
Volume 32, Issue 4, July 2010
ISSN 0140-9883
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ScienceDirect

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Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneco

Review

Risks, revenues and investment in electricity generation: Why policy needs to look beyond costs

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ARTICLE INFO

Article history:
Received 26 August 2008
Received in revised form 25 September 2009
Accepted 30 September 2009
Available online 9 October 2009

Keywords:
Investment
Electricity generation
Price
Risks
Policy

ABSTRACT

Energy policy goals frequently depend upon investment in particular technologies, or categories of technology. Whilst the British government has often espoused the virtues of technological neutrality, UK policies now seek to promote nuclear power, coal with CO_2 capture and storage, and renewable energy.
Policy decisions are often informed by estimates of cost per unit of output (for example, £/MWh), also known as levelised costs. Estimates of these costs for different technologies are often used to provide a 'ballpark' guide to the levels of financial support needed (if any) to encourage uptake, or direct investment away from the technologies the market might otherwise have chosen. Levelised cost estimates can also help to indicate the cost of meeting public policy objectives, and whether there is a rationale for intervention (for example, based on net welfare gains).
In the UK electricity sector, investment is undertaken by private companies, not governments. Investment is driven by expected returns, in the light of a range of risks related to both costs and revenues. Revenue risks are not captured in estimates of cost or cost-related risks. An important category of revenue risk is associated with electricity price fluctuations. Exposure to price risks differs by technology. Low electricity prices represent a revenue risk to technologies that cannot influence electricity prices. By contrast, 'price makers' that set marginal prices are, to an extent, able to pass fuel price increases through to consumers. They have an inherent 'hedge' against fuel and electricity price fluctuations.
Based on recent research by the UK Energy Research Centre, this paper considers the implications of such price risks for policy design. The authors contrast the range of levelised costs estimated for different generating options with the spread of returns each is exposed to when electricity price fluctuations are factored in. Drawing on recent policy experiences in the renewable energy arena, in the UK and elsewhere, the authors provide an assessment of investment risk in policy effectiveness and consider how policy design can increase or ameliorate price risk. They discuss the circumstances under which policy goals might be best served by 'socialising' price risk, through fixed price policies. The importance of increased and explicit attention to revenue risk in policymaking is discussed, along with the means by which this might be achieved.

Contents

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0140-9883/$ – see front matter
doi:10.1016/j.eneco.2009.09.017

1. Introduction

This paper considers the analytical tools used by energy policymakers to design interventions that seek to support objectives such as the development of lower carbon technologies or a diverse mix of fuels for electricity generation. It is focused upon the mechanisms used within the UK in the electricity generation arena, in particular recent decisions related to nuclear power, carbon capture and storage (CCS) and support schemes for renewable energy. Whilst the context for many of the issues discussed is UK specific its conclusions are relevant to all technologies and to all countries where electricity markets are privately owned and competitive, and governments provide incentives for particular technologies or technology/resource types.

In any privately owned electricity market government objectives must be met through the creation of policies that provide incentives for the market to deliver the desired outcomes. British policymakers in particular have frequently espoused the virtues of policy remaining technology neutral (see e.g. DTI, 2003). Nevertheless, policymaking often requires comparison between technologies. Analysis by the UK Government has focussed on assessment of relative costs. Examples include (DTI, 1999, 2000, 2002, 2003, 2006a,b, 2007; PIU, 2002).

The British Government's 2007 Energy White Paper, the basis for its 2008 Energy Bill and Act (BERR, 2008a; OPSI, 2008), seeks to support two primary goals[1] in the electricity supply sector: diversifying the fuel mix of new power stations and encouraging investment in lower carbon generation. The government announced measures intended to facilitate the development of nuclear power and to improve the support regime for renewable energy. Shortly before this paper was finalised the government announced its intention to provide further support for the development of CCS on coal-fired power stations (DECC, 2009). Hence whilst policymakers profess the importance of technological neutrality and explicitly avoid the 'generation mix' policies espoused by some commentators (e.g. Fells and Whitmill, 2008) *in practice* policies seek to actively promote the development of renewables, nuclear power and coal-fired CCS.

Despite these important technologically specific objectives the 2007 White Paper pays relatively little attention to the role of technology specific issues in corporate investment decisions. The White Paper does discuss investment issues related to markets and prices; supporting analysis by Redpoint Energy investigates investment issues in considerable detail (Redpoint Energy, 2007). However this analysis has a particular focus on whether the market will deliver sufficient investment in new capacity in the round, the likelihood of a so called 'energy gap' (DTI, 2007; Collins et al., 2008). Investment risk, including various price risks, does not feature in the discussion of policies to promote new nuclear power stations or indeed renewables and CCS. Analysis of the relative economics of nuclear power, gas, coal and renewables is dealt with almost entirely in terms of relative *costs*. This is the basis for the Government's opinion that nuclear is competitive with gas, which appears to be the principal reason it takes the view that new nuclear will not require dedicated financial support.

