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FACTORING RISK INTO INVESTMENT DECISIONS

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Factoring Risk into Investment Decisions

This report provides a brief review of how risks can be incorporated into investment decisions, and how financial analysis needs to go beyond an assessment of levelised costs in order to adequately represent the different sources of risk that a new power plant investment will face in competitive markets.

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. These range from the general (e.g. macro-economic, political and *force majeur* risks) to the more project-specific. Table 1 shows examples of uncertain variables that companies would typically incorporate into a cash-flow model when carrying out a financial appraisal for a proposed project.

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

Table 1. Risks directly affecting a company's cash-flow calculation

As a case study, we take data for different generation technologies from the UK's July 2006 Energy Review. The costs of generation for different technologies are presented in the Review in terms of levelised cost (£/kWh). This is the average cost per unit of electricity generated over the lifetime of the plant.

Figure 1 reproduces the levelised cost figures from the Energy Review for gas (CCGT), coal (PF coal plus FGD), and nuclear (pressurised water reactor). The low and high cases for coal and nuclear refer to the more favourable and less favourable technology assumptions used in the Review respectively. The ranges for gas and coal relate to the maximum and minimum levelised costs for the different fuel price and carbon price scenarios used in the Energy Review. The fuel price scenarios include two central scenarios (one favourable to coal, one favourable to gas), plus a high fuel price and a low fuel price scenario. There are four CO_2 price scenarios, £0/tCO_2, £10/tCO_2, £17/tCO_2, and £25/tCO_2.

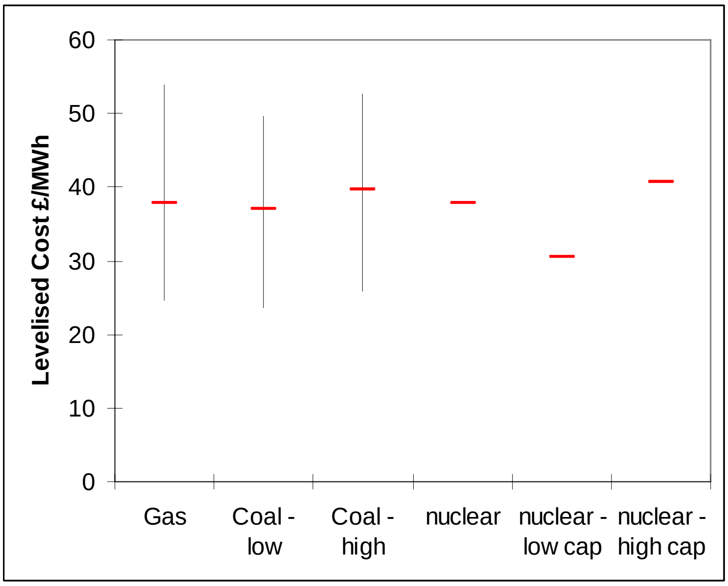


Figure 1. Spread in levelised costs arising from different CO_2 and fuel price scenarios (taken from UK Energy Review)

The levelised cost representation simply represents the costs of generation, and does not consider the revenue side of the equation. Whilst risk can to some extent be incorporated into this representation via the use of different price scenarios, it can be a bit misleading. For example, it would be easy to misinterpret the lack of any spread in the levelised costs for nuclear plant as indicating that the investment case for nuclear generation is independent of fuel and CO_2 price risk. It is true that these prices do not affect the costs of generation for nuclear, and therefore do not show up in the levelised cost representation. But it is vital that in addition to cost risk, the revenue risk also be incorporated into any appraisal of project risk.

Revenue risk may have technical and financial aspects, for example relating to uncertainty over the level of utilisation that the plant will achieve in practice compared to expectations, and the risk that a counter-party to an off-take agreement will default on the contract. But probably the greatest source of revenue risk in a competitive market is the price of electricity. To understand this, it is useful to briefly review electricity price formation.

