later in the report, the low cost of production of nuclear power generation gives a strong competitive advantage to EDF. Therefore, although EDF might be willing to welcome minority shareholders - as currently discussed with GDF Suez, Total and other European Utilities for the EPR in construction at Penly – EDF is unlikely to cede one of its assets to a third-party. Nevertheless, in order to have comparable sensitivity results, we have decided to keep the same financial structure on the nuclear power plant as for the other assets.

Finally, in order to model the LBO structure, we had to model realistic financial statements before the beginning of the LBO. Therefore, although our analysis focuses only on the operation phase, we had to start the model at the beginning of the construction for each power plant. We will present in the following section the hypotheses we used to build these theoretical examples.

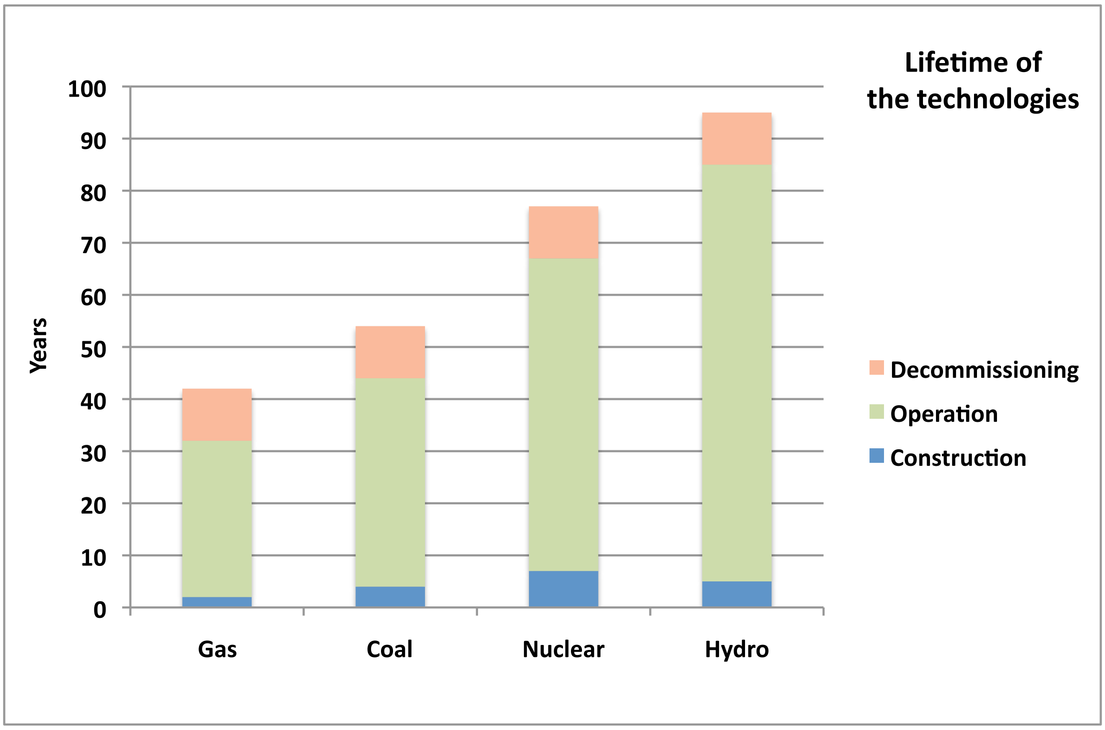
2 Operating, financing and contractual assumptions used in the models

The four financial models built around the four power plants are theoretical cases. To compensate for the lack of real data issued by a fund itself, we used the EGC study and current financial market trends.

2.1 Operating assumptions

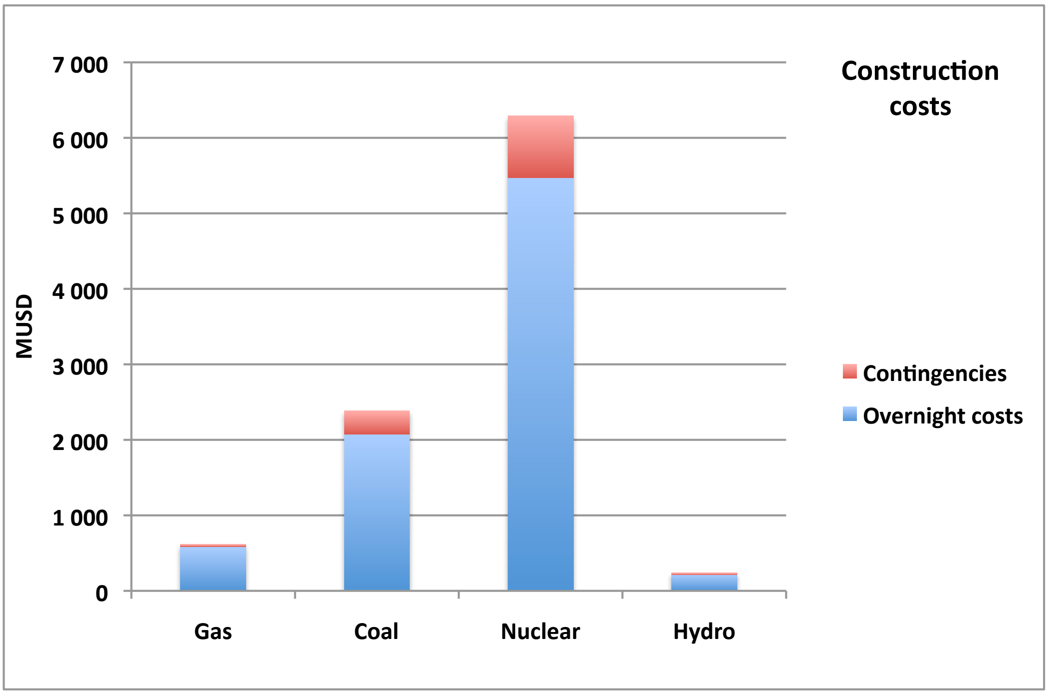
The operating assumptions used in the financial models such as the overall lifetime of the plant (from construction to decommissioning), the load factor, the electrical conversion efficiency of each technology, the O&M costs or the expected lifetime of each asset, are extracted from the EGC study.

Please note that regarding the O&M costs, the EGC study gives an overall variable cost and does not specify the proportion between fixed and variable costs. Therefore, in absence of any other data, we have followed the same method although it is not fully convincing given that the four technologies are expected to have very different levels of fixed O&M costs.



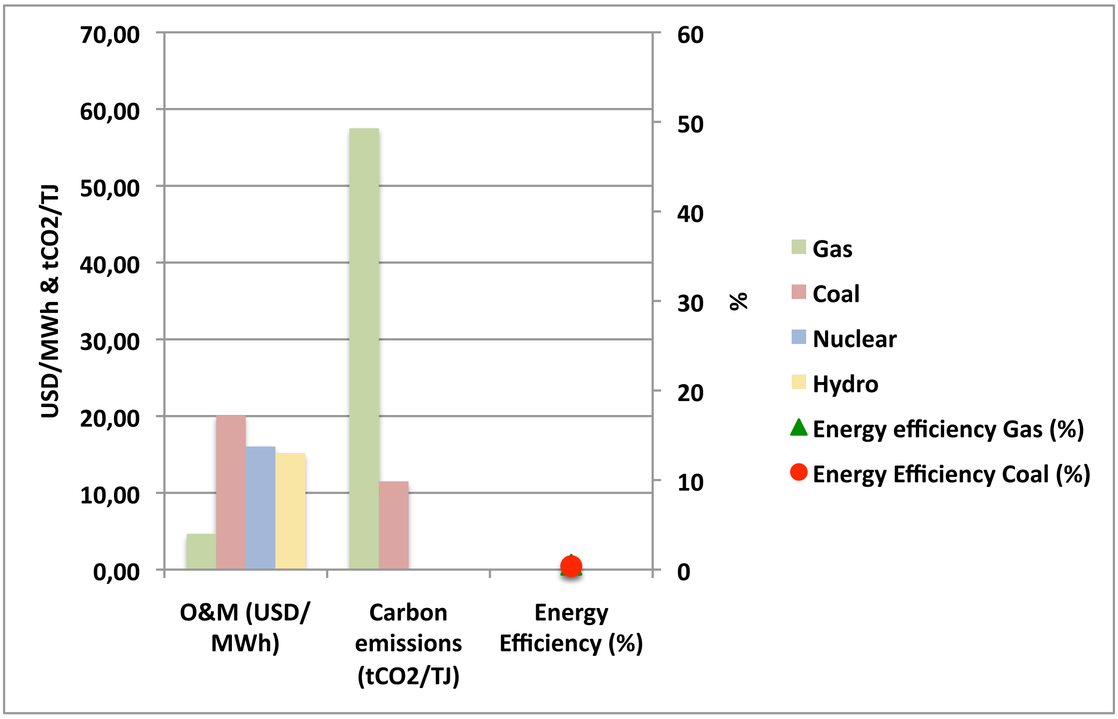
11) Lifetime stages of the four power plants considered[29]

[29] Own analysis based on EGC study, p. 43 - 44



12) Overnight construction costs and contingencies of the four power plants considered[30]

[30] Own analysis based on EGC study, p. 44 & 48 - 49



13) Operating specificities of the four power plants considered[31]

2.2 Financing assumptions

As previously stated, we have set the holding period at 7 years. Concerning the target IRR, although it is likely to be around 20% - 25% for a Private Equity fund, we identified that reaching an IRR above 20% required very high inflation rates that we deemed unlikely (above 38% over 7 years so more than 5,6% per year), therefore, we have set the IRR at 15% in the financial models.

Moreover, as previously stated, although we analyse an investment made during the operating lifetime of the power plant, we had to design a model starting from the first year of construction of the power plant to the end of the operating life.

In order to be as realistic as possible, we have decided to model a project-financing structure at the beginning of the construction before implementing the LBO structure during the operating lifetime.

We used standard market assumptions for the debt and equity structure, the swap rates, the debt margins and maturities, etc. of the initial financing and the LBO financing.

Thus, for the initial project financing structure, we opted for a simple debt structure with:

[31] Own analysis based on EGC study, p. 59 – 62.

- Gearing: 50%
- One tranche of debt with a margin plus swap rate of 5%
- A maturity of the debt equal to 30% of the lifetime of the asset

We made the following assumptions for the LBO structure:

- Gearing: maximum debt allowed in order to meet the Debt Service Cover Ratio (“DSCR”) set by the Banks
- Debt tranches - following the seniority ranking: Senior A tranche fully amortized (70% of the total amount of debt), a Senior B bullet (20% of the total amount of debt) and a Mezzanine debt (the remaining 10% of the total amount of debt)
- Debt maturities: 6 years for the A tranche, 7 years for the B tranche and 8 years for the mezzanine. Please note that it is not a problem to have longer debt maturity than the holding period because when the fund exits, the debt will be refinanced
- Total debt financing costs (weighted average of margin, maturities and amount): around 10%
- DSCR constraint of 1,2 which is a minimum for such projects
- Equity structure: 50% of ordinary shares and 50% of shareholder loan with a standard financing cost of 8% that corresponds to the usual minimum hurdle rate of Private Equity funds[32]. Please note that given the theoretical nature of our analysis, we have decided to freeze the repartition between ordinary shares and shareholder loan. In reality, the amount of shareholder loan is set according to the maximum amount of equity the managers involved in the LBO can provide and the proportion of ordinary shares they want to own[33]. Therefore, it is the result of a negotiation.
- Ordinary shares: managers own 10% and the fund owns 90%

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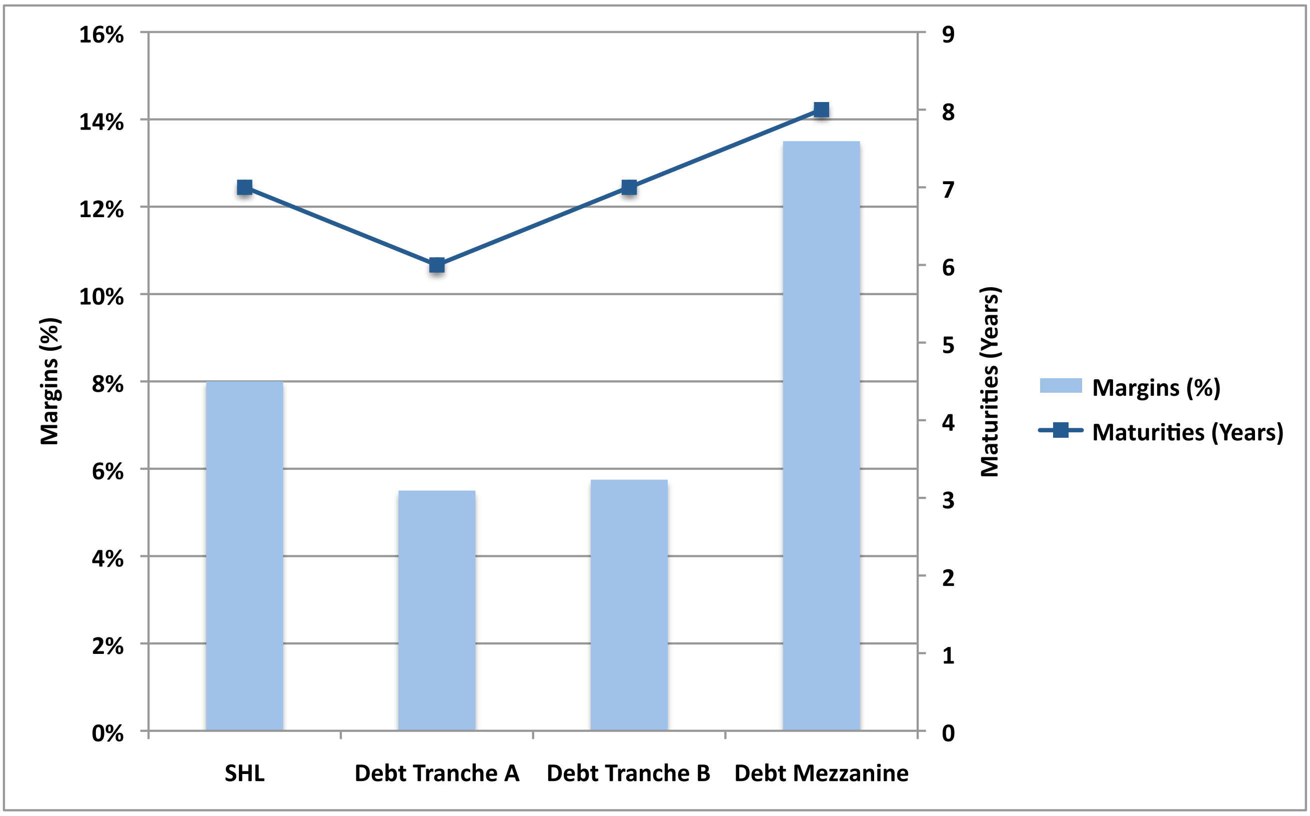
[32] Definition of hurdle rate from VC Experts website: “The minimum return to investors to be achieved before a carry is permitted. A hurdle rate of 10% means that the private equity fund needs to achieve a return of at least 10% per annum before the profits are shared according to the carried interest arrangement.”