A central contention of this paper is that over-reliance on analysis of costs can make the achievement of policy goals more difficult; because it cannot ensure that policy instruments properly address non-cost risks. Investment is driven by expected returns, which are a function of costs *and revenues* (IEA, 2003). The paper demonstrates, using a simplified illustration, how outcomes for investment can be very different when both sides of the cost/revenue equation are modelled. It discusses the relationship between risks and different types of policy instrument. It illustrates how some policies mitigate price risks whilst others exacerbate existing market risks.

2. The historical role of costs estimates in energy policy

When the UK electricity industry was in public ownership, *levelised costs* were often used to provide an approximate estimate of the relative merit of different technologies. The levelised cost calculation attempts to capture the full lifetime costs of an electricity generating installation, and allocate those costs over the lifetime electrical output, with both future costs and output discounted to present values. The result is expressed in cost per unit of output (such as £/MWh or p/kWh) which has the appealing characteristic of allowing ready comparison between different generation options.

Cost-minimisation has always been a key driver of energy policy and investment choices (irrespective of ownership arrangements) and, not unreasonably, levelised costs were, and remain, a starting point for analysis of technology choice. Under monopoly conditions planners would incorporate other factors into system design for achieving cost-minimisation. From the 1960s until liberalisation increasingly sophisticated cost optimisation models were used to determine optimal investment in the UK's state owned electricity network (Turvey and Anderson, 1977).

In liberalised markets, system-wide cost considerations remain a valid public policy concern, partly because delivery of affordable energy is an explicit element of energy policy, and partly because there may be public goods that exist at the level of the whole system that are not well captured within individual investment decisions made by competing private companies. Hence, levelised costs provide data that can be used in assessing the rationale for intervention and in informing policy—for example:

- High level comparison of generating technologies in terms of the relative performance and prospects of each, such as pollution abatement costs (e.g. £/tonne C), both now and (using cost projections) in future.
- Assessment of cost effectiveness of the contribution of new technologies to various policy goals and whether there is a rationale for intervention (Cost Benefit Analysis, Welfare Assessments, etc).
- Assessment of the potential value of investments intended to promote innovation, for example creating markets to allow learning by doing, again using cost projections or technology 'learning curves' that link costs to market growth (IEA, 2000).
- Technology based economic models of the electricity system, as used for energy scenarios that can inform policy (CCC, 2008; DTI, 2003; PIU, 2002).

Levelised costs can also provide an approximate view of the level of subsidy or transfer payment (if any) needed to promote individual technologies, or technology types, such as renewable energy. The extent to which they provide data accurate enough for this task is affected by the range of estimates that abound in the literature (see Fig. 1). Moreover, some commentators have argued that levelised costs should be adjusted to reflect the technologically differentiated

[1] The goals discussed here—fuel diversity and the development of lower carbon generation form part of a wider set of objectives derived from four 'pillars' described in the Energy White Paper of 2003, simply put these are to reduce CO_2 emissions, maintain reliable supplies, promote competitive markets and ensure that poorer consumers can afford adequate levels energy services, particularly domestic heating.

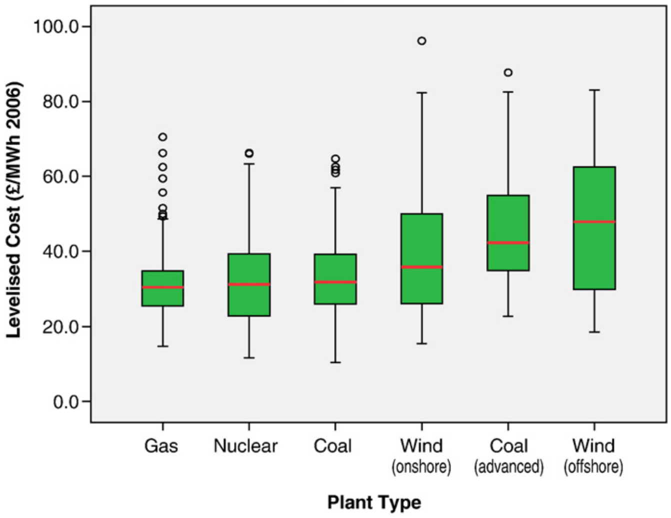

Fig. 1. Cost ranges for leading electricity generation technologies. Notes: The box for each plant type represents the inter quartile range (i.e. the central 50% of values), and the median value is denoted by the horizontal line within each box. The vertical lines from each box extend as far as the highest and lowest non-outlier values. Outliers (values further than 1.5 times the interquartile range from the box boundaries) are represented with individual circles. The 'Coal (advanced)' group includes a range of technologies which are at a less advanced stage of commercial development such as Integrated Gasification Combined Cycle, Oxycombustion, and CO_2 capture.
Adapted from Gross et al. (2007).

exposure of different technologies to a range of risks (Awerbuch, 2000, 2006).[2]

The wide range of estimates of cost is important to policymakers since it creates uncertainty and implies that support schemes might either over, or under, reward. The potential for costs to be significantly higher than forecast has been discussed in a range of contexts, see for example (MacKerron et al., 2006; MIT, 2003). It is also possible that technology developers or policymakers overestimate costs, and it has been argued that developers have an interest in overstating costs in order to secure excessive levels of subsidy (Gross et al., 2007).

