Using Probabilistic Analysis to Value Power Generation Investments under Uncertainty

Fabien A. Roques, William J. Nuttall
and David M. Newbery

July 2006

CWPE 0650 *and* EPRG 065

Using Probabilistic Analysis to Value Power Generation Investments Under Uncertainty[1]

Fabien A. Roques[2], William J. Nuttall, David M. Newbery

Electricity Policy Research Group, University of Cambridge, England[3]

21 April 2006

Abstract

This paper reviews the limits of the traditional 'levelised cost' approach to properly take into account risks and uncertainties when valuing different power generation technologies. We introduce a probabilistic valuation model of investment in three base-load technologies (combined cycle gas turbine, coal plant, and nuclear power plant), and demonstrate using three case studies how such a probabilistic approach provides investors with a much richer analytical framework to assess power investments in liberalised markets. We successively analyse the combined impact of multiple uncertainties on the value of alternative technologies, the value of the operating flexibility of power plant managers to mothball and de-mothball plants, and the value of mixed portfolios of different production technologies that present complementary risk-return profiles.

Keywords: investment, uncertainty, Monte-Carlo simulation, operating flexibility

JEL-Classification: C15, D81, L94

---

[1] The authors would like to thank anonymous referees from the EPRG for their helpful comments.
[2] Corresponding author, email: fabien.roques@gmail.com, Phone : +33 (0)140576641, Fax: +33 (0)140576659.
[3] Research support from Cambridge-MIT Institute under the project 045/P 'Promoting Innovation and Productivity in Electricity Markets' is gratefully acknowledged, as well as Platts for providing the data on electricity and fuel prices.

1 POWER INVESTMENT VALUATION TECHNIQUES

1.1 Investment planning prior to liberalisation

Before liberalisation, the electricity industry was dominated by state-owned utilities in Europe and private utilities under cost-of-service regulation in the US. These two industry frameworks corresponded to different approaches to the financing of utilities. In the US, electricity rates were set by regulators using cost-of-service regulation. Electricity prices were determined so as to provide the utility with a revenue equal to the 'revenue requirement', which corresponded to the revenue required to compensate a utility for all expenditures associated with construction and operation of a power plant. The regulator set the return on the rate base to cover the utility's cost of financing capital projects to meet the region's electricity demand (see EPRI (1986) for a detailed description of US valuation techniques under cost-of-return regulation).

In Europe, large state-owned utilities developed sophisticated models to plan capacity expansions: these programs determined the least-cost investment path, given the existing plants and different constraints related environmental or policy objectives. Nowadays comprehensive investment planning models remain widely used in developing countries (IAEA, 2004). The Wien Automatic System Planning Package (WASP) is the most widely used model in developing countries for power system planning (over 100 countries). Within constraints defined by the user, WASP determines the optimal long-term expansion plan for a power generating system. Constraints may include limited fuel availability, emission restrictions, system reliability requirements and other factors (IAEA, 2004). Optimal expansion is determined by minimizing discounted total costs. Alternative models include the Energy and Power Evaluation Program (ENPEP), which provides comprehensive evaluation of energy system development strategies, and the Model for Analysis of Energy Demand (MAED) evaluates future energy demands based on medium- to long-term scenarios of socioeconomic, technological and demographic development.

1.2 The levelised cost valuation method

The levelised lifetime cost per kWh of electricity generated is the ratio of total lifetime expenses versus total expected outputs, expressed in terms of present value equivalent. This cost is equivalent to the average price that would have to be paid by consumers to repay exactly the investor/operator for the capital, operation and maintenance and fuel expenses, with a rate of return equal to the discount rate.

The levelised cost approach is based on a discounted cash flaw (DCF) analysis. The DCF valuation method consists in discounting to present value all the future cash flows, and in accumulating them to find the net present value (NPV) of the investment. Corporate finance textbooks present the "NPV rule" as the key to making investment decisions: any investment with a positive NPV is a good investment and should be pursued. In the case of two or more mutually exclusive investment opportunities, the choice with the highest NPV is optimal (Brealey and Myers, 2000). The levelised cost approach is a specific case of DCF analysis, which reverses the procedure: given the objective of zero economic profit, the required annual revenues are calculated so that the present value of all revenues exactly balances the present value of project costs.[4]

The levelised cost methodology inherited from the pre-liberalisation times has been a useful tool for investors and for overall economic analysis because it evaluated costs and energy production and discounted them to take account of the time value of money. It remains widely used in the liberalised industry, both by energy planners and by electric companies (IEA/NEA, 2005). Power companies will apply this methodology based on an internal target for return on equity (the “hurdle rate”) to make a decision whether to invest or not and to decide between different projects. Roques et al. (2005) provide a comparative survey of the other recent levelised costs studies conducted in Belgium (Ampere, 2000), the U.K. (RAE, 2004), Finland (Tarjanne and Rissanen, 2000 and Tarjanne and Luostarinen 2003), France (Dideme, 2003), and the USA (Deutch et al., 2003, and Tolley et al., 2004) is provided in. This survey highlights wide differences in the levelised costs of nuclear and CCGT plants, stemming from differences in both costs and financing estimates.[5] These different assumptions make comparisons of the levelised costs of production across the different studies difficult. This highlights the limits of the levelised costs approach in liberalized electricity markets, and suggests the need for a different approach to valuing power generation technologies, with a detailed representation of the impact of uncertainty on key parameters on the production costs.

1.3 The levelised cost approach is of limited use in liberalised electricity markets

The traditional ‘levelised cost’ valuation approach was well adapted to assess power investments prior to liberalisation. It reflected the reality of long-term financing, passing on costs to the customers, known technology paradigms, a predictable place in the merit order, a steady increase in consumption, and, in the presence of steady technical progress, no problem in securing a favourable position in the merit order for new plant (Fraser, 2003).

The liberalisation of energy markets is removing the regulatory risk shield, as investors can no longer pass on their costs to consumers. Indeed, it is precisely one of the objectives of liberalisation to induce more efficient investment choices, by allocating investment risks to the power producers, which are best able to manage such risks. While many of the risks facing power producers in liberalised electricity markets existed in the regulated industry, the ability to pass through the approval costs

[4] Fraser (2003) details the different steps involved in a levelised cost valuation:

- Developing estimates of capital costs, operating and maintenance costs, and fuel costs based on forecasts of fuel prices;
- Estimating the average annual energy production from the power plant according to assumptions about technical availability;
- Discounting the stream of costs to estimate their present value according to an assumed discount rate;
- Using the same discounting procedure to estimate the present value of the energy production;
- Taking the ratio of the costs of energy output to obtain a levelised cost of power production.

[5] For instance, such studies use very different discount rates. The Appendix reviews the critical issue of the discount rate in power investment valuation methods in more details.

to consumers is no longer automatic. Moreover, investors now have additional risks to consider and manage in the liberalised industry. The most fundamental change affecting the value of investments in liberalised markets is the uncertainty about electricity prices. The market rules themselves can also be a source of risk.

Investment in power generation comprises a large and diverse set of risks, which include (IEA/NEA, 2005):

- Economy-wide factors that affect the demand for electricity and availability of labour and capital.
- Factors under the control of the policy makers, such as regulatory (economic and non-economic) and political risks, with possible implications for costs, financing conditions and on earnings. An example of such risk is the cost of additional emissions controls.[6]
- Factors under the control of the company, such as the size and diversity of its investment programme, the choice and diversity of generation technologies, control of costs during construction and operation.
- The price and volume risks in the electricity market.
- Fuel price and, to a lesser extent, availability risks.
- Financial risks arise from the financing of investment. They can to some extent be mitigated by the capital structure of the company.

These risks will affect different technologies differently. Some risks are inherent to the technology involved; others involve the interaction of technology and the environment in which the generating company operates. *Table 1* provides a qualitative assessment of how the various types of risks in liberalised electricity markets affect the three main base load generation technologies (gas fired, coal fired, and nuclear power plants).

Table 1 - Qualitative comparison of generic features of generation technology, Source: IEA/NEA (2005)

Technology	Unit Size	Lead Time	Capital Cost	Operating Cost	Fuel Prices	CO2 emissions	Regulatory risks
CCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Medium	Medium	High	High
Nuclear	Very large	Long	High	Medium	Low	Nil	High

In the liberalised electricity industry, what matters to the investor is the profitability of the investment against the risk to the capital employed. The level of

[6] In the European Union, one of the greatest uncertainty for investors in new power plants is controls on future carbon dioxide emissions. This uncertainty will grow in the future, particularly as future restrictions on levels of carbon dioxide emissions beyond the first commitment period of the Kyoto Protocol are unknown.

risk anticipated by an investor in a power plant will be reflected in the level of return expected on that investment. The greater the business and financial risks, the higher the return that will be demanded. It is difficult for the levelised cost methodology to incorporate risks and uncertainty effectively. In order to assess various risks, different scenarios or sensitivities are usually calculated, which often give only a limited assessment of the risks involved. IEA/NEA (2005) reckons for instance that "[the levelised 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.

1.4 Probabilistic approaches are powerful tools to give insights on the impact of uncertainties and risks on power investments

The most comprehensive approach to take into account a wide range of uncertainties in key risks is to use a probabilistic assessment (Rode et al., 2001). Monte Carlo simulation and related techniques are capable of addressing many of the limitations of decisions analysis (and of sensitivity analysis). The Monte Carlo simulation approach consists in characterising the uncertainty in model outputs by assigning probability distributions to inputs, and to simulate the output distribution by repeated sampling.

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

- Identification of key uncertain model input variables relating to resource options and their operational environment;
- Statistical description of the risk for these key inputs by assignment of probability distributions;[7]
- Identification and statistical description of any relationships (covariance) among key inputs;
- Multiple iteration, where sets of input assumptions are drawn from each specified variable's probability distributions;
- Description of key model outputs by probability distributions.