Electricity Price Formation

In competitive markets, electricity supply is matched to demand by dispatching generation plant in order of increasing short-run marginal cost. The spot price of electricity at any given time should then be set by the short-run marginal cost of the last generator to be dispatched (i.e. the most expensive) at that time on the system.

Short-run marginal costs include all variable costs, including fuel costs, variable operating and maintenance costs, CO_2 and other environmental costs associated with the production of electricity. They exclude fixed costs such as capital depreciation and fixed operating and maintenance costs. Figure 2 shows a schematic for the order of dispatch ("merit order") for an electricity system, together with a nominal distribution for electricity demand over any given period. The distribution of demand determines the amount of time any given plant will spend on the margin, thereby setting electricity prices.

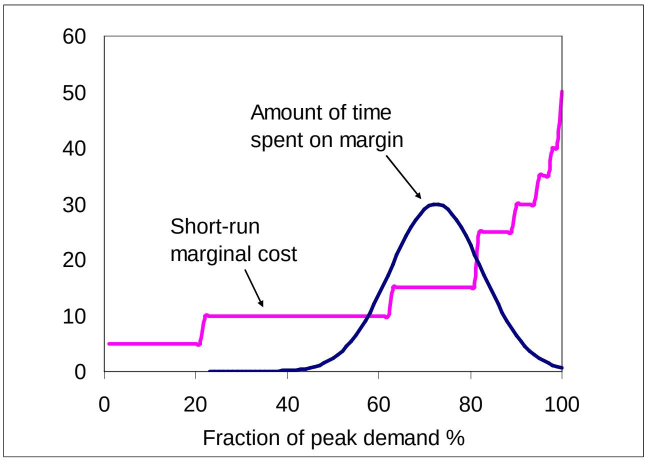


Figure 2. Schematic merit order for electricity system

Plants with high capital cost and low operating cost (such as hydro, wind and nuclear) will tend to have low short-run marginal costs, and will be dispatched early in the merit order (on the left-hand side of the curve). Fossil-fuel fired plant will tend to have higher variable costs, due to the price of CO_2 in the case of coal plant, and due to the price of fuel in the case of gas plant. They will therefore usually be the marginal plant, determining electricity prices.

The order that coal and gas plant appear in the merit order depends on the prices of gas, coal, and CO_2. Under current high gas prices and modest CO_2 prices, gas will tend to be on the margin (i.e. appears to the right of coal plant in the merit order). Coal will be pushed to the margin if CO_2 prices rise sufficiently. The CO_2 price at which this occurs depends on the price of gas.

The order in which coal and gas appear in the merit order is important, because it affects how fuel and CO_2 prices are passed through to the electricity price. If coal is generally on the margin, CO_2 will pass through at a higher rate because of the higher emissions per unit of electricity generated from coal compared to gas. This would lead to electricity prices being more sensitive to changes in CO_2 price. However, coal prices are relatively stable, so there would not be a significant fuel price risk element in the electricity price. If on the other hand gas is mostly on the margin, then the electricity spot price will become sensitive to the price of gas, and gas-price risk will affect all the other generators in the market. CO_2 price risk would be less pronounced in this case because of the lower emissions rate for gas compared to coal.

Not all electricity is traded at the spot price. Companies will often use a variety of trading activities and contract structures to help manage price risks, including forward delivery contracts and more complex financial derivative contracts. Some contracts can be as long as 15 years, set up in a way which removes much of the price risk for the duration of the project. However, in the bulk of cases, contracts do not go out more than a few years, and markets in electricity futures are generally not liquid beyond 1-3 years, designed to manage shorter-term risks associated with price volatility. The sort of long-run price uncertainty that is represented in the different Energy Review scenarios will not usually be hedged through contractual arrangements.

Including revenue risk

Revenue risk for generation plant will therefore typically include fuel price risk and CO_2 price risk, even if these prices do not directly affect the costs of generation. These risks can be assessed by incorporating both costs and revenues into a full discounted cash flow calculation. This requires some assumptions to be made about the electricity price formation process.

