Risks and uncertainties in low-carbon energy investments

William Blyth(*)

Oxford Energy Associates, Oxford, UK

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(*)William Blyth has over 14 years experience working in energy and climate change policy analysis. He is currently an Associate Fellow of Chatham House, as well as Director of Oxford Energy Associates, an independent research company. His recent research focuses on risk and uncertainty in energy-sector investment decisions and climate change policy decisions. He has written various publications on this topic including an IEA book entitled "Climate Policy Uncertainty and Investment Risk".
William previously worked at the International Energy Agency in Paris on energy security and climate change policy. Prior to joining the IEA, he worked for a short period at the European Environment Agency in Copenhagen having previously worked for over 8 years at AEA Technology Environment, one of Europe's largest environmental consultancies.
William has a DPhil in Physics from Oxford University.
Contact: william.blyth@oxfordenergy.com

Abstract

This paper provides an overview of the way in which uncertainty in climate change policy can affect investment decision-making in the power sector. The paper illustrates how different technology types have different exposure to climate policy risks, and how this exposure can depend on market structure. The paper draws the conclusion that low-carbon technology investments that are dependent on a particular level of policy support in order to provide a positive investment incentive will be most sensitive to policy uncertainty. The paper illustrates this through reference to literature based on real options analysis which estimates the magnitude of the policy risks facing investment in nuclear and carbon capture and storage technologies. The presence of these risks is likely to increase the carbon price threshold required to persuade companies to invest, as the investment needs to make an adequate return in order to cover all project risks. It is argued that policy-makers need to understand the potential magnitude of these risks, as they could affect the timing of investment, the choice of technology, and therefore the costs of achieving a particular emissions target. The paper then discusses some of the policy options available for reducing policy uncertainty. The practical difficulties of these options are also outlined, taking account of the fact that the structure of decision-making at the national and global level means there are likely to be competing demands to maintain policy flexibility as well as policy certainty.

1. Introduction – Sources of uncertainty

The transition towards a sustainable energy system requires, as a minimum, appropriate investment in infrastructure for energy supply and consumption. One of the key tasks of climate change policy-makers is to create the right incentive structures for companies to be able to undertake the necessary investments. This is particularly relevant to the power sector, the subject of this paper, where investment decisions taken now will determine the emissions profile of the sector for several decades to come, given the long-lived nature of the assets. However, the translation of climate policies into clear investment signals is not straightforward. Energy infrastructure investments occur in a highly dynamic context, where climate policy is one of many different risk factors to take into account.

The act of investment involves exchanging a lump sum of money now in return for an income stream in the future. Companies will make this exchange if the expected project returns are high enough to cover the initial lump sum as well as compensating them for taking on the project risks.

Project risks arise from many sources (see e.g. (IEA 2003a)). These range from the general (e.g. macro-economic, political and *force majeure* risks) to the more project-specific (see Table 1.1).

Table 1.1. Risks directly affecting a company's cash-flow calculation

	Price Risks	**Technical Risks**	**Financial Risks**
Costs	Fuel price	Capital cost	Weighted cost of capital
	CO_2 price	Operating and maintenance cost	Credit risk
		Decommissioning and waste	
Revenues	Electricity price	Utilisation levels	Contractual risk
		Build time	

These risk factors affect different technologies in different ways. Since project returns have to cover the risk premiums as well as the direct project costs, these different risk profiles may lead to a change in the prioritisation of investment options facing a generation company - see for example (IEA 2003b). This is why it is important to look at the effects of risk on projects. This is true to a greater or lesser extent for all the different risk factors in Table 1.1. For example, technical risks vary considerably between technology types, and will be an important element of investment decision-making, with higher risk technologies requiring a higher return.

Fuel price is an important component of the running costs for gas and coal-fired generators, and so fuel price variability is clearly an important source of uncertainty. Section 2 illustrates the impact of fuel prices on the cost of generating electricity from a number of different power generation technologies. The impact of fuel price uncertainty on investment risk also has another dimension, because fuel prices also affect electricity prices (and therefore revenue risk). This relationship is explored further in Section 3.

On the other hand, climate change policy risks are of a different character. Fundamentally, the uncertainties in the field of climate change arise from uncertainties about the potential physical impacts of an increase in greenhouse gas concentrations in the atmosphere, together with uncertainties about the cost of reducing emissions of greenhouse gases to slow down this accumulation in the atmosphere. The balance between physical impacts (damage costs) vs. abatement costs underlies the political decisions about how quickly to respond to the threat of climate change, how stringently to set targets, and therefore how high the carbon price is going to be. All these issues are fraught with uncertainty – how they play out may rest as much on political and ethical considerations as on economics[1]. The translation of climate change into financial terms that can be incorporated into the investment decision is therefore particularly dependent on expectations about policy decisions. The impact of policy uncertainty on investment decision-making is explored in Section 3, with policy conclusions drawn in Section 4.

[1] As discussed in the Stern Review (2006), the choice of discount rate is a critical parameter in deciding on the pace of change in mitigating greenhouse gases, and this choice is ultimately an ethical decision based on valuing the future relative to the present. On the other hand, how much of what may be considered 'optimal' from an economic point of view actually gets implemented in practice will depend on politics.

2. Fuel and carbon price components of electricity generation costs

Different types of power generation technology have different cost structures, and therefore respond differently to changes in market prices. For example, the cost of generating electricity from gas, coal and nuclear will depend on their respective fuel costs; coal is more carbon intensive than the other forms of generation, so will be become increasingly expensive under high carbon price scenarios; nuclear is more capital intensive than gas, and so is more sensitive to the cost of capital (IEA 2005).

A convenient way of comparing different technologies is to use levelised costs, which calculate the full cost (including all operating and capital costs) for producing a unit of electricity. Levelised costs have their limitations (see Gross et. al. 2007), as they do not represent risk very well, and therefore do not necessarily provide a good guide to what companies will actually invest in (see Section 5 for further discussion). Nevertheless, they provide a starting point for analysis.