However, in terms of the ability of policies to deliver investment, there is another important point of note and this is often overlooked in policy debates: the level of support needed to facilitate investment in particular technologies is not independent of the design of policy instruments that deliver the subsidy. This is because policy design has implications for the level of *price risk* attached to investment. Hence, levelised costs may be useful (despite cost uncertainties) in deciding *whether* support is needed, but are not sufficient alone to determine *how* to provide it. When the impact of policy design on price risks are neglected problems may arise, as we now attempt to explain.

3. Risk and investment in liberalised markets

Clearly costs still matter under liberalised markets, but they are joined by a range of additional factors that are relevant to investment decisions, and hence also relevant to policies that seek to encourage investment and influence technology choices. The principal reason for this is that in competitive markets investment decisions are made in the light of risks and prospective returns to investment (Blyth et al., 2007). Returns depend on revenues as well as cost, so the price of electricity becomes an important risk factor in the investment

Table 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 Decommissioning and waste Regulation	Credit risk
Revenues	Electricity price	Utilisation levels (and timing of utilisation, which can be important for price) Build time	Contractual risk

decision (Roques et al., 2006; White, 2006)). Price and other risk factors depend on the market structure and the investment being considered, and can affect the way an investment is financed and therefore the cost of capital. A range of risks are reviewed in Table 1.

Risk factors affect different technologies in different ways and may lead to a re-ordering of the relative attractiveness of the various investment options facing a generation company compared to a more static analysis that does not include risk. This is why it is important to look at the effects of risk on projects. For example, technical risks vary considerably between technology types, and will be an important element of investment decision-making, since all else being equal companies would prefer to invest in lower risk technologies (IEA, 2003).

3.1. Electricity price risk and technology type

The level of exposure to electricity price risk varies considerably between generating technologies. Under 'BETTA', the British Electricity Trading and Transmission Arrangements, over 90% of electricity in the UK is traded bilaterally between generators and suppliers. A small remainder is traded either through power exchange markets or the *Balancing Mechanism*,[3] depending on how close to real time the trade takes place (AEP, 2009). The utilisation of plants and the price of electricity at any given time of day have historically been set by the short-run marginal cost of generation (i.e. the most expensive) at that time on the system. Whilst centralised dispatch[4] is long gone, marginal cost based price signals are still reflected in both bilateral contracts and exchange market electricity prices. Both include a 'time of day' component, since generation must be increased and decreased as demands fluctuate and it is rational to contract for this on a least cost basis. Bilateral contracting will also reward flexibility of operation so that output can be adjusted as real time approaches and both suppliers and generators can minimise imbalance and associated costs.

Moreover, although a variety of bilateral contract structures (including forward delivery contracts and more complex financial derivative contracts) can help manage longer run fuel price risks associated with oil, gas and coal market movements, in the bulk of cases contracts do not go out more than a few years. The result is that significant long-run fuel price uncertainty, such as that represented in the different UK Energy Review scenarios (DTI, 2006b), cannot usually be hedged through contractual arrangements. Long-run fuel price changes, like time of day prices, are mediated by the current market arrangements but remain fundamental to electricity prices. Fuel prices

[2] Awerbuch argued that adjusting the discount rate applied to future cost streams to reflect the riskiness of different costs results in levelised cost values dramatically different from those typically found in the main stream economic and engineering studies of costs (e.g. The Royal Academy of Engineering, 2004). In particular he argued that the true risk-adjusted levelised costs for technologies which rely on fuel inputs is much higher than is traditionally thought because future fuel costs are uncertain so it cannot be discounted to the same degree as other cost streams.

[3] The Balancing Mechanism is the process used to resolve the contractual issues that arise when a generator's actual output (or a supplier's actual demand) in any half hour settlement period is different from their contracted output (or contracted demand). All contracts are recorded in a central system run by Elexon, the Balancing and Settlement Code Company, who manage the process and ensure that any debit or credit positions of market participants are cleared. See http://www.elexon.co.uk/default.aspx for full details on how this process operates.

[4] The use of the term 'dispatch' is useful shorthand. A small amount of generation is in effect directly dispatched by the system operator (National Grid Plc) in order to maintain system balance. A range of services are contracted for by the National Grid for these purposes (see Gross et al., 2006).

and plant efficiencies for the system marginal plant(s) therefore influence the price of electricity. Since fuel price increases are passed through to consumers fossil fuel generators have a substantial degree of natural 'hedge' against fuel price fluctuations.

High fixed cost and low/zero fuel cost plant such as nuclear power and renewables would typically expect to operate whenever they are physically able to do so. Unlike fossil fired stations (and possibly biomass fired stations) they cannot be rewarded for flexible operation, or determine time of day price differentials or long-run electricity price movements. Bilateral contracts for their output will reflect these characteristics. Hence they benefit when electricity prices overall are relatively high (as gas and electricity prices were during 2006 and 2007), but may suffer when prices are low (for example during 2001). For these reasons they are sometimes referred to as 'price takers'. Companies operating nuclear stations can overcome some of these issues by diversifying their portfolios and purchasing flexible generation such that they can shape contracts to meet supplier demand. British Energy's purchase of the coal-fired Eggborough power station in 1999 is an example (Taylor, 2007). Nevertheless, from a public policy perspective where generation mix diversity is a goal, the investment characteristics of nuclear stations viewed in isolation are relevant to policy choices.

