Investment in electricity generation

the role of costs, incentives and risks

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Investment in electricity generation: the role of costs, incentives and risks

A report produced by Imperial College Centre for Energy Policy and Technology (ICEPT) for the Technology and Policy Assessment Function of the UK Energy Research Centre

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Preface

This report was produced by the UK Energy Research Centre's Technology and Policy Assessment (TPA) function.

The TPA was set up to inform decision-making processes and address key controversies in the energy field. It aims to provide authoritative and accessible reports that set very high standards for rigour and transparency. The subject of this report was chosen after extensive consultation with energy sector stakeholders and upon the recommendation of the TPA Advisory Group, which is comprised of independent experts from government, academia and the private sector.

The objective of the TPA, reflected in this report, is not to undertake new research. Rather, it is to provide a thorough review of the current state of knowledge. It also aims to explain its findings in a way that is accessible to non-technical readers and is useful to policymakers.

The TPA uses protocols based upon best practice in evidence based policy, and UKERC undertook a systematic search for every report and paper related to this report's key question. Experts and stakeholders were invited to comment and contribute through an expert group. A team of expert consultants was commissioned to produce working papers on the key issues. UKERC also undertook a series of semi-structured interviews with industry analysts and project developers. Working papers, scoping notes and related materials are all available from the UKERC website, together with more details about the TPA and UKERC.

About UKERC

The UK Energy Research Centre's mission is to be the UK's pre-eminent centre of research and source of authoritative information and leadership on sustainable energy systems. It develops world-class research addressing whole-systems aspects of energy supply and use while maintaining the means to enable cohesive UK research in energy. UKERC is funded by the UK Research Councils.

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Shimon Awerbuch

This report is dedicated to our colleague Shimon Awerbuch who died tragically in a light plane crash earlier this year. Shimon was a member of the Expert Group advising the project. His experience and insights were a great help to the project. Shimon had joined the UK energy research community only recently. He had a significant impact in the short time he was with us.

His thoughtful contributions, always delivered with warmth and good humour, will be sorely missed.

Prof. Jim Skea

Research Director, UKERC

Executive summary

Policy goals can depend upon investment in particular technologies and policy must be designed with the investment risks, not just technology costs, in mind. This is not because concern with costs is wrong but because costs are only one part of the equation. Policymakers cannot determine which technologies get built; they can only provide incentives to encourage a diverse and/or low carbon generation mix. And if incentives are to deliver such investment, they must be based on a clear understanding of how investment decisions are made.

This report provides an analysis of the link between investment risks in electricity generation and policy design. The issues it discusses are relevant to a wide range of policy developments in the UK and elsewhere. These include 'banding' the Renewables Obligation, bringing forward the development of power stations with carbon capture, financial support for nuclear power and the future of emissions trading.

Investment and risk in liberalised electricity markets

1. The delivery of government policy goals in the electricity sector requires investment in technologies that differ from those that would be delivered by the market forces alone. Policy goals such as security of supply, reducing CO_2 emissions or decreasing price volatility might favour nuclear power, coal with CO_2 capture, or renewable energy. However, in many countries the market will continue to favour gas fired electricity generation.

2. Policymakers cannot dictate which technologies the electricity industry should build. Governments can set a framework and provide incentives, but private companies, not governments, make investment decisions. Hence, the effectiveness of incentives in shaping investment determines whether energy policy goals will be met. Examples of policies that seek to shape investment include the Renewables Obligation and European Emissions Trading Scheme. The UK government is also consulting on proposals related to new investment in nuclear power and coal or gas with carbon capture. The effectiveness of such policies will depend in large part on the conditions that they create for investment.

3. Policy decisions on power generation are often informed by estimates of cost per unit of output (e.g. £/MWh) also known as unit costs, or more technically as *levelised costs*. These are used to provide a 'ballpark' guide to the levels of support needed (if any) to encourage uptake of different technologies. They can also help to indicate the cost of meeting public policy objectives such as reducing CO_2 emissions, and whether there is a rationale for such support. In this report UKERC provides a review of the data on unit costs, and the range of estimates that exists in the literature.