Figures 2.1-2.3 show 'phase diagrams' of what technology would provide the lowest cost of electricity depending on the price of fuel and CO_2. The three shaded areas divided by bold lines show regions in which gas (cross-hatched), coal (grey) and coal + carbon capture and storage (lightly shaded) would be the most cost effective choice of technology in terms of levelised cost of electricity. The coal technology represented here is advanced super critical (ASC) technology. The technology assumptions used to calculate the levelised costs used in Figures 2.1-2.3 come from the Redpoint 2007, a modelling study that fed into the UK government's energy white paper (EWP 2007). These technology assumptions were then fed into a standard levelised cost spreadsheet model, assuming an 8% real discount rate for all technologies.

In Figure 2.1, a single set of coal prices is used, taken from the central EWP 2007 scenario. We can develop the intuition of this phase diagram by looking along the horizontal axis. At low gas prices below about 30p/therm, the cheapest way of producing electricity is with gas. As gas gets more expensive than this, coal would provide a lower cost method of production. However, higher carbon prices favour gas-fired generation because it is more efficient and is a less carbon intensive fuel. This is why the bold line representing the breakeven between gas and coal slopes diagonally to the right as carbon prices increase. If carbon prices become high enough (above

about €50/tCO_2 according to these figures), it becomes cheaper to generate electricity using coal + carbon capture and storage than with unabated coal. Above €50/tCO_2, the cheapest method of generation would be either gas or coal + CCS depending on the fuel price of gas. In Figure 2.1, a single coal price is used, resulting in a single set of breakeven lines between the various technologies (i.e. lines along which the levelised costs of two technologies is equal).

As well as gas, coal, and coal + CCS, Figure 2.1 also shows the breakeven lines for wind and nuclear power. These breakeven lines are calculated comparing their costs with either gas (in the cross-hatched shaded region) or coal (in the grey shaded region), whichever is the cheaper. In the region where gas is the cheapest alternative, the breakeven lines slope upwards to the left because the lower the price of gas, the higher the carbon price needs to be in order for the alternative (i.e. nuclear or wind) to breakeven. On the other hand, in the region of the chart where coal is the cheapest alternative, the gas price no longer matters, since we are comparing the alternative (nuclear or wind) with the cost of coal-fired generation. We then get a single price of carbon (shown as a horizontal line) at which nuclear or wind would breakeven with coal.

Clearly, these breakeven points depend on the technology assumptions. For example, the breakeven point for CCS shown in Figure 2.1 is substantially higher (at around €50/tCO_2) than the figure of \$38/tCO_2 derived in a similar type of analysis presented in IEA 2007. This is because the assumptions used in Redpoint 2007 are more favourable towards new coal plant (lower capital and operating costs and higher plant efficiency) and less favourable towards CCS plant (higher operating costs and lower efficiency). The technology assumptions in Figure 2.1 correspond to the costs for the 2007 vintage technology. Account is taken of technology learning in Figure 2.3 below.

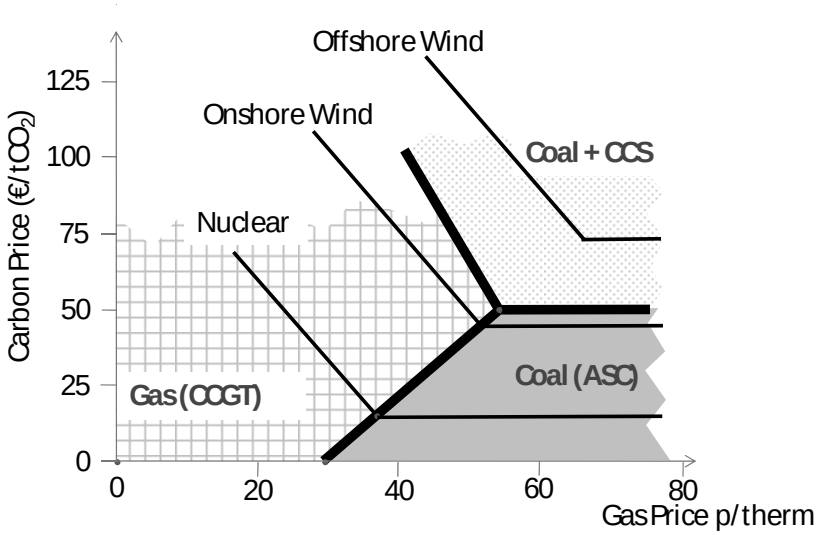


Figure 2.1 Phase diagram showing regions where different technologies would have the lowest levelised cost of electricity generation. Technology cost assumptions are 2007 vintage technology from Redpoint 2007, coal prices based on central scenario from EWP

Figure 2.2 extends this analysis with additional breakeven lines to show the sensitivity to coal price assumptions. The solid lines and shaded regions still represent the EWP central coal price scenario (identical to Fig 2.1). The effect of high and low coal prices are represented by dotted lines. A low coal price scenario has the effect of extending the coal region to the left, whereas a high coal price scenario extends the gas region to the right. The breakeven carbon price for CCS is relatively insensitive to these coal price scenarios, ranging from €47.4/tCO_2 under the low price scenario to €52.4/tCO_2 under the high price scenario. This small increase under higher coal prices is due to the lower generation efficiency of coal plant with CCS relative to unabated coal.

In regions of the phase diagram where nuclear and wind are being compared against coal, a higher coal price leads to a lower CO_2 breakeven price and *vice versa*. The high and low coal price scenarios lead to a range in the breakeven price relative to coal of €8-20/tCO_2 for nuclear, €38-50/tCO_2 for onshore wind and €67-79/tCO_2 for offshore wind.

The breakeven point for nuclear and wind relative to CCGT is unaffected by the coal price, so there is still only a single upward sloping line for each of these technologies in the region where the comparison is with gas, identical to the lines in Figure 2.1.

