Nuclear Power:
a Hedge against Uncertain Gas and Carbon Prices? [1][2]

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High fossil fuel prices have rekindled interest in nuclear power. This paper identifies specific nuclear characteristics making it unattractive to merchant generators in liberalized electricity markets, and argues that non-fossil fuel technologies have an overlooked 'option value' given fuel and carbon price uncertainty. Stochastic optimization estimates the company option value of keeping open the choice between nuclear and gas technologies. The merchant option value decreases sharply as the correlation between electricity, gas, and carbon prices rises, casting doubt on whether merchant investors have adequate incentives to choose socially efficient diversification in liberalized electricity markets.

Keywords: Nuclear economics, stochastic optimization, fuel-mix diversification, option value.

JEL reference: C15, C61, L52, L94.

1 INTRODUCTION

In the last decade, Europe and North America electricity supply industries have seen a transition from vertically integrated franchise monopoly structures (typically state-owned in Europe and regulated in the US) to unbundled companies trading in liberalized wholesale markets. There has been no new nuclear build in the last decade in liberalized electricity markets, with the exception of the recent Finnish (2004) and French (2005) European Pressurized Water (EPR) reactor orders.

The winter of 2005/6 has seen threats of gas supply disruptions in Europe and very high gas prices, particularly in the UK (with the most liberalized gas

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[2] An extended version of this paper presenting sensitivity analyses on cost and technical parameters is available on the Electricity Policy Research Group website at www.electricitypolicy.org.uk.

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market), which have revived concerns about energy security. The backdrop of such events is a general increase of fossil fuel prices since 2004, which has rekindled interest in nuclear power generation as one of the potential solutions to diversify the primary energy supply mix of oil and gas importing nations, to reduce greenhouse gas emissions from power generation, and to provide a source of electricity with stable production costs.

Besides problems of public acceptance and nuclear waste disposal, important economic, regulatory, and financial barriers confront private investment in new nuclear power stations in liberalized markets. In the U.S., the 'Nuclear 2010 project' supports actions intended to remove the regulatory barriers to new nuclear build, e.g. through streamlining the licensing procedure, while the 2005 Energy Act introduced a cost-overrun support of up to $2 billion total for up to six new nuclear power plants and a nuclear production tax credit of 1.8 cent per kWh for the first 8 years of production from new nuclear facilities (U.S. Congress, 2005). In Europe, both Finland and France are taking the first steps towards new nuclear build aided by the high carbon price now visible on the European Emissions Trading System. A number of other countries (including the U.K., Spain, Italy, Poland, the Netherlands, and the Baltic States) have reopened the debate about nuclear power.

Much of the conventional debate around the economics of nuclear power has focused on the expected levelized cost of nuclear power compared to other forms of base-load generation. This paper tackles the question as to whether a merchant generating company (that is, one with no ownership stakes in retailing) might choose to add a nuclear power plant to their existing generation capacity to hedge the risk of volatile prices for fossil fuels (natural gas) or for carbon dioxide emissions. We conclude that for likely commercial costs of capital such option values are severely eroded by the high correlation between gas, carbon and electricity prices. As there is likely to be a social and consumer benefit in fuel mix diversity, this paper will show that merchant generators appear to lack incentives to diversify by constructing new nuclear power plants in current liberalized electricity markets.

2 NUCLEAR ECONOMICS IN LIBERALIZED ELECTRICITY MARKETS

In 2005 there were 440 nuclear power reactors in 31 countries, with a combined capacity of 367 GWe, generating some 16% of the world's electricity (WNA, 2005).[4] Until recently, however, no new nuclear power station had been commissioned in a liberalized electricity industry. One key issue for the commercial future of nuclear power is to understand how the commercial unattractiveness of nuclear power is related to electricity market structures. To what extent has the risk redistribution brought about by liberalizing the electricity supply industry and the

[4] In 2005 about 30 power reactors are being constructed in 11 countries, notably China, the Republic of Korea, Japan and Russia (World Nuclear Association, 2005).

resulting higher cost of capital contributed to the success of gas-fired plants to the detriment of nuclear power and other capital-intensive technologies?

2.1 Levelized cost comparisons

The traditional approach for comparing the competitiveness of different generation technologies is the '*levelized cost*' methodology, based on a discounted cash flow analysis over the life of the plant. This valuation technique is appealing as it gives simple results in the form of comparable levelized production costs. The levelized cost approach was well suited to the stable environment of the electricity industry before liberalization. It continues to be widely used by utilities post liberalization, despite its inappropriateness for evaluating investment choices under uncertainty (Deutch et al. 2003, IEA/NEA, 2005).

Table 1 shows the model parameters and levelized costs for the most recent studies conducted in Canada (CERI, 2004), Finland (Tarjanne and Rissanen, 2000), France (DGEMP/Dideme, 2003), the U.K. (RAE, 2004), the U.S. (Deutch et al., 2003, and Tolley et al., 2004), and the OECD (IEA/NEA, 2005).

Table 1. Comparison of levelized cost estimates for nuclear plant

Study	Tarjanne	DGEMP	CERI	RAE	MIT	Univ. of Chicago	NEA/ IEA
Country	Finland	France	Canada	UK	USA	USA	International
Date	2000	2003	2004	2004	2003	2004	2005
Capacity factor	91%	91%	90%	85%	85%	85%	85%
Construction time (years)	5	5	6	5	5	7	5-10
Discount rate (real)	5% (4-6%)	8% (3-11%)	8%-10%	7.5% nominal	12.5%	12.5%	5%-10%
Overnight capital cost US2004$/kW	2190	1350 (10 units)	1800	2100	2040	$1080-1980	$1100-2500
Decomissioning	NA	Incl. in capital cost	$6m/yr	Incl. in capital cost	NA	$350m fund	Incl. in capital cost
Breakdown of levelized cost in 2004US$/MWh[5]							
Investment	12.9	16.9	26.6	24.2	-	-	-
O&M	11.8	4.2	9.7	8.2	1.53 (fuel plus O&M)	5.6	46-108 US$/kW
Fuel	2.9	4.7	4.2	10		4.35	2.8-11.8

[5] The different currencies have been converted into 2004 US$ using the U.S. Federal Reserve foreign exchange rates and the US Consumer Price index of the U.S. Department of Labor Statistics.

Total cost	**22.6**	**30**	**41**	**41.4**	**68.3**	**62**	**30-50**
Sensitivity range	20.9-24.4	22.9-39.1	41-56.3	41.4-44.7	50-80.5	53-71	-

The table shows wide differences in the results arising mainly from the different assumptions made for construction and operating costs of nuclear and the differing financing structures of the models.[6] Construction cost for new capacities exceeding 1000 MWe ranges from about $US1,100/kWe to $US2,500/kWe. The financing assumptions differ also greatly, with real discount rates varying from 5% to 12.5%, equity shares varying from 30% to 50%, and debt repayments concentrated in the first 10 years or spread over the life of the plant (Deutch et al., 2003, Tolley et al., 2004). These different assumptions reveal not only different degrees of confidence in the nuclear industry cost figures, but also a different understanding of the impact of the electricity industry liberalization on new nuclear plants economics and financing.

