Technology Choices for New Entrants in Liberalised Markets:

The Value of Operating Flexibility and Contractual Arrangements

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Technology Choices for New Entrants in Liberalised Markets: The Value of Operating Flexibility and Contractual Arrangements[1]

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Abstract

New entrants in liberalised electricity markets which are not vertically integrated and do not operate a large and diversified portfolio of generation technologies are likely to favour technologies which offer the best prospects to manage fuel and electricity price risks through contractual arrangements and operating flexibility. Monte Carlo simulations of a discounted cash flow model of investment in combined cycle gas turbine (CCGT), coal and nuclear power plant are run to compare the impact of fuel and electricity price risks on these different technologies, as well as the value of operating flexibility and contractual hedges. In the absence of long-term fixed-price power purchase contracts, CCGT is the least risky option as its cash flow is “self-hedged” given the high correlation between electricity and gas prices observed in most markets. Moreover, the value associated with operating flexibility and arbitrage between gas and power market is greater for CCGT plant. This makes CCGT particularly attractive to new entrants.

Keywords: fuel and electricity price risks, Monte-Carlo simulation, operating flexibility

JEL-Classification: C15, D81, L94

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[3] The views in this article are those of the author alone and do not necessarily represent the views of the IEA or of its various member countries.

1 INTRODUCTION

The liberalization of energy markets has created a new business environment which exposes power investors to greater risks than under the pre-liberalization regulatory regime. While many of the risks facing power investors in liberalized electricity markets existed in the regulated industry, the ability to pass through the approval costs to consumers is no longer automatic. The most fundamental change affecting the value of investments is the uncertainty about electricity prices, and its interaction with fossil fuel price risk - and CO_2 emission permits in Europe.[4] Such market risks affect technologies differently, and their impact on new investment choices will depend on the ability of investors to manage or shift part of these risks onto other stakeholders. This in turn depends on the institutional and contractual arrangements underpinning investment projects. Large incumbent generation companies with a diversified portfolio of technologies, and/or vertically integrated can be thought as having an advantage in this respect with regard to new entrants using project or merchant financing (Roques et al., 2006c).

The focus of this paper is on new entrants in liberalized electricity markets, which are not significantly vertically integrated, and do not operate a large and diversified portfolio of generation technologies. How do the different technologies risk and return profiles compare with regard to market risks, and to what extent can these risks be shifted away from the investor through long-term fuel and power contracts? How can the operational flexibility associated with some contracting arrangements and some technologies help new entrants manage fuel and electricity price risks? How large is the 'arbitrage' value associated with flexible plant operation and flexible fuel input and electricity output contracting arrangements?

Over the past two decades, liberalized electricity industries have seen the rise of combined cycle gas turbine (CCGT) as the favourite technology for new entrants (Watson, 1997 and 2004). The increase in gas-fired generation efficiency and changes in natural gas markets during the 1990s (prices decreases and withdrawal of some restrictions) participated in the success of CCGT plant (Colpier and Cornland, 2002, Islas, 1999). Despite the increase of gas prices over the past years, CCGT remain the favourite technology for new entrants in European and North American markets, contrasting with traditional levelised cost studies showing coal and nuclear as more competitive in many regions (IEA, 2006 and IEA/NEA, 2005).[5] Some distinctive economics and financial features of CCGT plant are critical advantages for new entrants in liberalized markets.[6] CCGT plant has low capital cost, a short construction time and are modular.

The paper explores other less well-known attributes of CCGT investment in liberalized markets in comparison to coal and nuclear plants. The paper investigates how operating flexibility and contracts allocating fuel and electricity price risks affect the competitiveness of different generation technologies. The operating flexibility offered by CCGT plant – particularly arbitrage opportunities between gas and electricity markets – has a value which is not captured by traditional valuation methods and contributes to new entrants' preference for CCGT plant. The paper develops a probabilistic discounted cash flow investment model with operating flexibility to capture the impact

[4] This paper concentrates on market risks (fuel price and electricity price risks). Investment in power generation comprises a large and diverse set of risks, as detailed in IEA/NEA (2005).

[5] In the European Union at the beginning of 2007, 58% of the 40 GW of power plants under construction and 50% of the 169 GW of planned power generation projects were CCGT plants.

[6] In the USA between 1990 and 1998, Independent Power Producers (IPP) have accounted for 49% of the total investments in gas and dual-fuel power plants, while only 11% of these investments were made by the incumbent utilities (Glachant, 2005).

of different degrees of exposure to fossil fuel and electricity price risks on different generation technologies. The results contrast with traditional levelized cost approaches and show that in the absence of long-term contracts, the high degree of correlation between gas and electricity prices in most markets makes CCGT "self-hedged" and appear paradoxically as the least risky option for investors, particularly new entrants. Besides, the value of operating flexibility is greater for CCGT plant than for coal or nuclear plant, all of which makes CCGT particularly attractive to new entrants.

The rest of this paper is organized as follows. Section 2 discusses the different kinds of contracts available to power plant investors to shift part of market risks onto plant operators, suppliers, or consumers. It also details the different opportunities for arbitrage between electricity and gas markets made possible by the technical operating flexibility of CCGT plant and some flexible gas supply agreements. We then introduce a probabilistic discounted cash flow model of CCGT, coal and nuclear plants with fossil fuel and electricity price risks and operating flexibility calibrated on empirical data from the UK markets. Section three uses Monte Carlo simulation to analyse the three technologies investment risk and return depending on the contracting arrangements shifting some of the fuel and electricity price risks away from the plant investor. It also computes the value of CCGT plant operating flexibility depending on the degree of correlation between fuel and electricity prices.

2 ELECTRICITY AND FUEL PRICE RISKS MANAGEMENT THROUGH CONTRACTS AND OPERATING FLEXIBILITY

2.1 Contracts to allocate electricity and fuel price risks

In liberalized electricity markets, electricity producers sell their production through a combination of long-term contracts and spot market sales in various proportions depending on the production technology and the electricity company strategy. Electricity can be bought and sold either (1) on the spot market, (2) through contracts that are indexed to the price of the fuel input, (3) through tolling agreements (whereby the power purchaser delivers fuel to the generator and takes delivery of the resulting power that is produced, having effectively ‘‘rented’’ the use of the generation plant), or (4) through fixed-price contracts (Bolinger et al., 2006). Power purchase agreements play a central role in allocating risks among parties in the electricity industry (Wiser et al., 2004). The extent of risk that the plant investor, the plant operator (if different from the plant owner), and electricity suppliers bear depends in large part on how risks are allocated in these contracts. The allocation of risks, in turn, influences electricity investment decisions, and thereby has a significant impact on what types of power plants are built and the overall portfolio of electricity supply.