The significance of this relationship between input/fuel prices and power prices for the ranges of cash flows that might be calculated for the three main types of electricity generation—coal, gas and nuclear power, compared to the ranges of levelised costs for these generators, is illustrated below. Fig. 2 reproduces the levelised cost figures from the Energy Review (DTI, 2006b) for gas (CCGT), coal (PF coal plus FGD), and nuclear (pressurised water reactor). Full details can be found in (Gross et al., 2007) and (Blyth, 2006). The factors relevant to nuclear power would also apply to wind, hydro and other high capital cost or non-dispatchable renewable plants. Data for nuclear costs are utilised in the figure to provide an illustration.

These estimates represent the costs of generation, and do not consider the revenue side of the equation. This has the potential to be rather misleading with regard to the relative attractiveness for investors of each of the three options. 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. In fact, whilst these prices do not affect the costs of generation for nuclear, and therefore do not show up in the levelised cost representation, nuclear plant, like other price takers, is exposed to revenue risk resulting from electricity price fluctuations.

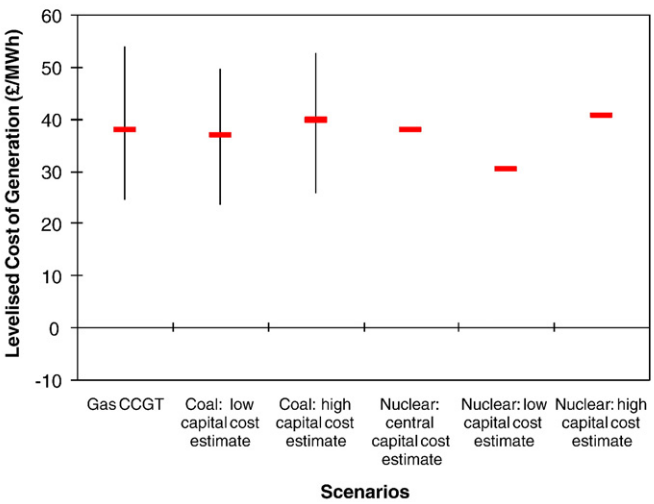

Fig. 2. Spread in levelised costs arising from different CO_2 and fuel price scenarios taken from Gross et al. (2007).

Table 2
Energy price scenarios.

Year	Central favourable to coal		Central favourable to gas		High		Low	
	Gas p/therm	Coal $/GJ	Gas p/therm	Coal $/GJ	Gas p/therm	Coal $/GJ	Gas p/therm	Coal $/GJ
2005	41.0	2.4	41.0	2.4	41.0	2.4	41.0	2.4
2010	33.5	1.9	25.8	1.9	49.9	2.6	18.0	1.4
2015	35.0	1.9	27.3	1.9	51.4	2.6	19.5	1.2
2020	36.5	1.8	28.0	1.8	53.0	2.6	21.0	1.0

To illustrate this, the technical information and price scenarios were taken from the Energy Review (DTI, 2006b), and put into a simple cash-flow model assuming 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 DTI Energy Review used 4 different energy price scenarios (shown in Table 2), together with 4 carbon price scenarios, £0/tCO_2, £10/tCO_2, £17/tCO_2 and £25/tCO_2. The high and low capital cost assumptions here are based on the upper and lower bounds on the ranges of cost estimates found in the Energy Review, as are the data on operating costs, efficiencies, plant lifetimes and load factors, all taken from Table B1 in the Appendix to the Energy Review.[5] The discount rate for all technologies was taken to be 10% for the purposes of these NPV and levelised cost calculations.

Details on the other assumptions used can be found in (Gross et al., 2007) and (Blyth, 2006). These assumptions are, of course, rather crude, and companies may incorporate much more sophisticated analysis than this when modelling revenue risk for a new project. Long-run contracts can mitigate such risks, though for the reasons discussed above they cannot eliminate them. The principal outcomes illustrated below will be refined rather than undermined by a more sophisticated treatment (Blyth, 2006).

The results are shown in Fig. 3. This takes the same projects shown in Fig. 2, but instead of giving the levelised costs, it shows the Net Present Value (NPV)[6] 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.[7] Fig. 3 neatly illustrates why generators have continued to favour investment in gas-fired generation—the NPV range is smaller (implying a less risky investment) and the downside risk of negative NPV is relatively small. This continues to be the case even when gas prices are high. By contrast the NPV range for nuclear power is wide, indeed single levelised cost estimates generate wide ranging NPVs. This is a product of nuclear's price taker characteristics. When gas and carbon prices are high, electricity prices are correspondingly high and nuclear benefits from high returns, but NPV becomes low or negative during conditions when power prices are low.