[33] Example: assume that the total equity required for a transaction is 100 MUSD. Assume also that the managers can put on the table up to 1MUSD and require 10% ownership of the ordinary shares. If the fund accepts the requirements of the managers, the total amount of ordinary shares should be 10MUSD with 1MUSD provided by the managers – who will therefore own 10% of the shares as required – and the additional 9MUSD provided by the fund. The remaining 90 MUSD will be added through a shareholder loan or preferred shares that will not reduce the % of ownership of the managers.



14) Chosen LBO debt financing structure: margins and maturities[34]

As previously mentioned, Private Equity funds can hedge their electricity production. However, Private Equity experts confirmed that there was no industry standard regarding hedging strategy: some funds prefer to take fuel price risk and electricity price risk other may want to hedge these risks knowing that the hedging costs may reduce their IRR. Therefore, we have not include any hedging strategy in the financial models.

2.3 Contractual assumptions

We have decided to consider fully merchant projects: no specific fuel supply agreement and no offtake agreement or tolling agreement although this type of agreement is common for power plants. Indeed, it enables us to carry out an analysis of the sensitivity of the IRR to fuel and electricity prices.

For the fuel and the carbon price assumptions, we both used the EGC study and updated prices data of the 2010 World Energy Outlook issued by the IEA.

The table below presents the fuel and carbon price assumptions used in the financial models. For each, we have a Min scenario as well as a Max scenario and a Medium one.

[34] Own analysis

		GAS	COAL	NUCLEAR
		USD/MMBtu	USD/tonne	USD/MWh
Fuel Price Min	-15%	10,6	89,5	7,9
Fuel Price Medium		12,5	105,6	9,33
Fuel Price Max	15%	14,4	121,7	10,7
		USD/tonne	USD/tonne	USD/tonne
Carbon Price Min	-40%	15	15	15
Carbon Price Medium		25	25	25
Carbon Price Max	40%	35	35	35

15) Fuel and carbon prices assumptions used in the financial models[35]

The above medium price assumptions for coal, gas and carbon prices correspond to the average of the prices issued by the IEA in the 2010 World Energy outlook under the New Policies Scenario and the Current Policy Scenario as presented in the table below. The 450 Scenario assumptions have been excluded from the average as we consider this scenario unrealistic.

			New Policies Scenario					Current Policies Scenario					450 Scenario				
	Unit	2009	2015	2020	2025	2030	2035	2015	2020	2025	2030	2035	2015	2020	2025	2030	2035
Real terms (2009 prices)																	
IEA crude oil imports	barrel	60.4	90.4	99.0	105.0	110.0	113.0	94.0	110.0	120.0	130.0	135.0	87.9	90.0	90.0	90.0	90.0
Natural gas imports																	
United States	*MBtu*	*4.1*	*7.0*	*8.1*	*9.1*	*9.9*	*10.4*	*7.0*	*8.2*	*9.3*	*10.4*	*11.2*	*7.0*	*8.0*	*8.9*	*9.4*	*9.7*
Europe	*MBtu*	*7.4*	*10.6*	*11.6*	*12.3*	*12.9*	*13.3*	*10.7*	*12.1*	*12.9*	*13.9*	*14.4*	*10.4*	*10.6*	*10.7*	*10.9*	*11.0*
Japan	*MBtu*	*9.4*	*12.2*	*13.4*	*14.2*	*14.9*	*15.3*	*12.4*	*13.9*	*14.9*	*15.9*	*16.5*	*11.9*	*12.2*	*12.3*	*12.5*	*12.6*
OECD steam coal imports	tonne	97.3	97.7	101.7	104.1	105.6	106.5	97.8	105.8	109.5	112.5	115.0	92.5	85.8	75.8	66.3	62.1
Nominal terms																	
IEA crude oil imports	barrel	60.4	103.6	127.1	151.1	177.3	204.1	107.7	141.3	172.7	209.6	243.8	100.7	115.6	129.5	145.1	162.6
Natural gas imports																	
United States	*MBtu*	*4.1*	*8.0*	*10.4*	*13.1*	*15.9*	*18.9*	*8.0*	*10.5*	*13.3*	*16.7*	*20.3*	*8.0*	*10.3*	*12.8*	*15.1*	*17.5*
Europe	*MBtu*	*7.4*	*12.2*	*14.9*	*17.8*	*20.9*	*24.1*	*12.3*	*15.5*	*18.6*	*22.4*	*26.0*	*11.9*	*13.6*	*15.4*	*17.5*	*19.8*
Japan	*MBtu*	*9.4*	*14.0*	*17.2*	*20.4*	*24.0*	*27.6*	*14.2*	*17.8*	*21.4*	*25.7*	*29.8*	*13.6*	*15.6*	*17.7*	*20.1*	*22.7*
OECD steam coal imports	tonne	97.3	112.0	130.6	149.8	170.2	192.4	112.1	135.9	157.6	181.4	207.8	106.0	110.2	109.0	106.8	112.1

16) Fossil-fuel import prices: IEA forecasts ($/unit)[36]

[35] Own analysis

[36] IEA, World Energy Outlook 2010, 2010 edition, p.71

	Region	2009	2020	2030	2035
New Policies	European Union	22	38	46	50
	Japan	n.a.	20	40	50
	Other OECD	n.a.	-	40	50
Current Policies	European Union	22	30	37	42
450	OECD+	n.a.	45	105	120
	Other Major Economies	n.a.	-	63	90

17) CO2 prices by main region: : IEA forecasts ($2009 per tonne)[37]

Please note that the ranges of variation of fuel prices (+/- 15%) and of the carbon prices (+/- 40%) have been chosen so that the minimum and max fuel and carbon prices correspond to the minimum and maximum IEA price forecasts presented in the above table (excluding the 450 Scenario).

For nuclear fuel cycle costs, we used the costs assumptions presented in the EGC study of USD 9,33/ MWh.

3 Sensitivity analysis

3.1 Factors of the sensitivity analysis

We have decided to carry out the sensitivity analysis on the following variables:

- Electricity price
- Fuel price for the nuclear, coal, gas power plants
- Carbon price also for the coal and the gas-fired power plants
- Load factor
- O&M costs

Electricity prices

For each technology, we have computed a minimum electricity price that we will from now on call the "breakeven price". This breakeven price is the price that enables the Project Co to satisfy a DSCR of 1 on its initial financing in the worst market conditions for fuel and carbon prices (please refer to the above table for the values we chose for Fuel Price Max and Carbon Price Max).

[37] IEA, World Energy Outlook 2010, p.74

We want to highlight that this “breakeven price” differs from the LCOE of the EGC Study for the following reasons:

- The fuel and carbon prices assumptions used to compute the breakeven price are more deteriorated than the ones used in the EGC study to compute the LCOE
- In the overall costs faced by the project, we include taxes which is not the case in the EGC study
- We only take into account the cash financial costs i.e. the financial costs on the debt, which account for 50% of the total financing and do not take into account at this stage the rate of return required by the shareholders

However, when using the same hypotheses as in the EGC study we do indeed find comparable results as in the study.

The table below presents the electricity price assumptions used in the sensitivity analysis:

		GAS	COAL	NUCLEAR	HYDRO
		USD/MWh	USD/MWh	USD/MWh	USD/MWh
Breakeven Price		116,9	107,0	65,6	74,8
Max Price	50%	175,4	160,5	98,4	112,2

Fuel and the carbon prices

For the fuel and the carbon prices sensitivities, we have defined three prices level as shown in the table above: a medium price, a minimum price and a maximum price.

Load factor and O&M costs

For the sensitivity on the load factor and on the O&M costs, we used the following values (please note that the medium values are directly taken from the EGC study):

		GAZ	COAL	NUCLEAR	HYDRO
Load Factor Min	-10%	77%	77%	77%	36%
Load Factor Medium		85%	85%	85%	40%
Load Factor Max	10%	94%	94%	94%	44%
		USD/MWh	USD/MWh	USD/MWh	USD/MWh
O&M costs Min	-10%	4,20	18,10	14,40	13,65
O&M costs Medium		4,67	20,11	16,00	15,17
O&M costs Max	10%	5,14	22,12	22,40	16,69

Please note that we have chosen to set a range of variation of +/- 10% considering that such extremes could be regarded as upper and worst cases.

We have chosen to freeze the other hypotheses;

- Entrance date of the Private Equity fund: systematically set after the initial debt on the power plant was fully reimbursed

- EV/EBITDA multiple: this multiple is used at entrance and exit date to compute the enterprise value ("EV") of the Project Co and therefore the price at which the NewCo buys and sells the Project Co[38]. We set this multiple at 8.

- Cost of financing of the LBO structure: 10% for the debt financing structure and 8% for the shareholder loan as stated previously

Indeed, we have considered that carrying out a sensitivity analysis on these variables was not of utmost importance or would complicate too much the analysis.

- Entrance date of the fund: if the entrance date is set before the initial debt of the power plant is fully reimbursed, we need to introduce a new tranche of debt in the model: the refinancing debt at the Project Co level. Therefore, it would require a complementary analysis on (i) the feasibility of raising such a debt to know precisely when it would have been possible for the fund to enter as well as on (ii) the costs of such a debt. Moreover, it would have required an additional sensitivity analysis on the initial debt structure (margins, amount, maturities). Thus, it would have added unnecessary complexity to our results. Indeed, to make an investment decision, a Private Equity fund should primarily focus on the operational track record and the future operational and financial performances of the project rather than on its financial structure.

- EV/EBITDA multiple: Given the lack of similar transactions in the power sector, it is difficult to have accurate insights on what the value of the multiple should be. Therefore, we chose 8 on the basis of professionals' advice. It is a conservative approach to take a high multiple. Indeed, the lower the EV/EBITDA multiple the less expensive to buy the Project Co and therefore the less equity injected per MWh so the higher the IRR. For instance, with a EV/EBITDA multiple of 8, under a Flat Breakeven Scenario (i.e. electricity prices flat over the holding period at breakeven level and medium fuel and carbon prices), the IRR is 7,98% for an investment in the gas-fired power plant (optimized debt level of 33%) and 8,42% (optimized debt level of 35%) for an investment in the nuclear power plant whereas the IRR is above 19% (optimized debt level of 65%) for both technologies with an EV/EBITDA multiple of 4.

- Cost of financing of the LBO structure: it will be defined at the beginning of the investment according to current market conditions. Therefore, we deemed the sensitivity on this factor of little interest

3.2 Scenarios

First, for each of the four technologies, we started with two simple scenarios: Flat Breakeven and Flat Max (scenarios 1 and 2 in the table below. These scenarios assume no change in the market and the operating conditions before and after the arrival of the Private Equity fund. In the Flat Breakeven scenario, before the arrival of the Private Equity fund, the electricity is at breakeven level, the fuel and

[38] Equity value = Enterprise Value – Net financial debt = EV/EBITDA multiple * $\text{EBITDA}_{\text{yearbeforeLBO}}$ - Net financial debt

the carbon prices are Medium prices (as defined above) and the load factor and the O&M costs are at the Medium levels (as defined above) and after the arrival of the Private Equity fund everything remains at the same level. The Flat Max is the same scenario except that the electricity price is set at the Max level (as defined above). The goal of these scenarios is to assess the type of IRR a fund could get with flat market conditions and flat operating conditions and therefore with the financial debt as the only value creation lever.

Second, for each technology we run scenarios assuming that electricity prices increases over the holding period (starting from the breakeven price). Each inflated scenario (scenarios 4 to 11 in the table below) differs from one factor (all the other factors are set at Medium level): scenario 4, assumes that after the entrance of the Private Equity fund, the fuel price decreases to the Min level, scenario 5 assumes that after the entrance of the Private Equity fund, the fuel price increases to the Max level, scenario 6 assumes that after the entrance date, the carbon costs decreases to the Min level whereas scenario 7 assumes it increases to the Max level, etc. All these scenarios (from 4 to 11) are benchmarked against the Benchmark scenario (scenario 3 in the table below), which assumes that electricity prices increases over the holding period (starting from the breakeven price) and that all the other factors remain constant at Medium level. The goal of these scenarios is to assess the minimum inflation on the electricity price that is required to reach the target IRR given the changes of the market or the operating factors after the fund buys the project. Therefore, these scenarios assess the sensitivity of the IRR to changing fuel costs, carbon costs, load factors or O&M costs. For each of these scenarios, the initial market conditions and operating assumptions (before the Private Equity fund's entrance) are the same - breakeven price, medium case market and operating assumptions, therefore, in each scenario the price at which the fund buys the Project Co is the same.

The table below summarizes the different scenarios of the sensitivity analysis

		ELECTRICITY PRICE		FUEL PRICE		CARBON PRICE		O&M COSTS		LOAD FACTOR	
		BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER
1	FLAT BREAKEVEN	Breakeven	Breakeven Flat	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
2	FLAT MAX	Max	Max Flat	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
3	BENCHMARK	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
4	UPPER FP Min	Breakeven	Breakeven (Inflated)	Medium	Min	Medium	Medium	Medium	Medium	Medium	Medium
5	WORST FP Max	Breakeven	Breakeven (Inflated)	Medium	Max	Medium	Medium	Medium	Medium	Medium	Medium
6	UPPER CP Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Min	Medium	Medium	Medium	Medium
7	WORST CP Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Max	Medium	Medium	Medium	Medium
8	UPPER O&M Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Min	Medium	Medium
9	WORST O&M Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Max	Medium	Medium
10	WORST LF Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Min
11	UPPER LF Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Max

18) Scenarios used in the sensitivity analysis[39]

Please note that the scenarios 5 and 6 are not appropriate either for the nuclear power plant or for the hydro power plant given the absence of carbon emissions. Moreover, the scenarios 3 & 4 are not appropriate for the hydro power plant given that the fuel – water – is free.

[39] Own anaysis

3.3 Tools

In order to support our quantitative analysis, we have built a flexible Excel tool to model the various financial flows under different assumptions for a given technology.

The tool provides two main VBA macros:

- The first macro computes for a given scenario – ie given market assumptions (electricity price, fuel price and carbon price) and given operating assumptions (load factor and O&M costs) – (i) the maximum level of debt that can be raised to finance the acquisition of ProjectCo and put at the NewCo level while meeting the DSCR requirement of 1,2 and (ii) the resulting IRR with this level of debt

- The second macro computes (i) for a given scenario the minimum inflation on electricity prices required over the holding period to reach the target IRR; (ii) the maximum level of debt that can be raised to finance the acquisition of ProjectCo and put at the NewCo level given the DSCR constraint and inflated electricity prices; and (ii) the resulting IRR given this inflation and the updated debt level

A third macro has been built in order to automatically run these two macros one after another.

4 Limitation of the model

4.1 Total costs

The EGC study, on which our analysis is based, gives costs at plant-level and does not include transmission, grid connection costs and distribution costs. In the absence of other accurate data we have decided to do the same and not include these costs in our analysis. However, to give an order of magnitude, the OECD estimates that generation costs account for 60% of total costs supported by power plants and the remaining 40% include transmission, distribution and marketing[40].

For the CCS technology, the EGC study analyses the impacts of the technology on the O&M costs as well as on the power plant efficiency. However, it does not include transportation costs to final carbon deposits and storage costs. Here again, we applied the same method as in the EGC study.