2.2 Biases against nuclear power in liberalized markets

When examining the alleged discrimination in technology choice caused by market liberalization, one should remember that the old regulated vertically integrated monopoly model also introduced biases. It was normally able to finance any required capacity in generation, but provided poor incentives for delivering investment in a timely and cost-effective way. Averch and Johnson (1962) demonstrated that regulated utilities might rationally prefer to invest in excessively capital-intensive technologies. Moreover, the subordination of utilities to regulation bodies gave rise to other distortions of investment choices. For instance, many countries directly controlled or influenced the fuel mix through subsidies to 'national' fuels (such as coal or lignite), or the financing of 'national' technologies (such as nuclear) (Newbery and Green, 1996).

In liberalized markets investments are profit motivated, with the choice of technology left to the market. The redistribution of risk among the different stakeholders is likely to make nuclear generation unattractive for an investor, even when its levelized costs are similar to the levelized costs of the dominant technology, for several reasons.

First, investors have a strong preference for a shorter payback period, which makes investments with short lead time more attractive. Nuclear lead times (5 years in the most optimistic scenario given the historical record in Table 2) are, for engineering and licensing reasons, much longer than CCGT lead times (2 years).

[6] Decommissioning costs are estimated at 9-15% of the initial cost of a nuclear power plant, but contribute only a few percent to the investment costs when discounted (in the USA, they account for 0.1-0.2 cents/kWh). The back-end of the fuel cycle contributes up to another 10% to the overall costs per kWh (the $18 billion US spent fuel program is funded by a 0.1 cent/kWh levy) (Uranium Information Center, 2004).

Table 2. Time from construction start to commercial operation of currently operating nuclear power plants.

Plants connected to the grid	Average (year)	Minimum (year)	Maximum (year)	Standard deviation	Number of plants
China	6.3	4.5	9.1	1.5	9
France	7.1	4.9	16.3	2.2	58
Japan	4.7	3.3	8.1	0.9	56
Russia	6.8	2.1	20.1	3.2	29
U.K.	10.8	4.9	23.5	5.9	22
U.S.A.	9.2	3.4	23.4	3.8	103
Worldwide since 1991	5.2	4.0	8.0	1.0	24

Data source: IAEA database.

Second, construction costs for nuclear plant are two to four times greater than for a CCGT (about $400 to $800 per kWe installed). Of the three major components of nuclear generation cost – capital, fuel, and operation and maintenance – the capital cost component makes up approximately 70% of the total, while it only represents about 20% of total costs for a CCGT (see Table 3). In addition, the size of a typical nuclear unit is much larger than the size of a typical gas turbine: recent nuclear technologies range from 1000MWe (AP1000 from BNFL) to 1600MWe (EPR from Areva), while CCGTs units are only of about 100 to 650 MWe (although it is common to build several on one site). This implies that the required minimum upfront capital investment for a nuclear plant can be ten to fifteen times greater than the smallest investment required for a CCGT.[7]

Table 3. Representative proportions of electricity generating costs.

Breakdown of MWh cost	Nuclear	CCGT
Construction or capital	65-80%	20-30%
O&M	10-20%	5-10%
Fuel	5-10%	60-80%

Source: Own estimates

Third, the lack of recent experience with new build makes it difficult to get reliable cost estimates. The traditional optimism of nuclear vendors reinforces investors' distrust of vendors' assessments. The history of nuclear electricity includes a list of seriously delayed construction and cost overruns (Nuttall, 2004). Besides, investors must confront the regulatory and political challenges associated with obtaining a license to build and operate a plant on a specific site.

[7] NEA (2000) presents a detailed analysis of the most significant means to reduce nuclear plant capital cost with current technologies, such as increased plant size, improved construction methods, reduced construction schedules, standardisation and construction in series, and multiple unit construction.

Fourth, the greater size of nuclear technology exposes investors to greater downside risks, as for the next decade only large-scale *Generation III* plants are commercially attractive.[8] Small (approximately 200MW) modular reactor systems are under development in various countries, but none are likely to be ready for commercial deployment on the timescales considered here.

2.3 The challenge of financing nuclear power

With its capital intensity and cautionary experiences of engineering difficulties and regulatory creep during construction, new nuclear build is likely to require a substantial risk premium over competing technologies. Rothwell (2006) uses a real options model to compute the risk premium arising from the uncertain profitability of a new plant, using historical construction costs, capacity factors, and electricity price data for an Advanced Boiling Water Reactor in Texas. He estimates a risk premium of 5.2%, implying a real cost of capital of 12%. This is consistent with the real discount rates of 12.5% assumed in the two studies of merchant financing in Table 1. Tolley et al. (2004) estimated that the risk premium required by bond and equity holders for financing new nuclear plants is around 3% higher than for other technologies. Similarly, Deutch et al. (2003) assume that merchant financing of nuclear power would require a 15% nominal return on equity (as compared to a 12% nominal return on equity for gas and coal), and a 50% equity share of financing (as compared to only 40% equity financing for gas and coal).

Innovative financing techniques have been investigated to disentangle the high construction risks from the lower operation risks of new nuclear build (Scully Capital, 2002). Whether it involves project finance or corporate finance, the financing arrangements of a nuclear power plant are likely to involve refinancing once the plant has started production. TIACT (2005) shows how a "toll gate approach" with options to defer and abandon the construction project after completing the site permission and regulatory licensing procedures substantially improves nuclear plant value. Such considerations provide some rationale for government-assured loans or construction cost overruns to compensate for the regulatory hurdles and procedures and cost uncertainty associated with the first units to be built.

Finally, a critical issue for the commercial future of nuclear power will lie in the willingness of large European and American utilities to share the risks and development costs of new nuclear power stations. Cooperative agreements might help to spread costs and risks, but their success will depend on completing a large program of new build, and on achieving operational learning despite fragmented ownership. The recent concentration movement of nuclear plant operators in the

[8] Gollier et al. (2005) compare the benefit of one large nuclear power plant project coming from increasing returns to scale, to the benefit of a modular sequence of smaller (300 MWe), modular, nuclear power units on the same site, and show that the benefit of modularity is equivalent in terms of profitability to a reduction of the cost of electricity by only one-thousand of a euro per kWh.

U.S. and of electricity utilities in Europe is an interesting development in this perspective.