Also shown at the bottom of Figure 2.2 is the range of gas prices under the EWP low, central and high price scenarios (shown here as the averages for those scenarios over the period 2010 to 2020). It can be seen that the scenarios almost exactly span the region of the phase diagram where gas is competing with coal as the lowest cost technology, making estimates of the carbon price critical to the choice of technology. This highlights the important role of uncertainty and risk regarding estimates of the future price of both gas and carbon when it comes to choosing the right technology for new power generation investment. The role of uncertainty is discussed more fully in Section 5.

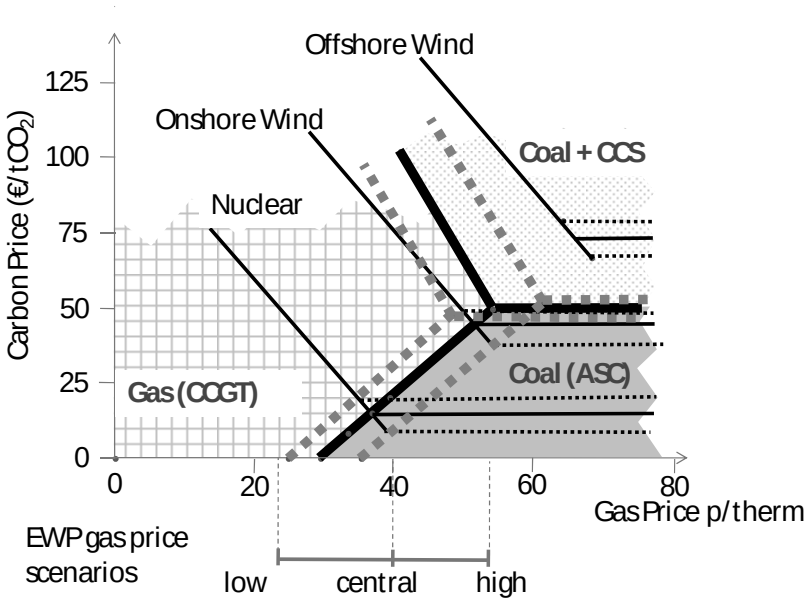


Figure 2.2. Phase diagram, again with same technology costs as Figure 2.1, but showing sensitivity to coal prices. Dotted lines indicate breakeven points for high and low coal price scenarios in EWP 2007.

Figure 2.3 shows how technology learning by 2031 is expected to alter these breakeven points (according to assumptions used in Redpoint 2007). The breakeven carbon price for CCS relative to coal drops to €40/tCO_2. Two competing effects are included in this price shift. CCS is assumed to become more favourable due to improved efficiency, and reduced capital costs. However, the effect of these improvements in terms of the reduction in required CO_2 price is dampened by the fact that the investment case for unabated coal is also assumed to improve due to improved efficiency and reduced capital costs. This improvement in unabated coal also reduces the extent to which nuclear and wind technologies benefit from their own learning. In fact, the breakeven CO_2 price for on-shore wind relative to coal *increases* from €44.6/tCO_2 under 2007 technology costs to €51.4/tCO_2 under 2031 technology costs. This is due to a relatively small degree of cost reduction associated with on-shore wind during this period in the assumptions used in Redpoint 2007, consistent with an assumption of constrained on-shore wind resource combined with the fact that the technology is already quite mature.

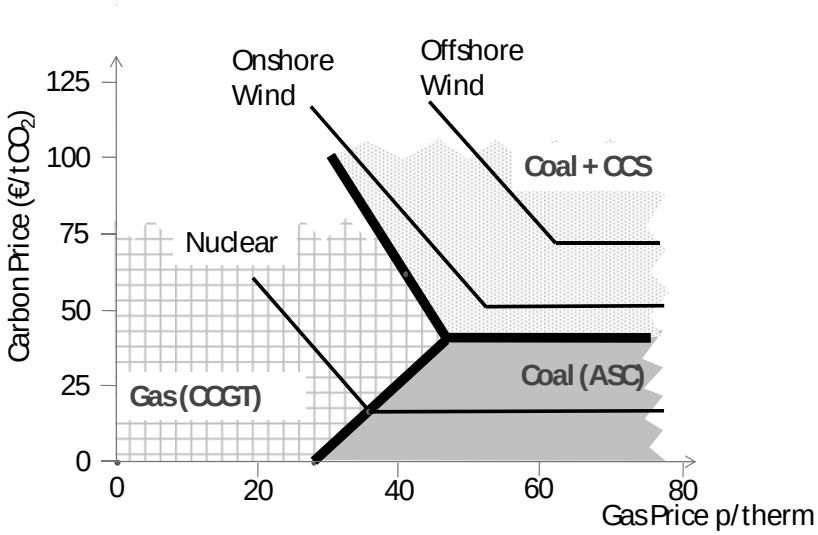


Figure 2.3. Phase diagram using 2031 vintage technology assumptions from Redpoint 2007, central coal price scenario (based on average of 2010-2020 coal prices in EWP 2007)

3. Investment decision-making under uncertainty

Whilst an analysis of levelised costs gives some idea of the comparative advantage of different technologies under different price scenarios, it is not well suited to understanding how risky different investment are likely to be, and risk is an important factor in investment decision-making. Figure 3.1 shows two sets of economic comparisons for coal and gas. This is a representation of the costs of different technologies, updating similar figures shown in Gross 2007 to include the technology assumptions presented in Redpoint 2007 and EWP 2007 fuel price scenarios. The figure includes two types of coal plant, advanced super critical (ASC), and integrated gasification combined cycle (IGCC). The former is a relatively more established technology, whilst the latter has greater efficiency (and could potentially prove more effective with future forms of capture and storage technology).