3.2. Other factors

The range of NPVs illustrated in Fig. 3 provides a simplified indication of a spread of possible returns. In reality any investment proposition will be further complicated by a range of other factors that affect the cost of capital and hurdle rate. Many companies run a detailed model of the electricity system they are considering making an investment into, with major generation plant (their own those of

5 Available at http://www.berr.gov.uk/files/file31890.pdf.

6 NPV is the product of the present value of the expected output of the plant times the market price of output over the lifetime of the plant, minus the present value of the capital costs of the plant, plus the annual maintenance costs, plus the output of the plant times its fuel and other variable costs.

7 For illustrative purposes this is expressed neglecting the effects of tax.

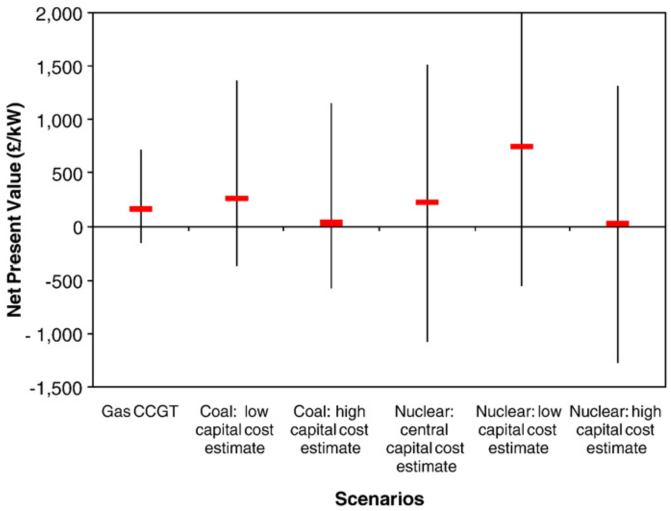

Fig. 3. Net present value representation of the spread of returns arising from different CO_2 and fuel price scenarios taken from Gross et al. (2007).

competitors) represented. Such models may be used to assess possible financial outcomes, by either generating NPVs from a set of discrete scenarios (see for example (Feretic and Tomsic, 2005)) and/or a by generating a spread of NPVs using a stochastic approach. The major variables that affect the financial performance of the plant include utilisation, fuel prices, CO_2 and other environmental costs, electricity prices and the value of support mechanisms such as the Renewables Obligation (RO). The impact of investment behaviour of other players in the market may also be incorporated, for example using a game theoretic approach. Whilst evidence of deliberate 'gaming' by companies is difficult to substantiate in practice, game theory has been applied in electricity market analysis e.g. (Green and Newbury, 1992; Powell, 1993).

Companies will also have strategic reasons for making particular investments. Whilst the relative importance of strategic factors is dependent on market and industry structures, they can often contribute as much as, or more than, the purely financial considerations. There are a range of strategic factors that affect investment, including:

- Projects may add value in addition to their own expected returns if they help to balance risks within a portfolio of generation assets (Awerbuch and Berger, 2003; Wiser et al., 2004).
- Companies may want to break into a new market or acquire plant to consolidate a market position.
- If companies believe that additional policy support is likely to be announced for a particular technology, then there will be a value attached to waiting until the support mechanism is available, and in retaining an option to invest in such technologies.
- Potential investments that build knowledge or help to reveal information may have additional value that will be factored into the investment decision process.

3.3. Investment finance

The share of debt and equity is fundamental to the overall cost of capital and the level of return expected of an investment. Because of the lower cost of capital associated with debt, investors will aim to get as much debt financing as they can. On the other hand, as the debt gearing rises, the risk of default also rises, so lenders would tend to increase interest rates and/or restrict gearing rates. The level of debt that can be raised therefore depends on the type of project and its perceived risk profile. In a riskier project, higher risk-taking equity will have to play a larger overall role, and project revenues will have to be high enough to sustain the higher cost of finance.

At the company level, the Weighted Average Cost of Capital (WACC) measures the weighted average of the cost of debt and the cost of equity. A firm's WACC is the overall return required by the firm as a whole, and represents a minimum value for the Internal Rate of Return (IRR) of a new project.

The lower cost of debt compared to equity arises because debt providers are paid first out of a company's revenues, with equity providers paid from any remaining revenues. The amount paid to debt providers is fixed according to the terms of the loan, whereas the amount paid to equity providers fluctuates depending on the profitability of the firm. The extent of these fluctuations depends strongly on the extent of debt financing because the residual profit will be more volatile if there is a high level of fixed cost in the debt repayment schedule (hence the term 'gearing' to represent the debt to equity ratio).

Power plant may be financed in many different ways, but typically may be project financed (where the risk and return is measured purely at the project level), or corporately financed (where a company incorporates the new investment into its overall portfolio of activities and measures the marginal impact on the company-wide risk and return characteristics). Theoretically, this choice of financing method should not make any difference to the marginal cost of capital required to finance a project with a particular risk profile. Although it is tempting to assume that risky projects could be financed at low capital costs if they are carried out by a company with a 'safe' set of assets and access to cheap capital, in theory this is not possible because the cost of capital for the firm as a whole should reflect the whole portfolio of projects. Capital costs for the firm as a whole would increase if it started to invest in riskier projects because of the increased risk of default on debt repayments. In practice, the ability to manipulate such risks by taking projects on or off balance sheets depends on the accountancy rules to which the company is subjected.