4.2 O&M costs

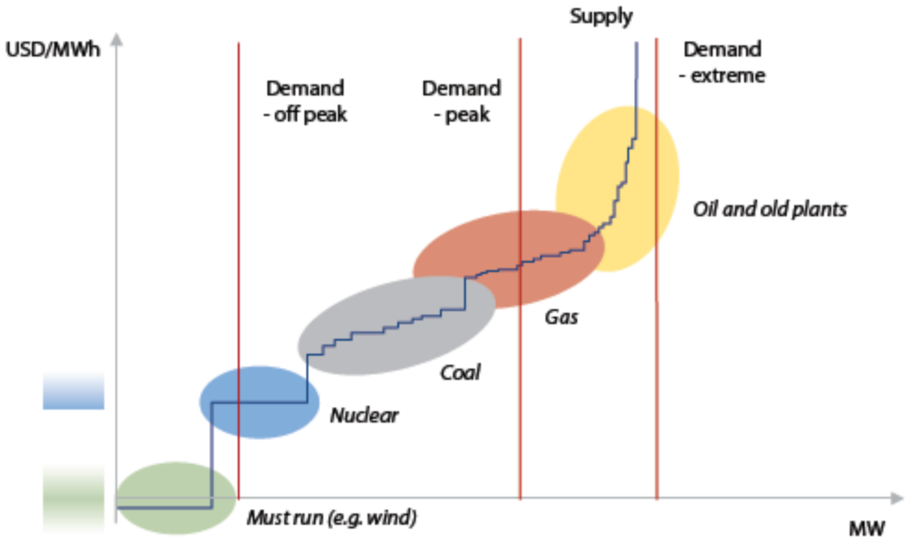
The sensitivity analysis on the O&M costs does not make any distinction between fixed and variable O&M costs because the EGC study gives no information on the proportion of fixed and variable costs in the total O&M costs.

4.3 Fuel price

When we carry out a sensitivity analysis to fuel cost, we only analyse the impact of the price variations of the fuel used in the power plant and not the impact of the price variations of other fuels on the

[40] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 166

profitability of the considered power plant. However, in competitive markets, wholesale electricity prices tend towards the highest short-term marginal costs of all the dispatched technologies[41]. The illustration below shows the order of priority in the dispatch. Hydro and nuclear power plants operate in baseload and are the first ones to be dispatched. Therefore, they are "price takers" (Mr. Gauthier, 2011). In contrast, coal and gas-fired power plants are "price makers" (Mr. Gauthier, 2011): they are the last units of production and their marginal costs of production set the final wholesale electricity prices.



19) Illustrative energy market clearing based on marginal costs of production[42]

Consequently, not only is the profitability of a power plant affected by the variation of the prices of its own fuel but it is also impacted by the variation of other fuel prices. Gas-fired power plants are the least concerned by this cross-sensitivity because their position as final price setter creates a "natural hedge": "increases in gas prices are passed on as increases in wholesale electricity prices, creating a natural risk management mechanism or hedge"[43]. Therefore, in order to make the sensitivity analysis more comprehensive, we needed to model the link between wholesale electricity prices and gas and coal prices. However, being unable to find accurate information on how to build such a model, we have decided to leave if for further analysis.

[41] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 168

[42] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 170

[43] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 124

4.4 Impact of demand and competition

In the model, we use one single electricity price and one single load factor per year. It shall be noted that these values are average values. In reality, these values have complex relationships with demand and competition and therefore vary along the year. Demand for instance varies within one day between peak and off-peak hours as well as between seasons. Also, as previously stated, electricity sources are dispatched depending upon demand and their marginal costs of production: nuclear electricity is one of the first to be dispatched given the low marginal cost to produce one marginal unit of electricity whereas gas electricity is the last one to be dispatched. Therefore, when nuclear power plants operate in baseload, gas-fired power plants will only be started when the demand is too high to be covered by the other generation sources. Consequently, the load factor is unlikely to be the same.

However, for the purpose of our analysis, we have decided to use an average load factor of 85% for the gas-fired power plant, the coal-fired power plant and the nuclear power plant to be consistent with the EGC study and because it is difficult to anticipate the evolution of the product of the electricity price and the load factor with the evolution of demand given that the load factor is a decreasing function of the marginal cost of production and the electricity price is an increasing function of demand. The only technology for which we used a different load factor (40%) is hydro because the load factor does not only depend on the choice of the operator to run or not the power plant but is restricted by technical constraints such as the time needed to refill the reservoir.

4.5 Tax rate

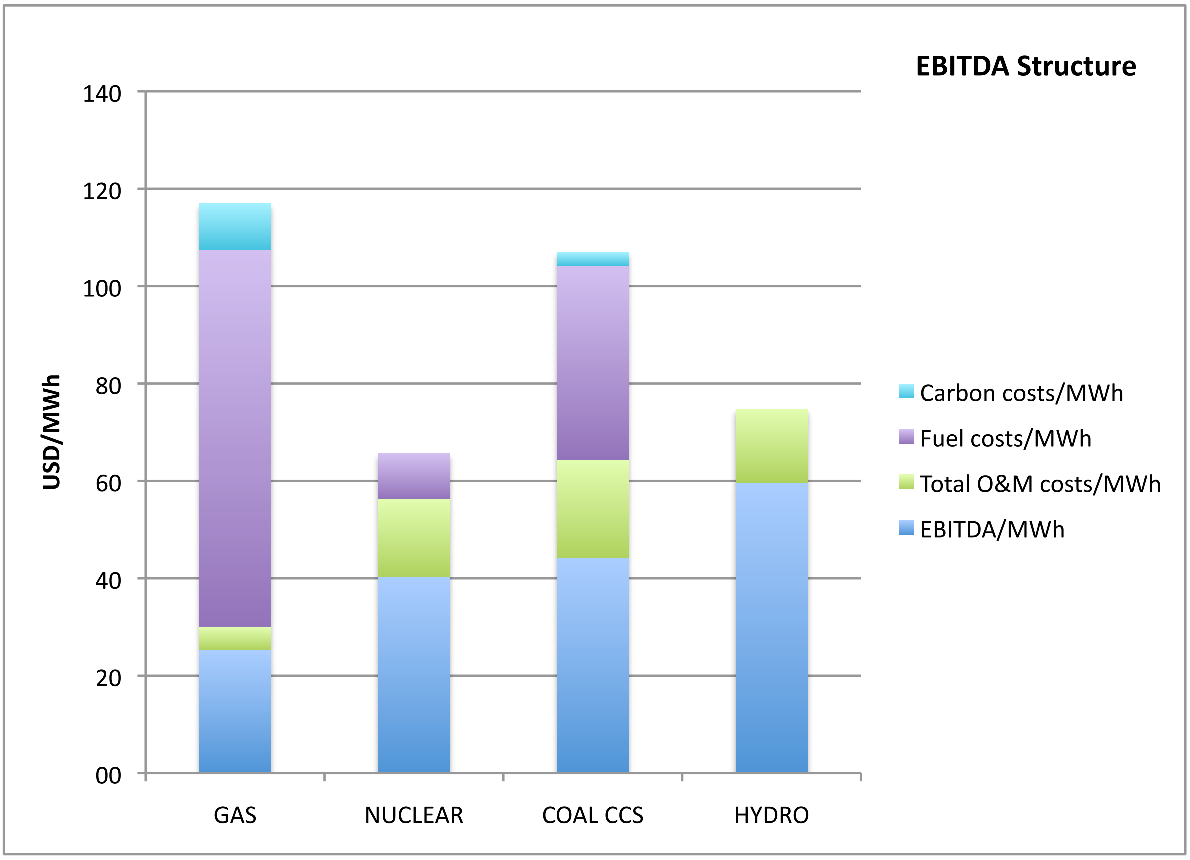
Finally, given the difficulty we had to find public data on taxation rate for power generator, we used a standard taxation rate of 33% for all projects.

III Investment case

1 Quantitative analysis: value creation levers

1.1 Entrance conditions

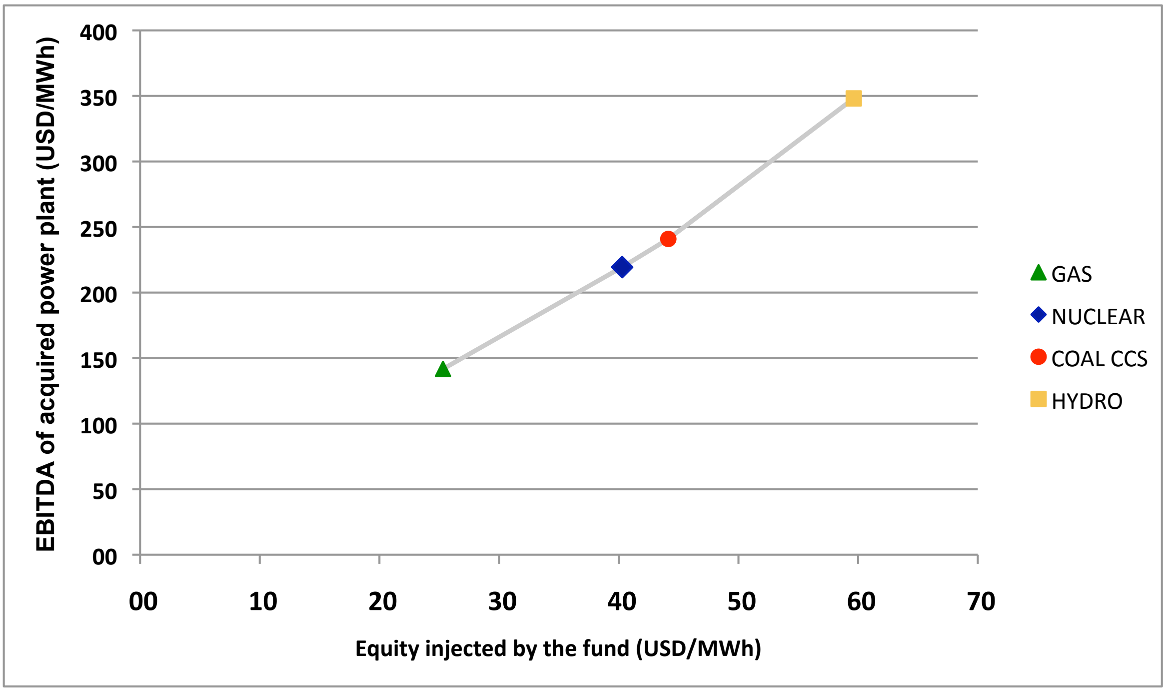
The chart below pictures the EBITDA/MWh of each of the four projects based on the Flat Breakeven scenario - scenario 1 as presented in table 18. We see that the hydro power plant has the highest EBITDA/MWh. It is followed by the coal-fired power plant with CCS, the nuclear power plant and finally the gas-fired power plant.



20) EBITDA structure per MWh of each power plants[44]

The ProjectCo with the highest EBITDA/MWh of electricity produced shall be the most expensive per MWh given that the price is derived from the same EV/EBITDA multiple for the four technologies. Given that for the fund, the most relevant criterion is the amount of equity it injects per MWh (i.e. the price/MWh), it is interesting to highlight that there is a linear relation between the EBITDA/MWh and the equity injected/MWh as presented in the chart below. Please note that for all projects the maximum authorized debt level in the financing of the acquisition under flat market and operation assumptions is around 33%.

[44] Own analysis – Financial model



21) Initial equity injected by the fund to finance the acquisition as a function of EBITDA/MWh of the power plant acquired[45]

1.2 Value creation levers

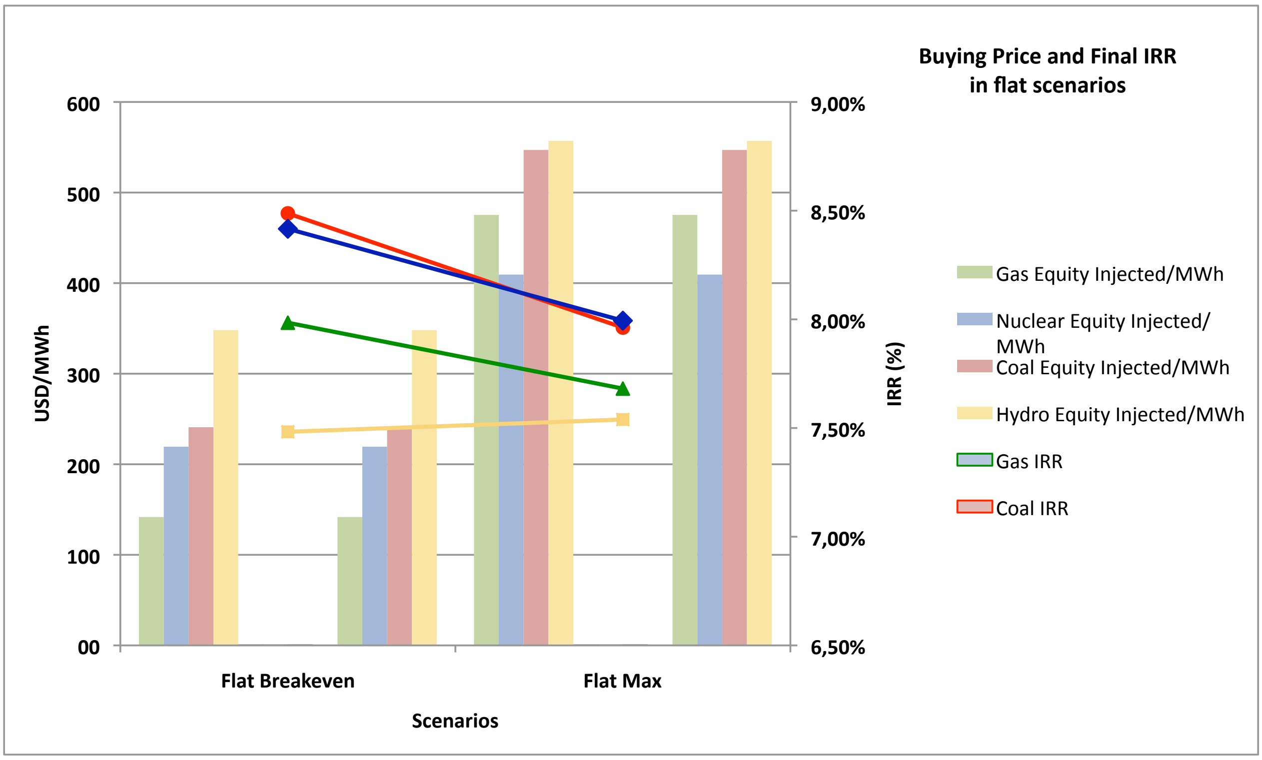
How should a Private Equity fund select the power plant it should invest into?

First, it is worth noting that the buying price is not the most relevant criterion.

The chart below depicts the IRR the fund would get under the two flat scenarios: Flat Breakeven and Flat Max – as presented in table 18.

Under the Flat Max scenario, the fund pays a higher price (higher amount of equity injected per MWh) due to higher electricity prices. However, the resulting IRR is not significantly lower than in the Flat Breakeven scenario. Therefore, it shows that the buying price does not impact significantly the IRR as long as both the buyer and the seller do not anticipate any future variations of the electricity prices or of the costs of production of the power plant that they incorporate in the buying price. Indeed, if the market and the operating conditions are equal and constant before and after the acquisition, the only value creation lever will be the tax shield through the optimization of the debt level. However, as pictured in the chart below, the leverage effect has only a limited impact on value creation: under the flat scenarios, the IRRs of all the investments are close to 8%.