For illustrative purposes, the technical information and price scenarios were taken from the Energy Review, and put into a simple cash-flow model that assumed that either coal or gas plant would be on the margin of the electricity system depending on the fuel and CO_2 price in any given year under each scenario. The efficiency of the marginal gas plant was taken to be 40%, and the efficiency of the marginal coal plant was taken to be 30%. Standard emission factors for each type of fuel were applied to calculate the rate at which a given CO_2 price would be passed through to the price of a kWh of electricity (assuming 100% pass through of costs independent of the allocation mechanism).

These assumptions are rather crude and arbitrary, and companies will generally incorporate much more sophisticated analysis than this when modelling revenue risk for a new project. However this illustrates the basic approach.

The results are shown in Figure 3. This essentially takes the same projects shown in Figure 1, but instead of giving the levelised costs, it shows the net present value (NPV) of the different projects, expressed per kW of capacity of the plant. The advantage of the NPV approach is that it represents the range of potential financial outcomes for each of the technologies on the same terms, and in the same units that matter to financial backers[1].

[1] The y-axis is related to the profit per MW that could be achieved from the projects, although a full analysis of profit would need to take account of taxation.

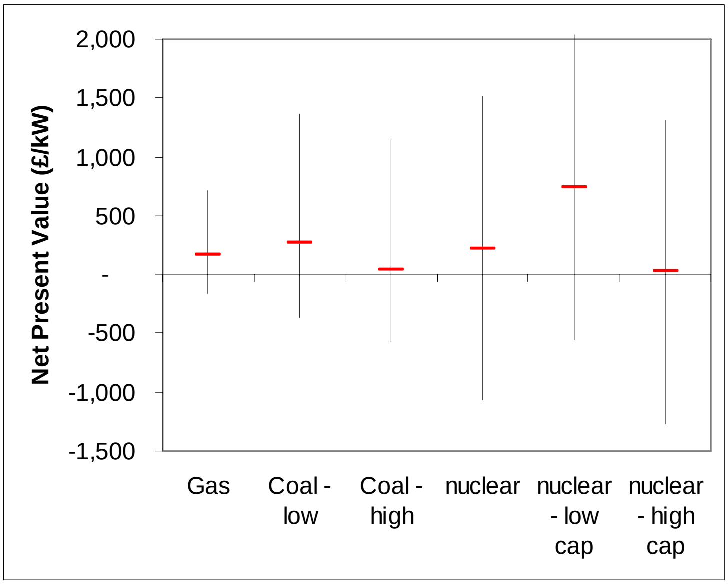


Figure 3. Net present value representation

The contrast with the levelised cost representation in Figure 1 is immediately apparent. The range of financial outcomes is significantly greater in the case of nuclear than for the other technologies, even if capital cost uncertainty is not taken into account, whereas gas plant has the smallest range of financial outcomes.

This reflects the fact that under the assumptions made about technology performance, gas plant is mostly on the margin of the merit-order. Coal plant becomes the marginal plant in the case of six out of the sixteen scenarios (those which combine higher CO_2 price with lower gas price), and for the other scenarios gas is assumed to be on the margin.

This means that gas prices are to a large extent incorporated into the electricity price. This provides a natural hedge for gas plants, since the uncertain gas price appears in both the cost and revenue sides of the financial equation, leaving the gross margin (difference between revenue and cost) relatively stable to gas price changes. Likewise, the sensitivity of gas plant to CO_2 price risk is somewhat dampened when gas plant are predominantly on the margin. For coal plant, and especially for nuclear plant however, the situation is the reverse. The pass-through of these price uncertainties into the electricity price leaves the revenue of the plant quite exposed to fuel price and CO_2 price risk, and leads to a substantially greater spread in possible financial outcomes depending on the scenario.

It is these spreads in NPV that usually form the basis for analysis of project risk. There are a number of different ways this is done.