Although large-scale power plant investments may often proceed with a high degree of corporate financing, the additional marginal cost of financing a project can still be analysed by looking at the achievable debt to equity ratio. This is a useful shorthand way of thinking about the cost of risk for any given investment, as it can be simpler to think about available debt–equity ratios than the marginal impact on a company's ability to honour their debt repayments and knock-on effects on their credit rating and costs of capital.

In project finance terms, a project's exposure to revenue risks limits the amount of debt that can be secured, increasing the requirement for (more expensive) equity finance. The point can be illustrated with reference to nuclear power but it is important to note that the issues are not unique to nuclear but apply to all capital intensive, low fuel cost technologies, including many renewables. Nuclear is a useful example because, at the time of writing, it is believed to have similar levelised costs to fossil fuel fired generation (DTI, 2006b, 2007). Neglecting portfolio effects (see below) and policy support it is possible to approximate the debt–equity split that might be representative of a new nuclear power station by considering the amount of debt that could be serviced if electricity prices were to fall to the low levels experienced in 2000–2003. This limits the debt share of a new £1.3 billion nuclear power station to less than £300 m or around 23% (White, 2006), effectively reversing the debt–equity ratio of a typical gas-fired investment and requiring an equity stake of more than £1 billion per power station. Given the low margins that appear typical of a competitive electricity market White concludes that new nuclear generation is not financially viable, at least not when viewed in isolation and in the absence of market power, innovative finance, or supportive policies. The investment proposition might be improved upon in a number of ways:

- A large utility may be able to borrow money against its wider portfolio or to explicitly value the portfolio diversity added by nuclear power.
- Electricity market might be modified such that the price 'collapse' experienced in 2001 becomes very unlikely to recur. This might

result from some regulatory intervention or through changes to market structure (such as the emergence of significant market power).
- The ‘floor’ price that nuclear power is exposed to could be protected in some way. Again this might require government intervention (such as a nuclear obligation or much strengthened EU ETS). It could also occur through co-operation between major electricity suppliers (for example if several large suppliers took equity stakes in new nuclear and agreed a fixed price for nuclear output).
- Large customers might take an equity stake in a nuclear plant and/or enter into a long term power purchase contract with the nuclear station operator (arrangements similar to this have been put in place in Finland).
- Developers may be able devise novel financing instruments, such as issuing bonds or creation of a closed mutual fund that owns the assets.
- Government could take an equity stake itself, perhaps in the form of a Private Finance Initiative (PFI).

It is not the purpose of this paper to explore these options in greater detail. The authors' objective is simply to illustrate that viewed as standalone investment propositions the price risk exposure of new nuclear power stations in the UK appears problematic for investors. Whilst not insurmountable this issue is a legitimate object for transparent public policy analysis. Such an analysis is not a feature of recent policy publications (DTI, 2007). A brief review of the wider policy implications provides the focus for the remainder of the paper.

4. Implications for policy

The policy implications of the issues described above are extremely significant in an environment where policy goals bring with them a high degree of technology specificity. If policy did not require the development of particular technologies or classes thereof then it might not matter whether policymakers attended to investment risks and returns. Such matters could be left to the market, with policy goals being delivered through other means. However the current policy context is that the Government has designed interventions to directly promote renewables, wishes to facilitate but not directly subsidise nuclear power and is consulting over a support scheme for CCS. Hence a technology neutral approach to policy analysis or laissez faire approach to policy design no longer matches policy goals. It is also important to note that these factors are relevant irrespective of the nature of the interventions government uses: subsidies and incentives, various trading schemes and direct (‘command and control’) regulation all have implications for investment. In all cases the investment conditions created by the policy will affect its success. In what follows we review in detail the different characteristics of a range of incentive schemes, focusing on support for renewables as this is where evidence exists from UK and overseas policy.

4.1. Policy design and market risk

Policy incentives that appear sufficient to deliver policy goals when viewed in terms of levelised cost may not deliver investment when risks and returns are taken into account. In addition, the detailed design of policy is important because policy instruments vary in terms of the risks that they mitigate, or indeed create, even where the level of remuneration offered by alternate policies is identical. It is therefore vital that the relationship between policy developments and electricity price risk is considered by policymakers, and that careful attention is given to how policy might respond to issues related to project finance, information flow in private markets and corporate strategy.

Policy itself can affect investment risk in a number of ways. Governments can provide incentives and support schemes but political changes can affect markets, particularly if incoming political parties have a different view of energy policies. Governments may ‘change the rules’, and such changes can impact on electricity prices, price volatility and risks. The approach that regulators take to market governance will affect market structure and price volatility. Market power can decrease price volatility, but fear of regulatory intervention may also discourage certain categories of investment. Policy or electricity regulation related issues such as the difficulty or otherwise of securing planning permissions, grid consents and transmission system pricing can all affect the viability of investments. Governments may also intervene directly to prevent investment, for example in the moratorium on new gas generation imposed in Britain during the late 1990s.

Hence a range of risks related to the perceived stability of the policy environment will affect the cost of financing for a project. However policy can also create markets, through a variety of support or incentive mechanisms that can increase returns or reduce risks.