[45] Own analysis – Financial model



22) Initial equity injected by the fund per MWh and resulting IRR at the end of the holding period under Flat Brekeven and Flat Max scenarios[46]

Please note that the small variations around 8% are explained both by the different optimized debt levels and the different EBITDA/MWh from one project to another. Under the Flat Breakeven scenario, the optimized debt level for the acquisition of the coal-fired power plant with CCS and the nuclear power plant is 35% whereas the optimized debt level for the acquisition of the gas-fired power plant and the hydro power plant is 33%. Under the Flat Max scenario, the optimized debt level for the acquisition of the coal-fired power plant with CCS, the nuclear power plant and the hydro power plant is 33% whereas the optimized debt level for the acquisition of the gas-fired power plant is 32%. At a given debt level, the cheapest technology in terms of EBITDA/MWh is the one with the highest IRR given that it is the one that requires the lowest amount of equity injected/MWh as previously stated.

By way of conclusion, the fund should choose the asset for which other value creation levers than debt are possible.

What are the other value creation levers?

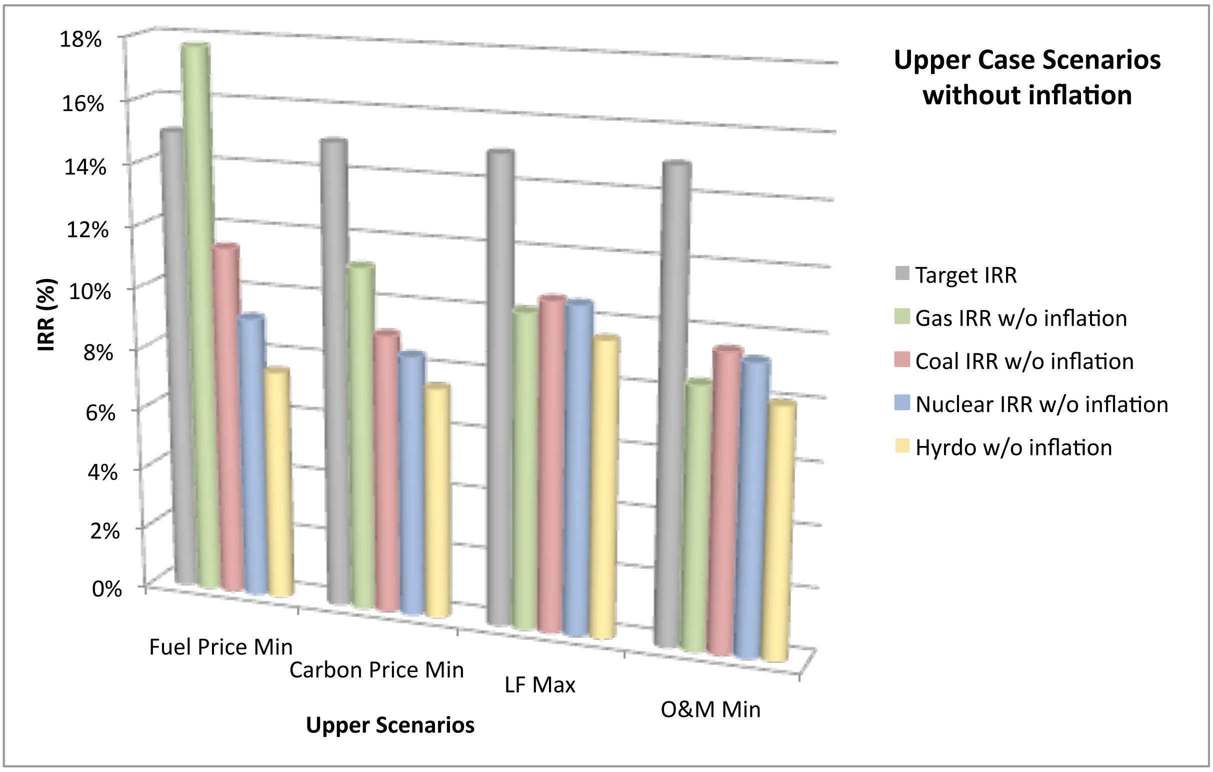
The IRR will be significantly improved if the fund can sell the power plant acquired at a higher price than the price at which it has bought the asset. Given that we value the power plant at entrance and exit dates with the same EV/EBITDA multiple, an increase of the EBITDA of the power plant after the

[46] Own analysis – Financial model

acquisition would increase the exit price vs the entrance price. Therefore, the possible value creation levers are either an improvement of market conditions - such as an increase in electricity prices or a decrease in fuel and carbon prices - or an improvement of operating conditions - such as an increase in the load factor or a decrease in the O&M costs - that were not anticipated by the seller at entrance date and therefore not included in the entrance price.

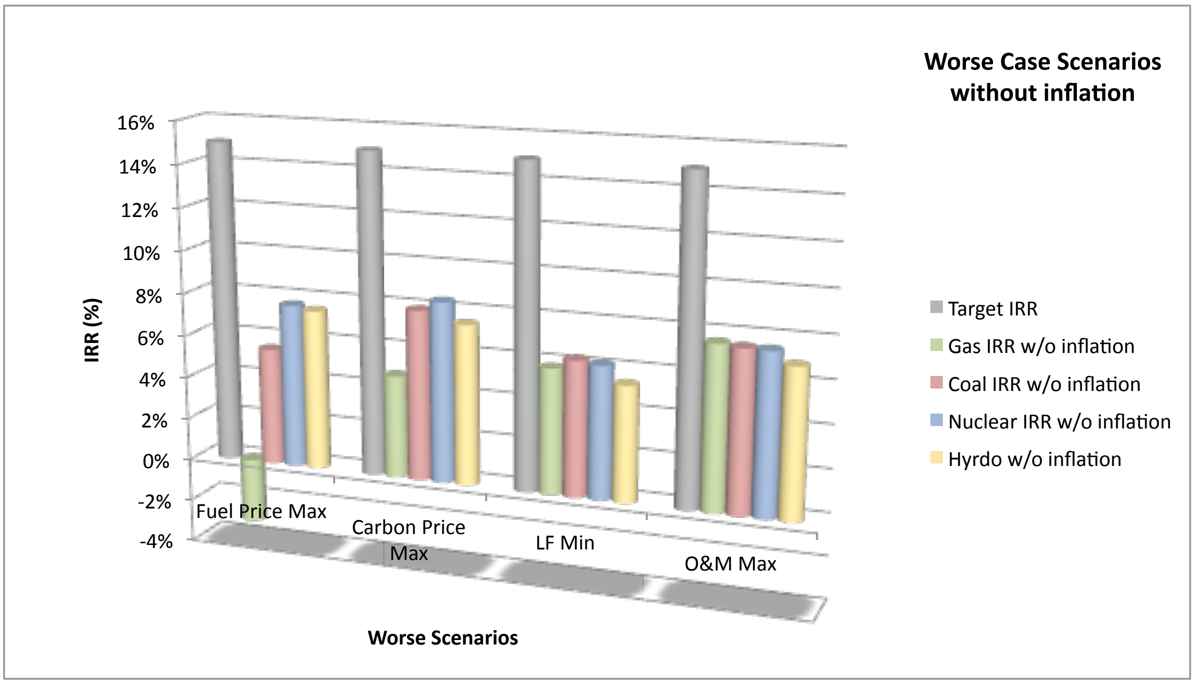
In order to assess the impact of these different levers on the IRR, we have (i) first computed the maximum IRR that can be reached under flat electricity prices assumptions (at breakeven level) while optimizing the debt level and improving the market assumptions (decrease of 15% in fuel prices or decrease of 40% in carbon costs) or improving the operating assumptions (increase of 10% in load factor or decrease of 10% in O&M costs); and (ii) second, we have computed the IRR under flat electricity prices assumptions (at breakeven level) while optimizing the debt level and deteriorating the market assumptions (increase of 15% in fuel prices or increase of 40% in carbon costs) or deteriorating the operating assumptions (decrease of 10% in load factor or increase of 10% in O&M costs). In both cases, the evolutions of market and operating conditions after the entrance date were not anticipated by the seller and therefore not priced in.

Second, in order to see how much inflation was necessary to improve these upper cases and worst cases IRR, we have run the same scenarios as above with inflation on electricity price. For each scenario, we have computed the minimum inflation necessary to reach the target IRR.



23) Maximum IRR in upper market or operating conditions with flat electricity prices and optimized debt level[47]

[47] Own analysis – Financial model



24) *IRR in worst market or operating conditions with flat electricity prices and optimized debt level*[48]

The first chart above (chart 23) clearly shows that improved fuel or carbon prices and improved operating conditions (in the range of variation we defined for our sensitivity analysis and that we consider being realistic ranges) without electricity price inflation are usually not enough to reach a target IRR of 15%. The gas offers an exception when fuel price is very low. The target IRR of 15% is reached without electricity price inflation thanks to the extreme sensibility of the gas-fired power plant to fuel price assumptions as will be shown later on. Therefore, in order to reach the target IRR, the fund should also anticipates inflation on electricity prices that the seller does not anticipate when selling the power plant.

The charts below depict the required levels of inflation on electricity prices to reach the target IRR of 15% in both the upper and the worst scenarios (scenarios 4 to 11 in the table 18).

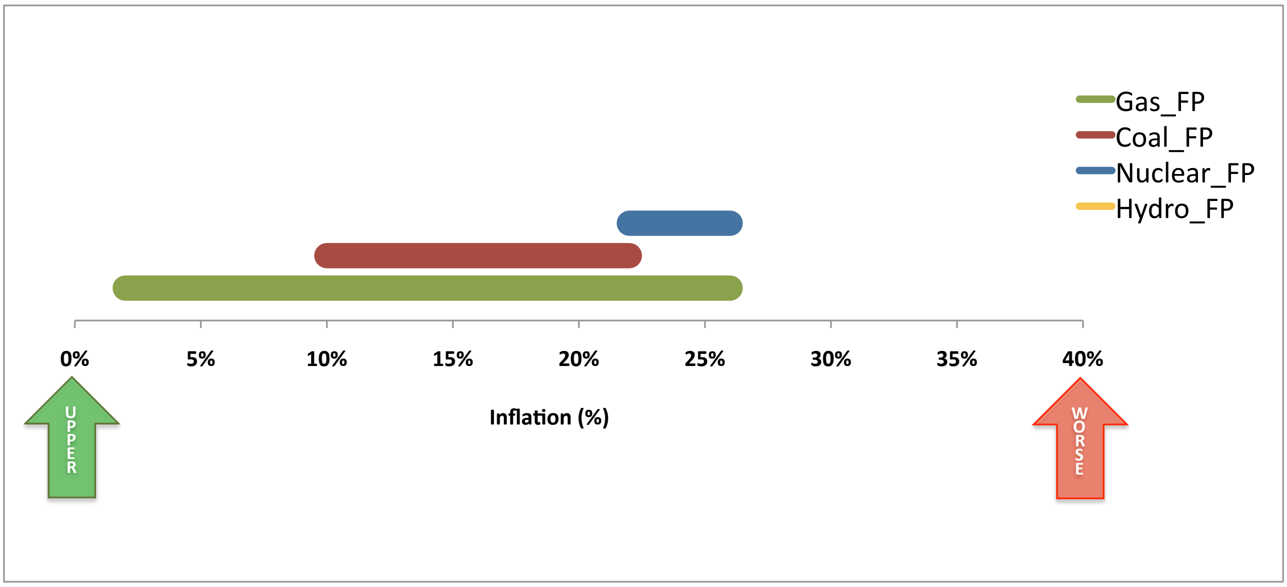
Please note that on the left of the horizontal axis of the charts below, the results of the upper case scenarios are displayed:

[48] Own analysis

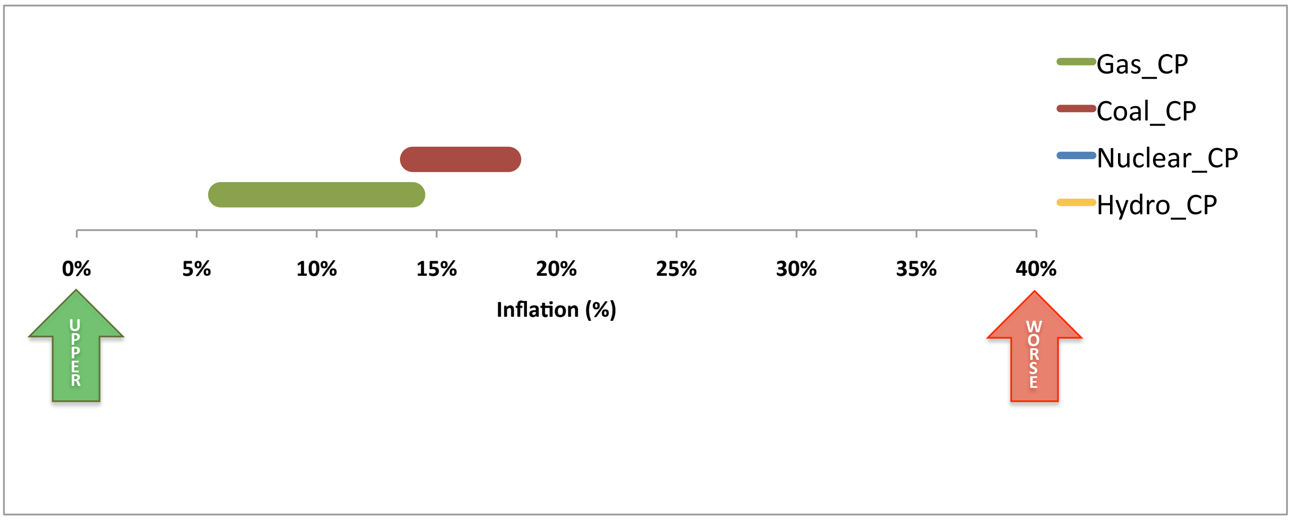
		ELECTRICITY PRICE		FUEL PRICE		CARBON PRICE		O&M COSTS		LOAD FACTOR	
		BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER
1	FLAT BREAKEVEN	Breakeven	Breakeven Flat	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
2	FLAT MAX	Max	Max Flat	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
3	BENCHMARK	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
4	UPPER FP Min	Breakeven	Breakeven (Inflated)	Medium	Min	Medium	Medium	Medium	Medium	Medium	Medium
5	WORST FP Max	Breakeven	Breakeven (Inflated)	Medium	Max	Medium	Medium	Medium	Medium	Medium	Medium
6	UPPER CP Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Min	Medium	Medium	Medium	Medium
7	WORST CP Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Max	Medium	Medium	Medium	Medium
8	UPPER O&M Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Min	Medium	Medium
9	WORST O&M Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Max	Medium	Medium
10	WORST LF Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Min
11	UPPER LF Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Max

And on the right side of the horizontal axis of the charts below, the results of the worst-case scenarios are displayed:

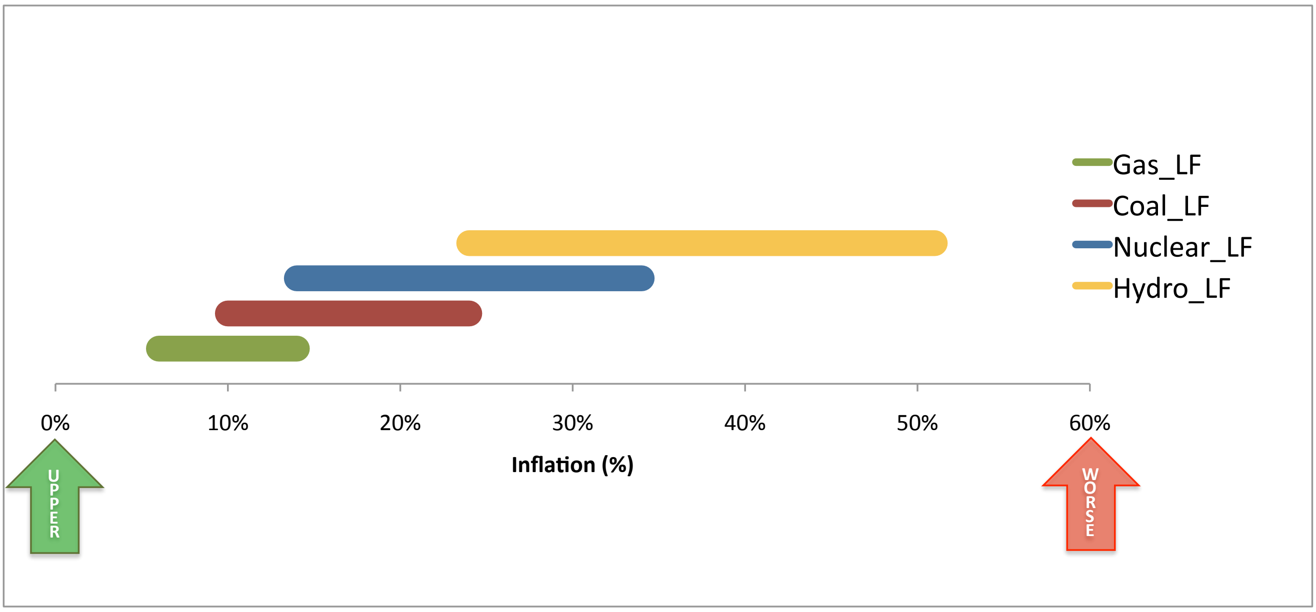
		ELECTRICITY PRICE		FUEL PRICE		CARBON PRICE		O&M COSTS		LOAD FACTOR	
		BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER	BEFORE	AFTER
1	FLAT BREAKEVEN	Breakeven	Breakeven Flat	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
2	FLAT MAX	Max	Max Flat	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
3	BENCHMARK	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
4	UPPER FP Min	Breakeven	Breakeven (Inflated)	Medium	Min	Medium	Medium	Medium	Medium	Medium	Medium
5	WORST FP Max	Breakeven	Breakeven (Inflated)	Medium	Max	Medium	Medium	Medium	Medium	Medium	Medium
6	UPPER CP Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Min	Medium	Medium	Medium	Medium
7	WORST CP Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Max	Medium	Medium	Medium	Medium
8	UPPER O&M Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Min	Medium	Medium
9	WORST O&M Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Max	Medium	Medium
10	WORST LF Min	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Min
11	UPPER LF Max	Breakeven	Breakeven (Inflated)	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Max



25) Fuel price sensitivity: inflation required to reach target IRR in Upper FP Min and Worst FP Max scenarios[49]



26) Carbon price sensitivity: inflation required to reach target IRR in Upper CP Min and Worst CP Max scenarios [50]

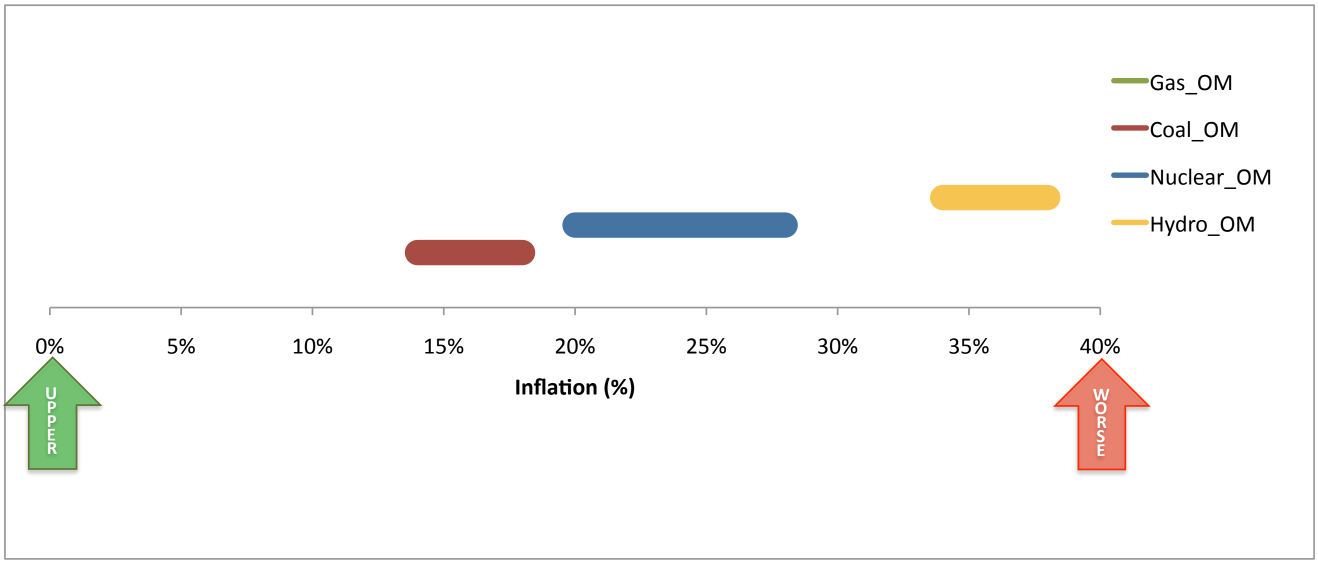


27) Load factor sensitivity: inflation required to reach target IRR in Upper LF Max and Worst LF Min scenarios [51]

49 Own analysis – Financial model

50 Own analysis – Financial model

51 Own analysis – Financial model



28) O&M costs sensitivity: inflation required to reach target IRR in Upper O&M Min and Worst O&M Max scenarios [52]

In these graphs, two types of sensitivities are displayed:

- What we have chosen to call a relative sensitivity, given by the length of the bars: the longer the bar the more sensitive the power plant profitability is to the considered factor. This sensitivity corresponds to the one analysed in the EGC study. We indeed find the same results as in the EGC study.
  - Sensitivity to fuel price variations: the most sensitive is the CCGT followed by the coal-fired power plant and only far behind the nuclear power plant[53]. The sensitivity is proportional to the weight of fuel costs in the EBITDA structure of each power plant as shown in chart 20.
  - Sensitivity to carbon price variations: the CCGT is more sensitive to this cost than the coal-fired power plant with CCS[54]. Again, The sensitivity is proportional to the weight of carbon costs in the EBITDA structure of each power plant as shown in chart 20.

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[52] Own analysis – Financial model

[53] Own analysis – Financial model & OECD, Projected Costs of Generating Electricity, 2010 edition, p. 116

[54] Own analysis – Financial model & OECD, Projected Costs of Generating Electricity, 2010 edition, p. 117

- Sensitivity to load factor and O&M costs variations: apart from the hydro power plant, the level of sensitivity to the load factor of the three other power plants is linked to the sensitivity to the O&M costs. The plants that are the most sensitive to O&M costs (nuclear and coal-fired power plant with CCS) are also the most sensitive to the load factor. Indeed, as mentioned in the EGC study, the nuclear power plant and the coal-fired power plant with CCS have the highest share of fixed O&M costs[55]. The load factor of the hydro power plant is very low because of technical constraints (filling the reservoir with water), which increases the sensitivity to the load factor.

- What we have chosen to call an absolute sensitivity, given by horizontal position of the bar in the chart: the more the bar is located on the right, the more the power plant requires high level of inflation to compensate for the worst market or operating conditions and reach the target IRR and therefore, the more risky for financial investors to not reach the target IRR.

Therefore, a financial investor should look at the two sensitivities. The table below ranks the four technologies in three different categories by order of interest for a Private Equity fund: the lower the number of points the more interesting for the Private Equity fund to consider this technology.

The first category is called “chance to reach the breakeven price”: the higher the breakeven price the riskier not to be reached and therefore the riskier to jeopardize the IRR of an investor

The second category is called “absolute sensitivity”. It ranks the technologied according to their absolute sensitivity (as defined above) to market and operaing factors: fuel and carbon prices, O&M costs and load factor. We have defined four sub-categories:

- “Upper without inflation”: the best ranked technology (1) is the one that has the highest IRR when considering flat electricity prices (at Breakeven price) and upper market or operating conditions - fuel price, carbon price, load factor or O&M costs. Please note that when the difference between two IRR was less than 0,05% we attributed the same ranking to the technologies – we used the same limit of 0,05% for the three other sub-categories. The IRR values can be found in the chart 23.

- “Worse without inflation”: the best ranked technology (1) is the one that has the highest IRR when considering flat electricity prices (at Breakeven price) and worst market or operating conditions - fuel price, carbon price, load factor or O&M costs. The IRR values can be found in the chart 24.

- “Upper with inflation”: the best ranked technology (1) is the one that requires the lowest level of inflation to reach the target IRR of 15% when considering upper market or operating conditions - fuel price, carbon price, load factor or O&M costs. The IRR values can be found in the charts 25 to 28.

- “Worse with inflation”: the best ranked technology (1) is the one that requires the lowest level of inflation to reach the target IRR of 15% when considering worst market or operating conditions -

[55] Own analysis – Financial model & OECD, Projected Costs of Generating Electricity, 2010 edition, p. 121

fuel price, carbon price, load factor or O&M costs. The IRR values can be found in the charts 25 to 28.

The third category is called “relative sensitivity”. It ranks the technologies according to their relative sensitivity (as defined above) to fuel and carbon prices, to O&M costs and to the load factor. Therefore, the ranking is different for a risk-averse investor and an investor who favours risk: a risk-averse investor will grant the best ranking (1) to the technology that is the least sensitive to a factor whereas it will be the exact opposite for an investor who favours risks.

	GAS	COAL W/ CCS	NUCLEAR	HYDRO
Chance to reach the breakeven price (1)	4	3	1	2
ABSOLUTE SENSITIVITY (2)				
UPPER W/O INFLATION				
Fuel Price Min	1	2	3	4
Carbon Price Min	1	2	3	4
Load Factor Max	1	1	1	2
O&M Min	2	1	1	2
WORSE W/O INFLATION				
Fuel Price Max	3	2	1	1
Carbon Price Max	4	2	1	3
Load Factor Min	2	1	1	3
O&M Max	1	2	3	4
UPPER W/ INFLATION				
Fuel Price Min	1	2	3	4
Carbon Price Min	1	2	3	4
Load Factor Max	1	2	3	4
O&M Min	1	2	3	4
WORSE W/ INFLATION				
Fuel Price Max	2	1	3	4
Carbon Price Max	1	2	3	4
Load Factor Min	1	2	3	4
O&M Max	1	2	3	4
TOTAL	24	28	38	55

RELATIVE SENSITIVITY (3)

	GAS RISK AVERSE	GAS PRO RISK	COAL W/ CCS RISK AVERSE	COAL W/ CCS PRO RISK	NUCLEAR RISK AVERSE	NUCLEAR PRO RISK	HYDRO RISK AVERSE	HYDRO PRO RISK
Fuel Price	4	1	3	2	2	3	1	4
Carbon Price	3	1	2	2	1	3	1	3
Load Factor	1	4	2	3	3	2	4	1
O&M costs	1	3	2	2	3	1	2	2
TOTAL	9	9	9	9	9	9	8	10

Two main conclusions can be drawn from the above table.

First, in view of the results of the relative sensitivity section, it appears difficult to differentiate the four technologies, except for the hydro investment that clearly offers a safer risk profile. For each project, a specific and in-depth risk analysis is thus required.

Second, when putting in perspective the results of both the relative sensitivity and the absolute sensitivity sections, the hydro investment seems to be a good candidate for investors looking for low risk profile and not necessarily looking to improve the overall profitability of the power plant whereas the gas investment appears to be the most interesting technology for a Private Equity fund. Indeed, it has the best ranking (lowest number of points) in the absolute sensitivity section, which shows that it is the technology that is the most sensitive to improvement levers. Indeed, it is the one that requires the lowest levels of inflation to reach the target IRR under upper and worst market and operating assumptions and in the absence of inflation of electricity prices, it is the one for which the IRR can still be improved the most through the fuel and carbon levers as well as through the operating levers. Of course, the downside is that in case of worst market and operating conditions without inflation on electricity prices, it is the technology for which the IRR is the most jeopardized. However, the upsides compensate the downsides more than in the three other technologies. Nevertheless, when investing in a gas-fired power plant, a fund must carry out an extremely careful demand and price evolution analysis because these upsides will only materialize if the breakeven price can be reached but the gas-fired power plant is the one that has the highest breakeven price.

2 Qualitative analysis

2.1 Analysis of the power market structure at the Western Europe and the national levels

The goal of this analysis is to point out the features of the market structure that could either favour or hinder the entrance of a Private Equity fund. It is important to carry out this analysis both at a Western European and at a national level (France, Italy, Germany and Sweden) given that certain markets such as France and Germany or Sweden and Germany are increasingly intertwined both in terms of demand and competition. Italy can be seen as the less integrated among the four but investments are currently being made to increase its integration with neighbouring countries.

The structure of the power market in Western Europe

Liberalisation of the European electricity market has been driven by three directive packages: a first one in 1996, a second one in 2003 and a third one in 2007.

These directives were made to grant all European consumers the right to choose their electricity suppliers, unbundle transmission activities from generation and retail activities, regulate cross-border trades, favour the establishment of independent regulators and increase the transparency of electricity markets. Nowadays, deregulation has been achieved in the generation sector. Power Exchanges have been created and are increasingly liquid. Deregulation in the retail segment has also been improved but most countries have maintained a regulated tariff for the end-users. Transmission networks remain regulated.

All in all, significant progress towards liberalisation has been made but Private Equity experts agree that some challenges still need to be overcome to make it easier for new actors to enter this market and compete with the Incumbents:

- The power generation market is highly concentrated in Western Europe in the hands of the Incumbents (Mr. Halbout, 2011)

- Deregulation has been carried out slowly and has mostly benefited the Incumbents. Indeed, the Incumbents have seized this opportunity to go out of their historical borders and grasp new market shares in neighbouring countries reinforcing the horizontal concentration of the market and leaving few opportunities for new entrants (Mr. Halbout, 2011)

- Conventional power generation assets in Western Europe have very low profitability levels. This can be acceptable for major utilities, which have lower WACC than funds and can more easily strike a balance between debt and equity in their balance sheet. However, for a Private Equity Fund, which targets a minimum IRR of 20% this is not necessarily acceptable. Infrastructure funds have lower profitability targets but are much more cautious about the risk structure and are generally wary of taking a price risk on fuel (Mr. Halbout & Mr. Kalthöfer, 2011)

- The vertical integration of power markets in Western Europe is also a significant barrier to entry for new actors in power generation. Indeed, the Incumbents are the biggest generation owners as well as the biggest retailers. Therefore, “independent generators find themselves competing with their own customers. There is ample opportunity for utilities to favour their own generation, which relegates the independent generators to compete for a sliver of the demand that the Incumbent utilities do not satisfy with their own generation. It can exacerbate over-supply situations as you have all independent generation competing for a subset of demand.” (Mr. D’Argenio, 2011)

- Although market integration, cross border trades and market coupling have significantly improved, some countries such as Italy are still poorly interconnected with the neighbouring countries creating more volatility in electricity prices

The structure of the national power markets

We used the Porter’s 5 forces as a framework of this analysis.