Given all these challenges to new nuclear build, what explains the 2004 decision to build a new nuclear power unit in Finland? The large capital costs of the plant have been financed by very long-term power purchase agreements. Interest in such long-term agreements, which are rare in liberalized markets, has been triggered by the specificities of local industries that have very long investment cycles and are extremely sensitive to the price of electricity. The Finnish electricity company Teollisuuden Voima Oy (TVO) is a cooperative grouping of local utilities and large industrial consumers, which are mainly paper makers with a very long investment cycle (over 40 years).[9] Each shareholder will enjoy electricity at production cost during the life of the plant (60 years), i.e. at a very stable price, in proportion to its share, as well as holding a useful option on the future carbon price (c.f. Table 4).

Table 4. TVO Olkiluto 3 nuclear plant ownership

Ownership and long-term contract shares		
Pohjolan Voima Oy	Energy Company	60.2%
UPM-Kymmene	Forestry products	25.6%
Stora Enso Oyj	Forestry products	9.4%
Others	Forestry products	25.2%
Fortum Power&Heat Oy	Government controlled power corp.	25.0%
Oy Mankala Ab	City of Helsinki	8.1%
Etela-Pohjanmaan Voima Oy	Distribution power company	6.6%
Graninge Suomi Oy	Forestry/energy group	0.1%

These long-term power purchase agreements enabled financing at low cost (5% real discount rate in the Tarjanne and Rissanen (2000) study that served as basis for the technology choice), which substantially improves nuclear economics. The Finnish case is therefore in many ways reminiscent of the institutional environment that made nuclear a competitive technology in the days of regulated monopoly (at least for certain fuel price configurations), through the transfer of investment and operation risks to consumers via contractual arrangements.

The Finnish example reminds us that low discount rates are obtainable in liberalized markets when the risks have been adequately mitigated, in this case by very long-term effectively fixed price power purchase agreements with large, credit-worthy consumers who necessarily (given their involvement in the forest industry) must take a very long-term outlook. It is not impossible to identify such consumers in other liberalized markets, but the dominant assumption is that electricity consumers are generally uninterested in hedging their risk exposure to electricity price fluctuations. Rothwell's (2006) theoretical estimates show that provided it were able to find interested counterparties, a nuclear plant operator could offer

[9] TVO is a public-private partnership company, 43% government-owned, 57% private.

fixed-price long-term electricity contracts at a premium of \$0.96/MWh without guaranteed output and with a \$2.96/MWh premium for a "firm" contract.[10]

Vertically integrated companies with both generation and retailing can effectively internalise the risk of wholesale power price volatility without an explicit contract, and are thus well placed to hedge wholesale price risks. There has been a sharp increase in the UK in mergers between unbundled (and hence merchant) generating companies and the recently unbundled (from distribution) supply or retailing companies. The largest UK gas supply company, Centrica, has aggressively entered the domestic electricity retail market, as well as generation with gas-fired CCGT units. Given its dominance of the "dual fuel" market (i.e. selling both electricity and gas to the domestic consumers), Centrica is short of electricity, and has been willing to sign long-term electricity contracts. In February 2005 the company signed a five-year contract with International Power at a price indexed against a coal-pricing formula, as an alternative to investing in coal-fired plant (which remains an option) and to diversify away from gas. Centrica also has an off-take contract for nuclear power with British Energy and has reportedly favoured new nuclear power "to maintain UK fuel diversity." (Platts, 16/3/06, 12/4/06). It is worth noting that Centrica also offers fixed price contracts to final consumers, and this is the key element needed to transfer the price risk.

Mergers between generation and supply companies raise competition concerns unless transmission and distribution have been unbundled into companies under different ownership and the wholesale and retail markets are workably competitive – a situation that is far from common on the Continent. It remains to be seen whether such mergers will be sufficient to address the potential risk market failure that we identify facing merchant generators contemplating nuclear investments, or whether the limited duration of contracts with final consumers remains a key obstacle to efficiently allocating nuclear risks.

2.4 The potential financial benefits of nuclear power

There are potentially two attributes of nuclear power generation that could make it more appealing to investors. First, nuclear generation costs are insensitive to both gas and carbon prices (as are most renewables).[11] Therefore, rising gas prices and carbon trading or carbon taxes will make nuclear more competitive against CCGTs and coal-fired plants.[12] Second, investing in nuclear can be thought as a

[10] The non-firm contract places plant availability risk on the buyer, whereas the firm contract price reflects the cost to the merchant generator of bearing the plant availability risk. Rothwell (2006) considers investment in one single plant and takes the electricity price risk as uncorrelated with any fossil fuel price, and hence ignores any portfolio choice issues.

[11] Nuclear fuel price have relatively little effect on electricity generation costs: a doubling of the uranium oxide price would increase the fuel cost for a light water reactor by 30%, and the electricity cost by only about 7%, whereas doubling the gas price would add 70% to the price of electricity (Uranium Information Centre, 2004).

[12] In the EU, CO_2 emissions are now priced by the emissions trading scheme.

hedge against the volatility and risk of gas and carbon prices for a (large) generating company. The uncertainty over the evolution of gas and carbon prices implies that there is an option value associated with being able to choose between nuclear power and other fossil fuel technologies in the future. Moreover, the hedging value of a nuclear power investment to a company is not restricted to the insensitivity of this plant to gas and carbon price risks. For a company already operating some fossil fuel generation plants, investing in a nuclear plant reduces the company's overall exposure to fossil fuel and gas prices.

While most valuation studies of competitive generation technologies take account of different gas and carbon prices through sensitivity analysis (and its more sophisticated variant, Monte Carlo simulation), as far as the authors know, there is no published study valuing nuclear as a hedge against uncertain gas and carbon prices from a company perspective. This 'hedging value' cannot be captured by the standard levelized cost approach, as it requires a dynamic model to capture the option value associated with the flexibility of waiting for more information on gas and carbon prices before making the best informed technology choice. Besides, standard levelized cost studies can only compare different technologies on a stand alone basis, whereas it is also important to consider how the risk-return profile of the investment affects the overall risk-return profile of the company. In other words, assessing the economics of a nuclear or CCGT power plant investment from a company perspective requires taking into account the complementarity of the risk-returns profiles of the different technologies that the company operates.[13]

The model presented next quantifies the 'option value' to a company of the ability to choose between a nuclear or a gas-fired plant investment at successive moments in the future, when the company faces stochastic gas, carbon, and electricity prices.[14] The 'nuclear option' therefore corresponds to the technical ability to choose nuclear and has two components:

- the value associated with the ability to wait and observe the evolution of gas and carbon prices; and
- the 'hedging' or diversification value associated with a more diverse portfolio of production technologies for the company.[15]

3 THE MERCHANT OPTION VALUE OF NUCLEAR

Our hypothetical generating company's investment plan consists of building five 1,000 MW power stations over twenty years. The managers face

[13] Awerbuch and Berger (2003) apply portfolio theory to identify Europe's best fuel mix from the cost side.