Monte-Carlo simulation allows one to simulate the impact of uncertainties on cost and technical parameters to obtain a probabilistic assessment of the risks and revenues of different generation technologies. Input parameter uncertainty is typically modelled by a probability distribution, and the simulation is run many times for

[7] A distinction is generally drawn between 'objective' and 'subjective' probabilities (Spinney and Watkins, 1996). Objective probabilities relate to events drawn from an explicit, known probability or distribution. Subjective probabilities do not specify an explicit probability model, although some kind of model may be implicit in their assessment.

different values of the uncertain parameters, yielding a Net Present Value (NPV) probability distribution. Correlations between the different uncertain parameters can be introduced. The resulting NPV distribution provides investors with a much richer analytical framework to assess power investments in liberalised markets. Feretic and Tomsic (2005) provide a probabilistic analysis of lifetime discounted costs of electrical energy if produced in coal-fired, gas-fired and nuclear plants entering in operation in Croatia around 2010.

Monte Carlo simulation (MCS), however, is not without its own potential pitfalls. Spinney and Watkins (1996) provide a useful literature review and highlight the following issues:

- It can be difficult to estimate both the probabilities and the interrelationships among variables in an MCS model.
- MCS techniques do not force explicit distinction between diversifiable and non-diversifiable (systemic) risks.
- MCS techniques, in explicitly representing risks associated with certain parameters, create the possibility that such risks will be double counted, particularly where the weighted average cost of capital (which presumably already incorporates these risks) is used as the discount rate (Seitz and Ellison, 1995).
- MCS do not account for the dynamic relationships between cost, price, demand, and hence revenues (Brealey and Myers, 2000).
- Presentation of model outputs in the form of probability distributions do not necessarily provide decisions makers with a clear picture of the implications for decision making.
- Some decisions do not necessarily justify the additional complexities introduced by use of MCS.

While it is important to keep in mind these issues, the sophisticated spreadsheet software now available greatly facilitate the practical implementation of MCS. Moreover, some of these concerns are at least as difficult to address with alternative methods.

In the next section, we introduce the main parameters of a valuation model of investment in three base-load technologies (Combined Cycle Gas Turbine (CCGT), coal plant, and nuclear plant), together with simple sensitivity analyses which serve as a useful intermediary step to identify the key parameters to be modelled by probability distributions in the Monte Carlo simulation. We then present successively three case studies using Monte Carlo simulation to assess different issues related to base load power generation choices in liberalised electricity markets.

2 BASE MODEL PARAMETERS AND SENSITIVITY ANALYSES

This section introduces the base model on which subsequent sections will build. The primary objective is to provide a tractable yet realistic comparative valuation of base-load generation technologies investments in the UK at the horizon of 2010. We concentrate on three base-load technologies (scrubbed coal, combined-cycle gas turbine (CCGT), and 'generation three' nuclear) that are likely to be the main base-load alternatives on the post-2010 time horizon. Coal, gas and nuclear together represent more than 90% of the electricity produced in the UK in 2005 and will remain dominant by 2010 - the U.K. government target for renewables is to reach a 10% generation share for renewables in 2010 (DTI, 2003). 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 4 nuclear, advanced renewables) that present promising technology prospects, but that are yet too immature to be considered ready by 2010.

2.1 Model parameters

The parameters of the model correspond to three base-load technologies (CCGT, coal and nuclear plants) available by 2010 for new build in the U.K.. All the costs are expressed in real 2005 British Pounds. Cost and technical parameters are derived from the most recent levelised costs studies, namely the MIT *'The Future of Nuclear Power'* study (Deutch et al., 2003), and the International Energy Agency Costs of Generating Electricity (IEA/NEA, 2005). *Table 2* summarises the model 'base case' costs and revenues assumptions. These figures are characterised by considerable uncertainty, and should therefore be interpreted as most likely values - each parameter will be represented by a probability distribution in the next subsections. The base case parameters thus should not be assessed independently of the range of costs and prices considered for the Monte-Carlo simulations, which are described in the next subsection.

The model provides a fairly realistic description of the specificities associated with an investment in the three different technologies. For example, the investment time lag 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.[8] The capital costs ('overnight cost' and 'O&M incremental cost') are much higher for the nuclear plant, and to a lesser extent for the coal plant, than for the CCGT plant, while the converse is true for fuel costs. Nuclear plant incurs a 'nuclear waste fee' to cover the cost of decommissioning and nuclear waste treatment.

The three plants are assumed to operate base-load with an average annual capacity utilisation factor of 85%.[9] The operating flexibility is explicitly modelled by assuming that they can stop generating whenever electricity, gas, and carbon prices make it uneconomic. The impact of operating flexibility on the value of each technology will be the focus of one of the third section of this paper.

[8] These investment lags are estimates of the construction times, assuming that the construction permit and regulatory approval have been obtained.

[9] This value represents a low estimate for nuclear (most nuclear plants are currently running at a capacity factor higher than 90% in Europe and in the US), but a relatively high estimate for gas which might be cycling up and down.

Table 2 - Base modelling parameters

Parameters	Unit	Nuclear	Coal	NGCC
Technical parameters				
Net capacity	MWe	1000		
Capacity factor	%	85%		
Heat rate	BTU/kWh	10400	8600	7000
Carbon intensity	kg-C/mmBTU	0	25.8	14.5
Construction period	year	5	4	2
Plant life	year	40	30	20
Cost parameters				
Overnight cost	£/kWe	1140	740	285
Incremental capital costs	£/kWe/yr	11.4	8.6	3.4
Fuel costs	£/mmBTU	0.35	1.30	3.3
Real fuel escalation rate	%	0.5%	0.5%	1.2%
Fixed O&M	£/kWe/year	36	13	9
Variable O&M	£/MWh	0.23	1.93	0.3
O&M real escalation rate	%	0.5%		
Nuclear Waste fee	£/MWh	0.6	0	
Financing parameters				
Projected Inflation rate	%/year	3%		
Real Discount rate	%	10%		
Marginal Corporate Tax	%	30%		
Regulatory actions				
Carbon tax	£/tC	40		
Carbon price esc. rate	%	1%		
Revenues				
Electricity price	£/MWh	40		
Electricity price esc. rate	%	0.5%		

The financing structure of the model is kept simple. The corporate tax rate is 30% in England, and we model two scenarios for the real weighted average cost of capital (WACC), 5% and 10% (similarly to IEA/NEA, 2005). These two scenarios represent respectively the cost of capital for a company in a stable environment (i.e. a regulated monopoly, or a company with a captive market or long term contracts), and for a merchant investment in the liberalised industry. A sensitivity analysis to the cost of capital is presented in Appendix 1. Plant life-times of respectively 20, 30, and 40 years for gas, coal and nuclear plants represent also the capital recovery period. Girard et al. (2004) and Deutch et al. (2003) explore the impact of more realistic ‘merchant project financing’ approaches in which the debt repayment period is shorter than the physical life of the plant.

Gas and coal prices are derived from historical and forecast data in the U.K.. The source of historical data is Platts, while forecasts are from the IEA World Energy Outlook 2004 (IEA, 2004) and the U.S DOE Annual Energy Outlook 2004 (DOE, 2004). The long–term real annual fuel cost escalation rate is 0.5% for coal and nuclear and 1.2% for gas, slightly higher than in the IEA (2004) reference scenario to reflect the recent considerable increase of fossil fuel prices. The nuclear fuel cost includes used-fuel disposal; it is based on the IEA (2004) assumptions for an open fuel cycle (i.e. without reprocessing) and on historical prices from the Uranium Information Centre (2004).[10]

Carbon emission permits cost are implemented in the form of a simple carbon tax, whose level was determined according to industry forecasts (data from PointCarbon). The cost of CO_2 emissions related to the European Emission Trading Scheme is represented by a 'carbon tax', which is estimated at £40/tC according to the EEX market data.[11]

On the revenue side, the electricity price forecasts are based on historical price trends in the UK (data from Platts).

2.2 NPV sensitivity analysis

The net present value (NPV) of the three technologies is very sensitive to the discount rate. For a commercial discount rate (10%) only the CCGT plant has a positive NPV (£22m), while both the nuclear and coal plants have similar negative NPVs (respectively £-167m and £-168m). With a 8% discount rate, a CCGT and nuclear plant have similar positive NPVs (respectively £80m and £83m), while the coal plant NPV is still negative (£-40m). With a 5% discount rate, all technologies have positive NPVs, the nuclear plant having by far the highest NPV. These tendencies are consistent with the results of recent levelised costs studies (Tolley et al. 2004, IEA/NEA, 2005).

Table 3 – Base case Net Present Values (£m)

Net Present value (£m)								
10% discount rate			8 % discount rate			5 % discount rate		
CCGT	Coal	Nuclear	CCGT	Coal	Nuclear	CCGT	Coal	Nuclear
22	-168	-167	80	-40	83	206	284	780

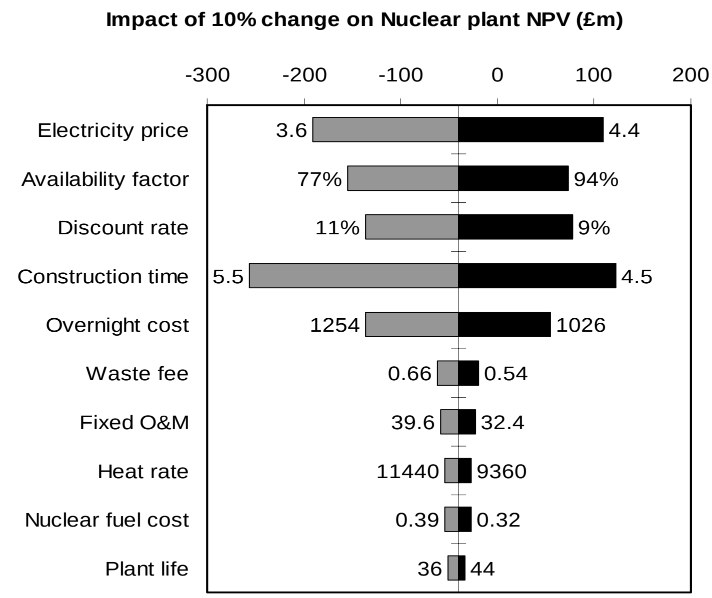
However, these NPVs are subject to the same critics than the levelised costs of production and only give little information on the risks and returns of the alternative technologies. A first step towards taking into account the different project risks through Monte Carlo simulations is to run sensitivity analyses. Despite their limitations, such sensitivity analyses serve as a useful intermediary step to identify the parameters whose variability has a large impact on the NPV of each technology, and which are thus to be varied in the Monte-Carlo simulation. The next paragraphs detail such sensitivity analyses for the three technologies, for the commercial discount rate scenario (10%). Only the 10 parameters having the largest impact on the NPV are shown on each technology's diagram. In such a sensitivity analysis, one parameter is varied at a time, everything else being held constant (such sensitivity analysis cannot take into account correlations between the different parameters).