4. While cost estimates can help indicate whether support is warranted, cost alone is not always a good guide to *how* to intervene. This is because the private companies making the investments will take into account a range of factors that are not captured well, or at all, in levelised cost data. Investment is driven by expected returns, which are assessed in the light of a range of risks related to both costs and revenues. Revenue risks are not captured in estimates of cost or assessments of cost related risks.

5. An important category of revenue risks result from electricity price fluctuations. These risks do not fall equally on all types of power station. For a range of reasons some options (usually fossil fuel generators) have a degree of control over prices and the ability to pass high fuel prices through to their customers. Others (nuclear, renewable and hydro plants), have little or no control over system prices and can face problems during a sustained period of low electricity prices. If prices are volatile then revenue risks may be high for the latter class of technologies, which may discourage investment irrespective of their relative costs. Revenue risks can also occur in the markets for CO_2 permits or green electricity certificates (see point 8 below).

6. In addition to assessment of risk and return, investment decisions will also be affected by a range of strategic considerations. For example, companies may place value on having a diverse portfolio to hedge against risk. They may avoid investment in technologies that go against principles of corporate governance such as social responsibility. Investment by electricity companies may be undertaken to reveal information or gain market advantage, and it may be delayed for the same reasons. In the case of new technologies or where new policies are expected, there may be value attached to delaying investment.

Lessons for policy

7. Policy needs to actively engage with investment risk. This means understanding where risk originates and how it affects investment. Policy analysis needs to model investment scenarios and incorporate revenue risk, rather than focusing largely on costs.

8. Policy design can affect revenue risks. For example, fixed price tariffs (such as the German 'feed in tariffs') and market-based schemes (such as the UK Renewables Obligation) differ in terms of risk allocation. The former passes risks through to consumers, since prices are fixed. The latter exposes developers to price risk. When defining the nature of revenue support schemes, and deciding between revenue support and capital grants, policymakers should weigh the risks created by policies against the potential for market forces to reduce costs. The choice will depend on the specific case being considered, and will include consideration of the state of technical development and the degree of confidence in cost estimates:

- Capital grants and/or PFI equity stakes are most likely to be appropriate for wholly new technologies emerging from R&D, and/or for unproven and large scale 'lumpy' investments where there is limited prospect of incremental learning through small scale early commercial units. E.g. carbon capture and possibly wave power.

- Fixed price tariff schemes may be most appropriate for initial roll out of emerging technologies; those that are demonstrated, but are yet to be used on a large scale, are subject to considerable technology risk and have yet to benefit from extensive 'learning by using'. E.g. offshore wind, also possibly carbon capture.

- Market based schemes are generally most suited to creating large markets for well proven technologies, or to incentivise least cost means for near-term carbon reduction. E.g. onshore wind and a range of fuel switching/efficiency improvements made attractive by the EU Emissions Trading Scheme.

9. Information about costs and performance for new technologies is often revealed through market activity. Policymakers may have poor information. Where information is scarce, investment is needed to reveal it. Policy may need to pay for this, overcoming the option value associated with waiting. Therefore policy must be prepared to make explicit provision for premium payments to 'first movers', since these higher risk investors will reveal cost and risk data for the wider market.

10. Policymakers should develop a 'shadow investment appraisal' model, to test proposed policies against a range of price risks created by electricity markets and policies as well as cost uncertainties related to technology. The model should be open, to allowing prospective investors and independent analysts to comment on assumptions and parameters. There may be a trade off between model sophistication and transparency. Developing such a model will be complex, and requires further research and consultation with investors and policy analysts.

11. Policymakers should also undertake qualitative assessments related to corporate strategy and the potential for appraisal optimism and gaming. To the extent to which it is feasible to do so government should build a shared understanding of policy goals, as this will shape expectations, an important driver of strategic investment in industry.