FRANCE

ENTRY	ELECTRICITY BUYERS
Favours entry in market: France needs peak generation investments[56] so having new shareholders on existing nuclear projects could foster a reallocation of funds to new investments Barriers to entry: EDF is likely to remain the main shareholder of all the French nuclear plants in the coming years (Mr. Haag, 2011)	Electricity can be sold on Power Exchanges or directly through bilateral contracts. Having a new generator can be perceived as an opportunity by existing alternative suppliers to diversify their suppliers (vs EDF alone) without investing themselves into generation facilities

COMPETITION
Conventional generation is highly concentrated. EDF has a market share of 85%[57]. EDF currently owns the 58 nuclear reactors in France and is the main shareholder in Flamanville & Penly EPRs Competition from other major European utilities is likely to increase: ENEL might become a minority shareholder in the Penly project for instance

FUEL SUPPLIER	SUBSITITUTES
Long-term contracts for nuclear fuel-cycle favour stability of prices[58]	Not the main threat given the significant need for baseload electricity in France and in Germany (especially after the shut down of 7 nuclear reactors in Germany)

56 RTE, Generation Adequacy Report, 2010 Edition, p. 12 & 13

57 EDF, 2010 Reference Document, p. 43

58 OECD, Projected Costs of Generating Electricity, 2010 edition, p. 124 & 129

ITALY

BARRIERS TO ENTRY

There is a strong vertical integration between generation and retail activities – Enel alone accounts for almost 50% of the retail market[59]

ELECTRICITY BUYERS

There are regional differences in electricity prices[60].

The fragile interconnection with neighbouring countries increases the volatility of prices on the Italian power exchange.

COMPETITION

The power generation is highly concentrated: the five biggest utilities account for 65% of total generation with Enel alone making up to 30%[61].

Enel, Edisson & ENI account for 50% of the power generation from gas[62]

FUEL SUPPLIER

There is a decline in domestic gas production.The domestic gas production and wholesale gas market is dominated by ENI, also a competitor on the power generation segment.
Most of the imported gas comes from Russia, Algeria and Libya (80% of imports), mostly via long-term contracts (10 to 35 years) with residual life between 5 to 20 years[63]

SUBSITITUTES

Free-carbon technologies could be favoured to meet 20-20 target

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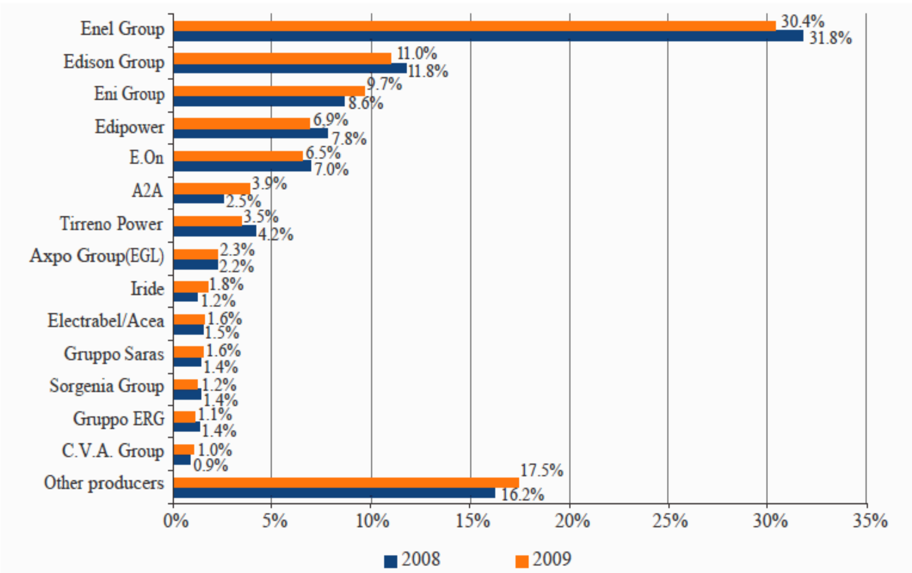
59 AAEG, Structure, prices and quality in the electricity sector, 2010 edition, p. 71

60 AAEG, Structure, prices and quality in the electricity sector, 2010 edition >, p. 61

61 AAEG, Structure, prices and quality in the electricity sector, 2010 edition, p. 4

62 AAEG, Structure, prices and quality in the electricity sector, 2010 edition, p. 44

63 AAEG, Structure, prices and quality in the electricity sector, 2010 edition, p. 113 – 114 & 118 & 120



29) Italy, major suppliers' contribution to gross national production[64]

[64] AAEG, Structure, prices and quality in the electricity sector, 2010 edition, p. 4

GERMANY

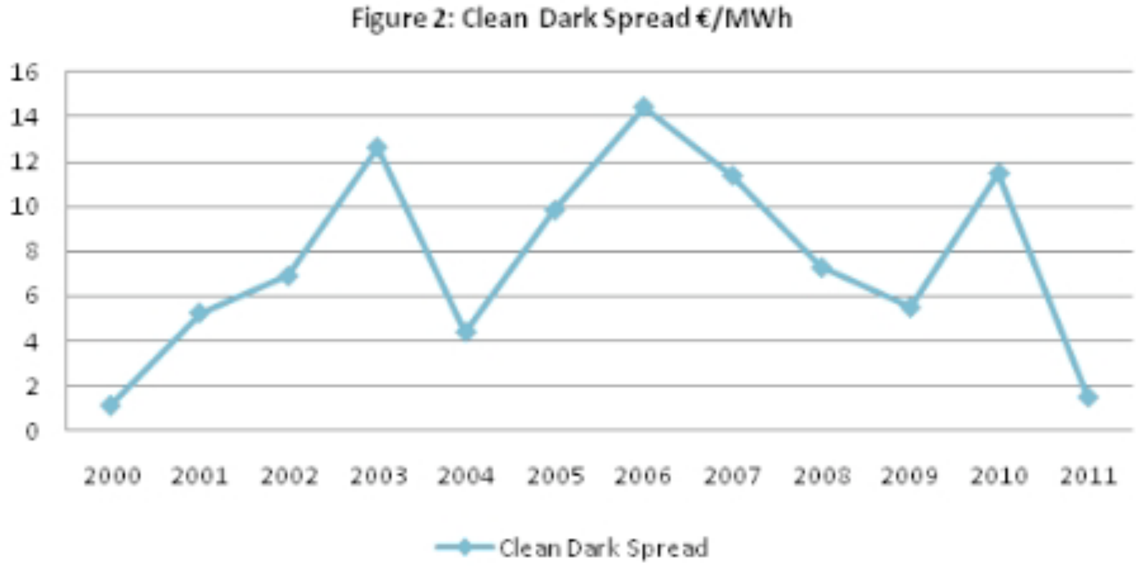
BARRIERS TO ENTRY	ELECTRICITY BUYERS
The CCS regulation has still to be clarified in Germany CCS investments face strong public resistance especially regarding onshore storage (Mr. Schubert, 2011) Clean dark spread for coal-fired power plants without CCS are very low nowadays in Germany (see chart below) because of an increase in fuel price that has not been compensated by an increase in electricity prices. It may be the same for plants with CCS.	The German power exchange is one of the most liquid in Europe

COMPETITION
Power generation is highly concentrated: the four original Incumbents _ E.ON, RWE, Vattenfall and EnBW _ account for 90% of the power generation market with E.ON and RWE alone accounting for 60%[65].

FUEL SUPPLIER	SUBSITITUTES
Most domestic coal production is lignite whereas black coal is mostly imported from Russia, Poland, South Africa and Australia[66]	Renewable power generation is one possible substitute. Indeed, Germany plans to become a European leader in renewable technologies (see above). However, coal is likely to remain a significant source of electricity especially after the shut-down of 7 nuclear reactors

[65] Business Insights, The Western European Electricity Market Outlook 2010, 2010 edition, p. 64

[66] IEA, Energy Policies of IEA countries - Germany, 2007 edition, p. 79 & 80



30) Clean dark spread of coal-fired power plants in Germany[67]

[67] IHS Global Insight, Energy Report - Germany, June 2011, p.3

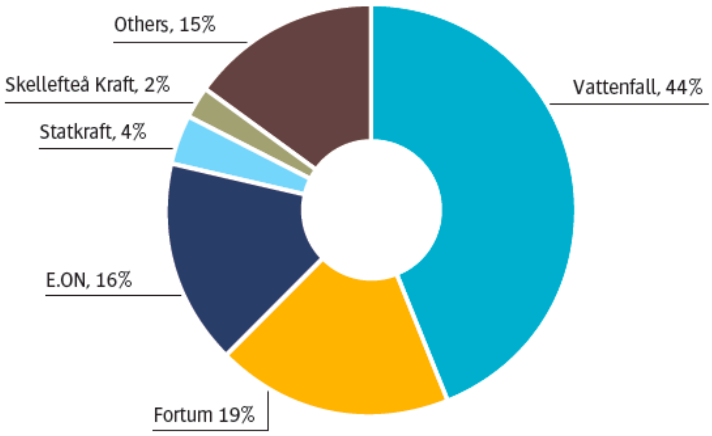
SWEDEN

BARRIERS TO ENTRY	ELECTRICITY BUYERS
Divestitures of operating power plants by existing utilities are likely to be very seldom (Mr Robberts, 2011)	Nordpool Power Exchange is very liquid PPA are unlikely in Sweden given the liquidity of the Nordpool Power Exchange (Mr Robberts, 2011)

COMPETITION
Power generation is highly concentrated around 5 actors: in 2009, they accounted for 85% of total production, with Vattenfall, E.ON and Fortum together making up for 79%[68]. Vattenfall, the largest producer, is a state-owned company.

FUEL SUPPLIER	SUBSITITUTES
The fuel is free but hydro projects are reliant on hydrological conditions. Therefore, they are exposed to volume risks.	Hydro benefits from its free carbon impact

[68] Energy Market Inspectorate, The Swedish electricity and natural gas markets 2009, 2009 edition, p.24



31) Sweden: the five largest electricity producers in 2009[69]

2.2 Regulatory framework

Among the four power plants we analyse, the most exposed to regulatory risk are:

- The nuclear power plant in France: the nuclear industry is facing unprecedented uncertainty after the Fukushima disaster and is currently undergoing some regulatory changes (Loi Nome)
- The coal-fired power plant with CCS in Germany: the CCS technology has never been deployed at commercial scale, therefore, the CCS regulation is still at its beginning creating a great deal of uncertainty unlikely to be acceptable for a Private Equity fund
- The gas-fired power plant in Italy: the end of the Kyoto Protocol is looming creating uncertainty around the evolution of carbon prices on the European carbon market – EU-ETS market

Nuclear in France

In France, companies wishing to start a power generation business need to ask for a generation licence, which is granted on the basis of the French pluri-annual investments programme (Mr. Haag, 2011).

As for other generation sources, investing in nuclear generation is open on the paper to other actors than EDF. However, regarding future green-field nuclear investments, it is unlikely that France schedule new investments soon, especially after the Fukushima disaster. Indeed, two major nuclear projects are already been undertaken by EDF: the Flamanville and the Penly EPR.

[69] Energy Market Inspectorate, The Swedish electricity and natural gas markets 2009, 2009 edition, p.24

As far as existing reactors are concerned, although no other actor than EDF is currently involved in these existing nuclear plants, the regulation allows third parties to invest into such projects if EDF agrees (Mr. Haag, 2011).

In view of EDF de facto monopoly on nuclear power plants in France and the very low costs of production of nuclear electricity, electricity suppliers have been complaining about their inability to compete on the retail segment with EDF. Therefore, based on the recommendations of Champsaur Commission in 2009, the French government passed a new reform called “Loi Nome”. This reform should be applicable starting from the 1st of July 2011. Under Loi Nome, EDF is required to sell 100 TWh of baseload nuclear electricity to its competitors at cost (circa 20% of its generation capacity)[70]. The tariff is set at 40 €/MWh until the beginning of 2012 and 42 €/MWh afterwards. A fund should analyse the impact of such an obligation if it decides to invest in a nuclear power plant whose electricity is diverted in order to meet this new obligation.

Will the future French regulation be favourable to nuclear power investments in a post-Fukushima era?

Since the Fukushima disaster in March 2011, nuclear energy is under the spotlight. France is unlikely to follow the German example given the high reliance of the economy on nuclear power and France’s declared objective to guarantee its energy security. However, France is not spared by the debates and the nuclear industry faces new uncertainty that is likely to curb investors’ appetite for this industry as shown by Total SA decision to freeze negotiation with EDF about its possible participation as minority shareholder in the EPR reactor in Penly.

Coal with CCS in Germany

Although the CCS technology is not a new technology, it has never been deployed at commercial scale. Therefore, the regulation framework is still at its beginnings.

The EU has issued a CCS directive but the European states are still in the process of transposing it into national laws.

In the meantime, some European and national programmes granting subsidies to CCS projects have been deployed.

The EU has launched two main CCS funding programs to support large-scale projects totalling around €3.3 billion. The first program completed at the end of 2009 and called the European Energy Programme for Recovery (EEPR) granted financing to 6 selected projects including the German one, Jänschwalde. Under this program, the Jänschwalde project has been awarded c. €180 million. The second program, the NER300 Decision, confirmed at the beginning of 2010, is aimed at providing funds for both CCS and renewable energy projects. Out of the €4.7 billion expected available funds in the NER300 Decision, €2.3 billion are expected to be allocated to CCS selected projects. The EU should officially present the selected projects by the end of 2013.

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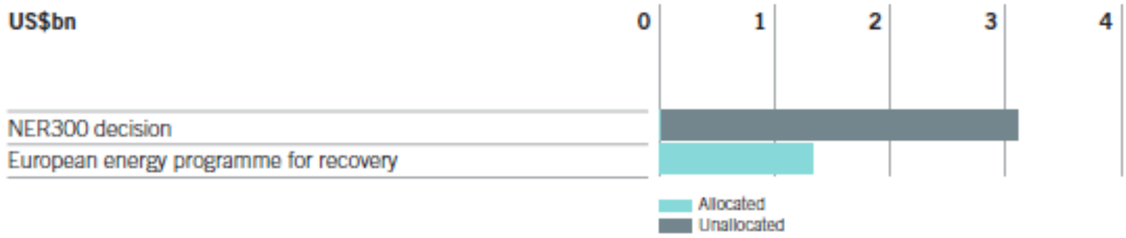
[70] IHS Global Insight, France: French National Assembly Passes Power Market Reforms But Liberalisation Remains Distant Prospect, November 2010



32) European Union funding programmes for CCS projects[71]

In Germany, CCS projects can also apply to national subsidy programmes such as the COORETEC funding initiative, which is part of the 5th Energy Research Programme launched by the German Government and aimed at promoting R&D in CO2 reduction technologies.

Although investors can rely on subsidies, the absence of clear regulatory framework creates too much uncertainty for a Private Equity investor. Indeed, it makes the licensing process highly uncertain, especially in Germany where public opposition to carbon onshore storage remains strong (Mr Schubert, 2011)

EU-ETS market

The EU-ETS is the largest carbon market in the world. It was established in order to meet the CO2 emission reduction objectives set by the Kyoto Protocol. Although the Kyoto Protocol will come to an end in 2012, the EU has decided to maintain the EU-ETS until at least 2020 in order to meet the 20-20 target. However, the end of the Kyoto Protocol may introduce some changes in the way this market works and it creates additional uncertainty around carbon prices.