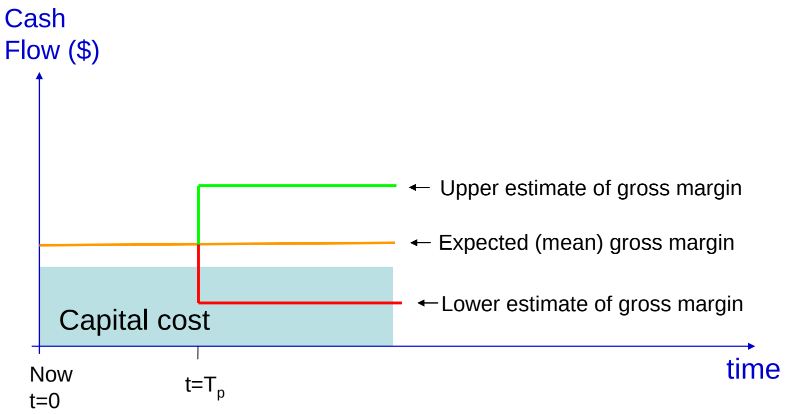
Evaluating risk

For this discussion, we need to introduce the concept of ‘expectation’ value. If the future value of some parameter is uncertain, the expectation value is the probability-weighted mean of the distribution of possible outcomes. We can illustrate this concept by taking Figure 3 as an example. There we showed the range and mean NPV’s for the scenarios used in the Energy Review. This mean falls short of our definition of an expected value however, since there are no probabilities attached to the different scenarios in the Energy Review. If (and only if) all the scenarios were deemed equally likely, then the mean of the distributions in Figure 3 would also be the expected value of NPV. If different scenarios had different probability weightings, the expectation value would deviate from the mean. The expected value of the NPV is basically a ‘best guess’ about an uncertain future.

For a company faced with uncertain future costs or revenues, there may financial benefits 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, improving the timing of investment, or avoiding investment altogether. Since the expected value of the NPV is a probability-weighted mean, by avoiding some of the worst outcomes, the expected value of the project will go up. 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.

The form of this payment would depend on the type of information that was needed. Figure 4 follows a recent IEA publication on the effects of policy uncertainty (Blyth 2006), 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 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.

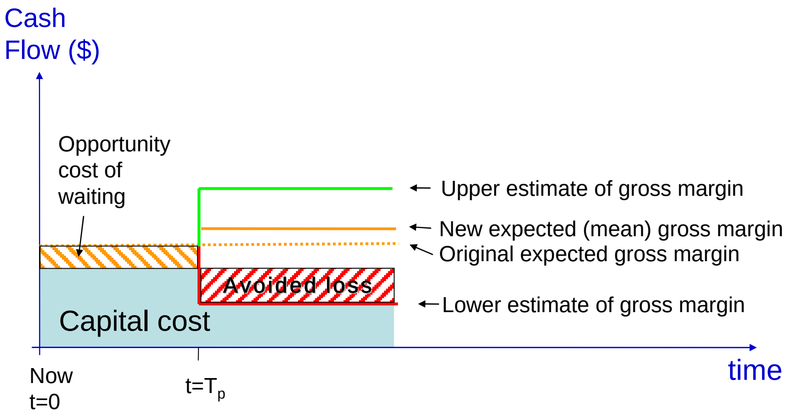


Figure 4. The value of waiting for regulatory information

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 of investing at t=0 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. The criteria for investment is therefore no longer that the project should exhibit a positive expected NPV, but that the expected NPV should exceed some minimum threshold which is essentially a risk premium.

If we use Figure 3 again as an example, making the very strong assumption that the average of the scenarios is the expected value of NPV, then we can see how this works in practice. Although the average NPV is positive in every case, they may not be sufficiently high to overcome the risk premium. The risk premium would be higher in the case of coal and nuclear, since the spread of outcomes is greater, leading to a higher value of waiting.

To calculate these risk premiums, a dynamic programming approach is used which allows the timing of the investment decision to be optimised in the face of uncertain future prices. There is quite a substantial literature developing on the use of these techniques. The approach is described in textbooks such as Dixit 1994 and Trigeorgis 1996. Applications of the approach are described widely in the literature, see for example Blyth 2006, Edelson, EPRI 1999, Frayer 2001, Ishii 2004, Lambrecht 2003, Laurikka 2006, Reedman 2006, Rothwell 2006, Sekar 2005.