The implications for policy options can be illuminated by focusing on revenue support schemes. It is possible to identify three ‘levels’ of price risk associated with different forms of revenue support for renewable energy operating in different countries:

1. Fixed price: Fixed prices for renewables output for a fixed period of time (Feed in Tariffs as in use in Germany and many other countries).
2. Fixed premium: A fixed ‘uplift’ over and above electricity prices, again fixed by technology (an option available to wind farm developers under Spanish legislation for example).
3. Trading: A market exists for renewable energy certificates (The UK RO and Renewables Portfolio Standards in place in parts of the US for example).

In case 1, feed in tariffs provides a fixed price, and revenue risks associated with electricity price movements are effectively removed from the developer's investment decision. In case 2, developers are exposed to electricity price movements, although they are guaranteed a minimum payment. In case 3 developers are exposed to price risks in both the electricity market and the market for renewables certificates. The UK RO has no ‘floor’ price on Renewable Obligation Certificates (ROCs) so at least in theory the price for these could fall to low levels, even zero. Prices may also rise in situations of shortage and give low cost generators a ‘windfall’, but this may not in itself mitigate the risk of low or zero ROC prices.

The UK's Renewables Obligation therefore has greater price risks associated with it than the feed in tariffs common in other parts of Europe. As noted previously, a period of low average electricity prices poses a particular risk for capital intensive investments. Whilst the ROC price is not bound to electricity prices, it cannot insulate investments from electricity price risks, and ROC prices are themselves uncertain. It should therefore be expected that investors will view low electricity/ROC prices as an added risk, and seek higher returns. Investors may also be more averse to projects which have high technology risks under the RO than they would under fixed tariff arrangements. This is because overall risk exposure will be higher under the RO.

Fixed tariff schemes do not, however, remove price risks altogether, they simply remove them from project developers. Fixed tariffs require policymakers to ‘second guess’ the costs that markets are able to deliver and therefore carry the risk that society (or electricity consumers) pays too much for renewables output. Instead of exposing the renewable energy market to commercial risk they oblige electricity consumers to bear the risk of over remunerating renewables. In effect, an element of risk is transferred from developers to consumers (or socialised). The important question for policy is under what conditions might this risk transfer be a desirable thing for policymakers to do?

It is also important to note that whilst feed in tariffs require a judgement on the part of policymakers about prices, trading schemes also require very similar judgement, it merely moves the focus from price to quantity: Government is responsible for setting the level of the obligation, so a judgement about the tariff needed to encourage a particular renewable technology is simply replaced by a judgement about the appropriate volume of renewable electricity. This judgement may be made in part on the basis of costs; hence judgement about technology costs may be implicit. Put another way, whereas feed in tariffs set price, obligations using tradable certificates set quantity—which determines price—so in either case a social (or political) choice ultimately determines price. The distinction between fixed price and market based schemes is a matter of who bears what price related risk, rather than whether or not to provide a premium price.

As well as the presumed avoidance of second guessing market prices, notions of economic efficiency are a main argument in favour of trading schemes such as the RO. However, it is important to avoid overly simplistic assumptions about markets moving to equilibrium rapidly (least cost, optimal deployment). Markets may be out of equilibrium (targets not met) for a long time, resulting in high prices for renewables certificates and 'windfall' gains for existing renewable schemes. An important feature of the RO is that if development cannot proceed because of grid limitations or planning, then ROC prices will go up and consumers will pay a high price for renewable energy. Whilst in the long run this would be expected to provide greater incentives for development and ultimately growth in renewable generation it may lead to criticisms such as 'overpayment' relative to feed in tariffs or developers getting 'supernormal' profits (NAO, 2005; Ofgem, 2007).

Finally, whilst markets will find the least cost way to meet a target, delivery of only the cheapest options may fail to achieve the wider portfolio of new technologies that policymakers desire. Hence concern in the UK about excessive reliance on onshore wind, co-firing and waste based technologies (DTI, 2006b, 2007) and the decision to band the RO (OPSI, 2008).

Within the EU the majority of countries (18 of the 25 member states) have variants of the fixed price and fixed premium schemes described above. Similar schemes operate in a range of other OECD countries (Olz, 2008). Several countries have abandoned trading based schemes in favour of fixed price arrangements (EC, 2008). The international evidence suggests that in most cases countries with fixed price schemes have been more successful at deploying renewables than those with trading schemes (Olz, 2008; EC, 2008). Whilst the reasons for this are complex and varied it appears likely that investment risk plays an important role (Mitchell et al., 2006; Olz, 2008).

4.2. Decision making where information is poor or asymmetric

A range of factors that relate to the amount and quality of information about technology costs and risks available to policymakers and market participants are relevant when considering incentives and investment in new technologies:

- Policymakers may have relatively poor information about costs for emerging technologies.
- 'Appraisal optimism' (where technology/project developers underestimate the cost of unproven technologies/systems) is a common feature in the development of new technologies (Bream, 2006; MacKerron et al., 2006).
- When providing cost data to policymakers technology developers or equipment suppliers may also have incentives to play up or play down costs and potential according to circumstance (Green and Newbury, 1992; Powell, 1993).
- Where new or unproven technologies are being utilised for the first time, information about costs may be limited for all concerned. Actual costs will be revealed primarily through market actions.
- There may be an 'option value' for potential investors in waiting (delaying investment) where there is poor information and high levels of technology and market risk. Policy may need to recompense at least to the option value of waiting, as well as the (high initial) cost of the technology and both technology and market risk.