2.3 Operation risk

The only technology that presents a strong operational risk among the four technologies analysed is the CCS technology. Indeed the various elements of the CCS system have already been used separately in large-scale plants but the combination has never been proven at commercial scale[72]. Nowadays, it is still at very early stage with pilot projects and demonstration plants. Therefore, it is highly unlikely that a Private Equity fund would be interested in a coal-fired power plant equipped with CCS:

"I think that the main reason is the relative youth of this technology that creates enormous risk to financial investors. In general, these financial investors are either Private Equity fund looking for technologies with a proven track record for which it is possible to improve their operating performance or Infrastructure funds looking for secure investments providing lower but more secure IRR than Private Equity investments. New technologies are more the target of Venture Capital funds or Utilities itself" (Mr Schubert, 2011, translated from French)

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[71] Global CCS Institute, The Global Status of CCS 2010, 2011 issue, p. 158

[72] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 187

It is worth noting that a CCS equipment reduces the efficiency of the power plant – by 7 percentage points on average[73] and generates higher O&M costs at the power plant level. The strong operational advantage of this technology is that it lowers carbon costs for the plant by almost 85% on the pilot and demonstration plants in Germany[74].

2.4 Fuel and Electricity prices

Overview of the historical volatility of market fuel prices

Commodities face a significant price volatility making it difficult for investors to forecast long-term price trends.

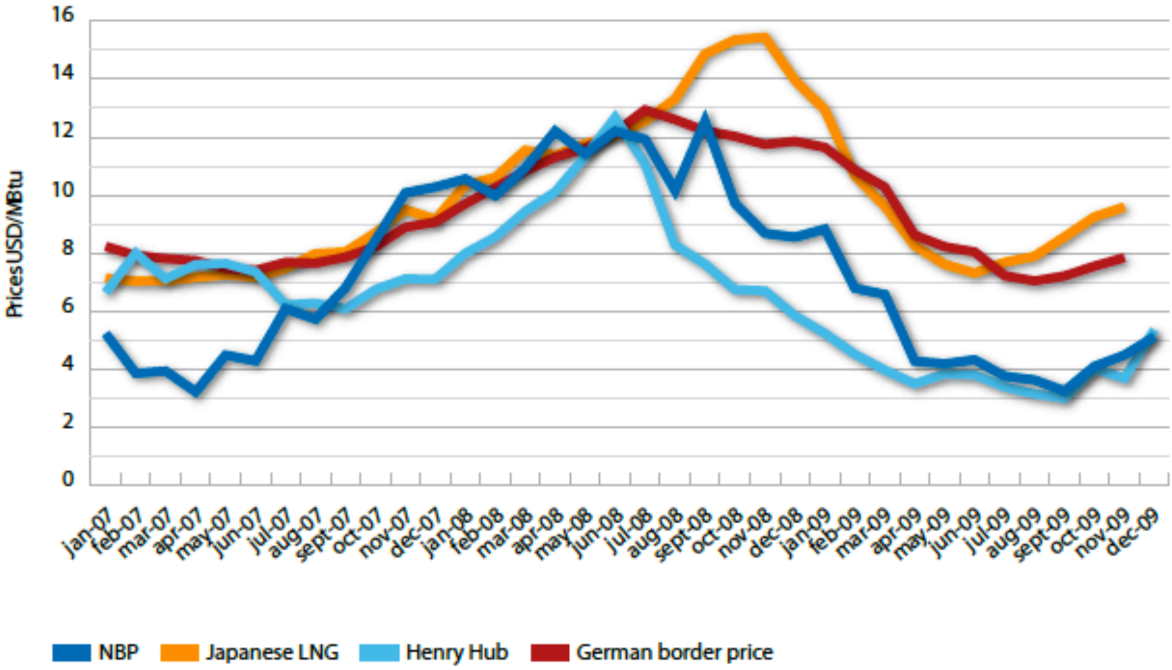
As shown with the previous quantitative analysis, depending on the type of power plants considered, the uncertainty can be more easily handled by the Private Equity funds. Hydro power plants do not face any fuel price volatility risks given that the fuel – water – is free, however, they are exposed to hydrological conditions (rains….) and therefore faces volume risk. Nuclear power plants are quite protected against fuel price volatility for two main reasons: first, as shown in the quantitative analysis, fuel costs account for only a small share of the EBITDA[75]; second, most nuclear power plants buy uranium and fuel cycle services under long-term contracts reducing the volatility in the costs[76]. On the other hand, as shown in the quantitative analysis, coal-fired power plants and gas-fired power plants are the most sensitive to fuel price variations.

[73] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 54

[74] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 60

[75] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 116

[76] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 124 & 129

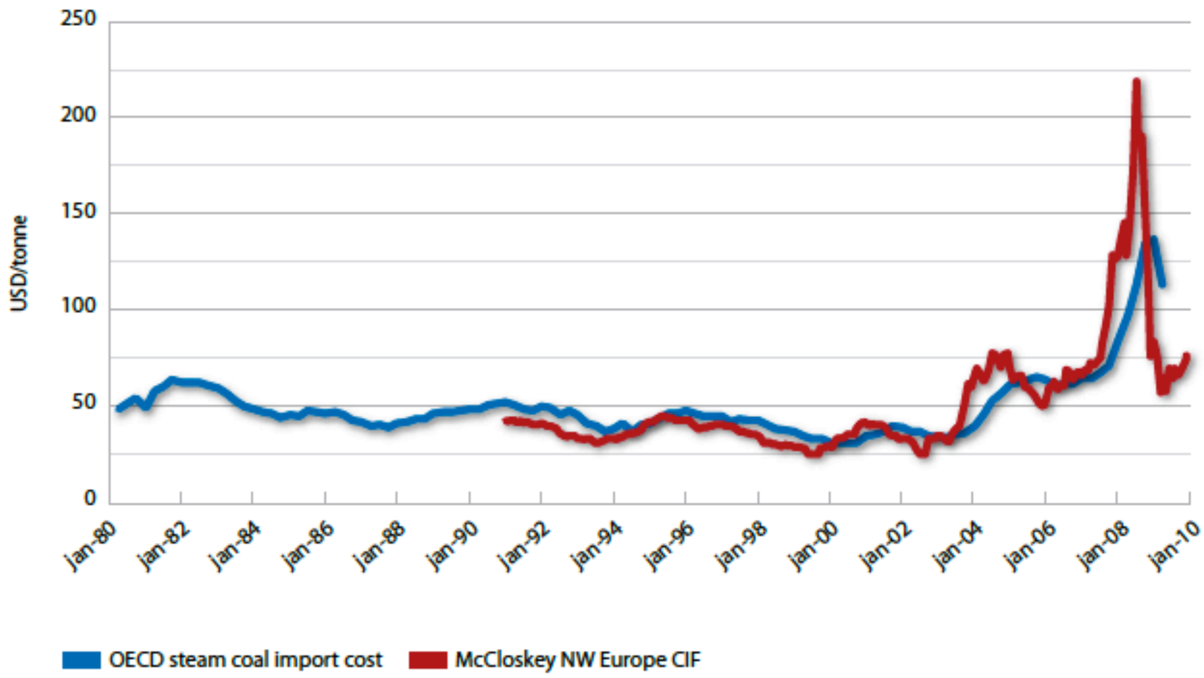


33) Historical monthly gas prices in key OECD regional gas markets[77]

After a drop in prices over the past two years triggered by an oversupply in gas - US shale gas, increasing LNG production, decreasing demand because of economic crisis -, the IEA expects demand to resume in the coming years releasing the pressure on gas prices which are expected to rise slightly above 10 $/MMBtu under the New Policies Scenario[78].

[77] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 127

[78] IEA, World Energy Outlook 2010, 2010 edition, p.71



34) Historical steam coal quarterly import costs and monthly spot prices[79]

The above illustration shows the average CIF costs of importing steam coal into OECD countries no distinction being made on the quality of coal as well as CIF costs for coal delivered to Antwerp-Rotterdam-Amsterdam ports - high quality coal. After a sharp increase in prices in 2007 – 2008 due to an increase in demand, industrials responded with higher investments putting downward pressure on prices[80]. In the World Energy Outlook 2010, the IEA forecasts demand for coal in OECD countries to gradually decrease and prices to stabilized around 100 $/tonne[81].

Overview of the historical volatility of electricity market prices

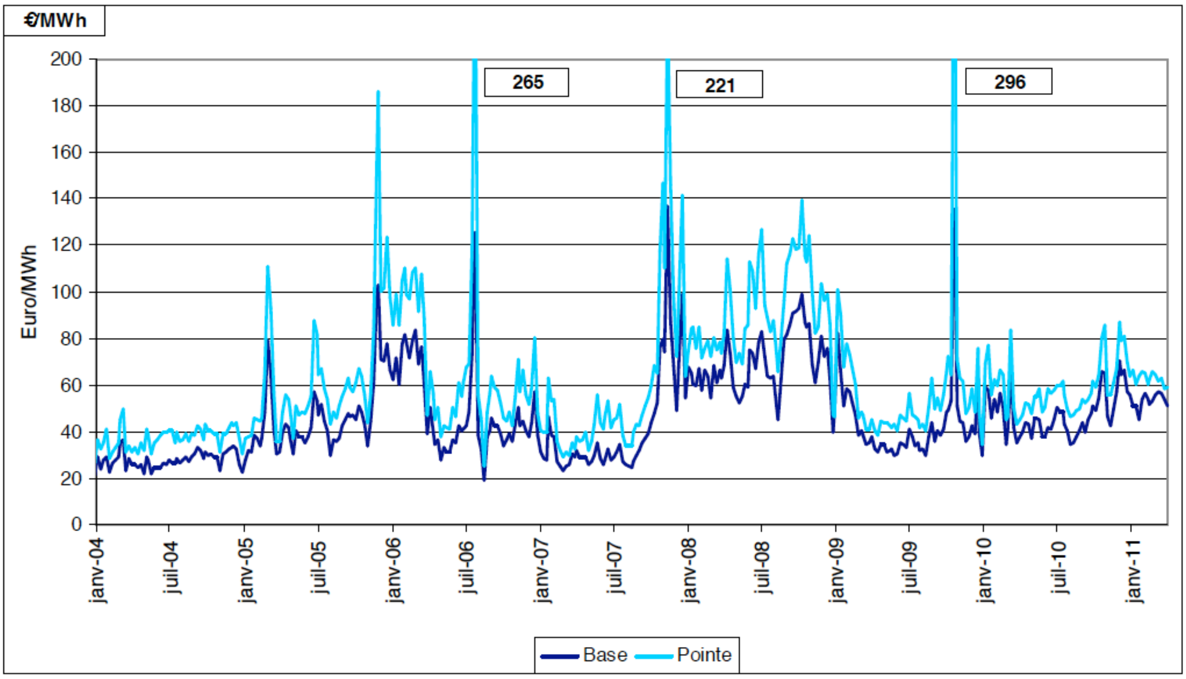
New actors in power generation are expected to either enter into a bilateral contract (OTC) or to sell its power on Exchanges at market prices. As shown in the charts below, wholesale electricity prices have historically been highly volatile and are expected to remain volatile in the future. This is obviously the main obstacle to a Private Equity investment in this sector, especially given the maximum maturity of

[79] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 128

[80] OECD, Projected Costs of Generating Electricity, 2010 edition, p. 129

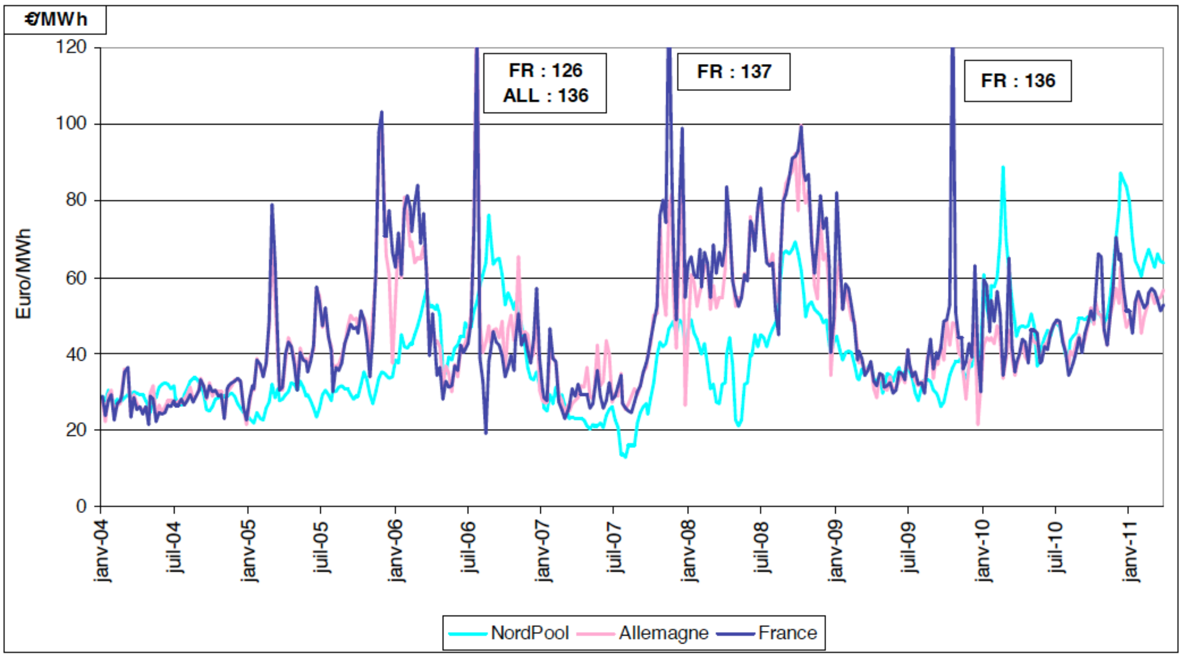
[81] IEA, World Energy Outlook 2010, 2010 edition, chapter 6

derivative products to hedge against this volatility of 3 to 5 years, which is highly insufficient in regard of a 7-year holding period for a Private Equity investment.