[10] For a detailed assessment of the costs of the nuclear fuel cycle, see NEA (2002).
[11] Note that to express this as a cost per tonne of CO_2 multiply by 3.67.

- **Nuclear sensitivity analysis**

The sensitivity analysis for nuclear (see *Figure 4*) provides insights on the relative impact of uncertainty about the different parameters. It is striking that nuclear economics depends greatly on the cost of capital. The electricity price, the capital cost, the construction time, and the availability factor have quite an important impact on nuclear NPV. The availability factor of nuclear plants in operation in liberalised electricity markets has greatly improved in the last decade, in particular in Britain and in the US.[12] Moreover, NEA (2000) reckons that reducing capital cost is key to nuclear deployment in restructured electricity industries, and provides an extended survey of the scope for such capital cost reductions.

Figure 4 - Nuclear plant NPV sensitivity analysis (10% discount rate)

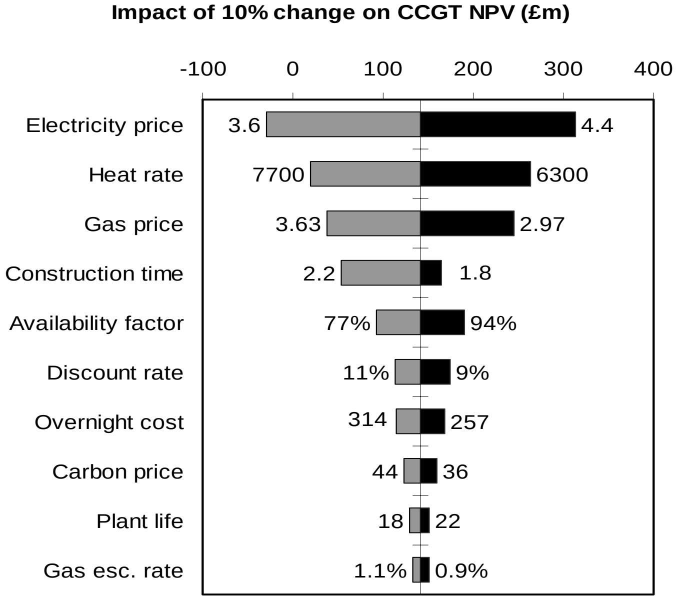


- **CCGT sensitivity analysis**

The sensitivity analysis for a CCGT (see *Figure 5*) shows very different patterns than the Nuclear case. The CCGT NPV is very sensitive to changes in electricity price, gas price, and heat rate. It is, however, much less sensitive than nuclear to the discount rate and the overnight capital cost, as a CCGT investment is much less capital intensive than an investment in a nuclear plant, with fuel and operating expenses representing a much larger share of the total cost. Interestingly, carbon price uncertainty within a reasonably realistic range for the next 5 years does not affect much the CCGT NPV.

[12] In 2000, the capacity factors for the nuclear plants in Japan were 79%, for those in South Corea 91%, and 76% for those in France where some plants have to be cycled up and down because of the large share of electricity supply accounted for by nuclear (data from the EIA web site).

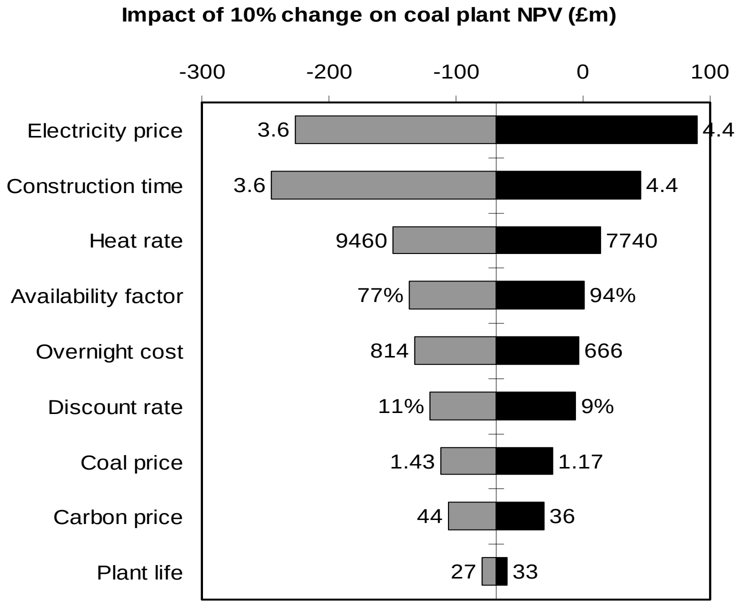
Figure 5 - CCGT NPV sensitivity analysis (10% discount rate)



- **Coal sensitivity analysis**

The sensitivity analysis for a coal plant (see *Figure 6*) gives results somewhat in-between the results for gas-fired and nuclear plants. The most important parameters are the electricity price, the overnight capital cost, the heat rate, and the availability factor. Uncertainty on the carbon price has much more impact than on the CCGT NPV, reflecting the greater ratio of carbon emission to electricity output of coal plants. On the other hand, the coal plant NPV's sensitivity on coal prices is much lower than the CCGT's NPV sensitivity on gas prices.

Figure 6 - Coal plant NPV sensitivity analysis (10% discount rate)



The following sections present successively three case studies of applications of Monte Carlo Simulation (MCS) to value different aspects of the three competitive base load technologies:

- The first MCS case study assesses the combined impact of multiple uncertainties on the risk-return profile of the three alternative technologies.
- The second case study uses a MCS to value the operating flexibility of power plant managers to mothball and de-mothball plants.
- The third MCS case study highlights the complementarity of the three technologies by comparing the risk-return profiles of different portfolios of plants.

3 MCS CASE STUDY 1: ASSESSING THE IMPACT OF MULTIPLE UNCERTAINTIES SIMULTANEOUSLY

The sensitivity analyses presented above give useful insights into the relative importance of the different parameter uncertainties and therefore serve as a useful preliminary step towards a Monte Carlo approach. However, sensitivity analyses limit themselves to changes to the NPV. By running a Monte-Carlo simulation, the shape of the investment NPV distribution, in particular its spread (i.e. standard deviation), its skewness, and kurtosis give a much richer picture of the impact of uncertainties on the project value (Ragsdale, 2001).

Moreover, sensitivity analyses only vary one parameter at a time, everything else being constant, and therefore cannot give insights on the combined impact of multiple uncertainties on the three competitive technologies. This section uses a Monte-Carlo simulation to assess the simultaneous impact of a wide rage of parameters uncertainties on the three base load investment alternatives considered.

3.1 Probability distributions of uncertain parameters

The technical or cost parameters uncertainties are modelled by a normally distributed random variable distributed around the base case value described in the previous section. The uncertainty range of each parameter is meant to reflect the state of knowledge in 2005 for an investment in a plant ready for operation by the end of 2010. The standard deviation for each parameter is whenever possible defined by using historical data, or alternatively we rely on expert judgement and the uncertainty ranges described in the literature (see *Table 7*). Standard deviation on fuel, carbon and electricity prices are derived from historic empirical data for the UK market. For fixed and variable O&M costs risk, as well as construction time risk, we relied on Awerbuch and Berger (2003) standard deviation estimates.[13]

[13] Awerbuch and Berger (2003) use financial proxies to estimate O&M risk. They assume that fixed O&M cost present a "debt equivalent" risk as they are contractual in nature, and therefore use estimates of the historic standard deviation for various corporate bonds. Similarly, Awerbuch and Berger (2003) assume that variable O&M cost, as they are volume driven, are equivalent to the overall market risk and use a broadly diversified market portfolio standard deviation as a proxy (the Morgan Stanley MSCI Europe Index).