As described in Wiser et al. (2004), fixed-price electricity contracts establish a fixed and known price per MWh of delivered electricity. Such contracts clearly allocate fuel price risk to the generator (i.e. the ‘‘Seller’’) because the generator is responsible for selling electricity at fixed prices, while simultaneously dealing with an inherently variable fuel price stream. Indexed-price contracts generally index the price of electricity to either inflation or to the cost of another commodity, for example, the cost of the fuel used to generate the electricity. When electricity contracts are indexed to the price of the natural gas used to generate the electricity, the fuel price risk is allocated to the Buyer because the Buyer receives a variable-priced product. Tolling contracts provide the Buyer a service: the right to use the Seller's power plant to convert natural gas to electricity. The Seller is paid not only for the use of its facility, but also for simply being available to generate. The Buyer pays for the natural gas used to generate the electricity. The risk of fuel price variability is therefore clearly allocated to the Buyer in tolling contracts.

A power plant investor exposure to fuel price risk depends essentially on four factors: (1) the sensitivity of generation costs to fossil fuel price risk, (2) the variability of the fuel's price, (3) the allocation of fuel price risk between the power plant investor and other parties through long-term contracts, and (4) the ability of the investor to mitigate the risk to which it is exposed. While gas costs can contribute to up to 70-80% of a CCGT production costs, coal costs represent between 25 and 35% of the plant generating costs, and nuclear fuel costs have a small impact (less than 10%) on a nuclear plant generating costs. The IEA (2006) estimates that a 50% increase in uranium, gas and coal prices would increase nuclear generating costs by about 3%, coal generating costs by 21% and CCGT generating costs by 38%. There is little empirical data publicly available on the terms and conditions of power purchase agreements, and in particular the way in which fossil fuel price risk is allocated. Natural gas-fired generation is commonly sold through all four of the contract types described above, with gas price risk falling on the power purchaser in the first three, and the generator in the final type (Wiser et al., 2004).[7] Bolinger et al. (2006) point out that renewable generation, on the other hand, is typically sold through long-term fixed-price contracts (perhaps indexed to inflation).[8]

2.2 Interruptible contracts, operational flexibility, and arbitrage between electricity and gas markets

Operational flexibility is valuable in liberalized power markets, particularly for gas plant which can profitably arbitrage between electricity and gas markets. The degree of flexibility that a plant operator will have depends on factors intrinsic to the technology, as well as on the terms and conditions of the fuel supply contract. Designing contracts with flexibility, i.e. with specific provision or options that allow one or both parties to respond appropriately as conditions change can save renegotiation time and be more economically efficient for both parties to allocate risks (Borison and Hamm, 2005). A plant owner-operator might be willing to pay higher prices for nuclear megawatts if methods for mitigating price, cost, and capacity risk through contracts or real assets could be found. For example, Rothwell (2006) estimates that for a new nuclear plant in Texas the owner-operator might be willing to offer long-term contracts at a risk premium of $0.86 for fixed-price, but "interruptible," power. On the other hand, the owner-operator could offer a fixed-price, "firm" power contract for a premium of $2.96/MWh.

Gas-fired power stations operational patterns can be expected to respond to market price signals, decreasing gas consumption when the cost of generating from other fuels is lower than the price of burning gas. The willingness of the CCGTs to commercially interrupt themselves will be determined by a number of factors, including: the spark spread, which is itself influenced by the ability of the power generation sector to meet demand through switching to other fuels; the price of CO_2 emission allowances; the price of alternative fuels; and any environmental constraints (e.g. SO_2) that limit the extent of running on other fossil fuels. There is a large body of literature focusing on optimal dispatch for a portfolio of plants (see e.g. Kahn and Stoft, 1993, Connors et al. 2004). On a longer time scale, power generators can 'mothball' a plant temporarily if the power and fuel price projections make it uneconomic to use, and 'de-mothball' it later on if it is profitable.

[7] Wiser et al. (2004) analyze a contract sample 27 long-term (3 years and longer) electricity procurement contracts signed by the California Department of Water Resources (DWR) in 2001 on behalf of the customers of California's three investor-owned utilities. They find that 41% of the electricity is supplied in ''tolling'' agreements, most of which give the DWR some flexibility to dispatch the facility. Fifty-nine percent of the electricity is supplied at fixed prices; these contracts are mostly non-dispatchable.

[8] Going further, Johnston et al. (2007) discuss the theoretical benefits of take-or-pay contracts to facilitate the deployment of renewables.

Arbitrage between gas and electricity markets is of particular relevance to gas-fired power plants which are operated via tolling agreements or have flexible gas procurement contracts: operators can decide not to produce electricity and sell back the gas on the spot market if gas prices are too high relatively to electricity prices to make it uneconomic to produce.[9] Many gas fired power plants have contracted natural gas supplied on interruptible contracts. Asche et al. (2002) analyze long-term take-or-pay contracts regulating gas exports to continental Europe and show that Dutch gas contracts usually have the highest volume flexibility; Norway has a fair swing component, whereas the Russians deliver the base load with a limited amount of swing.[10]

The progressive liberalization of the gas market in Europe should improve the integration of gas and electricity markets, and make such arbitrage strategies for power producers easier, as gas supplies are increasingly secured through flexible short-term "non-take or pay" contracts (Stern 1998, Chevalier, 2000).[11] Neuhoff and von Hirschhausen (2005) analyze the changing patterns of long-term gas procurement contracts associated with the gas sector liberalization, including the evolution of the "flexibility clause" which used to be an integral part of long-term contracts in Europe, and the "destination clause" which remains an obstacle for competition in the European gas markets.[12] Similarly, changes in regulation of US natural gas pipelines could provide power generators with more flexibility and services and facilitate arbitrage between electricity and gas markets (Costello, 2006).[13]

Some gas-fired power plants may also have the technical possibility to switch to distillate fuel. CCGT plant can be engineered to operate as a dual fuel plant by installing back-up fuels burning equipment supplied from alternative fuels such as liquefied petroleum gas or distillate fuel oil, requiring delivery and storage infrastructure (Söderholm, 2001). In the UK, a significant response from the electricity generating industry was observed over winter 2005-06 when gas supplies to the UK were tight (NGT, 2006).[14] However, the theoretical scope for fuel-switching behavior and gas/power arbitrage might fail to be realized in practice, for a number of reasons. These include environmental constraints on substituting gas, the costs of maintaining back-up inventories and fuel-switching equipment and of actually changing operations from base-running to alternatives and back, the often short duration of windows for profitable switching, and the conservatism of operational engineers.[15]

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[9] The ability to arbitrage between gas and power is, however, not restricted to those power stations that have interruptible gas transportation arrangements. For example, in the UK during the 2005/06 winter, there were occasions when firm CCGTs commercially self-interrupted whilst interruptible power stations continued to generate (DTI, 2006).