The option value of waiting depends not only on the extent of the uncertainty, but also on the quality of the information that will be gained by waiting. In the case of regulatory uncertainty, this may be resolved as time goes on as more information becomes available about policy design, stringency and so on. With fuel prices, the future will always be to some extent uncertain, but new information does arise which can alter organisations view of the future direction of prices, and so again there is value to waiting.

For technical risks, the value of waiting depends on the nature of the risk. In the case of new technologies which have had a limited number of applications globally, there may be uncertainty about the capital costs or the operating performance which will be resolved as the number of applications of the technology increases. A company may in this case have an incentive to wait if they can learn from the experience of others. In order to incentivise immediate investment, the expected pay-off from the project would have to be correspondingly higher to offset the risks of going ahead without the new information. Early movers with new technologies will therefore expect to be compensated for taking these technical risks. In principle, some estimate of the required compensation could be gained through an options-based approach by evaluating the potential down-sides from technical risk, and evaluating the extent to which these might be avoided by waiting.

On the other hand, there may be site-specific technical risks which do not get resolved until the project actually goes ahead. In this case, there would not be a value to waiting, although there may be other options available such as additional R&D etc, the value of which would again be related in some way to the value of avoided loss.

Although real options approaches to evaluating risk have been quite widely explored in the academic literature, and have been applied in a number of cases, they are not widely used by companies. A more typical approach is to assess the range of possible financial outcomes either using different scenarios or using a stochastic approach. The financial outcomes are usually expressed in terms of NPV, or sometimes the internal rate of return (IRR) or other related measure.

Companies will typically run a detailed model of the electricity system they are considering making an investment into, with every major generation plant represented. Ranges will then be included for the major variables that affect the financial performance of the plant, including fuel prices, CO_2 and other environmental costs. Different scenarios for investment behaviour of other players in the market may also be incorporated.

A scenario approach would then build scenarios which give a forward curve for each of these parameters, such that each scenario leads to a given NPV outcome. The analysis would give a range of NPVs for the project depending on how the project performs under the different scenarios.

A stochastic approach would run the model hundreds or thousands of times, each time picking a different value from within the range for the different uncertain parameters. The model would pick values with a frequency determined by an assumed probability distribution for the uncertain variable. Correlation between different variables would also be taken into account (i.e. so that if a high value of one variable was picked, there would be a greater probability of a high value being picked for another correlated variable). This analysis would give a probability distribution for the NPV, the mean of which would be the expected NPV for the project.

Companies will then have different ways of assessing the importance of the distribution around the mean. We have described above one formal approach using options theory to quantify the risks, but companies may take a less formal approach, perhaps simply putting some value on the down-side risks, and comparing these between the various projects available to them to reduce risk exposure. In any case, companies will be concerned about the absolute level of down-side risk to which they can be exposed without damaging their credit ratings which would affect their cost of borrowing.

Companies will also have strategic reasons for making particular investments. These can often contribute as much as, or more than, the purely financial considerations. Strategic considerations would be important for example when a company wants to break into a new market, to acquire plant from competitors to consolidate market position, or if the company wants to diversify the technology base of its generating portfolio. In these situations, a new plant could add value to the company in a way that cannot be captured simply by looking at the finances of the individual project. Companies may try to evaluate this additional value with formal analytical techniques (such as portfolio theory), or may simply address these factors by assessing the extent to which the individual project is consistent with the overall corporate strategy.

Reducing risks through policy design

The range of financial outcomes shown in Figure 3 results from fuel price and CO_2 price uncertainty. It is possible that the CO_2 uncertainty element could be reduced through policy design, for example by introducing price floors or by extending the duration of the CO_2 price signal.

The first of these we can analyse explicitly for the Energy Review figures. Figure 5 shows the revised NPV if a price floor of £10/tCO_2 is introduced. This is done by replacing the scenario with zero carbon price with a scenario at the floor price.