Table 7 – Random variables Normal Distribution parameters

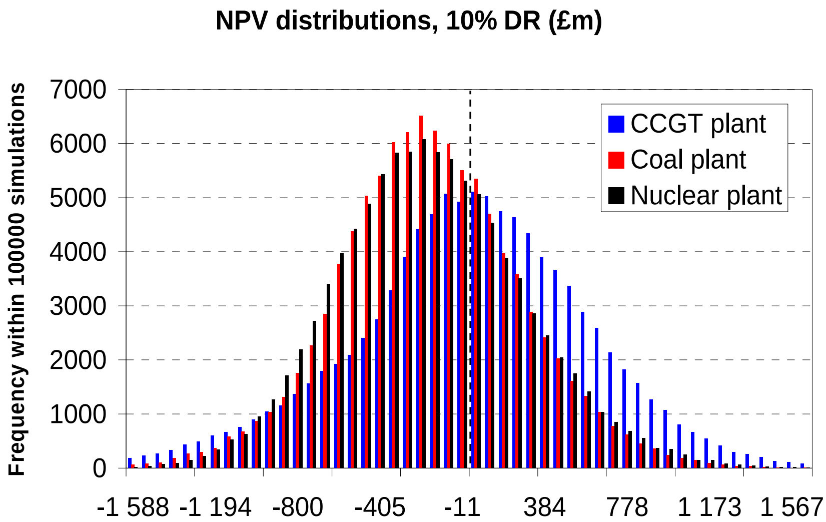
Normal Distributions Parameters	Technology	Mean	Standard deviation
Technical parameters			
Capacity factor	All	85%	10%
Construction time (years)	Nuclear	5	1
	CCGT	2	0.2
	Coal	4	0.4
Heat Rate (BTU/kWh)	Nuclear	10400	500
	CCGT	8600	500
	Coal	7000	500
Plant life (years)	Nuclear	40	10
	CCGT	30	3
	coal	20	2
Cost parameters			
Overnight cost (£/kWe)	Nuclear	1140	200
	CCGT	285	28.5
	Coal	740	74
Incremental capital costs (£/kWe/yr)	Nuclear	11.4	1.14
	CCGT	3.4	0.34
	Coal	8.6	0.86
Fuel cost (£/mmBTU)	Nuclear	0.35	0.1
	CCGT	3.3	1
	Coal	1.3	0.2
Fuel cost escalation rate (% p.a.)	Nuclear, coal	0.5%	0.5%
	CCGT	1%	1%
Fixed O&M (£/kWe/yr)	Nuclear	36	3.6
	CCGT	9	0.9
	Coal	13	1.3
Variable O&M (£/MWh)	Nuclear	0.23	0.023
	CCGT	0.3	0.03
	Coal	1.93	0.19
Nuclear waste fee (£/kWh)	Nuclear	0.6	0.2
Carbon tax (£/tC)	All	40	10
Carbon Price escalation (% p.a.)	All	1%	0.5%
Revenues			
Electricity price (£/MWh)	All	40	10
Electricity price escalation (% p.a.)	All	0.5%	0.5%

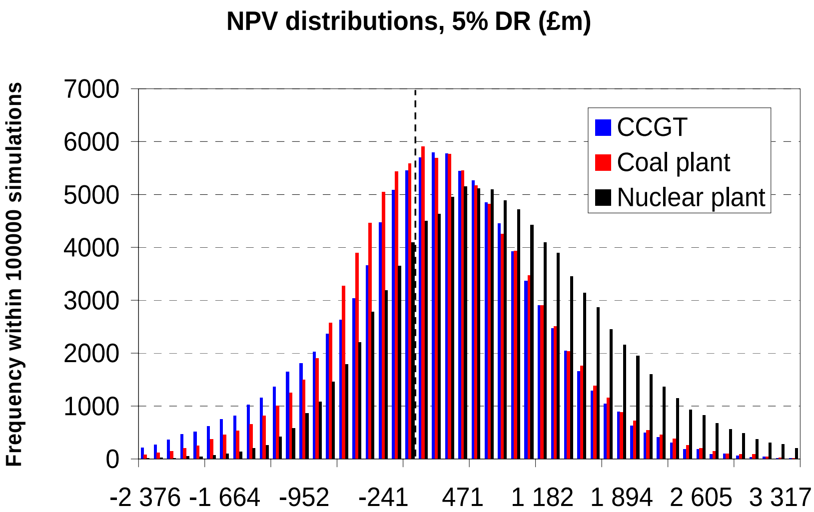
3.2 Monte Carlo simulation results

Figure 8 shows the NPV probability distribution of the three technology alternatives resulting from 100000 simulations, in the case in which managers don't have any operating flexibility, i.e. the plants are assumed to produce at full output whenever they are technically available, even if they are making a loss (the results with operating flexibility will be detailed in the section). This is a realistic assumption for the nuclear technology, which has very low marginal costs but is less usual for coal and gas-fired plants which usually cycle up and down depending on the evolution of electricity and fuel prices. However, this 'no operating flexibility' case can correspond to a producer having a 'must-run' contract, for instance when the entire output of the plant has been contracted forward. The results are presented using the two discount rates scenarios defined in the previous section (5% and 10%).

Unsurprisingly, as all uncertainties are represented by normally distributed random variables, the three technologies NPV distributions are close to a normal distribution. Besides, as the normal distribution is symmetrically distributed around its mean value, the expected NPV of the three technologies is identical to the base case in which there was no uncertainty.

Figure 8 - NPV distributions for the 3 technologies, 10 & 5% discount rates (£m)





The NPV probability distributions of the three technologies exhibit different features which provide the investor with a much richer set of information to compare the three investment alternatives.

Starting with the 10% discount rate case, the first observation is that CCGT NPV distribution is more spread than the coal and nuclear NPV distributions, thereby indicating that the gas investment is somewhat riskier than the nuclear or coal one. As summarised in *Table 9*, the standard deviation of the gas NPV (£587 million) is indeed larger than the coal (£442m) and nuclear (£451m) values. Interestingly, the left tail of the distributions reveals that the probability of making a large loss is greatest with a CCGT, and lowest with a nuclear plant. Concurrently, the right hand tail of the NPV distributions shows that a CCGT has a greater upside potential than a coal or nuclear power plant. The Monte Carlo simulation therefore gives two important insights. While the expected net present value (ENPV) of a CCGT is the only one to be positive, a CCGT has a greater chance to make a large loss (NPV lower than £800m) than a coal of nuclear power plants, due to the different nature of the uncertainties affecting this technology. However, the upside potential (i.e. the probability of making a large profit) is also much higher than that of the coal or nuclear plants.

In the case of a low discount rate (5%), the nuclear plant is unambiguously the best choice. It has indeed both the highest ENPV, a standard deviation similar to the other technologies, and a higher upside potential. All distributions statistics are presented in *Table 10*, for discount rates of 5%, 8%, and 10%.

Table 9 - Single plants NPV distribution statistics, no operating flexibility (£m)

	10% discount rate			8 % discount rate			5 % discount rate		
Statistics - 100,000 sim.	**CCGT**	**Coal**	**Nuclear**	**CCGT**	**Coal**	**Nuclear**	**CCGT**	**Coal**	**Nuclear**
Mean	22	-168	-167	80	-40	83	206	284	780
Median	47	-177	-184	108	-53	54	252	264	710
St. Deviation	587	442	451	705	567	586	943	869	970
Skewness	-0.34	0.02	0.24	-0.33	0.03	0.30	-0.37	0.05	0.43
Kurtosis	3.76	3.55	3.34	3.75	3.55	3.40	3.87	3.64	3.54
Minimum	-3488	-2615	-2402	-3739	-2958	-2707	-6027	-4546	-3680
Maximum	2787	2062	2386	3407	2999	3731	4056	5007	6643
Range	6275	4676	4788	7145	5957	6438	10083	9553	10323

4 MCS CASE STUDY 2: THE VALUE OF OPERATING FLEXIBILITY

The previous section showed how a Monte-Carlo simulation provides investors with a much richer framework to understand the impact of the various uncertainties that power generators face in liberalised electricity markets. In this section, we use a Monte-Carlo simulation to study the impact of operational flexibility on the three technologies investment values.

4.1 Plants operational flexibility in electricity markets

In the previous section, as in all levelised cost studies mentioned in previous chapters, the different technologies were compared assuming that they were all producing at full output, i.e. at their maximum technical availability factor. This is a reasonable assumption insofar as we are comparing base load technologies, which might have 'must run' contracts. Moreover, uncertainty over plants' output was to some extent taken into account through the representation of the availability factor by a normally distributed random variable, reflecting for instance the risk of technical plants breakdowns.

In liberalised 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. This implies that producers are generally not guaranteed an off-take for the full output of their plant, and may have to run them "part-loaded".

Furthermore, electricity producers may themselves choose not to produce at full capacity if it is not profitable to do so. This is of particular relevance to gas-fired power plants, for which producers can decide not to produce 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. In the UK for instance, some gas-fired power plants have interruptible gas procurement contracts, or can switch to distillate fuel. Connors et al. (2004) study of New England's power generators plants utilisation reveals that gas-fired, and to a lesser extent coal-fired power plants, cycle up and down according to power and fuel prices. The progressive liberalisation of the gas market in Europe should 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). Neuhoff and von Hirschhausen (2005) analyse the changing patterns of long-term gas procurement contracts associated with the institutional changes brought by the gas sector liberalisation.[14]

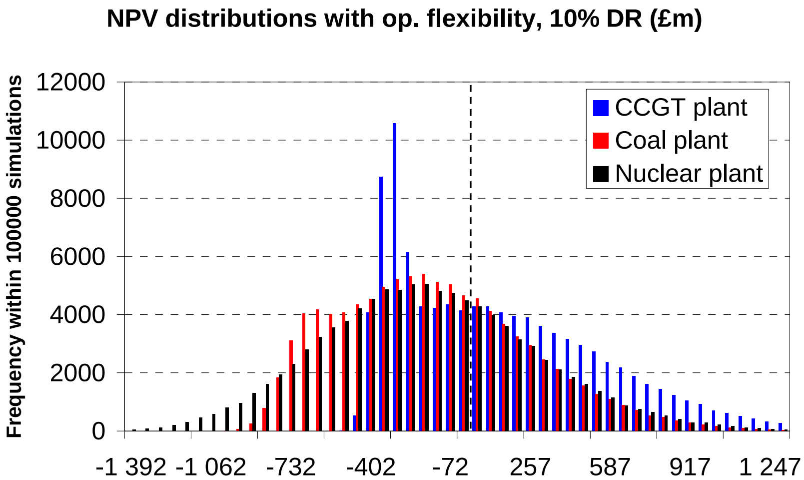
On a longer time scale, power generators can 'mothball' a plant temporarily if the power and fuel prices previsions make it uneconomic to use, and 'de-mothball' it later on if it is profitable. In this section, we embed in the Monte-Carlo simulation model described previously the managerial flexibility to switch plants on or off yearly, whenever the expected costs of production exceed the expected electricity sales revenues. We assume that plants can be switched off and on at no costs (i.e.