[10] Asche et al. (2002) conclude that the most plausible explanation to the difference in the basis price for contracts from Russia, Norway, and the Netherlands is that longer distances make it more expensive to offer value-generating volume flexibility (swing services) for the Russians and to some extent the Norwegians, since this would require excess capacity in the pipelines.

[11] The basic idea of 'take or pay' provisions is that the buyer is obliged to pay the contract quantity of gas even if he fails to take delivery in order to guarantee a cash flow for the seller.

[12] Most long-term contracts between gas-exporters and European gas utilities bar buyers from reselling the gas to third parties other than final private and industrial consumers within their territory. They argue that the destination clause allows gas producers to profitably price discriminate and impacts competitiveness not only through prices, but also in that it reduces liquidity in the European gas market.

[13] See also Hubbard and Weiner (1986) about the experience of the US natural gas industry with contracting and regulation between producers and pipelines during the 1980s, and take-or-pay provisions.

[14] For the winter 2007/2008, CCGTs are expected to provide a maximum of 24.9 GW of generating capacity in the UK, of which 4.8 GW have the capability to run on distillate (NGT, 2006).

[15] NGT (2006) identifies a number of practical issues that could limit the extent of any CCGT response:

- Technical risks associated with frequent switching to/from and prolonged use of distillate;
- Potential limits on the extent to which fuel stocks can be replenished;
- Limitations on the levels of switching to coal and oil as a result of environmental constraints;

2.3 Capturing operating flexibility and contracting arrangements in power plants valuation

Flexibility in plant operation can be of great value to investors in liberalized markets with high fuel and power prices volatility, and is an important parameter to consider when comparing different technologies. The traditional levelized cost valuation approach was well adapted to assess power investments prior to liberalization, and remains widely used in the liberalized industry, both by energy planners and by electric companies (IEA/NEA, 2005, Roques et al., 2006d). However, it is difficult for the levelized cost methodology to incorporate risks and uncertainty effectively. IEA/NEA (2005) reckons for instance that "[the levelized cost] methodology for calculating generation costs does not take business risks in competitive markets adequately into account" and that "it needs to be complemented by approaches that account for risks in future costs and revenues".

Spinney and Watkins (1996) provide a thorough description of methods of examining risk for utilities investments, including sensitivity analysis, decision analysis, and Monte Carlo simulation. The most comprehensive approach to take into account a wide range of uncertainties in key risks is to use a probabilistic assessment using Monte Carlo simulation (Rode et al., 2001, Feretic and Tomsic, 2005, Roques, 2006b).[16] Monte Carlo simulation computes outcomes as functions of multiple uncertain inputs, each expressed as a probability distribution. Such distributions can take various different functional forms, which provide a much richer description of possible outcomes for an input variable than the small number of discrete, point probabilities used in decision analysis.[17] The resulting NPV distribution provides investors with a much richer analytical framework to assess power investments in liberalized markets.

Another issue with traditional discounted cash flow models based on levelized cost or on the standard NPV criterion is that they do not incorporate the value of managerial flexibility and operating flexibility. New valuation techniques borrowed from the financial engineering literature, including dynamic optimization and Real Options, can capture the value of managerial flexibility. Uncertainties over fuel and electricity prices create an opportunity cost of investing today rather than waiting to get more information on these uncertain parameters. If for instance natural gas prices escalate more rapidly than expected, then the project can be deferred or a different technology chosen. These option values are likely to have an important impact on the choice of generation technology in a competitive wholesale market (Chaton and Doucet, 2003, Gollier et al., 2005, and Roques et al., 2006a).

Dynamic investment valuation models can also provide some insight into what actions and design features could improve the competitive position of a certain technology. Flexibility in plant operation is valuable in liberalized markets and is not captured by traditional valuation approaches. The next sub-section presents a discounted cash flow model in which operating flexibility is dynamically

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- Potential limitations on the ability to replenish stock in prolonged severe weather conditions, in particular if stocks are delivered by road tankers;
- Possible impacts on behavior of potential exposure to high imbalance costs if plant fails to generate.

[16] Monte Carlo simulation (MCS), however, is not without its own potential pitfalls. See Spinney and Watkins (1996), Roques (2006b), and Roques et al. (2006d) for a discussion of the main issues associated with Monte Carlo simulation.

[17] Monte Carlo simulation entails typically the following steps (Spinney and Watkins, 1996):

- Identification of key uncertain model input variables;
- Statistical description of the risk for these key inputs by assignment of probability distributions;
- Identification and statistical description of any relationships (covariance) among key inputs;
- Multiple iteration;
- Description of key model outputs by probability distributions.

modelled (i.e. plant operators choose to operate or shut down temporarily the plant, depending on relative fuel and power prices). Monte Carlo simulation are used to compute the impact of electricity and fuel price risks in three illustrative case studies corresponding to different fuel and electricity price risks allocations between plant operators and the other stakeholders.

2.4 A probabilistic valuation model with risky fuel and electricity prices and operating flexibility

We concentrate on three technologies (scrubbed coal, CCGT, and "generation three" nuclear) that are likely to be the main base-load alternatives on the post-2010 time horizon.[18] Table 1 summarizes the model 'base case' cost and revenue assumptions, based on (IEA/NEA, 2005) and (IEA, 2006). The model provides a simple yet fairly realistic description of the specificities associated with an investment in the three different technologies. The construction time is five years in the case of nuclear, four years in the case of coal, while it is only two years in the case of the CCGT plant. Nuclear plant incurs a "nuclear waste fee" to cover the cost of decommissioning and nuclear waste treatment. When operating flexibility is not taken into account, the three plants are assumed to operate base-load with an average annual capacity utilization factor of 85% (the capacity factor is endogenously determined in the case with operating flexibility).

Table 1 - Base case parameters

Parameters	Unit	Nuclear	Coal	CCGT
Technical parameters				
Net capacity	MW	1000	1000	1000
Capacity factor	%	85%	85%	85%
Heat rate	BTU/KWh	10400	8600	7000
Carbon intensity	kg-C/mmBTU	0	25.8	14.5
Construction period	years	5	4	2
Plant life	years	40	40	25
Cost parameters				
Overnight cost	€/kW	2000	1120	520
Incremental capital costs	€/kW/yr	16	9.6	4.8
Fuel costs	€/mmBTU	0.4	2	5.8
Real fuel escalation	%	0.5%	0.5%	0.5%
Nuclear waste fee	Mill€/kWh	1	0	0
Fixed O&M	€/kW/year	52	40	20
O&M real escalation rate	%		0.5%	
Financing parameters				
WACC	%		10% / 8%	
Government actions				
Carbon tax	€/tCO_2		10	
Carbon price escalation	%		1%	
Revenues				
Electricity price	€cents/kWh		5.5	
Electricity escalation rate	%		0.5%	

[18] Our focus on base-load generation technologies justifies the exclusion of many renewable technologies. Besides, this 2010 time horizon requires current mature technologies, which excludes many technologies (pulverized coal, small-scale modular "generation IV" nuclear, advanced renewables) that present promising technology prospects, but that are yet too immature to be considered ready by 2010.