4.3. Corporate strategy and policy goals

Corporate strategy can be aligned positively or negatively with policy interests. For example, in many cases the public policy objective to diversify the fuel mix may be at odds with the generation company objective of building least cost generation However in some cases there may be value to a business of holding a diverse portfolio of generation assets, such that policy and corporate interests align well. If companies seek diversity for strategic reasons and policy seeks to promote diversity there may be a common interest that can be served. Some analysts and policymakers have sought to explicitly align policy and company goals along 'transition paths', particularly the Dutch experience with building a shared understanding of change between government and industry (Foxon, 2003; Kemp and Loorbach, 2005). The innovation literature places considerable emphasis on the role of expectations of future policy in driving corporate investment (Foxon et al., 2005). It may therefore be important for policy to explore the potential for government and industry to build shared expectations of future policy goals, and align corporate and public policy objectives.

5. Conclusions

The first conclusion is that policymaking in the energy area needs new tools of analysis that can deal with the market risks associated with policy design.

Modelling based on cost estimates is appropriate for some policy purposes, such as undertaking cost benefit analyses of different technologies, but is of limited use when designing policies intended to promote or direct investment. In particular, policymakers need to be mindful of the role of *revenue risk* as well as cost risk in the business case for investment. Whilst policy analysis often assesses a range of cost uncertainties, it seldom pays similar attention to the effects of uncertainty about future electricity (or carbon or ROC) prices.

Extending policy analysis to include investment risks need not be overly complex. Industry experts interviewed by the authors (Gross et al., 2007) emphasised the importance to potential investors of exploring a range of electricity price scenarios as part of investment appraisal modelling work. The impact of sustained low prices on capital intensive investments was highlighted as an important example. Whilst some companies use highly sophisticated models to assess such scenarios, many companies assess them in a relatively simple way. It would be perfectly feasible for policy analysts contemplating incentives for particular technologies to undertake a similar form of assessment. For example a set of scenarios for rate of return could be generated using the simple model described above and adjusting for different forms of policy support.

It is not practical or necessarily appropriate for policymakers to attempt to second guess the investment decisions of private companies in detail, not least because different companies may make different investment decisions even when faced with the same market conditions. However policy analysis could undertake relatively simple modelling of potential returns to investment in particular technologies. Existing cost data could be combined with a range of scenarios for electricity prices, carbon prices, and premium payments, together with assumptions about the correlation between these quantities, to generate a set of NPVs or IRRs. Levelised costs are used only to indicate 'ballpark' differences between technologies (Gross et al., 2007). A simplified investment analysis could provide a similarly approximate level of information about the prospects for investment in response to different forms of incentive.

The second main conclusion is that policymakers can choose whether to reduce, or remove, price risks through the design of incentive schemes. Doing so can make policies more effective in terms of delivering investment.

Some incentive schemes have been effective internationally and others have not. One reason is that some schemes (such as the RO) create revenue and price risks for developers whilst others (such as feed in tariffs) insulate developers from market derived revenue risks. In an environment where policy is increasingly technologically prescriptive (explicitly seeking to support renewables, CCS, new nuclear), it is appropriate for policymakers to make a judgement about whether they wish to socialise price risks and opt for fixed price incentives.

The arguments provided in this paper lend support to the notion that the government is right to be considering fixed price support in markets where investors are risk averse (as private consumers investing in small scale renewables or 'micro-generation' might be) or where technological uncertainties are large (as in the case of CCS). These considerations appear to be feeding into policy design; the Government recently announced its support in principle for the use of feed in tariffs for micro-generation (BERR, 2008b). Similarly, whilst the incentive mechanism to deliver three coal-fired power plants with CCS (announced in the budget, 2009) will be subject to consultation during summer 2009, the Government has already mooted that these 'could be based around a feed-in tariff for CCS, so these projects would receive a fixed price for electricity, or around a fixed price for carbon abated' (DECC, 2009). The arguments set out above indicate that these developments should be welcomed. However, the investment characteristics of CCS need further investigation and it is to be hoped that the government pays attention to them in designing support schemes. It remains to be seen whether 'banding' the RO will be sufficient to overcome the various problems associated with it, and the Government's view that replacing the RO with a fixed price scheme is not merited (BERR, 2008b) will prove correct.

As British energy policy moves away from the notion that technology choice is a matter for markets alone it is to be hoped that attention to investment decisions will become a more explicit element of policy discussion. The arguments set out in this paper indicate that greater attention to investment choices would benefit policy design, but it is possible that adherence to certain shibboleths along the lines that governments don't 'pick winners' may inhibit their adoption. Perhaps explicit policy recognition of the desirability of strategic technology policies is a necessary initial step towards more effective promotion of secure, low carbon electricity supplies.

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