[14] In contrast to a CCGT plant, operating a nuclear plant requires a dedicated set of skills to address the specific technological, regulatory and legal issues related to this technology, which could get lost if no investment was made for a long time. Stenzel (2003) details the different challenges associated with 'keeping the nuclear option open' in the UK.

[15] Awerbuch and Berger (2003) and Roques et al. (2006) use Markowitz Mean-Variance Portfolio theory to compute optimal portfolios of plants respectively from a social welfare maximisation perspective and for a large private company.

investment decisions in years 0, 5, 10, 15 and 20 and choose either a nuclear plant or a combined cycle gas turbine (CCGT). The managers maximize the expected value of their 5-plant investment plan, and their choice will depend on the relative prices of electricity, gas and carbon.

For a given sample path of stochastic electricity, gas, and carbon prices, the nuclear option value is calculated as the difference between the Net Present Value (NPV) of the investment plan when managers have the choice between investing in a nuclear or a CCGT power plant at each decision point, and the NPV of the default scenario in which managers have no choice and can only invest in a CCGT. The model simulates 100,000 realizations of the stochastic electricity, gas, and carbon prices and their associated NPVs to give a probability distribution for the two NPVs. The probability distribution of the NPV of the nuclear 'option value' corresponds to the difference between these two distributions.

3.1 Model general settings

Our model of dynamic power investment choices uses stochastic optimization. Murto and Nese (2002), Pindyck (1993), and Gollier et al. (2005) use a Real Options approach to study respectively the impact of input price risk, construction cost risk, or construction modularity on investors' technological choices. Solving Real Options models using dynamic programming faces the problem that solutions can become difficult to find with more than one stochastic parameter, when the stochastic parameters do not follow a random walk, and when parameters are correlated (Dixit and Pindyck, 1994).

Our model differs from these approaches in several respects. It includes a detailed description of the cost and technical specificities associated with each technology, a realistic evolution of correlated stochastic electricity, gas, and carbon prices, and a tractable investment decision rule using observations to date that represents investment behavior under limited information.

3.1.1 Cost and technical parameters

The parameters of the model correspond to technologies available by 2010 for new build in the U.K. and are summarized in Table 5. All the costs are expressed in real 2005 British Pounds (£). Cost and technical parameters are derived from the MIT *Future of Nuclear Power* study (Deutch et al., 2003), updated with the International Energy Agency *Costs of Generating Electricity* (IEA/NEA, 2005).[16]

The capital costs ('overnight cost' and 'O&M incremental cost') are much higher for the nuclear plant than for the CCGT plant, while the converse is true for fuel costs. Construction time and plant life are longer for a nuclear plant than for a CCGT. Nuclear plant incurs a 'nuclear waste fee' to cover the cost of

[16] Sensitivity analyses to each cost and technical parameters have been carried out and are presented in an extended version of the paper available on the EPRG website: www.electricitypolicy.org.uk

decommissioning and nuclear waste treatment. These critical parameters are subject to a sensitivity analysis reported in the Appendix. The cost of CO_2 emissions related to the European Emission Trading Scheme is represented by a 'carbon tax'.[17]

Table 5. Technical and Cost Parameters

Parameters	Unit	Nuclear	CCGT
Technical parameters			
Net capacity	MWe	1,000	
Capacity factor	%	85%	
Heat rate	BTU/kWh	10,400	7,000
Carbon intensity	kg-C/mmBTU	0	14.5
Construction period	Year	5	2
Plant life	Year	40	30
Cost parameters (Real 2005 £)			
Overnight cost	£/KWe	1,140	285
Incremental capital costs	£/KWe/year	11.4	3.4
Fixed O&M	£/KWe/year	36	9
Variable O&M	£/MWh	0.23	0.3
O&M real escalation rate	%	1%	1%
Nuclear waste fee	£/MWh	0.6	0
Financing parameters			
Real WACC	%	5%-10%	5%-10%
Marginal Corporate Tax	%	30%	30%
Market prices (Real 2005 £)			
Carbon tax	£/tC	See next section	
Fuel (gas) costs	p/therm		
Electricity price	£/MWh		

Both plants are assumed to operate on base-load with an average annual capacity utilization factor of 85%.[18] The operating flexibility of the CCGT plant is explicitly modeled by assuming that it can stop generating whenever electricity, gas, and carbon prices make it uneconomic. Due to the low marginal costs of production, it seems a realistic assumption to assume that the nuclear plant always produces at maximum output.

The financing structure of the model is kept simple, with a corporation tax rate of 30% and three scenarios for the real weighted average cost of capital (WACC) of 5%, 8% and 10%. The latter two appear more realistic for merchant

[17] Note that to express this as a cost per tonne of CO_2 multiply by 3.67.
[18] This value represents a low estimate for nuclear (most nuclear plants are currently running at a capacity factor higher than 90% in the US), but a relatively high estimate for a CCGT which might be cycling up and down.

investment, although the special contractual agreement in the Finnish case described in the previous section has enabled the economic planning study to use a 5% real discount rate (Tarjanne and Rissanen, 2000). Again this is subject to a sensitivity analysis reported below in the Appendix.

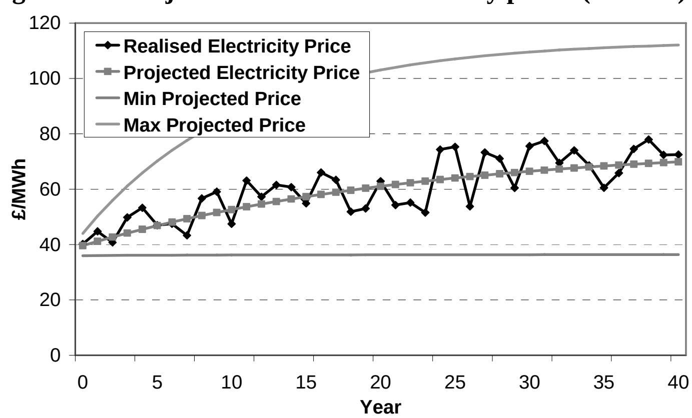
3.1.2 Stochastic gas, carbon and electricity prices

When modeling commodity prices, it is important to distinguish price variability from price risk. In the case of electricity, price variability corresponds to usual daily and seasonal fluctuation patterns which are easy to forecast (Geman, 2005, Li and Flynn, 2004). Uncertainty about prices can in turn be decomposed into short-term risk due to unexpected events (e.g. plant or transmission line breakdowns and weather unpredictability), and long-term risk about price trends.