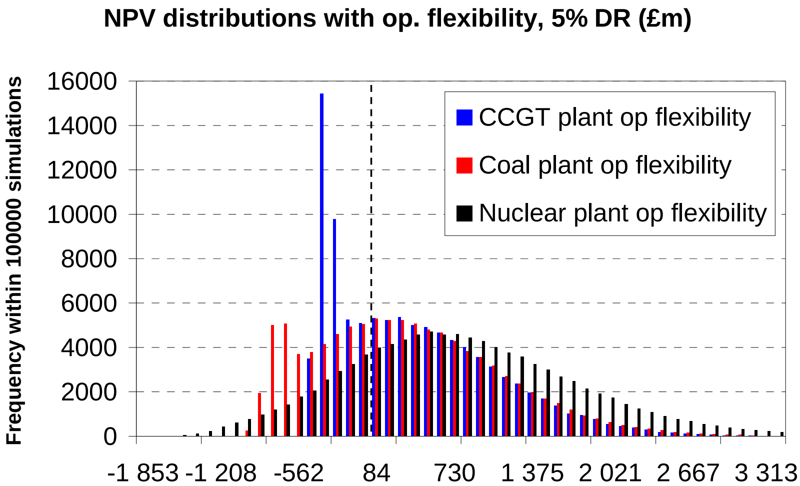
[14] The basic idea of 'take or pay' provisions is that the buyer is obliged to pay the contract quantity of gas even if he fails to take delivery in order to guarantee a cash flow for the seller.

there are no mothballing or de-mothballing costs), that the non-consumed fuel can be sold back on spot markets, and that there are no operating costs while the plant is mothballed. These assumptions imply that we are probably over-estimating the value of operating flexibility.

Running a Monte Carlo simulation with the same distribution parameters as in the previous section, we obtain NPV distributions for the three technologies shown on *Figure 10*. Comparing these NPV distributions with the NPV distributions without operating flexibility on *Figure 8* gives interesting insights, and the general patterns are similar in the 5% and 10% discount rate scenarios.

Figure 10 - NPV distributions for the three technologies with operating flexibility, 10% and 5% discount rates (£m)





First, the operating flexibility increases substantially the CCGT ENPV (from £22m to £126m with a 10% discount rate, and from £206m to £379m with a 5% discount rate) and slightly the coal ENPV (from -£148m to -£166m with a 10%

discount rate, and from £284m to £333m with a 5% discount rate), while it leaves the nuclear ENPV unchanged.

Second, the shape of the distributions is greatly modified by the operational flexibility embedded in the project: 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 (see *Tables 9* and *11* for a detailed comparison of the NPV distribution statistics).

Therefore, taking into account plants operating flexibility modifies the relative attractiveness of the different technologies. Considering the commercial scenario of a 10% discount rate, the previous section concluded that without operating flexibility, while the CCGT plant had the higher ENPV, it was also more risky and likely to make a large loss than a nuclear or coal plant. When the CCGT operating flexibility is taken into account, it becomes unambiguously the best investment choice. Indeed, the operating flexibility not only increases the CCGT ENPV relatively to the coal and nuclear plants ENPVs, but it also reduces the riskyness of the CCGT plant and caps the likelihood of largely negative NPVs to a lower level than for a nuclear or coal plant.

Table 11 - Single plant NPV distribution statistics, with operating flexibility (£m)

	10% discount rate			8 % discount rate			5 % discount rate		
Statistics - 100000 sim.	CCGT op. flex.	Coal op. flex.	Nuclear op. flex.	CCGT op. flex.	Coal op. flex.	Nuclear op. flex.	CCGT op. flex.	Coal op. flex.	Nuclear op. flex.
Mean	126	-145	-166	207	-9	85	379	333	783
Median	48	-177	-184	109	-53	54	252	264	710
St. Deviation	430	399	448	514	511	581	681	779	961
Skewness	0.89	0.54	0.29	0.92	0.57	0.36	0.92	0.61	0.49
Kurtosis	3.42	3.10	3.25	3.52	3.13	3.29	3.53	3.22	3.45
Minimum	-505	-1042	-2061	-510	-1056	-2374	-545	-1102	-1924
Maximum	2787	2062	2386	3407	2999	3731	4056	5007	6643
Range	3292	3104	4447	3917	4055	6105	4601	6109	8567

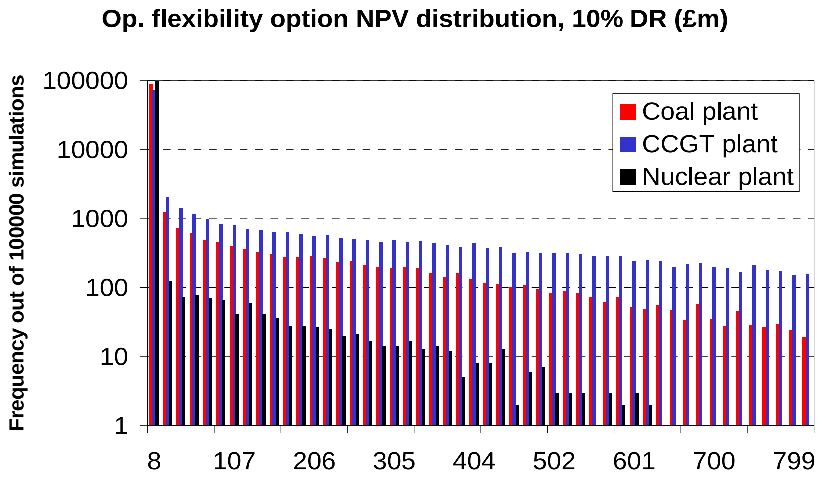
4.2 The operating flexibility 'option value'

The operational flexibility of power plants has a value which is not captured by traditional levelised cost valuation approaches. The simple spreadsheet model and Monte Carlo simulations described in the previous sections proved a powerful analytical tool to embed this flexibility in the project valuation. There is a growing literature applying innovative valuation approaches such as real options to capture the flexibility built in investment projects, generally through managerial flexibility. In this perspective, 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.

The operating flexibility 'option value' can be defined as the difference between the NPV of the power plant with and without operating flexibility. *Figure 12* shows the NPV distribution of the operating option value for the CCGT, coal and nuclear plants for 100,000 simulations. The scale is logarithmic as the option value is for most simulations equal to zero. The option is only valuable when a – rare - combination of high fuel prices and low electricity prices make it unprofitable to produce.

It is interesting that the operating option flexibility expected NPV is much higher for the CCGT (£104m with a 10% discount rate) than for the coal plant (£23m), and is worthless for the nuclear plant (see *Table 13* for the option NPV distribution statistics). 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. Moreover, 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.

Figure 12 - Operating flexibility 'option value' NPV distribution (£m)



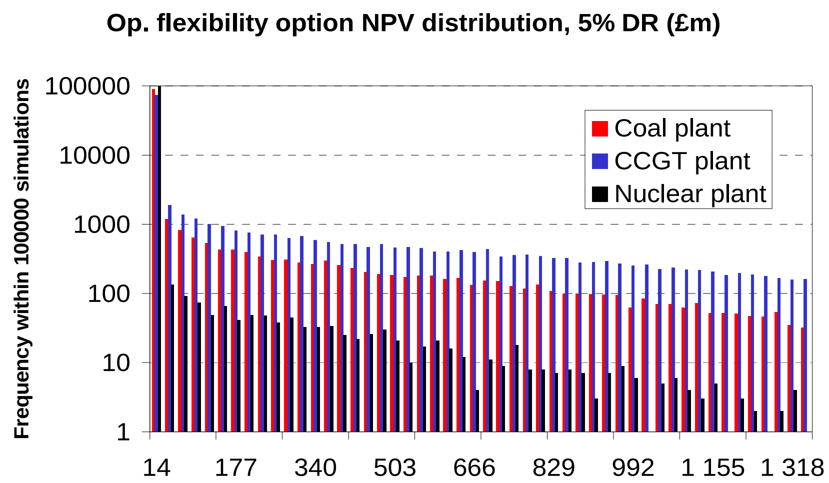


Table 13 - Operating flexibility 'option value' NPV distribution statistics (£m)

Op. flexibility option value	10% discount rate			8 % discount rate			5 % discount rate		
Statistics - 100000 sim.	CCGT	Coal	Nuclear	CCGT	Coal	Nuclear	CCGT	Coal	Nuclear
Mean	104	23	2	127	31	2	173	49	4
Median	0	0	0	0	0	0	0	0	0
St. Deviation	257	99	21	312	128	30	424	201	49
Skewness	3.38	6.00	21.24	3.31	5.76	19.61	3.37	5.83	19.18
Kurtosis	16.80	47.83	612.53	15.87	43.59	503.63	16.98	45.61	477.88
Minimum	0	0	0	0	0	0	0	0	0
Maximum	3186	1892	1211	3414	2348	1425	5694	3624	2407
Range	3186	1892	1211	3414	2348	1425	5694	3624	2407

5 MCS CASE STUDY 3: THE COMPLEMENTARITY OF THE DIFFERENT TECHNOLOGIES RISK RETURN PROFILES

This section deals with another weakness of the standard levelised cost valuation approach, namely the fact that generation technologies are valued on a stand alone basis, without recognising the complementarities in the risk-return profiles of different assets that a utility operates.

While the previous sections considered a single power plant investment in isolation, this section therefore concentrates on technological choices for a portfolio of plants. This can apply either to an electrical company already operating some power plants and considering an investment in an additional unit, or to an electrical company wishing to invest in a series of plants.