A 10% real weighted average cost of capital is used, corresponding to the cost of capital for a commercial investment in the liberalized industry.[19] Plant technical life-times are assumed at respectively 40 years for nuclear and coal plants and 25 years for CCGT plants.[20] Gas and coal price assumptions are based on (IEA, 2006), with long–term real annual fuel cost escalation rate of 0.5% for the three fuels. The nuclear fuel cost includes used-fuel disposal, based on an open fuel cycle.[21] The cost of carbon emission permits within the European Trading Scheme cost is assumed to be 10€/tCO_2. The electricity price is based on an average of future base load electricity price contracts for 2009 in Europe as of early 2007 with a 0.5% annual cost escalation rate.

For a discount rate of 10%, the coal plant has a much higher NPV (€342 /kW) than the nuclear and CCGT plant (respectively €74/kW and €-48/kW). With an 8% discount rate, all technologies have positive NPVs, the nuclear plant NPV increasing relatively more than other technologies as nuclear is the most capital intensive technology. These results are consistent with recent levelized costs studies (IEA/NEA, 2005, IEA, 2006): the increase of natural gas prices has made coal-fired plant – and to a lesser extent nuclear plant – relatively more competitive in the US and Europe than gas plant on a static levelized cost basis (IEA, 2006).[22]

The characterization of fuel and electricity price risks is simple as the focus is here on price risk in the medium- to long-term (monthly to yearly). [23]The model concentrates on lifelong discounted cash flows, and monthly fossil fuel, electricity, and CO_2 emission permit price risks are modeled by random variables with a normal probability distribution whose parameters are described in Table 2. The most likely values correspond to the base case detailed in the previous section, while the standard deviation estimate is based on empirical data on 5 years of UK NBP term ahead forward gas prices, coal ARA term ahead forward prices, and term ahead UK base load future electricity prices.

Correlations between fuel, electricity and CO_2 prices are critical to assess the combined impact of such risks on the different technologies risk and return profiles. As in IEA (2007), a correlation of 0.5 between electricity and gas prices, as well as between electricity and coal prices is used as base case working assumption. CO_2 certificates prices are also assumed to be 0.5 correlated with electricity and coal and gas prices in this "base case" simulation. The last section of this paper provides a detailed sensitivity analysis to the degree of correlation between fuel, electricity, and carbon prices.

Table 2 – Random variables normal distributions characteristics

Variable	Technology	Unit	Expected value	Standard deviation
Nuclear fuel price	Nuclear	€/Mbtu	0.4	0.15
Coal price	Coal	€/Mbtu	2	1.0
Gas price	CCGT	€/Mbtu	5.8	2.9
Carbon Price	All	€/tonneCO_2	10	4.6
Electricity price	All	€cents/KWh	5.5	1.8

[19] For a discussion of discount rates to be used in power generation investment valuations, see e.g. Awerbuch (1993 and 1995), Roques et al. (2006d), and IEA (2006).
[20] For generating cost models with a more detailed treatment of the financing issues, see e.g. Girard et al. (2004) and Deutch et al. (2003) who explore the impact of merchant project financing approaches in which the debt repayment period is shorter than the physical life of the plant.
[21] For a detailed assessment of the costs of the nuclear fuel cycle, see NEA (2002).
[22] Note that the advantage for coal generation is less pronounced in Europe than in the United States, because European coal prices are higher and gas prices somewhat lower.
[23] Commodity prices in the short-term are usually modelled using complex stochastic processes to capture the impact of seasonality, daily demand variability and other operational risks (Geman, 2005).

3 VALUING OPERATING FLEXIBILITY AND CONTRACTUAL RISK TRANSFERS

Electricity and fuel price risks are often allocated to other parties than the plant investor through long-term contracts. While there are various theoretical possible combinations of fuel and power contracts, the next sections will investigate three polar case studies:[24]

- In the first case study, fuels used to run the plant are purchased on spot markets, and the plant owner (or operator) bears all of the fuel price risks. The plant electricity output is sold at a fixed price through a long-term contract thereby shifting the electricity price risk away from the plant investor onto electricity suppliers or consumers.
- In the second case study, fuels are purchased through long-term fixed-price contracts, thereby shifting the fuel price risk away from the plant investor onto the fuel suppliers. The plant electricity output is sold on spot markets, such that the plant investor bears all of the electricity price risk.
- In the third case study, both the fuels used to run the plants and the electricity produced are bought and sold from spot markets. The plant investor therefore bears both fossil fuel and electricity price risks.

For each of these three case studies, two different hypotheses on the nature of the fixed-price long-term contracts will be considered. By default, it will be assumed that the long-term contracts are binding, i.e. that electricity power purchase agreements require the plant to be run (“must run contracts” for electricity, or gas contracts with a “non-resell” clause) even if it is uneconomic to do so. In the variant, it will be assumed that the contracts have some kind of flexibility clauses such that the plant owner (or operator) has the possibility not to run the plant if it is more economical to resell the fuel on the spot market. This later case will be referred to as the case with operating flexibility.

The managerial flexibility to operate or not a power plant can be interpreted as an option “built in” the investment project, which cannot be captured by standard valuation approaches. We model the managerial flexibility through a decision rule which switches plants off whenever the expected costs of production exceed the expected electricity sales revenues in the discounted cash flow Monte-Carlo simulation model. For simplicity, we assume that the revenues from selling the non-consumed fuel on spot markets compensate for the additional costs associated with stopping and restarting the plant (e.g. increased O&M expenditures related to faster materials fatigue) and the fixed costs of plant when it does not produce. This assumption is quite conservative and implies that we are estimating a lower bound of the value associated with operating flexibility. Each case study presents the NPV probability distribution of the three technology alternatives resulting from 100,000 simulations in the 10% discount rate case with and without operating flexibility.

[24] Note that the case in which both fossil fuel and electricity are bought and sold through long-term fixed-price contracts corresponds to the deterministic valuation presented in the previous section.