Glossary

BETTA	British Electricity Trading and Transmission Arrangements
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
DfT	UK Department for Transport
DTI	UK Department of Trade and Industry
EC	European Commission
EU	European Union
EU ETS	EU Emissions Trading Scheme
FGD	Flue Gas Desulphurisation
GW	Gigawatt – a measure of power, one thousand MW
GWh	Gigawatt Hour – unit of electrical energy, one thousand MW of power provided for one hour
IAEA	International Atomic Energy Agency
ICEPT	Imperial (College) Centre for Energy Policy and Technology
IEA	International Energy Agency
IRR	Internal Rate of Return
kW	Kilowatt – a measure of power, one thousand Watts
kWh	Kilowatt Hour – unit of electrical energy, one thousand Watts of power provided for one hour
MBI	Market Based Instruments
MW	Megawatt – a measure of power, one thousand kW
MWh	Megawatt Hour – unit of electrical energy, one thousand kW of power provided for one hour
NETA	New Electricity Trading Arrangements
NPV	Net Present Value
O&M	Operation and Maintenance
Ofgem	Office of Gas and Electricity Markets
PF	Pulverised Fuel
PFI	Private Finance Initiative
PIU	Performance and Innovation Unit – now the Prime Minister's Strategy Unit, UK government Cabinet Office

PPA	Power Purchase Agreement
RAEng	Royal Academy of Engineering
R&D	Research and Development
RD&D	Research, Development and Demonstration
RIIA	Royal Institute of International Affairs
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RPS	Renewables Portfolio Standard
SPRU	University of Sussex Science and Technology Policy Research
TPA	UKERC Technology and Policy Assessment
UKERC	UK Energy Research Centre
WACC	Weighted Average Cost of Capital
Watt(W)	The standard (SI) unit to measure the rate of flow of energy

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1. Introduction

The UKERC technology and policy assessment (TPA) function was set up to address key controversies in the energy field. It aims to provide authoritative inputs to decision-making processes through accessible and credible reports using protocols to ensure high standards of rigour and transparency. This latest report addresses the following key question:

How can a better understanding of risk and return in private sector investment decisions improve the selection and design of policy instruments?

Rationale

Several recent UK and international policy developments seek to influence or shape the direction of investment in electricity generation. Examples include the British Renewables Obligation (RO), EU Emissions Trading Scheme (EU ETS) and recent UK government consultations related to investment in new nuclear power stations. In Britain, the government has also examined the overall level of power sector investment, and the efficacy of market and regulatory arrangements in delivering new capacity and avoiding an 'energy gap' (DTI 2006d).

In many cases the delivery of policy goals requires electricity companies and private investors to invest in technologies that differ from those that would be delivered by the market in the absence of intervention. In many countries this means expanding renewables or investment in nuclear or clean coal technologies, rather than continuing to invest solely in generation fired by natural gas. Government incentives therefore need to induce investments in order to achieve policy goals, and investment decisions have become an important determinant of policy success. Unless policies encourage or facilitate investment effectively they will not deliver their objectives.

Governments are refining and revising existing policies, reviewing their effectiveness or considering expansion of support to new classes of technology. For example the UK government is consulting over amendments to the RO, and there are debates at the European level over new renewable energy targets and the future of emissions trading. Several countries, including the UK, are considering how best to support carbon capture and the role of nuclear power.

It is important to take stock of the analytical tools used by governments when deciding not just *whether*, but also *how* to intervene in electricity markets. Policy decisions on power generation are often informed by estimates of cost per unit of output (e.g. £/MWh) or '*levelised cost*'[1]. Recent UK energy policy examples include the Supporting Analysis for the RO, 2002 Energy Review, consultations over offshore wind, 2003 Energy White Paper and 2006 Energy Review (DTI 1999; DTI 2000b; DTI 2002; DTI 2003; DTI 2006b; DTI 2006d; PIU 2002). Cost estimates may be helpful in informing governments which

1 Levelised costs (Perhaps more accurately 'levelised unit costs' though the standard term is simply 'levelised cost') attempt 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. A range of approaches have been used to estimate levelised costs. See Ch. 2 for a full definition and explanation.