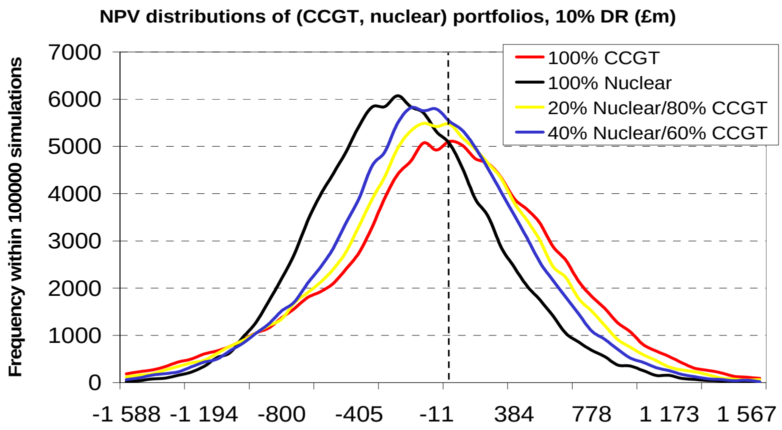
As the three base-load technologies studied in the previous section present different risk-return profiles, basic portfolio theory considerations indicate that a large utility contemplating investment in more than one plant would not put all its eggs in the same basket. Similarly, if a utility decides to invest in only one plant, its choice should be influenced by the kind of plants it already owns and operates. In other words, contrary to traditional power generation investment models, which concentrate on the economics of the technology alternatives in isolation of the utility's physical and financial assets, the investment choice of one electric company is contingent upon the portfolio of plants it already operates and assets it owns. If the electric company invests in one technology which mitigates the risk exposure of its plant portfolio, there is a diversification value for the company in investing in this technology which is not captured by stand-alone traditional project valuation.

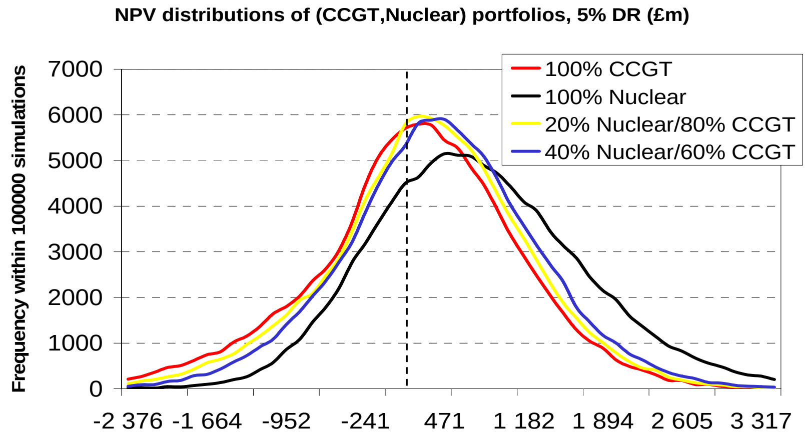
In this section, we do not consider the portfolio theory hedging effect that arises when holding different assets whose returns are not perfectly correlated. Roques et al. (2006) concentrate on the application of mean-variance portfolio theory to study the impact of varying degrees of correlation between different plants returns. For now, we set aside this correlation effect by assuming that the same-technology plants returns are perfectly correlated, and different technology plants are not correlated. We concentrate on the 'intrinsic' diversification effect arising from the different risk-return profiles of the three technologies.

The previous section has shown that CCGT, coal and nuclear plants have different risk – return profiles. In the case of a 5% discount rate, a nuclear plant is unambiguously the best investment choice, as it presents both the highest ENPV and the lowest NPV standard deviation, i.e. the higher expected return and lower riskiness. Therefore there is no 'intrinsic' value in mixed portfolios of technologies.

With a commercial 10% discount rate, a CCGT plant has the highest ENPV, but is also somewhat more risky than a nuclear plant. In particular, the probability of very low NPVs is higher for the CCGT. An electric company that would invest in a 100% CCGT portfolio would for instance have a much higher expected NPV (£22m with a 10% discount rate) than an electric company investing in a 100% nuclear plants portfolio (-£167m). But at the same time the standard deviation of the 100% nuclear portfolio is lower than the standard deviation of the 100% CCGT portfolio (respectively £481m and £587m). Therefore an interesting trade-off between expected returns and the riskiness of the investment appears. While a risk neutral investor would choose an "all gas" strategy, it is likely that in practice a utility would choose to go for one of the intermediary technology mixes, preferring to have lower expected profits in exchange of a lower probability to make a loss.

Figure 14 - Portfolios of (CCGT, Nuclear) plants NPV distribution (£m)





Looking at the mixed technology portfolios on *Figure 14*, different combinations of plants present a range of risk-return profiles that might be favoured depending on the investor risk-aversion. For instance, introducing 20% of nuclear in an "all CCGT" portfolio reduces slightly the ENPV (from £22m to -£15m), but reduces also significantly the riskiness of the investment (the standard deviation decreases from £587m to £533m).

Moreover, the greater risk of CCGTs in the Monte-Carlo simulation is mostly due to the high sensitivity of their profits to volatile gas and carbon prices. Therefore, an electric company may consider investing in a nuclear plant on top of a series of CCGT plants to mitigate the company exposure to a specific risk, such as gas or carbon price risks.

Table 15 - Portfolios of (CCGT, Nuclear) plants NPV distribution statistics (£m)

Portfolios	100% Nuclear	20% CCGT/ 80% Nucl.	40% CCGT/ 60% Nucl.	60% CCGT/ 40% Nucl.	80% CCGT/ 20% Nucl.	100% CCGT
Statistics - 100,000 sim.	**10% discount rate**					
Mean	-167	-129	-91	-53	-15	22
Median	-184	-140	-95	-48	-1	47
St. Deviation	451	447	460	490	533	587
Skewness	0.2	0.2	0	-0.1	-0.2	-0.3
Kurtosis	3.3	3.3	3.4	3.5	3.6	3.7
Minimum	-2402	-2404	-2407	-2579	-3033	-3 487
Maximum	2386	2466	2546	2626	2706	2 786
Range	4788	4871	4954	5206	5740	6 275
Statistics - 100,000 sim.	**8% discount rate**					
Mean	83	82	82	81	81	80
Median	54	61	73	83	97	108
St. Deviation	586	574	581	607	649	705
Skewness	0.3	0.2	0.1	-0.1	-0.2	-0.3
Kurtosis	3.4	3.4	3.4	3.5	3.6	3.8
Minimum	-2 707	-2 693	-2 756	-2 935	-3 266	-3 739
Maximum	3 731	3 445	3 165	2 886	3 110	3 407
Range	6 438	6 138	5 921	5 821	6 376	7 145
Statistics - 100,000 sim.	**5% discount rate**					
Mean	780	665	550	436	321	206
Median	710	615	524	434	341	252
St. Deviation	970	915	883	877	898	943
Skewness	0.4	0.3	0.2	0	-0.2	-0.4
Kurtosis	3.5	3.5	3.4	3.5	3.7	3.9
Minimum	-3 680	-3 507	-3 591	-3 784	-4 905	-6 027
Maximum	6 643	5 783	4 947	4 318	4 097	4 056
Range	10 323	9 289	8 538	8 102	9 002	10 083

6 CONLUSIONS

Liberalisation has not only introduced new risks (e.g. electricity price risk) and uncertainties, but it has also amplified the potential economic impact of such risks on generators as these are no longer able to pass their costs onto consumers. While the levelised cost methodology was well adapted to the stable environment in which regulated power generation companies operated, in liberalised markets it needs to be complemented by approaches that account for risks in future costs and revenues.

This paper introduced a probabilistic valuation model of investment in three base-load technologies (Combined Cycle Gas Turbine (CCGT), coal plant, and nuclear plant) and demonstrated through three successive case studies how Monte Carlo simulation provides investors with a much richer analytical framework to assess power investments in liberalised markets. We successively explored how such a probabilistic valuation approach can give insights on the three problematic issues with the traditional levelised cost approach, namely its failure to take into account simultaneously the multiple uncertainties that characterise generation investments in electricity markets, its inability to incorporate the value associated with technological and managerial flexibility to operate or mothball plants, and the fact that generation technologies are valued on a stand alone basis, without recognising the complementarities in the risk-return profiles of the portfolio of assets that a generation company operates.

The first case study showed in particular that while a CCGT investment clearly has the highest expected NPV (i.e. the lowest levelised costs) for a 10% discount rate, the combined effect of the multiple uncertainties results in longer tails for a CCGT NPV distribution as compared to a nuclear and to a lesser extent coal power plants NPV distribution, indicating that the CCGT investment is significantly more risky.

The second Monte Carlo simulation case study showed that the operating flexibility of power plant managers to mothball and de-mothball plants (depending on the relative fuel, carbon, and electricity prices) adds significant value to a CCGT plant, but very little to coal and nuclear power plants. As a consequence, the operating flexibility option value greatly improves the value of a CCGT as compared to the two other technologies.

The third Monte Carlo simulation case study compared the risk-return profiles of different portfolios of plants of different technologies. It highlighted the complementarity of the different production technologies when the electric company faces various uncertainties, and how investors can take advantage of such synergies by investing in mixed portfolios. In particular, introducing nuclear in a gas-dominant portfolio mitigates the likelihood of making large losses due to gas and carbon price uncertainty, without major negative impacts on the expected NPV. Investors therefore face a trade-off between maximising expected returns and lowering the risk exposure of their investment. While a risk neutral investor would choose an “all gas” strategy, it is likely that in practice a utility would choose to go for one of the intermediary technology mixes, preferring to have lower expected profits in return of a lower probability to make a loss.