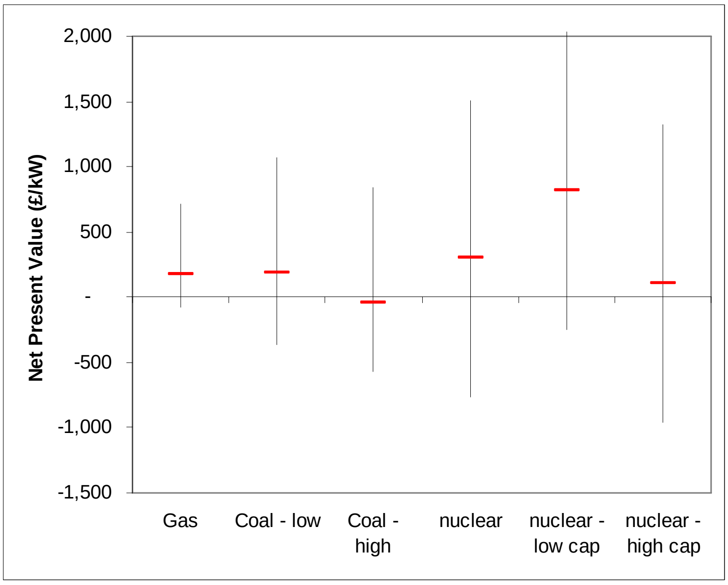


Figure 5. Effect of introducing a floor price of £10/tCO_2

The effect of the floor price can be seen by comparing the ranges in Figure 5 with the ranges in Figure 3. The case for gas is not strongly altered, the worst-case scenario improving from a loss of £160/kW to a loss of £81/kW. The average over all scenarios increases from £163/kW to £176/kW.

The effect of a price floor on coal is to reduce the upside potential. The best-case scenario for the more favourable coal plant reduces from an NPV of £1360/kW without a price floor, to £1070/kW with a price floor. The average NPV over all scenarios stays positive, but is reduced from £264/kW to £191/kW. The average NPV for the less favourable coal plant is tipped negative with the introduction of a price floor.

The price floor has quite a strong effect in reducing the potential losses for nuclear. The worst-case scenario gives a loss of £1000/kW without a price floor, and this reduces to a loss of just over £750/kW with a price floor. However, the average over all scenarios is not changed so much, increasing from £220/kW to £300/kW.

The effect of a price floor on the average NPVs for all three technologies is quite weak because the floor price only affects one out of the four scenarios. This suggests that price floors may not strongly affect the expected investment case for projects, although the effect would be stronger if the zero-price scenario had a high probability of occurring, as then it would have a greater weight (the above figures assume that all scenarios are equally likely).

A carbon price of £10/tCO_2 is sufficient to ensure that the average NPV for nuclear over all fuel price scenarios is positive. However, this does not necessarily mean that a price floor set at this level would be sufficient to stimulate investment. The price floor does much less to improve the average NPV than it does to improve the worst-case outcome. What determines whether the price floor is sufficient to stimulate investment is a whether the expected NPV exceeds the risk premium, since as already discussed, a positive NPV is not a sufficient criteria.

Another perhaps more effective way of reducing carbon price risks is to provide a longer duration over which there is visibility of prices. Given 10 years of reasonable policy certainty, carbon price risk can in principle be reduced well below fuel price risk (Blyth 2003), although longer periods may be needed for nuclear because of the long build time involved.

The overall message for policy-makers is that accounting for risks is an important part of commercial decision-making. The effects of risk should therefore also be included in assessments of policy in order to help understand how companies are likely to react in practice. Compared to a basic financial analysis such as a levelised cost assessment, the inclusion of risk could indicate an increase in power prices, a tendency to choose technologies that are less risk-exposed, and a possible narrowing of the reserve margin. Policies that are designed to promote investment in certain types of technology will be less successful the more uncertain they are. Creating policy certainty would involve ensuring sufficiently long policy timescales, and possibly using some type of contractual arrangement with companies to ensure credibility of the support mechanism.

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