3.1 Case study 1: Electricity price fixed through a long-term contract – fossil fuel bought on spot markets

In this case study, fuels are purchased on spot markets, and the plant owner bears all of the fuel price risk. The plant electricity output is sold at a fixed price through a long-term contract, thereby shifting the electricity price risk away from the plant investor onto electricity suppliers or consumers. As discussed in section 2, a power plant investor exposure to fuel price risk depends both on the sensitivity of generation costs to fossil fuel price risk and the variability of the fuel's price. Figure 1 shows the NPV probability distribution resulting from 100,000 simulations of the 3 technologies NPV. The spread of the three technologies NPV distributions is very different (Table 3), reflecting the larger sensitivity of the CCGT NPV – and to a lesser extent coal plant NPV – to gas and coal prices (standard deviation of respectively 1211 and 556 €/kW). In contrast, the narrow distribution of the nuclear plant NPV (standard deviation of 84 €/kW) illustrates the relatively small impact of nuclear fuel cost on the overall profitability of a nuclear plant investment.

The impact of operating flexibility, which would enable plant to stop producing electricity (i.e. contracts which have a dispatch clause, contrary to "must run" contracts which contain a large penalty clause in case the plant does not generate the quantity contracted) is of relatively small magnitude and mostly valuable for gas plant. The low value of operating flexibility for nuclear and coal plant can be explained by the relatively low impact of fossil fuel price uncertainty on plant profitability for these technologies. In contrast, the operating flexibility of CCGT plant makes arbitrage profitable in case of high gas prices, by reselling the contracted gas on spot market and stopping production of electricity. Arbitrage possibilities between gas and electricity markets reduce the potential losses of gas plant, as the 5% percentile of the CCGT NPV probability distribution is reduced from -2044 to -474 €/kW (by 77%). Operating flexibility reduces the CCGT NPV distribution standard deviation from 1211 to 847 €/kW (by 30%) – which remains however significantly higher than the NPV distribution standard deviation of coal and nuclear plant. To sum up, operating flexibility is of relatively low value and does not change radically the relative risk and return profiles of the three technologies when considering only fuel price risk (i.e. with electricity prices fixed through long-term contracts).

Figure 1 – Case study 1: NPV distributions with fuel price risk (€/kW, in 10^{-4} for 100,000 simulations)

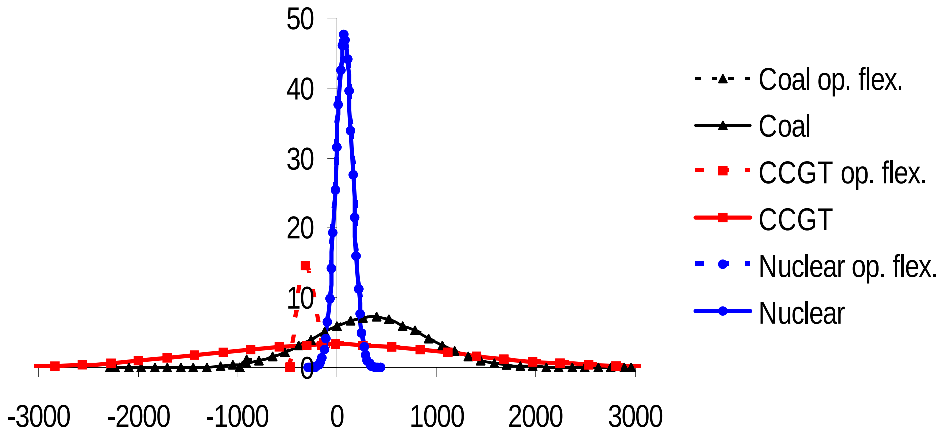


Table 3 - Case study 1: NPV distributions with fuel price risk (€/kW)

NPV (€/kW)	Minimum	Mean	Maximum	Std. deviation	5% percentile	95% percentile
CCGT	-5526	-48	5780	1211	-2044	1943
CCGT op. flex.	-474	252	5780	847	-474	1943
Coal	-2291	342	2955	556	-571	1255
Coal op. flex.	-976	344	2955	552	-571	1255
Nuclear	-283	74	443	84	-63	212
Nuclear op. flex.	-283	74	443	84	-63	212

3.2 Case study 2: Fossil fuel prices fixed in a long-term contract – electricity sold on spot markets

In this second case study, fuels are purchased through long-term fixed-price contracts, thereby shifting the fuel price risk away from the plant investor onto the fuel suppliers. The plant electricity output is sold on spot markets, such that the plant investor bears all of the electricity price risk. The case without operating flexibility can be interpreted as modelling fuel purchase contracts with a "non-resell" clause. Figure 2 shows that electricity price risk has a very similar impact on the risk profile of nuclear, coal or CCGT plant, whose NPV distribution have standard deviation of respectively 1076, 1080 and 964 €/kW. As shown by the dashed lines on Figure 2, plant operating flexibility is more valuable to cap potential downside losses of CCGT plant than coal and nuclear plant. The operating flexibility reduces the CCGT NPV probability distribution standard deviation from 1076 to 768 €/kW (by 29%). It reduces coal and nuclear NPV probability distributions standard deviation respectively from 1080 to 979 €/kW (by 9%) and from 964 to 934 €/kW (by 3%). The main insight is that while electricity price risk affects the three technologies to a relatively similar extend, plant operating flexibility is of much greater value to CCGT plant and lowers risk associated with CCGT investment to lower levels than for coal and nuclear plant.

Figure 2 – Case study 2: NPV distributions with electricity price risk (€/kW, in 10^{-4} for 100,000 simulations)

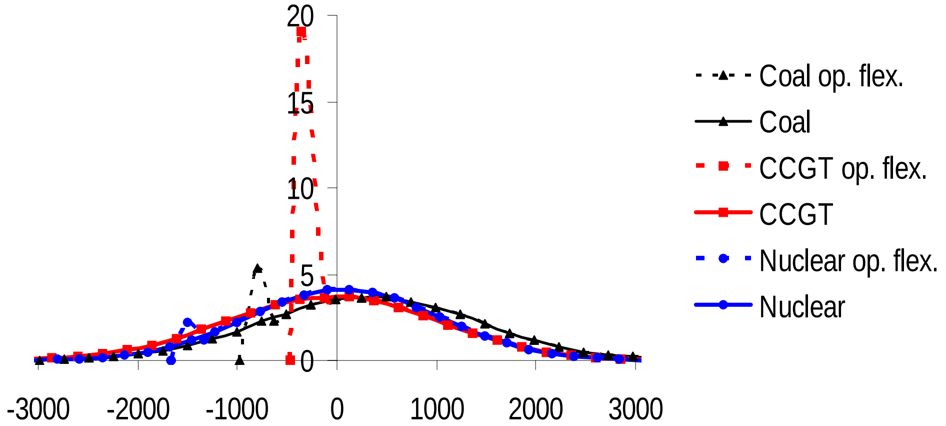


Table 4 - Case study 2: NPV distributions with electricity price risk (€/kW)