Figure 3.1a shows the range of levelised costs for each technology under the different EWP energy price scenarios (low, central and high), and for carbon price scenarios of €0/tCO_2, €15/tCO_2, and €25/tCO_2. These comparisons are for the unabated technologies (i.e. without CCS). The range of levelised costs is greatest for CCGT (£25-53/MWh) because the gas price spread in the EWP scenarios is higher for gas than it is for coal, and in addition the costs of generating electricity from gas are more sensitive to fuel price changes since fuel price is a higher proportion of overall costs. The range of levelised costs for ASC coal is £29-51/MWh, and for IGCC coal £33-54/MWh. The average levelised cost across these price scenarios for CCGT is very close to that for ASC coal (at around £40/MWh), with the average for IGCC coal coming out slightly more expensive at £44/MWh.

However, if we look at the revenues that would be generated from these plant, we get a different story, as shown in Figure 5.1b. This shows the range in the net present value (NPV) of the investments taking into account the effect on the electricity price of the different fuel and carbon price scenarios. These NPVs are calculated by assuming that the price of electricity follows the short-run marginal cost of the marginal plant (i.e. the most expensive) on the system required to meet demand.

Because of the large amount of gas in the supply system in the UK, it is likely that gas plant will continue to be used under all scenarios. Therefore,

if the price of gas is high, gas-fired generation would become the marginal plant in the system, driving up the price of electricity. Even though the cost of generation with gas increases at high gas prices, gas-fired plant would still be able to recover their costs because variations in cost and revenue can be quite closely correlated, reducing overall investment risk. We can see this effect in Figure 3.1b, where the range of NPVs for gas is significantly lower than for coal, even though the range of costs in Figure 3.1a is greater.

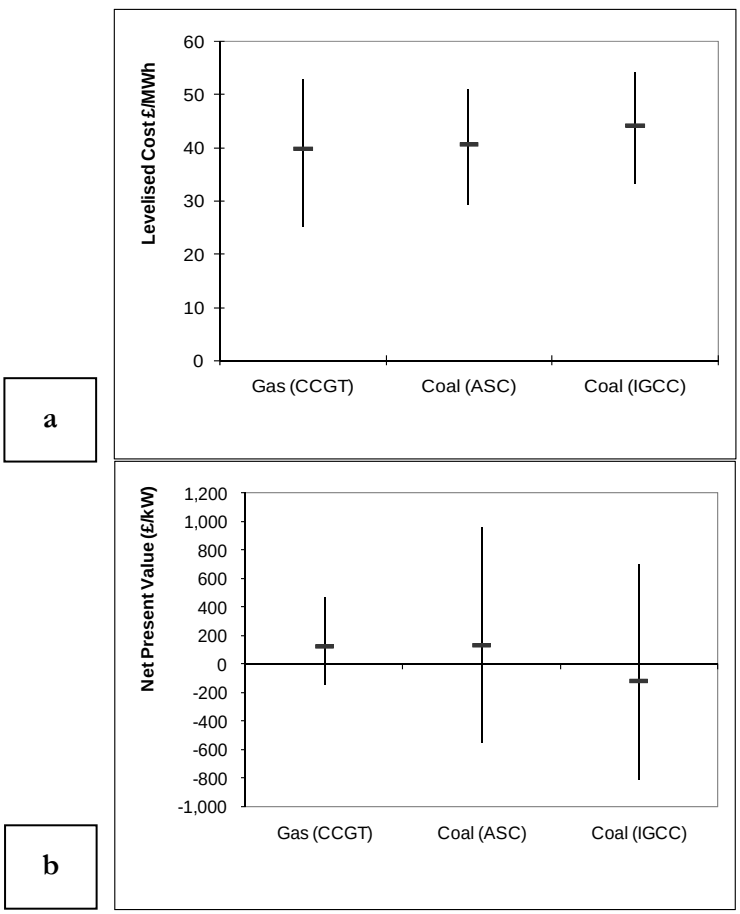


Figure 3.1. Cost comparisons for gas and coal a) levelised cost, b) NPV

The range of possible returns in Figure 3.1b provides a relatively simple indicator of risk. In this example, coal appears to be a significantly more

risky investment prospect, because there is the possibility of significant losses (which could occur under a low gas price, high carbon price scenario). Even though these potential losses are balanced by the possibility of very high returns (which would be the case in a high gas price, low carbon price world) giving the same average returns as for gas, companies may be more concerned about the possibility of large losses than about the possibility of large gains.

In practice, analysis of risk is more complex than this simple comparison suggests. For example, in addition to identifying various price scenarios, companies need to think about the correlation between the various risk parameters. In the case of energy prices and CO_2 prices for example, there is currently a relatively high level of correlation in the price variance because of the structure of the carbon market: namely that switching between existing coal and gas-fired generation forms the marginal abatement option in the carbon market. This means that the price of carbon which triggers this switch is in turn dependent on the relative prices of coal and gas. One way of analysing these effects is through mean-variance analysis which looks at the spread of returns on a given investment using statistical methods such as Monte Carlo simulations (see for example Roques et. al. 2008).

This type of analysis shows how companies may take into account the value of diversity in the generation portfolios, favouring a spread of technologies that help to balance out their exposure to different sources of risk. This is likely to be an important factor behind companies' considerations of the value of building new coal plant given the extent to which existing coal plant is expected to retire, and given concerns over risks associated with supplies and prices for gas.

Many other factors will also enter the decision. Companies will also take into account the expected build decisions of their competitors, the overall policy framework to judge whether either excessive losses or excessive profits might be capped as a result of policy decisions, as well as other strategic factors. Practical issues such as the amount of time taken to get planning permission and to build new plant may also an important factor. Generally build times and planning processes are significantly quicker for CCGT than for coal.

Power generation investments will ultimately be driven by companies' forward view of what is driving the electricity price, as this will tend to

dominate their risk and return profile. Whilst fossil generators continue to set electricity prices, and to the extent that carbon prices will be an important factor in future electricity prices, it is becoming more likely that investment decisions will need to manage carbon policy risks.