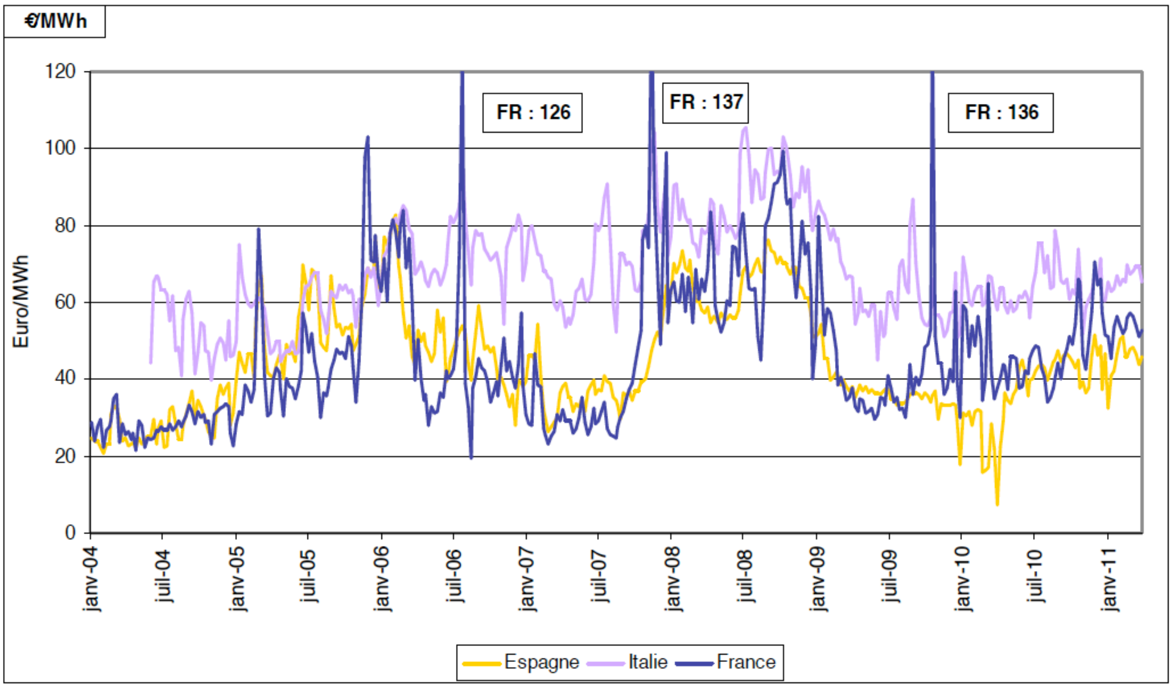


35) Historical day ahead prices on EPEX Spot – weekly average[82]

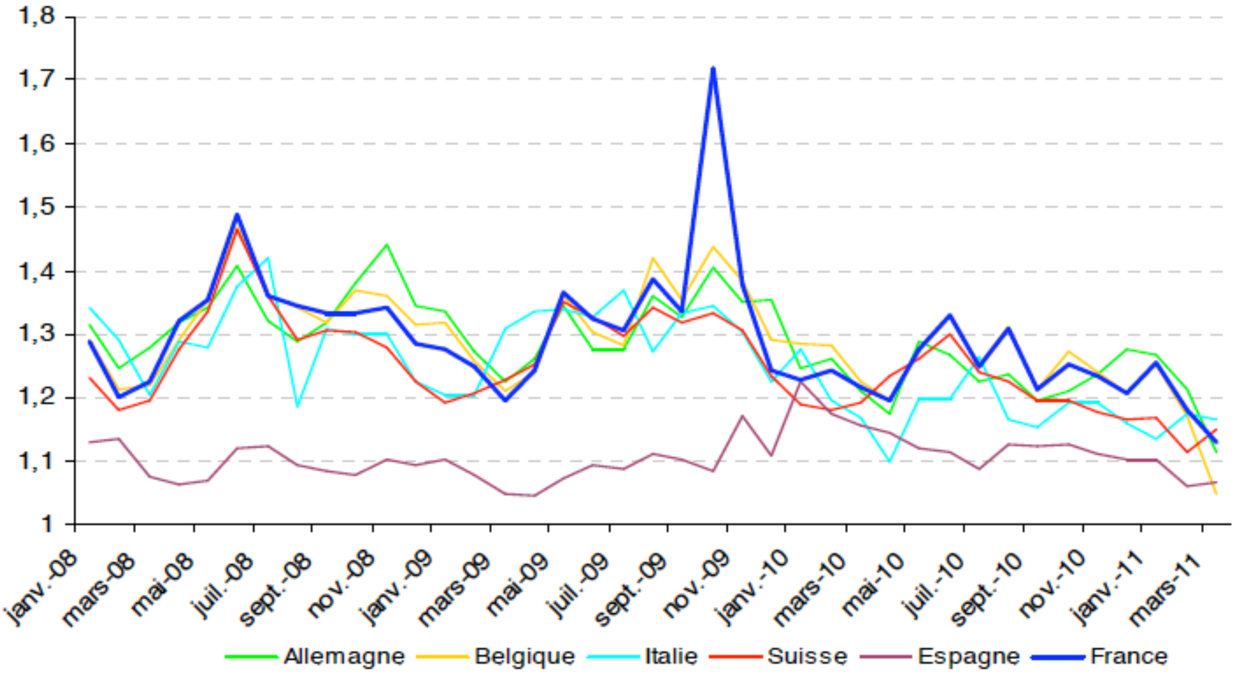
[82] CRE, Observatoire des marchés, Observatoire du 1er trimestre 2011, p. 27



36) Historical day ahead base prices on EPEX Spot & Noordpool Spot – weekly average[83]



37) Historical day ahead base prices on EPEX Spot & Ipex – Weekly average[84]

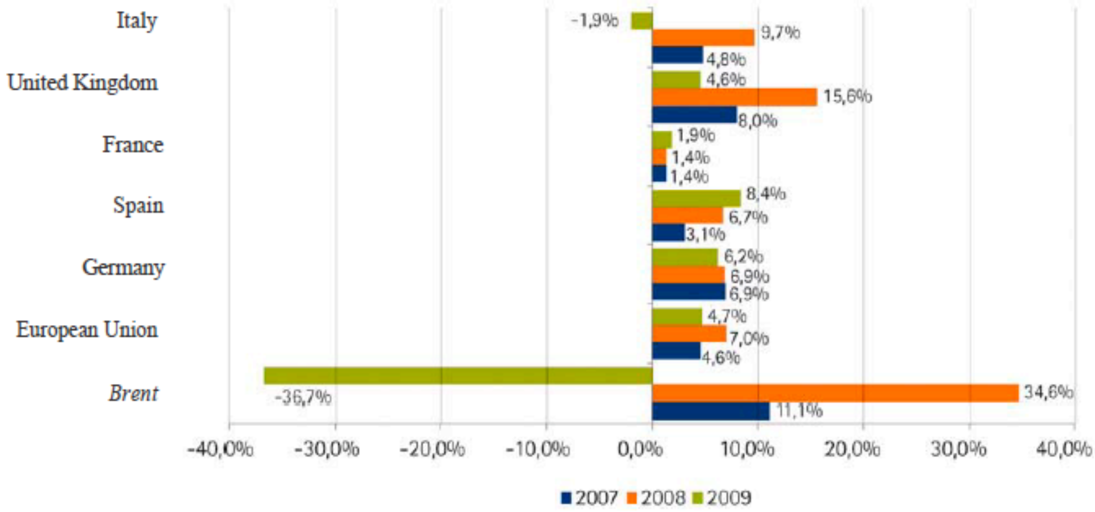


38) Historical base/peak ratio – Spot prices[85]

83 CRE, Observatoire des marchés, Observatoire du 1er trimestre 2011, p.28

84 CRE, Observatoire des marchés, Observatoire du 1er trimestre 2011, p.29

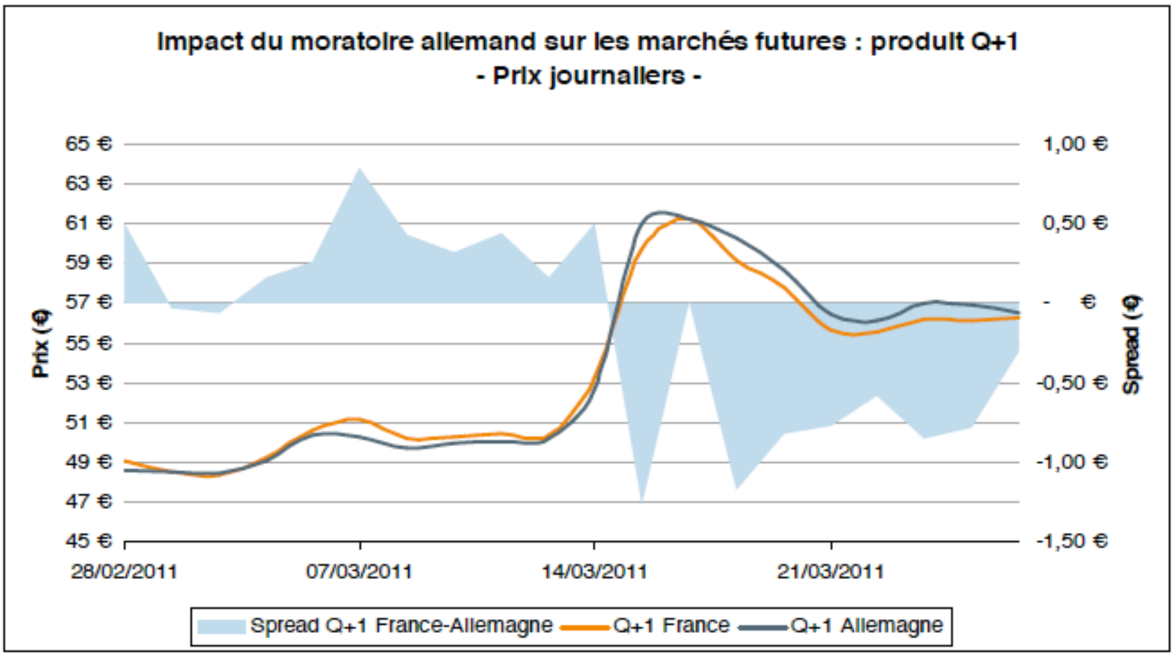
85 CRE, Observatoire des marchés, Observatoire du 1er trimestre 2011, p. 34



39) Changes in electricity price in main European countries (% changes on previous year)[86]

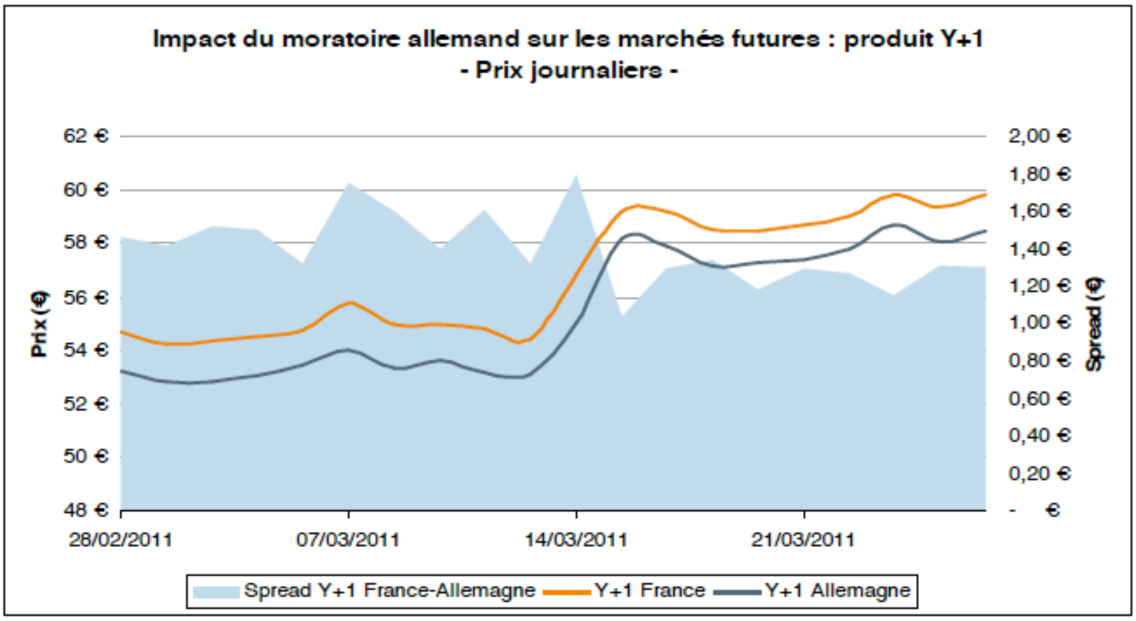
Another source of uncertainty regarding the evolution of wholesale electricity prices mostly in Germany and in France has arisen after the Fukushima incident and the German decision to immediately shut down 7 nuclear reactors and to progressively carry out a nuclear phase out. Immediately after the shutdown, day-ahead prices as well as derivative prices increased.

[86] AAEG, Structure, prices and quality in the electricity sector, 2010 edition, p. 50



40) Impact of the nuclear phase out in Germany on futures prices - Q+1 horizon[87]

[87] CRE, Observatoire des marchés, Observatoire du 1er trimestre 2011, p. 32



41) Impact of the nuclear phase out in Germany on futures prices - Y+1 horizon[88]

The long-term impact of this decision remains difficult to predict and increases the uncertainty surrounding investments in power generation, which ultimately is likely to alter the appetite of Private Equity funds for power generation assets.

2.5 Risk matrix

	NUCLEAR FRANCE	GAS ITALY	COAL W/ CCS GERMANY	HYDRO SWEDEN
MARKET STRUCTURE				
Liberalization	Yes	Yes	Yes	Yes
Liquidity of Power Exchanges	Medium	Medium	Strong	Strong
Interconnection with neighbouring countries	Good	Poor	Good	Good
Market coupling	Increasing	Poor	Good	Good
Concentration	High	High	High	High
Vertical integration	High	High	High	High
REGULATORY RISK	Medium	Medium	High	Low
TECHNOLOGY/OPERATING RISK	Medium	Low	High	Low
FUEL PRICE RISK	Low	High	High	NA
ELECTRICITY PRICE RISK	Medium	High	High	Medium

[88] CRE, Observatoire des marchés, Observatoire du 1er trimestre 2011, p. 33

CONCLUSION

Nowadays, Private Equity investments in conventional power generation in Western Europe are seldom. On the other hand, renewable power generation centralizes the bulk of Private Equity investments. The reason behind that is the difficulty for Private Equity funds to enter the conventional power market and to understand the fundamentals of this market.

First, current levels of electricity prices are most often than not below the breakeven prices that we have computed, especially for coal and gas-fired power plants. Moreover, once breakeven prices are reached, the inflation required to obtain a 20% IRR are often not realistic (more than 38% over 7 years). To reach a 15% IRR target, the observed necessary inflation is between 2% and 53% (over 7 years) depending on the technology as well as the market and operating conditions. Therefore, it is critical for a Private Equity investor to have clear views on future market evolutions before investing in a power plant.

Second, the fundamentals of this market are very difficult to comprehend. Unlike renewable investments that benefit from feed-in tariffs making it less crucial to fully grasp the specificities of such a market, the above analysis shows that investing in the conventional power sector requires a deep understanding of the underlying of demand and competition.

Third, although Western European power markets are liberalised, the entrance of new actors remains difficult because of the high degree of concentration and vertical integration.

All in all, "[…] investment in utility assets and operations should not be undertaken without a team of experts experienced in power markets, generation plant engineering and design, environmental issues that range from environmental permitting to global warming, legislative relations and customer expectations."[89]

These dynamics are unlikely to change in the near future. Maybe some funds will invest on a case-by-case basis in portfolios of generation assets rather than in single assets but the bulk of investment opportunities are more likely to be in transmission assets rather than in generation. Indeed, utilities are increasingly divesting because of the regulation and in order to free some part of their balance sheet. Recent examples illustrate this trend: in Italy, for instance, GDF Suez is expected to sale its Italian gas network to the Italian Infrastructure fund F2i and AXA Infrastructure (75% - 25% ownership) for up to 800 million euros. The consortium F2i and AXA Infrastructure has already bought similar assets from E.ON and Enel also in Italy[90].

[89] Nixon Peabody Private Equity Newsletter, Private Equity investment surges into the utility industry, Spring 2007 issue, p. 8

[90] Reuters Africa, Update 2 – GDF Suez selling Italian gas grid in $ 1.1 bln deal, June 2011

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VC Experts. Availbale at <http://vcexperts.com>

ERMES Site HEC - 620_1111_1027 As

Groupe HEC
78351 Jouy-en-Josas Cedex
Tél : 01 39 67 70 23
Fax : 01 39 67 73 44
feiguel@hec.fr
http://www.hec.fr/club-finance

HEC PARIS

une école de la Chambre de commerce et d'industrie de Paris