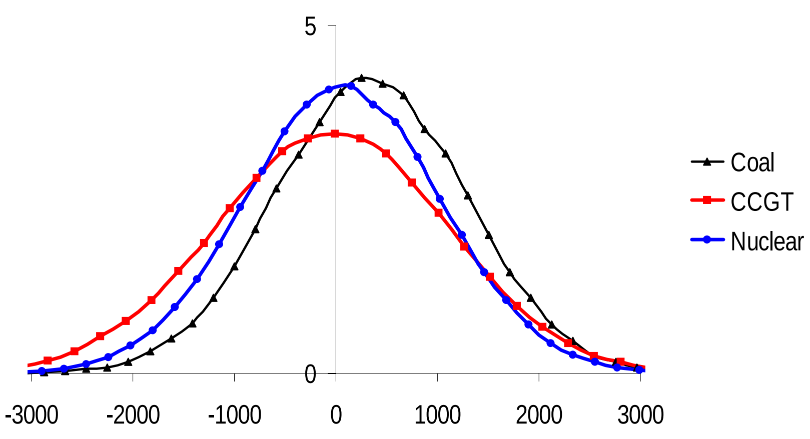
NPV (€/kW)	Minimum	Mean	Maximum	Std. deviation	5% percentile	95% percentile
CCGT	-4469	-48	5457	1076	-1817	1718
CCGT op. flex.	-474	201	5457	768	-474	1718
Coal	-4107	342	5832	1080	-1432	2114
Coal op. flex.	-976	400	5832	979	-976	2114
Nuclear	-4050	74	4979	964	-1511	1659
Nuclear op. flex.	-1668	88	4979	934	-1511	1659

3.3 Case study 3: Electricity and fuel price sold and bought on spot markets

In this third case study, both fuels used to run the plants and the electricity produced are bought and sold from spot markets. The plant owner (or operator) therefore bears both fossil fuel and electricity price risks. The combined impact of electricity and fuel price risks on the profitability of the three different technologies depends on the degree of correlation between these prices. The impact of different degrees of correlation between electricity and gas prices will be studied in detail in the next section. In this subsection, an arbitrary degree of correlation of 50% is assumed, as in IEA (2007).

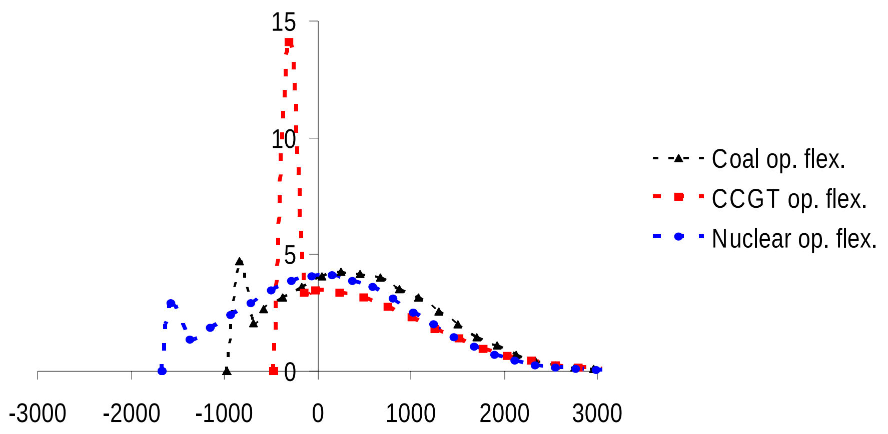
In the case with no dispatch choice, Figure 3 shows that the three technologies have relatively similar NPV distributions standard deviation: 1148 €/kW for CCGT plant, 942 €/kW for coal plant, and 967 €/kW for nuclear plant. The NPV probability distributions also show that an investment in a coal of gas plant has a greater upside potential than an investment in a nuclear plant: the NPV distribution 95% percentile for a CCGT stands at 1829 €/kW, while it is 1893 €/kW for coal plant and only 1666 €/kW for nuclear plant. In contrast, a CCGT investment appears as the most risky investment, with a greater downside potential than other technologies. Such occurrences of large losses correspond to simultaneous low electricity prices and high gas prices. The NPV distribution 5% percentile for CCGT is as large as -1952 €/kW, versus -1205 €/kW for a coal plant and -1516 €/kW for a nuclear plant. Such theoretical result should, however, be interpreted with care as CCGT plant is unlikely to be operated with 'must run' contracts in practice.

Figure 3 – Case study 3: NPV distributions without operating flexibility, fuel and electricity price risks (€/kW, in 10^{-4} for 100,000 simulations)



In the more realistic case with operating flexibility, Figure 4 shows significant differences. The first observation is that the shape of the NPV distributions is greatly modified: the lower left hand side tail of the CCGT – and to a lesser extent coal plant – NPV probability distributions are removed. In other words, as losses are capped by the operational flexibility, the probability of very low NPVs decreases significantly: the 5% percentile for the CCGT NPV distribution increases from -1952 to -474 €/kW, from -1205 to -976 €/kW for coal plant, and remains at -1516 €/kW for nuclear plant (Table 5). The operating flexibility increases substantially the CCGT ENPV (from -48 to 229 €/kW) and slightly the coal ENPV (from -342 to 377 €/kW), while it leaves the nuclear ENPV hardly unchanged (increasing from 74 to 88 €/kW).

Figure 4 – Case study 3: NPV distributions with operating flexibility, fuel and electricity price risks (€/kW, in 10^{-4} for 100,000 simulations)



The main insight is that taking into account plant operating flexibility modifies the relative attractiveness of the different technologies. When the CCGT operating flexibility is taken into account in the valuation, CCGT plant becomes a more profitable and less risky investment choice. Indeed, the operating flexibility not only increases the CCGT expected NPV relatively to the coal and nuclear plant expected NPVs, but it also reduces the riskiness of CCGT plant by capping the likelihood of largely negative NPVs to a lower level than for nuclear or coal plant.

Table 5 – Case study 3: NPV distributions with fuel and electricity price risks (€/kW)

NPV (€/kW)	Minimum	Maximum	Mean	Std. Deviation	5% percentile	95% percentile
CCGT	-5527	4724	-48	1148	-1952	1829
CCGT op. flex.	-474	4724	229	807	-474	1829
Coal	-4023	4318	342	942	-1205	1893
Coal op. flex.	-976	4318	377	876	-976	1893
Nuclear	-4100	4625	74	967	-1516	1666
Nuclear op. flex.	-1668	4625	88	937	-1516	1666

3.4 The impact of the degree of correlation between electricity and gas prices on the value of operating flexibility

In practice, the correlation between fuel and electricity prices is the result of complex set of phenomena, including the fuel used by the plants which have the highest marginal cots of production and are therefore "clearing" the market, but also other factors such as the terms and duration of fuel procurement contracts, the operational dispatch strategies of electric companies holding portfolios of diverse generation technologies, and the behaviour of traders on electricity and fuel markets.[25] In Europe, the interaction between fuel and electricity markets has been made more complex by the introduction of the European Union Trading Scheme. Newbery (2005) demonstrates the detrimental impact of emissions trading on market power in gas markets, while Green (2007) uses a supply function approach to asses the impact of emissions trading on generators' profits and risks.