The most likely response to an increasing level of risk will be to favour investment in low capital cost options. These will represent the "least expensive mistake" if future conditions turn out to be less favourable than expected. The lowest capital cost option may be to extend the use of existing plant beyond their normal technical lifetime, allowing companies to delay the replacement of existing plant until more information is obtained. If capacity expansion is required to meet expanding demand, the lowest capital cost option for new generation is gas-fired plant, and this may gain a competitive advantage over other technologies in a more uncertain investment environment.

Increasing the level of risk in the electricity sector will create a requirement for higher rates of return. This essentially means that electricity prices would need to rise. There are two mechanisms by which such prices rises might occur.

Firstly, the cost of entry to the market should rise to incorporate the increased price of risk (both in the debt and equity components). If the cost of entry increases, the electricity price would rise accordingly, since in a competitive market the electricity price will be determined by the cost of entry. In this situation, the same level of investment would be achieved, but at a higher equilibrium price of electricity.

The other mechanism by which electricity prices might rise is if the reserve margin drops, i.e. reducing the levels of spare generation capacity in the system. Electricity price is derived in a competitive market based on balancing demand at any given time with a supply stack which is dispatched in order of increasing marginal cost. If electricity demand grows over time, and if new capacity is not added to the system, then generation plant further up the supply stack will get dispatched more often, leading to higher electricity prices. If the supply cost curve is steep towards the margin, then the required electricity prices increases could occur with relatively small decreases in supply margin.

Which of these two mechanisms occurs in practice probably depends on the market design. In some markets, there are explicit mechanisms for maintaining reserve margins in order to ensure certain standards are achieved for the reliability of supply. This can include explicit mechanisms to support investment in reserve capacity, or simply applying reliability standards. In these cases, reserve margins may not drop, but investment may be steered more towards peaking and mid-merit plant than would be considered optimal in a more certain investment environment. Again, this would tend to favour investment in gas generation over base-load coal or nuclear generation investments.

3.1. Carbon price uncertainty: evaluating using option theory

The previous section looked at how risk could alter investment decisions relative to simple analyses based on static price expectations. Policy-makers wishing to understand or project likely levels of build for different technologies therefore need to take these risk effects into account. One possible tool for doing this is real options analysis.

Real option theory is an extension of standard financial appraisal methods, adding the ability to explicitly model the effect of individual sources of uncertainty, and accounting for the flexibility that managers often have over the timing of their investment when faced with uncertain future cash flows. Originally developed for valuing financial options in the seventies (Black and Scholes, 1973, and Merton, 1973), economists soon realized that option pricing also provided considerable insight into decision-making concerning capital investment. Hence the term "real" options. Early frameworks were developed by McDonald and Siegel (1986), Pindyck (1988, 1991, 1993), and comprehensive textbook treatments are given by Dixit and Pindyck (1994) and Trigeorgis (1996).

Investment in the electricity sector has been analyzed within real options frameworks. Work was carried out by EPRI (1999) to provide a framework for managing the effects of regulatory uncertainty, and Ishii (2004) looked at the overall effects of regulatory uncertainty on investment rates in the US. In the area of short-term planning, real options were used by e.g. Tseng and Barz (2002) and Hlouskova et al (2005). At the same time, a number of long- term planning frameworks have emerged. Recent examples include Fleten et al (2007) who find that investment in power plants require greater returns than the traditional NPV break-even point when a real options

approach with stochastic prices is used.

Real options have also been quite widely used to model the effects of uncertain climate change policy. Rothwell (2006) finds that returns on investment in nuclear plant need to be higher in a scenario with uncertain carbon prices than in a world with certain prices. Also, Laurikka and Kojonen (2006), Kiriyama and Suzuki (2004) deal with the influence of future uncertain emissions trading and with CO_2 penalties within a real options setup. In these models the design of emissions trading schemes and the number of allowances that are freely distributed are main features of the overall model. Another example of the application of real options to the problem of uncertain climate policy is Reedman et. al (2006) who show that uptake of various electricity generation technologies varies significantly depending on investor's view of carbon price uncertainty.

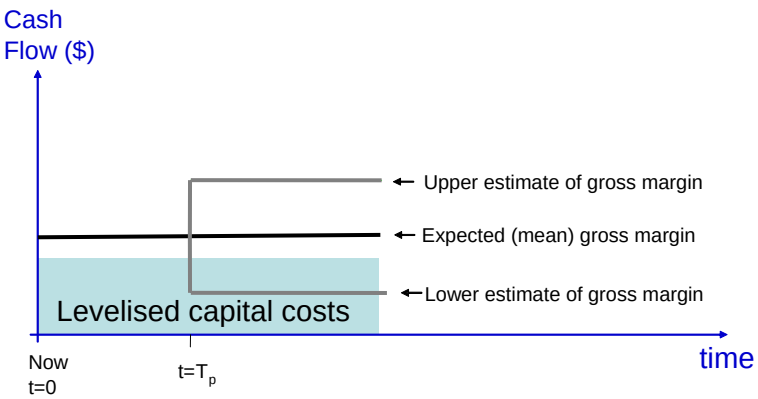
3.1.1. Towards an intuitive understanding of real options

For a company faced with uncertain future costs or revenues, there may financial benefit to reducing the range of these uncertainties. If new information can be acquired prior to investment, then there may be an opportunity to avoid the worst financial outcomes – e.g. by investing in a different type of technology, or avoiding investment altogether. Since the expected value of the NPV is a probability-weighted mean, the ability to avoid some of the worst outcomes leads to an increase in the expected value of the project. It would therefore be rational for a company to pay some money to acquire this information in exchange for an improved (expected) financial performance of the project. Management flexibility on the timing of investment with respect to uncertain future events is an important way in which companies may acquire such information – in other words, waiting until the uncertainty is resolved.