The stochastic process used to generate electricity, gas and carbon prices in our model does not represent daily and seasonal variations, as broadly these are foreseeable by investors. The model concentrates on price risk and models both medium (yearly) and long-term trend risk. The long-run stochastic trends of electricity, gas, and carbon prices are based on current projections, and capture the range of values likely looking forward. The expected parameters are based on judgment informed by historical data and British and U.S. forecasts (DTI, 2005 and DOE, 2006). The lower trajectory represents the most optimistic scenario in which prices remain stable, while the upper bound corresponds to a ‘worst case’ ‘gas shock’ scenario in which prices would nearly double over the next forty years.

Random trajectories for the electricity, gas, and carbon prices are drawn for a series of Monte Carlo simulations. The continuum of possible long-term price trajectories of electricity prices is represented on Figure 1, together with the upper and lower bounds of the projected price. The long-term gas and carbon price trajectories follow similar patterns.

Figure 1. Projected and realized electricity prices (£/MWh)



The long-term risk about the evolution of electricity, gas, and carbon prices is represented using an exponential formula which makes equilibrium price forecasts for year zero (P_0), year 10 (P_{10}) and year 20 (P_{20}).[19] The parameters in these forecasts are the initial (equilibrium or expected) price level, P_0, and the subsequent decadal rates of growth, (P_{10} - P_0), and ($P_{20} - P_{10}$), all of which are independent random variables uniformly distributed around their expected values. Table 6 shows the expected value of electricity, gas, and carbon prices in year zero, and the subsequent expected decadal price increases, with the upper and lower bounds of these uniform distributions.

Table 6. Price trend distribution parameters

	Electricity Price (£/MWh)		**Gas Price (p/therm)**		**Carbon Price (£/tC)**	
Forecast Parameters	Expected value	Spread of uniform distribution	Expected value	Spread of uniform distribution	Expected value	Spread of uniform distribution
P_0	40	10%	30	20%	50	50%
$P_{10} - P_0$	20	100%	15	100%	25	100%
$P_{20} - P_{10}$	15	100%	15	100%	25	100%
Uniform Distribution Bounds	Lower bound	Upper bound	Lower bound	Upper bound	Lower bound	Upper bound
P_0	36	44	24	36	25	75
$P_{10} - P_0$	0	40	0	30	0	50
$P_{20} - P_{10}$	0	30	0	30	0	50
Price Volatility p.a.	Uniform distribution of price growth spread around projected value					
	20%		20%		30%	
Correlation	Correlation coefficient btw. Electricity, gas, and carbon prices					
	Any from 0% to 100%					

In addition, the stochastic process incorporates a shorter-run (annual) risk component, corresponding to the yearly deviations from the long-run trend. Gas and electricity are assumed to be bought and sold on spot markets, or through contracts indexed on the spot market price, thereby subjecting generators to annual price

[19] The mathematical formulation of this "projected price" is $P(t) = P_{20} - \alpha . e^{-\beta t}$, where $\alpha = P_{20} - P_0$, and $\beta = -\frac{1}{10} . \ln\left(\frac{P_{20} - P_{10}}{P_{20} - P_0}\right)$.

volatility.[20] This annual risk is modeled by multiplying the predicted price for a given year by a uniformly distributed independent random variable with upper and lower bounds of 0.8 and 1.2 for electricity and gas prices, and 0.7 and 1.3 for the carbon price.[21]

Finally, the random variables modeling the price P_0 and the price increases (P_{10} - P_0), and ($P_{20} - P_{10}$) of electricity, gas and carbon prices are correlated via a coefficient which can be varied between 0% and 100%.

3.1.3 Investor technology choice

Following the work from Ford (1999 and 2001) and Olsina et al. (2005) on investor behavior in electricity markets, investors are modeled as having a somewhat limited knowledge about future electricity, gas, and carbon prices. Our model assumes that investors have neither perfect foresight nor perfect information. They form estimates of the future profitability (future cash flows) of the two different technologies at each decision point based on historical electricity, fuel, and carbon price data. Investors choose to invest in nuclear if the expected cash flow of a CCGT plant using price estimates based on their average value over the last 5 years is lower than a certain profitability threshold P^*. This '5-year average threshold' P^* is chosen in order to maximize the expected NPV of the investment program by using a dynamic optimization program.[22]

The use of such a 'backward-looking' technology choice rule ignores any mean-reversion effects but appears justified by the behavior of investors in liberalized electricity markets. For example in the U.S. in 1999-2000 investors, based on their recent experience saw nothing but cheap natural gas prices and started building CCGT plants. All of that additional demand came on stream as gas prices rose sharply and led to the financial collapse of many investors**.** The sensitivity analysis presented in the Appendix shows that the nuclear option value is robust to small optimization errors around the optimal 'profitability threshold' P^*.[23]

[20] The model does not account for long-term fixed-price gas procurement or electricity sales contracts. Such contracts would affect the nuclear option value in two opposite ways. First, by reducing the fuel price risk for gas generators, fixed-price gas procurement contracts reduce the hedging value associated with technologies such as nuclear that are not exposed to gas price fluctuations. On the other hand, long-term power purchase agreements under which the Finnish nuclear plant is now being constructed reduce nuclear plant profit uncertainty and thereby increase nuclear's hedging value.

[21] Note that these annual volatility estimates are conservative (see e.g. Geman, 2005 for empirical estimates), reflecting the possibility for merchant generators to hedge part of the spot market risks (through e.g. financial products).

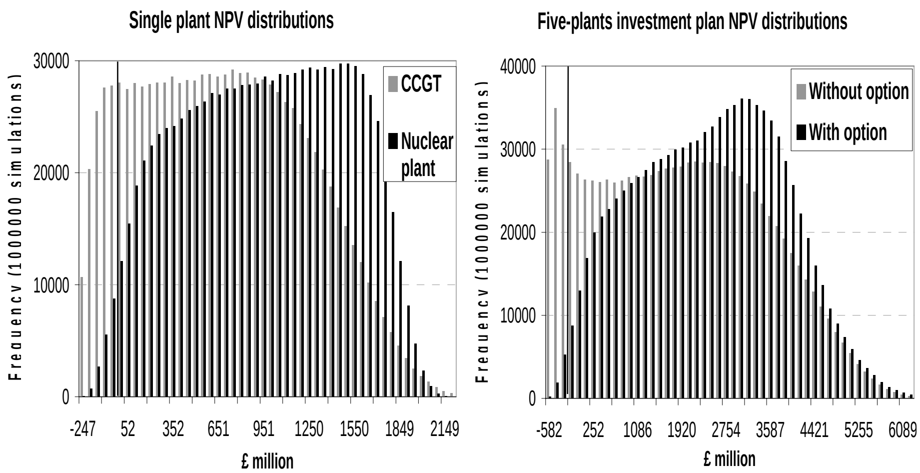
[22] The stochastic optimisation program @RISK was used to derive the optimal profitability thresholds. The code is available from the corresponding author upon request.