Figure 5 – Expected (mean) NPV with and without operating flexibility versus correlation between electricity and fuel prices (€/kW)

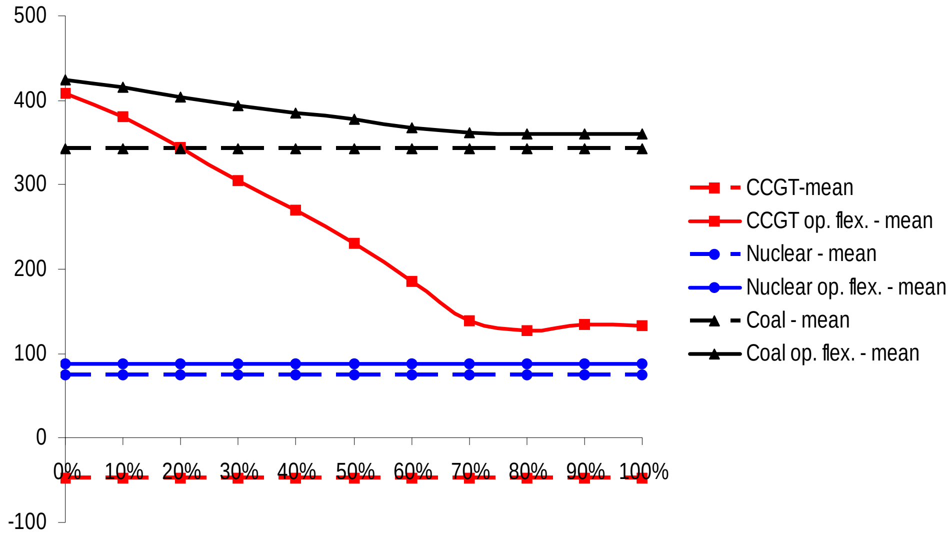
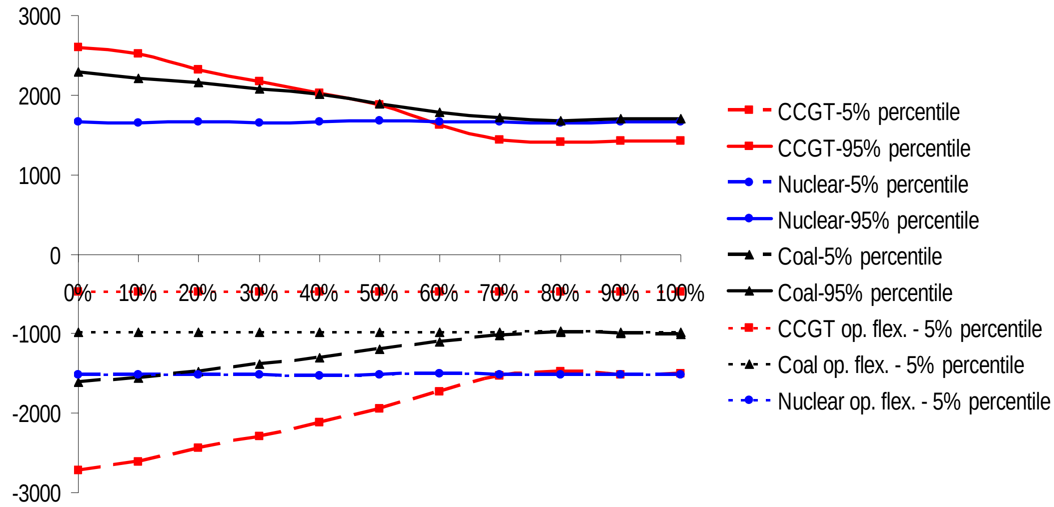


Figure 5 shows that the CCGT expected NPV with operating flexibility decreases by two-thirds (from 408 to 133 €/kW) as the correlation between electricity and gas prices increases from 0 to 100%. Coal plant ENPV with operating flexibility is much less affected by the correlation between electricity and coal prices, with coal plant ENPV decreasing by 15% (from 425 to 361 €/kW) as the correlation between electricity and coal prices increases from 0 to 100%. Nuclear plant ENPV with operating flexibility remains stable at 88 €/kW. Figure 6 illustrates the expected 5% and 95% percentiles of the three technologies NPV distributions in the cases with and without operating flexibility. It shows that the probability of making a large profit (illustrated by the 95% percentile) is not affected by operating flexibility, while the probability of making large losses is reduced by the operating flexibility (illustrated by the 5% percentile). In other words, plant operating flexibility caps potential downside losses while leaving unchanged potential upside profits.

[25] Roques et al. (2006c) report relatively high correlation in the UK market over 2001-2005 (ranging from 70 to 95%), where gas plants where setting the marginal electricity price most of the time. In 2004 in the PJM market, natural gas plants set the clearing price 31% of the time, coal plants set the price 56% of the time and petroleum generators set the price 12% of the time, according to PJM's market monitor's 2005 State of the Market Report.

Figure 6 shows how these potential upside profits and downside losses evolve as a function of the degree of correlation between electricity and fuel prices. In the case without operating flexibility, upside profits and downside losses are symmetrically reduced as the correlation between electricity and fuel prices increases. The intuition is that the occurrences of extreme high fuel prices and low electricity process reduce as the correlation between these two streams increases. Interestingly the decrease of upside potential and the decrease of the downside potential reach a plateau for a degree of correlation between electricity and fuel prices of about 70%. Such degree of correlation is not unusual in liberalized markets, as is observed by Roques et al. (2006c) in the UK over 2001-2005 or Awerbuch and Berger (2003) in the EU. Figure 6 also shows that in the case without operating flexibility, the downside asymptote reached by the 5% percentile for correlation between electricity and gas prices greater than 70% corresponds to the 5% percentile of the same technology with operating flexibility, which does not change as correlation increases. This also confirms *a posteriori* that the operating flexibility embedded in the model captures appropriately the arbitrage opportunities between fuel and electricity markets.