It follows that a company which already possesses this flexibility on timing of investment would need to be financially compensated in order to give up this flexibility and go ahead with an investment immediately rather than waiting for new information (Blyth et al. 2007). Figure 3.2 follows a recent IEA publication on the effects of policy uncertainty (IEA 2007), and illustrates the economic rationale for waiting to gain information about an expected regulatory uncertainty at time T_p. This could be for example the introduction of a new policy, or a new phase of an existing policy that could affect the project's financial outcome either positively or negatively. For

simplicity, the diagram assumes an equal probability of an increase or decrease in gross margin, so that the expected (i.e. mean) value is unaffected by the introduction of the new policy.

Case A: "Now or never" investment option at t=0



Case B: Company has the option to wait until after $t=T_p$, the expected time of some policy change that affects the investment.

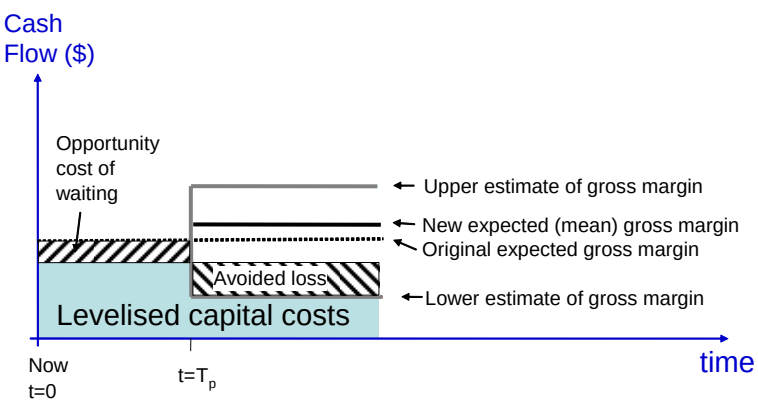


Figure 3.2. The value of waiting for regulatory information

In Case A, the company has to choose whether to invest immediately, or not invest at all. In this case, since the expected NPV is positive (gross margin is greater than capital costs), the company would choose to invest despite the future uncertainty, assuming the company is not risk averse.

In Case B, the company has flexibility over the timing of its investment. In this case, there is a financial benefit to waiting until after T_p when information is available on how the new policy will affect the project. This gives the company the option to avoid investing in a loss-making project, which increases the expected gross margin of the project. The company will pay for this option by foregoing income from the project in the period up to T_p. The value of the option to wait therefore has to take into account the opportunity cost of waiting as well as the possible rise in expected project value.

The greater the range of uncertainty, and the less time available until T_p, the greater the option value of waiting will be. In order for the company to go ahead with the investment immediately rather than waiting, this option value would have to be recouped by the project – i.e. there would need to be an increase in the expected value of investing immediately to overcome the value of waiting. Another way to think about this is that if the expected gross margin in Case A is sufficiently high compared to the capital costs, then the opportunity costs of waiting will outweigh the value of waiting. The option value of waiting therefore creates an additional financial threshold that the project must exceed in order to justify immediate investment.

3.2. An application of real option analysis to evaluating climate policy risk

This section introduces an application of real option analysis, as presented in IEA 2007. This looks at the effects of climate policy risk, represented in the form of carbon price risk (for example as applied through an emissions trading scheme). To model carbon trading, prices are allowed to vary from year to year according to a random walk (geometric Brownian motion) with 7.75% annual volatility, as well as having a potential price shock (representing an unexpected shift in policy) at some fixed point in the future. The price shock is represented by a shift in price in the range $\pm$ 100%, with a flat probability distribution within this range. The expected (mean) price is unchanged by the price shock, since it is assumed that positive shocks are just as likely as negative shocks. Initial carbon prices are sufficient to give a positive NPV for the investment. The annual variation is meant to represent fluctuations in prices that might occur either in an emissions trading scheme, or in other types of policy where the difficulty of

meeting an emissions target might be uncertain (e.g. due to uncertainty in technical costs and projected emission levels). These annual volatility variations in carbon price are assumed to be partially correlated with the gas price volatility, with a correlation coefficient of 50%.

The shock in price on the other hand is meant to represent a policy discontinuity, for example a change in policy regime, or a significant change in stringency of targets. These shocks are not assumed to be correlated with energy prices. The assumption of symmetry in these price variations allows us to separate out very easily the specific effects of uncertainty as opposed to shifts in the expected future economic case for different technologies, because the expectation about the future economic case is assumed to remain constant irrespective of the price variability.

One of the experiments presented in IEA 2007 is to look at the relative importance of annual variations (volatility) vs. the one-off shocks (uncertainty). This experiment would be relevant to the comparison of a carbon tax with an emissions trading scheme. For a tax, the carbon price would be known exactly, so there would be no annual variation. This removes one element of the price uncertainty. However, investors would not be able to rule out the possibility of step changes in the tax level or changes in policy regime which might occur as a result of political review. The question then arises of how important the price shocks are compared to the annual variation – does removal of the annual variation significantly reduce the investment threshold? The answer appears to be no.

Other experiments include constraints on the size and timing of the price shocks. Pushing out the price shocks further into the future correspond to policy-makers ability to provide confidence in the longevity of their policy signals, whereas constraints on the size of price movements could reflect policy instruments for limiting prices (e.g. through price floors/ceilings or through banking / borrowing provisions).

The results of these experiments are shown in Table 3.1 for two different low carbon technologies, nuclear and carbon capture and storage (CCS). The results show a measure of risk premium that is presented in terms of the additional return on investment that would be required to persuade a risk-neutral investor to go ahead with the investment immediately rather than exercise the option to delay pending further information. These are total additional returns (in present value terms) over the lifetime of the

project, expressed in terms of a fraction of the capital cost.