[23] This approach avoids the curse of dimensionality of dynamic programming faced by the standard perfect foresight option valuation approach. Given the complexity of the model (in particular the embedded option not to operate an already built CCGT at a loss, and the correlation between the three different stochastic price processes), such an approach would be computationally intractable.

3.2 Results: nuclear option value

Monte Carlo simulation yields a probability distribution for the nuclear option NPV, calculated as the difference between the NPV distributions with and without the nuclear option. Two factors affect the five-plant investment plan option value: the ability to choose and the hedging or diversification value of a more diverse portfolio for the company. The latter can be further decomposed in two components: the single-plant distributions shown in the left hand-side of Figure 2 show that a single nuclear investment is intrinsically less risky than a single CCGT investment. In addition, there is the portfolio risk-reducing effect when two assets have non-perfectly correlated costs.

Figure 2. Distributions of NPV for single plant and for the 5-plant portfolio with and w/o nuclear option (10% discount rate), *zero correlation between electricity, gas, and carbon prices* (£*million*)**.**



The nuclear option affects the risk-return profile of the company investment plan in two ways:

- First, comparing the shape of the 5-plant investment plan NPV distribution with and without the nuclear option, the likelihood of low NPVs is much less when the company can choose nuclear if the spark spread is low.[24] This is represented graphically on the right hand side of Figure 2 by the shift downward of the lower left hand tail of the 5-plant NPV distribution: in the scenarios where the spark spread is low, a nuclear plant has a higher NPV than a CCGT, while the reverse is true when the spark spread is high.

[24] The spark spread is the difference between the electricity price and the cost of the gas needed to generate the unit of electricity, and contributes to non-fuel costs.

- Second, high NPVs are more likely when the company has the choice between two technologies, as shown by the shift upward of the right hand side tail of the five plant NPV distribution.

When there is no correlation between electricity, gas, and carbon prices, the expected value of the nuclear option distribution for the five-plant investment plan with a 10% discount rate is £181 million or £36 million per plant (i.e. £36/kW capacity), around 9% of the expected NPV of the nuclear plant itself (£418 million). It stands at respectively £524 million and £1551 million for 8% and 5% discount rates, reflecting the large influence of the cost of capital on the relative profitability of a nuclear and CCGT plants highlighted in the previous section.

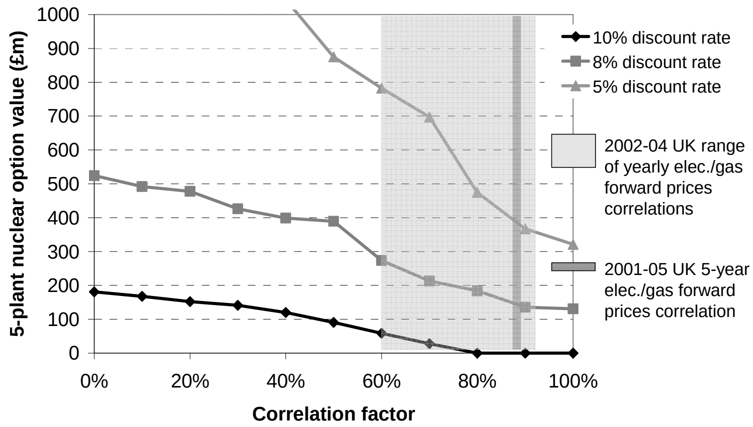
3.3 The impact of gas and electricity price correlation

The previous estimate of the option value relies critically on the assumption that gas, carbon and electricity prices are uncorrelated. In reality these prices exhibit quite a strong correlation, reflecting the complex interaction between electricity, gas, and carbon markets. This arises because gas-fired plant frequently sets the price of electricity, and because generators can arbitrage between electricity production or reselling the contracted gas.

Daily quarter–ahead forward prices for base-load electricity and gas in the U.K. market from 2001 to August 2005 exhibit a correlation factor of 89%. The correlation between electricity and carbon prices from the start of trading in October 2004 until September 2005 stands at 73%.[25] Clearly such high correlations cannot be ignored. In this subsection, the model assumes that the correlations between electricity, gas and carbon prices are identical and constant over time in the stochastic price processes described in section 3.2.1. Figure 3 shows that high price correlations drastically reduce the value of the nuclear option.

Figure 3. Relation between the value of the nuclear option and the correlation between electricity, gas, and carbon prices (*£million for five plants*)

[25] The reference of the daily quarter-ahead data on electricity base-load prices in the UK market from Platts is AAFPP00, and the reference for the daily quarter-ahead UK NBP gas prices from Platts is AACPV00, while the carbon price data are from the EEX CO_2 index. These results are consistent with Awerbuch and Berger's (2003) correlation estimates.



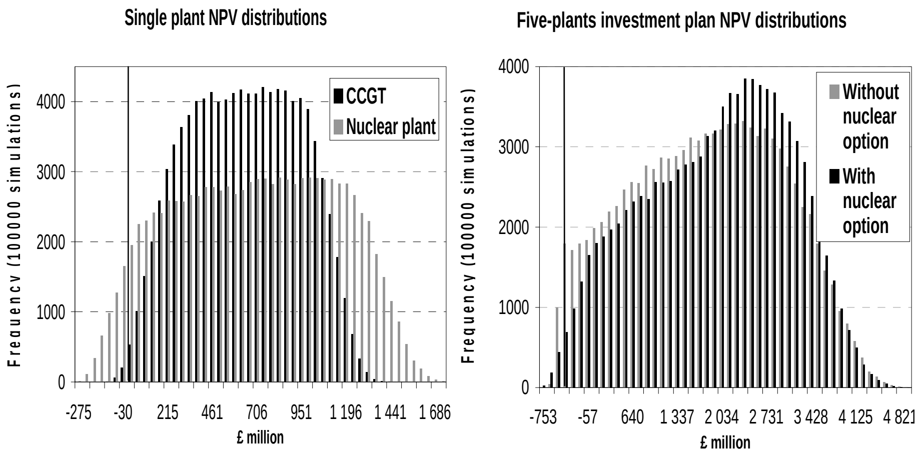
In the case of a 10% discount rate, the expected NPV of the nuclear option is reduced by 85% for a 70% correlation (to £28 million, or £5.6 million per plant). For discount rates of 8% and 5%, the expected NPV of the nuclear option is reduced respectively by 59% (to £213 million), and by 55% (to £698 million) for a 70% correlation.