Figure 6 – NPV distributions 5% and 95% percentiles with and without operating flexibility versus correlation between electricity and fuel prices (€/kW)



3.5 The operating flexibility option value

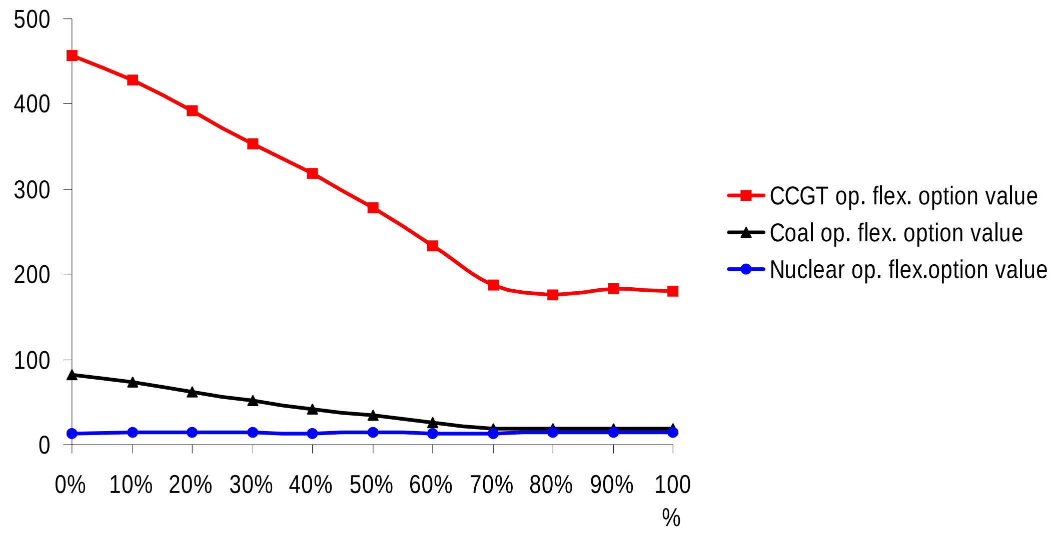
The operating flexibility 'option value' can be defined as the difference between the NPV of the power plant with and without operating flexibility. The option is valuable when a – relatively rare – combination of high fuel prices and low electricity prices makes it unprofitable to produce. As shown in table 6, gas plant operating flexibility option value is very large as compared to the total project expected value. In this 10% discount rate case, gas plant ENPV without operating flexibility is negative, while gas plant ENPV with operating flexibility is largely positive, highlighting the critical importance of taking into account operating flexibility in project valuation (the operating flexibility option value represents between 112% and 135% of total project expected value as correlation between electricity and gas prices varies between 0% to 100%). In contrast, the operating flexibility of coal and nuclear plant only represents about 5 to 20% of the project total expected value.

Table 6 – Operating flexibility option value as percentage of project value

	CCGT op. flex.		Coal op. flex.		Nuclear op. flex.
Expected NPV (€/kW)	0% correlation gas/elec.	100% correlation gas/elec.	0% correlation coal/elec.	100% correlation coal/elec.	Impact of correlation nuclear fuel/elec. neglectable
Project	408	133	425	361	88
Op. flex. option value	456	180	82	19	14
Option value/Project value	112%	135%	19%	5%	15%

Figure 7 shows the NPV distribution of the operating option value for the CCGT, coal and nuclear plants for 100,000 simulations as a function of the correlation between electricity and gas prices. The operating option flexibility expected NPV is both much higher for the CCGT plant than for the coal and nuclear plant, and much more sensitive to the degree of correlation between electricity and fuel prices. The operating option flexibility expected NPV for a CCGT plant decreases by 60% (from 456 to 180 €/kW) as the correlation between electricity and gas prices increases from 0 to 100%. The operating flexibility option expected NPV for a coal plant decreases by 77% (from 82 to 19 €/kW) as the correlation between electricity and coal prices increases from 0 to 100%. Finally, the nuclear plant operating flexibility expected NPV remains stable at 14 €/kW as the correlation between electricity and nuclear fuel price increases from 0 to 100%. The intuition is that the nuclear plant has a very low marginal cost of production, such that once the upfront investment has been made it is always optimal to produce at full capacity. The CCGT plant, on the contrary, has much higher operating – in particular fuel – costs, which combined with volatile gas prices, makes the operating flexibility option very valuable.[26]

Figure 7 - Operating flexibility "option value" ENPV vs. correlation between electricity and fuel prices (€/kW)



[26] Note that the operating flexibility option value is higher with a lower discount rate, as future hypothetical losses when there is no operating flexibility are discounted back at a lower discount rate.

4 CONCLUSIONS

Power purchase agreements, fuel procurement contracts, and operating flexibility play a central role in allocating risks among parties in the electricity industry. The allocation of risks, in turn, influences electricity investment decisions, and thereby has a significant impact on what types of power plants are built and the overall portfolio of electricity supply. The focus of this paper is on new entrants in liberalized electricity markets, which are not significantly vertically integrated, and do not operate a large and diversified portfolio of generation technologies. The paper details how CCGT, coal and nuclear plant risk and return profiles compare with regard to fuel and electricity price risks, and how contracting arrangements and operating flexibility can shift some of these risks away from the investor and change the relative riskiness of the different technologies.

The paper argues that operating flexibility offered by CCGT plant – particularly arbitrage opportunities between gas and electricity markets – has a value which is not captured by traditional valuation methods and contributes to new entrants' preference for CCGT plant. The paper develops a probabilistic discounted cash flow investment model with operating flexibility to capture the impact of different degrees of exposure to fossil fuel and electricity price risks on different generation technologies. The results contrast with traditional levelized cost approaches and show that in the absence of long-term contracts, the high degree of correlation between gas and electricity prices in most markets makes CCGT "self-hedged" and appear paradoxically as the least risky option for investors, particularly new entrants.

Most interestingly, the combination of electricity and fuel price risks magnifies the value of operating and contract flexibility for CCGT plant, as it makes arbitrage between electricity and gas markets very profitable. While operating and contract flexibility are of relatively little value for coal and nuclear plants - from 5 to 20% of total project value depending on the correlation between fuel and electricity prices - , it can represent a significant part of the net present value of a CCGT project. Moreover, the modelling results showed that gas plant operating and contract flexibility value is very sensitive to the degree of correlation between electricity and gas prices in a particular market. For correlation in the order of 70 to 95%, as observed in the UK over 2001-2006, gas plant operating option value is about half of the value obtained if gas and electricity prices are assumed uncorrelated.

Taking into account operating and contracting arrangements flexibility can therefore radically improve the attractiveness of CCGT plant to investors as compared to coal and nuclear plant – particularly to new entrants. As an extension to this work, one could wonder to what extend the "self-hedged" character of CCGT plant in liberalized markets participated in the success of electricity market liberalization, in that it lowered one of the critical barriers to entry. Further research is in progress to explore this case of co-determination and co-evolution between technologies and institutions.

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