Investment thresholds (% of capital cost)	**Base case – carbon price shock and annual variation**		**Shock only, no annual variation**	**Annual variation only, no price shock**	**Price cap (150%) and price floor (50%)**
	Case 1	**Case 2**	**Case 3**	**Case 4**	**Case 5**
	Price shock after 5 years	Price shock after 10 years	Price shock after 5 years	No price shock	Price shock after 5 years
Nuclear (with coal on margin)	31%	21%	30%	13%	28%
Carbon capture and storage	84%	37%	80%	18%	47%

Table 3.1. Investment thresholds for nuclear and carbon capture & storage investment options under different assumptions of price variability. The table shows the additional net present value (expressed as a percentage of the project capital cost) that the project would need to exceed in order to stimulate immediate investment. These values can be compared to the hypothetical case where there is no price uncertainty, in which case there would be zero additional net present value required to stimulate investment.

The risk premium values shown in Table 3.1 are higher for CCS than for nuclear. This is because the CCS investment case is compared to a baseline of an existing coal plant. When the CO_2 price goes up, the CCS financial case improves whilst the alternative financial case (i.e. sticking with the unabated coal plant) gets worse. The relative difference between the CCS case and the unabated case is therefore more sensitive than in the case of nuclear where the investment is considered against a fixed baseline of no investment. In absolute terms, the risk premiums expressed in $/kW are more closely balanced.

From these results, it can clearly be seen that Case 4, the complete removal of the price shock, would have the greatest effect in reducing the risk premium. This represents the case where some kind of guarantee could be given that no significant policy shifts would ever be made. A somewhat more realistic scenario of providing such an assurance for 10 years (Case 2)

does mark a significant improvement compared to 5 years (Case 1), and is perhaps more politically feasible than Case 4.

Providing a price cap and floor (Case 5) does help reduce the risk premium, but not as much as delaying the possible price shock (Case 2). It should be noted that these price cap and floor assumptions represent quite tight constraints: given our assumption of a flat probability distribution for the price shock, the cap would be expected to be exercised in 25% of cases, and the price floor exercised in 25% of cases. So there would be a 50% chance of some kind of price control under these assumptions. In the case of carbon capture and storage, the range between cap and floor would have to be narrowed such that one or other would be in effect for 60% of the time in order to bring the risk premium down to the same level as in Case 2, the policy extension case.

Case 3 represents the pure tax situation – i.e. no annual price volatility, but still the possibility of a shock in future prices. It can be seen that this does not significantly reduce the investment threshold compared to Case 1, indicating that the possibility of a price shock dominates the investment threshold, whereas annual variation is relatively unimportant. Therefore, from the point of view of investment risk, taxes do not perform any better than trading or other quantity instruments, unless they can be linked to ways of providing more credible assurances against future price shocks.

3.3. Managing price uncertainty

A firm price ceiling and / or price floor could be implemented in a number of ways, for example by committing to sell unlimited number of allowances at the ceiling price, and committing to buy unlimited number of allowances at the floor price. However, if the government is buying and selling these allowances within the context of a fixed emissions cap under the Kyoto Protocol, then allowances cannot simply be generated for free, and committing to this programme would entail significant government risk, and could attract speculation in the same way that policies to fix exchange rates have in the past.

A less risky approach from the government's point of view might be to introduce a carbon tax at the floor price level which could then be waived if the carbon price exceeds this level. The income stream arising from the tax

would be rather uncertain, but it would not entail any additional expenditure commitments.

More targeted approaches have been proposed by Helm and Hepburn (2005), suggesting a carbon contract arrangement by which governments could contract ahead with companies for the supply of emission reductions over long time periods to back up their political commitment to long-term targets. From the companies' point of view, such long-term contracts would provide a guaranteed source of income for their low carbon investments. Helm proposes to auction these contracts, ensuring long-term emission reductions were achieved at the lowest possible cost.

Ismer and Neuhoff (2006) extend these ideas to define a carbon option contract which gives companies the right but not the obligation to sell allowances to the government at a certain price. Under this arrangement, companies investing in low carbon technologies would not carry the risk that the market price might turn out higher than the strike price in the contract. Governments on the other hand would be fully committed to a floor price, creating an incentive for them to maintain sufficient policy stringency to keep market prices above the strike price in order to manage their liabilities.

The results in Chapter 3 indicate that the key to the success of such schemes would be the ability to ensure the credibility of the established price over long period into the future. The contractual nature of these schemes may provide sufficient legal basis to provide such credibility.

Hepburn et. al. (2006) shows how a softer form of price support could be achieved in the context of Phase II of the EU emissions trading scheme (2008-2012) through the use of auctioning of 10% of allowances with the use of a minimum reserve price. This would not guarantee a floor price if the market price were considerably below the reserve price. However, in this case the allowances would then be withheld from the market which would at least partially support the price.

Banking and borrowing also effectively create price floors and ceilings respectively by ensuring that the carbon price transition between phases is relatively smooth (Rubin 1996). For Phase II of the EU-ETS and beyond, banking of surplus allowances into subsequent phases is allowed, and this

should prevent any risk of a price collapse towards the end of a period as was experienced in Phase I. The provision of borrowing would also prevent the risk of a price spike towards the end of a period in the case of an unexpected shortfall in allowances. Allowing borrowing would somewhat increase the risks of non-compliance if companies simply kept borrowing from the future to meet present day obligations, but this behaviour could be dissuaded by introducing a tax on borrowing and maintaining strong verification procedures.

In the long-run, it may be that the credibility will increase of ideas around the development of an independent agency charged with controlling supply and demand so as to manage prices within a certain range (analogous to the idea of a central bank controlling monetary supply). This could work if this central 'carbon bank' were able to auction allowances, withholding allowances if the price seemed to be dropping to low and increasing supply if prices were rising too high. At the moment, this idea does not work structurally within the context of the current international emissions trading architecture. Another major barrier is that European member states would have to agree to delegate a major revenue-raising activity (i.e. auctioning of allowances) to a centralised body, a move that seems highly unlikely in the near future, however efficient it may seem from a scheme design point-of-view. Further work would be required to assess whether or not active price management by such a body would be more or less effective than explicitly stated (i.e. static) price bounds.