The three case studies demonstrated how the analytical approach developed in this paper using Monte Carlo simulation can be used to capture the value associated with a wide variety of power investment issues. Other potential applications include issues such as modularity (the ability of a resource to be added in relatively small increments) and the covariance between demand and resource outputs. It is however important to recall that subjective judgements are often still required in assigning appropriate probability distributions for uncertain model inputs. Model results and the particular resource decisions supported by such results are therefore sensitive to the assumed form for input distributions, and the parameters selected to generate distributions of a particular form. On the other hand, these concerns are at least as difficult to address with alternative methods and it is our view that these concerns can be effectively addressed through appropriate use of Monte Carlo simulation. Overall, the graphical probability output distributions produced in a Monte Carlo simulation analysis appears both more intuitive and insightful than single points expected values and the associated confidence level. The three case studies in this paper show that Monte Carlo simulation, when properly employed, is a potentially powerful – if underutilised – tool for examining electric utility resource decisions.

7 APPENDIX 1: CHOICE OF THE DISCOUNT RATE

One key determinant of any asset valuation approach is the discount rate at which the future cash flows are discounted. The cost of capital depends essentially on two things: the perceived risk of the project, and how it is financed. When making comparisons about discount rates, it is important to distinguish between differences in discount rates resulting from differing assumptions about the underlying risk of the project from those resulting from different financing assumptions.

7.1 Capturing project risk

To estimate the discount rate for the project assuming it is 100% equity financed, the most common practice is to add a project specific risk premiums to the risk free rate of return.[15] The risk free rate of return is generally assumed to equal long term rates of return to government bonds, which is equal to about 3% in the United States in real terms over long time periods. The estimation of risk premium is complex. If the risk of the project in question is similar to the other ones undertaken by the firm, if the firm's common stock is traded on open markets, and if the past is a good predictor of the future, then in principle the risk premium can be estimated using published historical stock price data.

[15] The most common model used in this area is called the capital asset pricing model (CAPM) which assumes a linear relationship between the riskiness of a project and the rate of return that is earned. The riskiness is quantified by a parameter known as beta. A beta of 1 indicates that the project's risk is average and the required return is equal to the average return of the stock market.

IEA/NEA (2005) estimates that over the 1970-1984 time period, independent of financing issues, the discount rate for a typical utility investment project would have been about 5% (the 3% real risk free rate plus the 2% risk premium). This was in fact lower than the discount rate for typical US investments and reflected the fact that costs could in general to be passed on to consumers and that a large proportion of the investments were in relatively low risk projects, i.e. transmission and distribution.

In the more open electricity market environment, cost recovery is not guaranteed, and building and operating any power plant is risky. The US Energy Information Administration (EIA) (Tolley et al., 2004) suggests to use a discount rate based on the stock prices of two industries, airlines and telecommunication, whose "structure and size are an appropriate guide to the current and future utility industries." Independent of financial issues, the discount rate used by EIA for evaluating utility investment are about 10% in real terms (the 3% risk free return plus a 7% risk premium).

7.2 The impact of the financing structure

When the financing structure of a project is taken into account, the risk-adjusted discount rate is a weighed average of the cost of funds obtained from shareholders ("cost of equity") and borrowed from debt-holders ("cost of debt") with relative amounts of equity and debt being the respective weights. Since debt-holders have first claims on the assets of the firm in case of bankruptcy and their returns are fixed, the cost of debt will always be less than the cost of equity (Brealey and Myers, 2000).[16] The nominal before tax discount rate used in the power generation cost assessment for a regulated utility is formally equivalent to the Weighted Average Cost of Capital (WACC), which can be calculated by using the following formula:

$$\text{Nominal before tax Discount Rate } = WACC_{beforetax} = \alpha . r_E + (1-\alpha) . r_D \,,$$

where α is the percentage of equity fund, (1- α) is the share of debt in the investment cost, r_E is the real rate of return on equity before tax, and r_D is the real rate of loan interest.[17]

Increases in the amount of debt financing will, therefore, have two effects on the risk adjusted discount rate that work in opposite directions. Increases in debt financing will result in the substitution of relatively less expensive debt capital, and this will cause the discount rate (or weighted average cost of debt and equity capital) to decrease. However, the cost of the equity component will also increase, and this effect by itself will cause the discount rate to increase. Thus, the overall effect of increased debt financing on the discount rate will depend upon the relative size of these two effects.

[16] The cost of equity capital is the rate of return that the equity funds could have earned if they were invested in another project of equal risk in the market place. The estimation of this rate is discussed shortly.

[17] Tax deductibility of interest effectively makes debt cheaper for the company. The after-tax nominal cost of capital can be formulated as $WACC_{aftertax} = \alpha . r_E + (1-\alpha) . (1-\tau) . r_D$, where τ is the rate.

7.3 Technology specific discount rates

The various generation technologies present different risks and have been affected differently by the new risks introduced by the liberalisation of the electricity industry. As a consequence, some recent studies use different discount rates for different technologies. These different discount rates reflect different assumptions about how they can be financed. Technologies seen as financially risky may require a higher return on investment.

Two US economic analyses of nuclear power, one carried out at the Massachusetts Institute of Technology (Deutch et al., 2003) and the second at the University of Chicago (Tolley et al., 2004), attempt to correct for the additional risk involved with nuclear power investment in the United States. Both studies assumed that investors in nuclear power plants in the United States require higher returns on equity and a higher share of relatively costly equity in the capital investment for nuclear power investment compared to natural gas. Moreover, Deutch et al. (2003) show that inclusion of income tax also more heavily affects the more capital intensive technologies. Both studies find that the financing effects alone raise the weighted cost of capital for nuclear power by around 2% as compared to natural gas. The impact of corporate taxes increases effective discount rates for both technologies, but increases the gap in discount rate for nuclear versus natural gas by a further 0.6%.

Technology specific discount rates will vary by country given the different situation with regard to perceived risk of investment in different options and the cost of finance among other factors. For example, countries where perceived risks in nuclear power are lower might have a much smaller gap in the weighted cost of capital between the two options. Besides, a particular firm might have rather different costs of capital. However, IEA/NEA (2005) emphasises that access to cheaper capital does not reduce risks, but merely transfers these risks to others (e.g. to the state or to the power consumers).

7.4 Using market based discount rates for project valuation

Another innovative and relatively controversial approach to discount rates is to use different market-based discount rates for the costs and revenues of a generation project (see e.g. Seitz and Ellison, 1995, for a presentation of capital budgeting and market-based discount rates in project valuation). The idea is to discount the costs and revenues of a project at different rates according to their riskiness. Awerbuch (1993, 1995, 2000, 2003, 2004) suggests that the Capital Asset Pricing Model (CAPM) provides a framework to incorporate market risk into a project valuation, by using market-based discount rates estimates of the different cost and revenue outlays.

All projected operating and capital cost streams exhibit some degree of risk. There are two aspects to risk. The first consists in the periodic variability of a particular operating cost stream as statistically measured by the standard deviation. The second aspect to risk relates to the degree to which the periodic variability systematically coincides with the movement of broad financial market indicators, and is often referred to as “systematic risk” or “non-diversifiable” risk (Seitz and Ellison 1995).

Beta, a measure of financial covariance risk, provides the basis for estimating discount rates for generating projects. CAPM discount rates are a simple linear function of beta.[18] Fossil fuel outlays clearly present the greatest risk, but projected labour costs associated with O&M outlays may also be risky. Cost outlays for capital-intensive technologies such as wind and nuclear are largely sunk, which makes them "systematically riskless", in a finance sense. The negative macroeconomic relationship between oil prices and GDP gives rise to the expectation that fossil fuel cash flow betas will also be negative. Kahn and Stoft (1993), Awerbuch (1993, 1995), and Bolinger et al. (2004) have reported empirically estimated negative cash flow betas for oil and gas. Awerbuch (2003) estimates that the historical betas of coal, gas, and oil in the European Union are on the order of -0.4, -0.1, and -0.05, respectively. Bolinger et al (2004) regressed historical percentage changes in natural gas prices delivered to electricity generators against historical percentage changes in the S&P 500 index. Their cumulative estimate of beta typically ranges from -0.2 to -0.4.

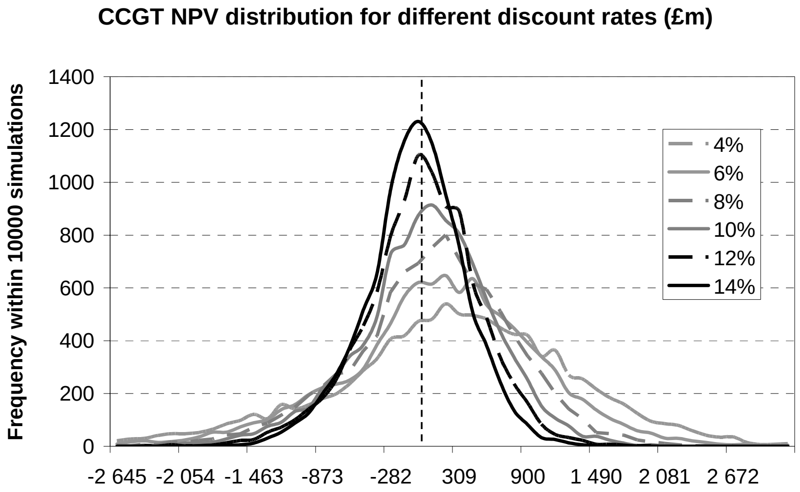
Negative betas for fossil fuel generation imply that discount rates for fuel outlays must be at or below the risk-free rate (about 3-4% pre-tax). Therefore according to Awerbuch (2003, 2004), traditional discounted cash flow methods that arbitrarily discount fuel outlays at much higher rates (between 5 and 15%) significantly underestimate the present value cost of fossil fuels. Awerbuch (2003) argues that the use of arbitrary discount rates in traditional valuation models make fossil fuel alternatives seem considerably less costly that they actually will be.