The intuition is that a higher correlation reduces both the intrinsic riskiness of CCGT investment (as electricity prices rise when gas and/or carbon prices rise), and the portfolio diversification benefits of having two assets with non-perfectly correlated returns.

Figure 4 shows the effect of a 70% correlation on the distribution of the NPV of each investment on the right-hand side, and on the 5-plant investment plan with and without the nuclear option on the left-hand side. The right-hand side shows that the spread of the CCGT distribution, as well as the likelihood of a negative NPV, falls to lower levels than for a nuclear investment.[26]

Figure 4. Distributions of NPVs for single plant and for the 5-plant portfolio with and w/o nuclear option (10% discount rate), *70% correlation between electricity, gas, and carbon prices* (£*million*)

[26] The detailed statistics of the probability distributions of *Figures 2* and *4* are presented in the extended working paper available on the Electricity Policy Research Group website at www.electricitypolicy.org.uk.



The correlation between the main cost (gas and carbon prices) and revenue (electricity price) drivers of the CCGT investment reduces its intrinsic riskiness to a lower level than a nuclear plant, which is only subject to revenue (electricity price) risk. The more correlated the costs and revenues of the CCGT plant, the narrower is its NPV distribution, while the NPV distribution of the nuclear plant remains unchanged. This implies that a greater degree of correlation between electricity, gas and carbon prices reduces the potential intrinsic risk reduction value for the company, and thereby significantly reduces the nuclear option value.

In addition, higher correlations also reduce the portfolio diversification effect for two reasons. First, as the volatility of the spark spread falls, the nuclear plant investment is chosen less often, so that the company has a greater proportion of CCGT plants. Second, as the volatility of the spark spread falls, the correlation between the returns of a CCGT plant and a nuclear plant increases, so that the value of the portfolio risk-reduction effect associated with a mix of the two technologies falls. For commercial discount rates (10%), a CCGT investment is about as profitable as a nuclear plant, so that this portfolio diversification effect is the dominant source of risk mitigation. This explains why the nuclear 'option value' is relatively more affected by correlation for high discount rates. [27]

3.4 Policy implications

The conclusion of our model is that there is little private value for a merchant generator in retaining the option to choose between nuclear and CCGT technologies in future in liberalized European electricity markets, which exhibit a strong correlation between electricity, gas and carbon prices. This result appears

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[27] Roques et al. (2006) show using a Mean-Variance Portfolio theory model to power plants diversification that the diversification benefits of a nuclear plant for a power company operating gas and coal fired plants and facing risky electricity, fuel, and carbon prices are very low for the degrees of correlation between these prices characterising the UK market.

consistent with the observation that most new power plants built in liberalized electricity markets since the 1990s have been gas-fired power stations.

The increase in the share of gas in the electricity fuel-mix has raised concerns among policy-makers about the growing gas-import dependency and the resulting increased foreign exchange rate exposure to gas price fluctuations.[28] The literature investigating the optimal national degree of generation diversity (Awerbuch and Berger, 2003, Stirling, 2001) argues that a diverse fuel and technology-mix has two macroeconomic benefits. First, non-fossil fuel technologies reduce fossil fuel price risk and help avoid costly economic losses. Awerbuch and Sauter (2005) assert that the observed negative relationship between fossil fuel price changes and economic activity justifies subsidies for renewable energy, nuclear power and demand side management. Second, a diverse system is intrinsically more robust to supply shocks and therefore fuel diversity benefits security of supply (Stirling, 2001).

One critical issue to the long-term sustainability of liberalized electricity markets lies in their ability to deliver adequate and timely investment signals to ensure security of supply. In particular, there are concerns that a liberalized industry would fail to provide appropriate incentives for diversification, to deliver the macro-economically optimal fuel diversity. Ideally, micro-economic investment incentives should reflect the macro-economic value of a diverse fuel-mix. Our results and the observed investment patterns in liberalized electricity markets over the last decade lend some support to this fear. The correlation between electricity, gas, and carbon markets makes "pure" portfolios of gas power plants more attractive than diversified portfolios as gas plants' cash flows are "self-hedged". For a merchant generation company, investing in an additional CCGT has therefore an externality value as it increases the correlation between electricity and gas prices, thereby not only reducing the volatility of the returns of the new CCGT investment, but also reducing the risk of the other CCGT units that the generating company already operates.

One possible way in which private and social objectives might be reconciled is through the portfolio decisions of final consumers, who would value assets that had high returns in cases of high electricity prices (i.e. high gas and/or carbon prices). One natural hedge would be for consumers to hold shares in a specialized nuclear power generating company that would earn higher profits when selling at higher electricity prices. For instance, from the time when British Energy was relisted on 17 January 2005 to the end of 2005, British Energy Shares have exhibited a 91% correlation to the one-year forward electricity price in the UK (Roques et al., 2006).

Moreover, adequately long-term fixed price contracts could encourage diversification in non-gas fired generation and favor the nuclear option, but there are few examples of very long-term consumer contracts outside the Finnish example. In time consumers will surely become more sophisticated and we note recent moves to offer even domestic retail consumers long-term price-capped, albeit at premium,

[28] The EU gas import dependency is forecast to rise from 50% in 2004 to more than 81% by 2030 in the European Commission 2000 Green Paper Reference Scenario (EC, 2000).

rates. In the Nordic electricity market, von der Fehr et al. (2005) note that there was a general move from variable-price contracts to fixed-price contracts in the wake of the price increase during the winter of 2003. More than 60% of the manufacturing industry, 30% of the service industry, and 20% of the households were purchasing their electricity through fixed-price contracts in 2004.

Further research is therefore needed to assess the optimal macroeconomic degree of technology and fuel-mix diversity, and whether and how policy makers or regulators could modify the market framework, given the macroeconomic and security of supply benefits of a diverse fuel-mix. If the case for a market failure in the form of unpriced fuel-mix diversity externalities providing economics and security of supply benefits were to be demonstrated, it might justify intervention in electricity markets to encourage longer-term contracts (e.g. by reinstating the domestic franchise) or by offering long-term hedges for the electricity price as a more cost-effective climate change mitigation policy than the volatile Emissions Trading System with its uncertain future.

4 CONCLUSION

Despite recent revived interest in nuclear power, the prospects for merchant nuclear investment in liberalized industries without government support do not seem promising. The reason is relatively simple: quite apart from overcoming any regulatory and public opinion difficulties, the economic risks of nuclear power have been adversely affected by liberalization. High capital cost, uncertain construction cost, and potential construction and licensing delays are likely to lead private investors to require a substantial risk premium over coal and gas fired power plants to finance at least the first new nuclear units. Couching the debate over the economics of nuclear power in terms of the expected levelized cost fails to capture these concerns adequately. Recent cost estimates reveal both the large underlying nuclear cost uncertainties and different interpretations of the impact of liberalization on the cost of finance and hence investment choices.