In summary, there are several price management options available to governments, ranging from radical options that would require a re-design of the scheme to options that are more achievable but still provide some risk-management benefits. Although it is tempting to assume that price management is a completely win-win situation in terms of reducing risk, there will nevertheless be occasions when price management transfers risk from private companies to the government. And there remains some risk to companies that government policy on price floors / ceilings turns out to be unreliable, with the possibility of changing for example with a change of government.

4. Policy conclusions

Climate change policy uncertainty is one of many sources of risk affecting investment decision-making in the electricity generation industry. However,

to the extent that these risks are within the power of policy-makers to control, the implications for policy design are more direct than for some other sources of risk. This paper illustrates some of the effects of climate policy risk by using carbon price uncertainty as a proxy for policy uncertainty. The impact of carbon price risk on company decisions is to raise the investment threshold for new build, essentially acting as a risk premium. For some technologies, these risks are only moderately important – fuel price risks may continue to dominate the risk profile for many power generation investment decisions. However, in some circumstances, low carbon technologies which rely more heavily on the carbon price may be more sensitive to policy risks. In these cases, the carbon price required to trigger investment may need to be higher than would be expected if risks were not taken into account. The implication of including risks into policy analysis is that long-run carbon prices are likely to be higher than might otherwise be expected. Companies may also respond to policy uncertainty in a number of other ways. This includes building a portfolio of different generation assets to help manage the risks.

The implication for policy design is that the horizon over which there is reasonable stability in prices is an important factor in determining the risk profile. Price controls (e.g. price floors / ceilings or banking / borrowing provisions) could also help to reduce the effects of price risk. Fundamentally however, the key requirement from the point of view of investors is to increase as far as possible the visibility and transparency of policy-making to aid long-term decision-making.

There is however a potential counter-balance to this need for long-term policy commitments, since policy-makers also face risks associated with binding themselves into long-term commitments domestically in the face of an uncertain international policy context. The transition to a sustainable energy system will require decisions to be made at the global, national and company levels (rectangular boxes in Figure 4.1). In an ideal world, decisions would be fully consistent, informed by the factors in the oval boxes in Figure 4.1: the costs and benefits of mitigation would be known, and reflected in international commitments within in a binding global policy framework which allocated the necessary emission reductions down to the national level. Emission reductions would then be delivered by companies responding to carbon price signals or other incentives set at national or regional level that would deliver the agreed reductions.

In practice, decision-making within each of the 3 levels is often complex, and to make matters worse, the communication between the different levels of decision-makers is indirect and subject to various sources of uncertainty. Not only is there uncertainty about the costs and benefits of mitigation for example, but these costs and benefits are significantly different for different countries. The gaming nature of international negotiations means that each country's commitment to action depends on other countries commitments. Company-level investments will depend on expectations about the stringency of national regulation, while conversely political will to set stringent targets will be more-or-less constrained by companies' willingness to act. Each party in the system therefore faces different risks and incentives, and these risks and incentives interact with one another.

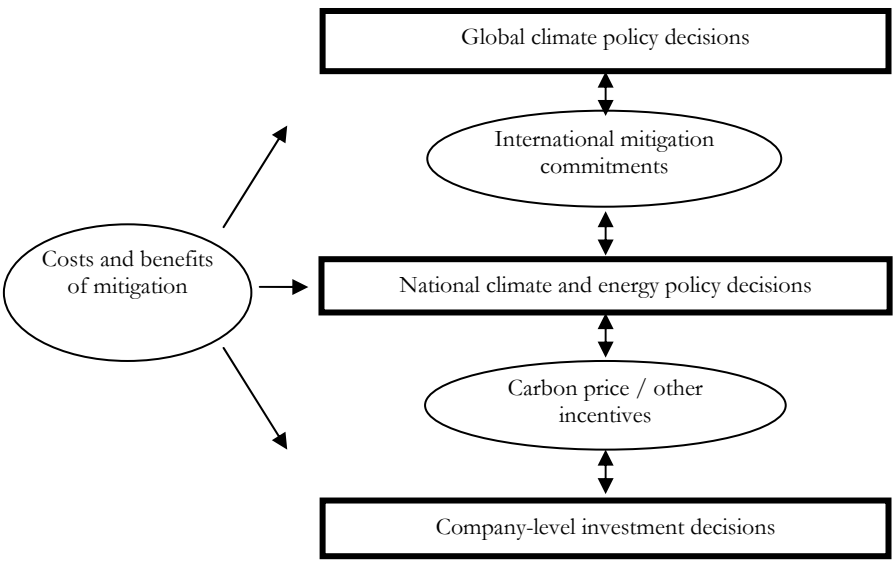


Figure 4.1. Decision-making involves interaction between different levels

Policy-making at the national and EU level is therefore sandwiched between 2 competing sets of constraints: namely, signals being sent to and received from global negotiations, and signals being sent to and received from companies who will implement the policy. A graphic illustration of this is the EU's 2007 Spring Council meeting decision to set a Europe-wide 20% emission reduction target, which could be extended to 30% if other countries were to follow suit. This negotiating tactic is presumably designed

to generate benefits to the EU through encouraging a greater level of international participation in climate change mitigation leading to greater levels of emission reductions. It also presumably is intended to create a certain degree of political capital in showing leadership on a topic that is currently highly visible in the media. In practice, the benefits of being able to respond to international events in this way have to be weighed against the cost of maintaining the flexibility to change course from a 20% target to a 30% target, which given the inertia involved in implementing emission reduction programmes, may be significant.

These trade-offs are caused by the fact that policy-makers may be simultaneously trying to achieve multiple sets of strategic objectives – for example, on the one hand negotiating with international partners on a global climate policy deal, and on the other hand setting domestic-level policy goals. These two 'games' may require different tactics; policy-makers may value flexibility with regards to the former, whilst aiming to achieve greater certainty in order to facilitate the latter. Further work will therefore be needed to investigate these trade-offs between policy certainty and policy flexibility, and to understand the balance of risk for different levels of decision-maker at company, national and global levels.

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