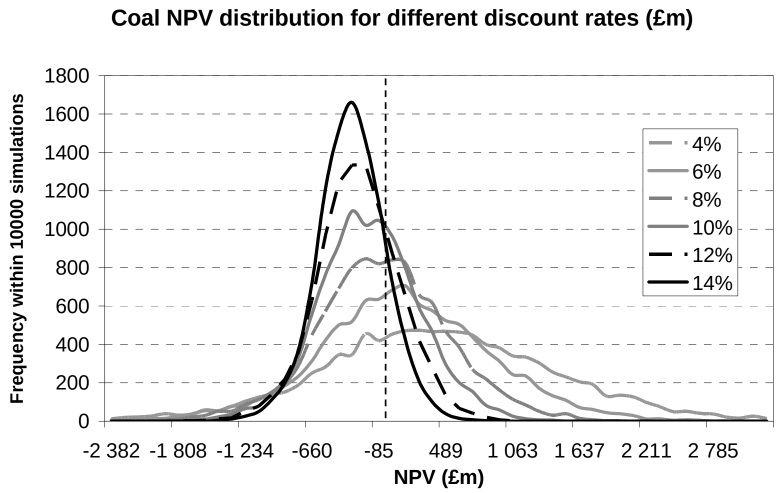
8 APPENDIX 2: SENSITIVITY ANALYSIS TO THE DISCOUNT RATE

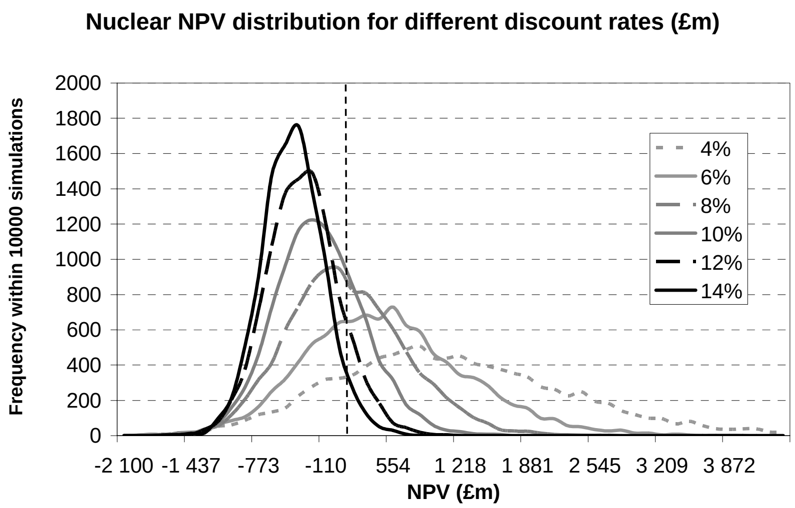
The Monte-Carlo simulations in this paper were run with two discount rates (10% and 5%). The relative attractiveness of the three technologies varies greatly with the discount rate. *Figure 17* shows a sensitivity analysis of the NPV probability distributions presented in section one to the discount rate, within the range [4%, 14%]. *Figure 17* shows that the three technologies are more or less affected by the choice of the discount rate. In particular, nuclear – and to a lesser extent coal – are very capital intensive, such that their NPV depends crucially on the choice of the discount rate.

[18] A CAPM discount rate = Rf +β(RP), where Rf is the risk-free rate, and RP is the market risk premium.

Figure 17 - Sensitivity analysis of the three technologies NPV distributions to the discount rate (£m)







9 REFERENCES

Ampere (2000), «Rapport de la Commission pour l'Analyse des Modes de Production de l'Électricité et le Redéploiement des Énergies (AMPERE)», Bruxelles. English translation of Section I "evaluation of the current and future production cost of electricity and the external costs" available at www.mineco.fgov.be/energy/ampere_commission/I.pdf.

Awerbuch, S. (1993), "The Surprising Role of Risk and Discount Rates in Utility Integrated-Resource Planning," *The Electricity Journal*, 6, 3, 20-33.

Awerbuch, S. (1995), "Market-Based IRP: It's Easy!!!," *The Electricity Journal*, 8 (3): 50-67.

Awerbuch, S. (2000), "Investing in photovoltaics: risk, accounting and the value of new Technology", *Energy Policy* 28: 1023-1035.

Awerbuch, S. (2003), "Determining the real cost: why renewable power is more cost-competitive than previously believed", *Energy World*, March-April 2003.

Awerbuch, S. (2004), "Towards A Finance-Oriented Valuation of Conventional and Renewable Energy Sources in Ireland", Report prepared for Sustainable Energy Ireland, Perspective from Abroad Series, Dublin, June 2004.

Awerbuch, S. and M. Berger (2003), "Energy Security and Diversity in the EU: A Mean-Variance Portfolio Approach," *IEA Research Paper*, Paris, February 2003, www.iea.org/techno/renew/port.pdf.

Awerbuch, S., Stirling A., Jansen J., Beurskens L. (2004), "Portfolio and diversity analysis of energy technologies using full-spectrum uncertainty measures", Commissioned Conference Paper, Understanding and Managing Business Risk in the Electric Sector, April 15-16, 2004.

Bolinger, M., Wiser, R., Golove W. (in press), "Accounting for fuel price risk when comparing renewable to gas-fired generation: the role of forward natural gas prices," *Energy Policy,* 2004.

Brealey R., and S. Myers (2000), Principles of Corporate Finance, Sixth Edition, Irwin McGraw-Hill.

Chevalier, J.-M. (2000), "The Deregulation of Natural Gas and Power Industries in Europe," Economia delle Fonti di Energia, No. 1, p. 15-25.

Connors S., K. Martin, M. Adams, E. Kern (2004), "Future Electricity Supplies: Redefining Efficiency from a systems perspective", Analysis Group for regional Electricity Alternatives (AGREA), MIT Laboratory for Energy and the Environment (LFEE), Working Paper, June 2004.

Department of Energy (2004), U.S. Energy Information Administration (EIA), "Annual Energy Outlook", DOE/EIA-0383(2004), January 2004, available at: http://www.eia.doe.gov/oiaf/aeo.

Department of Trade and Industry (2003), Energy White Paper, Our energy future: Creating a low carbon economy, February 2003.

Deutch J., E. Moniz, S. Ansolabehere, M. Driscoll, P. Gray, J. Holdren, P. Joskow, R. Lester, and N. Todreas (2003), The Future Of Nuclear Power, an MIT Interdisciplinary Study, http://web.mit.edu/nuclearpower.

Dideme (2003), « *Coûts de reference de la production électrique* », December 2003, DGEMP-DIDEME, Paris. www.industrie.gouv.fr

Electric Power Research Institute (EPRI) (1986), Technical Assessment Guide, Volume 1: Electricity Supply.

Feretic, D. and Z. Tomsic (2005), "Probabilistic analysis of electrical energy costs comparing: production costs for gas, coal and nuclear power plants," *Energy Policy* 33: 5-13.

Fraser, P. (2003), Power Generation Investment in Electricity Markets, OECD/IEA publication 2003.

Girard, P., B. Barre, and B. Tinturier (2004), "Nuclear Investments and markets," Proceedings of the World Energy Congress 2004.

IAEA (2004), Department of Nuclear Energy, Planning & Economic Studies Section (PESS), "Capacity Building: PESS Energy Models", available at http://www.iaea.org/OurWork/ST/NE/Pess/PESSenergymodels.shtml

IAEA and NEA (2004), Uranium 2003: Resources, Production and Demand, OECD, Paris, France.

International Energy Agency (2004), World Energy Outlook 2004, OECD/IEA, Paris, France.

International Energy Agency/Nuclear Energy Agency (2005), Projected costs of generating electricity, 2005 update, OECD publication, Paris.

Kahn, E., Stoft, S. (1993) (unpublished draft), "Analyzing Fuel Price Risks Under Competitive Bidding," Berkeley: Lawrence Berkeley National Laboratory.

NEA (2000), Reduction of Capital Costs of Nuclear Power Plants, OECD, Paris, France.

NEA (2002), Trends in the Nuclear Fuel Cycle, OECD, Paris, France.

Neuhoff, K and C. von Hirschhausen (2005), "Long-term vs. Short-term Contracts: A European Perspective on Natural Gas," EPRG Working Paper 05, www.electricitypolicy.org.uk.

Rode, D., Fishbeck P., and Dean, S. (2001), "Monte Carlo Methods for Appraisal and valuation: A Case Study of a Nuclear Power Plant", *Journal of Structured and Project Finance*, 7:3 (2001), p. 38-48.

Roques, F., D. Newbery, and W. Nuttall (2006), "Fuel mix diversification incentives in liberalised electricity markets: a Mean-Variance Portfolio Theory Approach," EPRG Working Paper, www.electricitypolicy.org.uk.

Royal Academy of Engineering (2004), The Cost of Generating Electricity, a study carried out by PB Power for the Royal Academy of Engineering, London. http://www.raeng.org.uk/news/temp/cost_generation_report.pdf

Seitz, N. and M. Ellison (1995), Capital Budgeting and Long-Term Financing Decisions, Dryden Press.

Spinney, P. and G. Watkins (1996), "Monte Carlo simulation techniques and electric utility resource decisions," Energy Policy 24(2):155-163.

Stern, J. (1998), Competition and liberalisation in European Gas Markets: A diversity of models, London: The Royal Institute of International Affairs.

Tarjanne R. and Luostarinen, K. (2003), "Competitiveness Comparison of the Electricity Production alternatives," Lappeenranta University of Technology research report EN B-156.

Tarjanne R. and Rissanen S. (2000), "Nuclear power: least cost option for base-load electricity in Finland". The Uranium Institute 25th Annual Symposium, 30 August-1 September 2000, London. http://www.world-nuclear.org/sym/2000/pdfs/tarjanne.pdf.

Tolley G., and D. Jones (2004), "The Economic Future Of Nuclear Power," A Study Conducted At The University Of Chicago, www.ne.doe.gov/reports/NuclIndustryStudy.pdf

Uranium Information Center (2004), "Uranium Markets", Nuclear Issues Briefing Paper 36, October 2004. Available at http://www.uic.com.au/nip36.html