The second part of the paper examined the claim that nuclear and non-fossil fuel technologies have a private ‘option value’ not captured by traditional valuation approaches. This is modeled in a 5-plant company investment plan capturing the main technology-specific characteristics of nuclear and CCGT plant. The model uses stochastic optimization to estimate the option value of being able to choose between nuclear and CCGT technologies in the future. We find, for the higher discount rates that could be expected for most private new nuclear build (10% real), that the nuclear option value represents 9% of the expected net present value of a nuclear plant investment when there is no correlation between electricity, gas, and carbon prices, but that this positive attribute falls away sharply with increasing correlation between these prices. The nuclear option value is close to zero for the correlations observed in the U.K over the last five years.

These results imply that there is little private value to merchant generating companies in retaining the nuclear option in risky European electricity markets with the consequent high discount rates, given the strong correlations between electricity, gas and carbon prices. Our modeling does not conclude that fuel diversity from nuclear power is of no value in liberalized markets. We simply conclude that there is little or no value for merchant generators in preserving such an option. The U.K. government clearly accepts that there is a social or consumer value in '*keeping the nuclear option open'* as this has formed a part of U.K. government policy since the Energy White Paper of 2003 (Stenzel, 2003). The Finnish experience shows that if well-informed electricity-intensive end users with long time horizons are willing to sign long-term contracts, then nuclear new build can be a realistic option in liberalized markets.

However, given that the bulk of electricity consumers (even industrial consumers) are not well-informed about the electricity market, and seem reluctant to sign contracts for longer than three years, as well as attaching minor importance to hedging electricity price risks, our modeling would appear to indicate that there may be a case for policy intervention to ensure fuel mix diversity in fully liberalized markets, such as those operating in England and Wales, providing of course that there is clear evidence of a costly market failure that can be cost effectively remedied by such intervention.

APPENDIX

1. Robustness of the option value to investors' decision rule

Figure 5. Sensitivity of investors' optimal threshold impact on the 5-plant nuclear option value (£*million*)

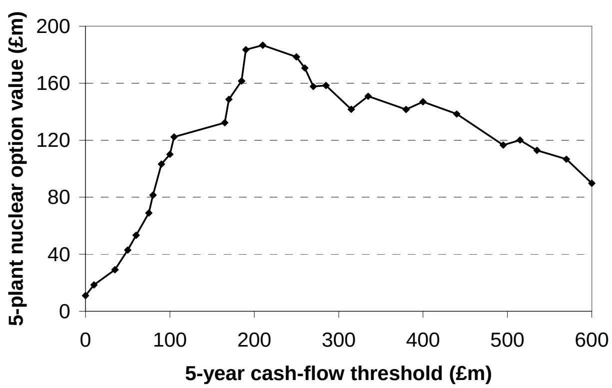
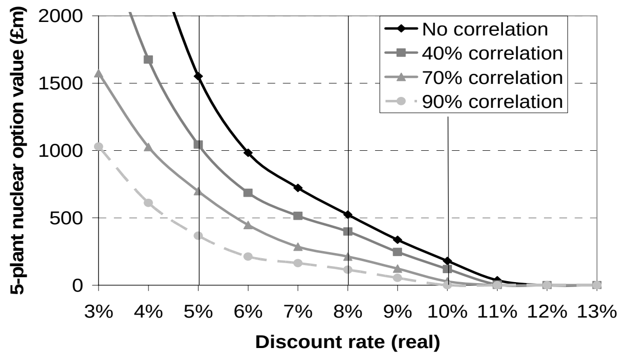


Figure 5 shows that the nuclear option value is robust to small errors of the optimization program around the optimal threshold (217£/kWh in this case): the nuclear option value varies less than 2% over the range [200; 250] spread around the optimal 5-year threshold.

2. Discount rate

Figure 6 shows that as the discount rate is lowered below 10%, a nuclear plant investment becomes much more profitable than a CCGT investment, and therefore the nuclear option value increases. Moreover, it shows that the impact of correlation between electricity, gas, and carbon prices is relatively greater for high discount rates.

Figure 6. Effect of the Discount rate on the 5-plant nuclear option value (£m)



3. Construction time and overnight capital cost

Figures 7 and 8 show that the impact of varying the construction time and the overnight capital cost on the 5-plant investment plan option value is much larger for high discount rates.

Figure 7. Impact of construction time on the 5-plant nuclear option value (£m)

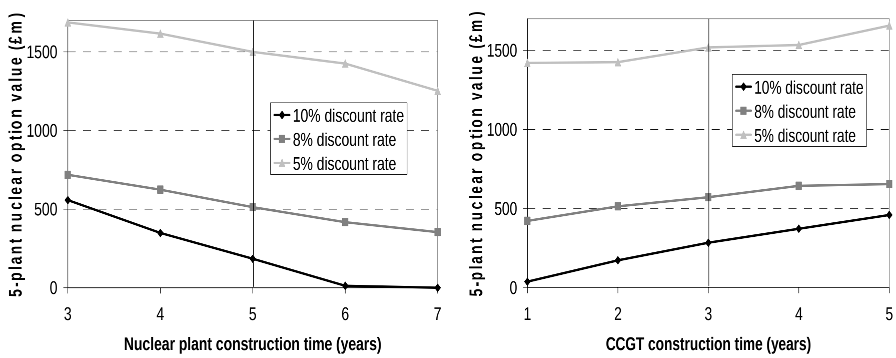
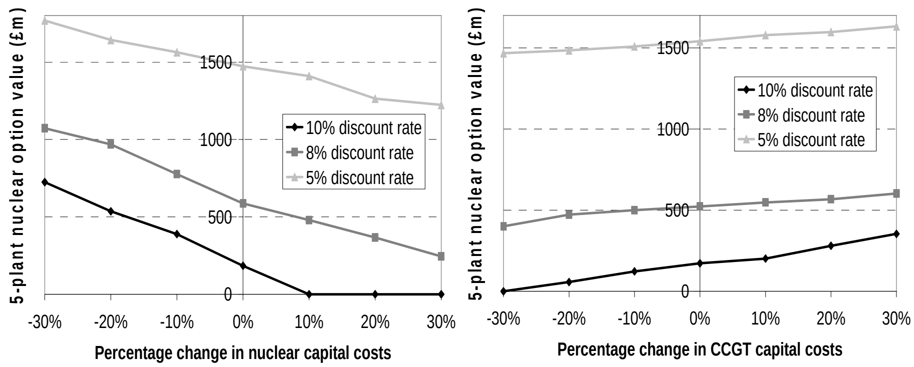


Figure 8. Impact of the overnight capital costs on the 5-plant nuclear option value (£m)



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