Box 1.1: Overview of the TPA approach

The approach the TPA takes to all its work seeks to learn from a range of techniques referred to as *evidence based policy and practice*, including the practice of *systematic review*. This aspires to provide more convincing evidence for policymakers, avoid duplication of research, encourage higher research standards and identify research gaps. Energy policy gives rise to a number of difficulties for prospective systematic review practitioners and the approach has in any case been criticised for excessive methodological rigidity in some policy areas. UKERC has therefore set up a process that is inspired by the approach described above, but that is not bound to any narrowly defined method or technique.

Assessment activities:

- The process carried out for this assessment has the following key components:
- Publication of Scoping Note and Protocol.
- Establishment of a project team with a diversity of expertise.
- Convening an Expert Group with a diversity of opinion and perspective.
- Stakeholder consultation.
- Systematic searching of clearly defined evidence base using keywords.
- Categorisation and assessment of evidence.
- Synthesis, review and drafting.
- Expert feedback on initial drafts.
- Peer review of final draft.

technologies it may be in the national interest to adopt, and are often used to provide a 'ballpark' guide to the levels of subsidy needed (if any) to encourage uptake of different technologies. However, the private companies making the investments will also take into account a range of other factors that are not captured well, or at all, in levelised cost data. These include revenue risks created by electricity price volatility and a range of strategic commercial considerations that may affect both the timing and the nature of investment decisions. If some of the factors that affect real investment decisions are overlooked or underestimated then a cost focused approach to policy design may lead to ineffective policies. Moreover, levelised costs are controversial and disparate estimates of costs abound (PB Power 2006; PIU 2002). It is important for analysts and decision makers to understand both why there is such a range of estimates and, crucially, their relevance (or otherwise) to investment decisions.

This report describes how the cost of electricity generation arose as a public policy concern when the electricity system was in public ownership. It goes on to look at how cost considerations currently fit within a market framework where the system-wide costs of generation are still a relevant public policy concern, but where individual investment decisions are made by private companies responding to market conditions and policy incentives. In so doing it seeks to re-focus a debate that has become focused on a specific concept of cost, in order to better reflect how investment decisions are made, and how government can improve the design of policy instruments. The report is not seeking to determine what the goals of energy policy *should be*; rather it seeks to assist in the design of policy instruments to ensure that high level policy goals are delivered in an effective and efficient way.

1.1 How this report was produced

All TPA topics are selected by the TPA Advisory Group; senior energy experts from government, academia and the private sector. The Group's role is to ensure that the TPA function addresses policy-relevant research questions. The Advisory Group noted a predominance of levelised cost estimates in policy analysis and controversy over estimates. They also noted a concern that a range of other factors relevant to investment decisions were being overlooked. This led UKERC to undertake this study.

The object of this report is not to undertake new research on investment decisions or levelised costs. It is to provide a thorough review of the current state of knowledge on the subject, guided by experts and in consultation with a range of stakeholders. It also aims to explain its findings in a way that is accessible to non-technical readers and is useful to policymakers. A key goal is to explain controversies, where they arise.

As part of this project UKERC undertook a systematic search for every report and paper related to levelised costs of electricity generation and investment decision determinants such as risk, portfolio effects and option values. This highly specified search revealed over 140 reports and papers on the subject, each of which was categorised and assessed for relevance – see Annex 3 for the full list and Working Paper 4 for details of this process. Experts and stakeholders were invited to comment and contribute through an expert group. A team of expert consultants was commissioned to produce working papers on the key issues (see Annex 2). UKERC also undertook a series of semi-structured interviews with industry analysts and project developers, held a number of brainstorms with experts and consulted with policymakers.

Each stage of the process has been documented so that readers and reviewers can identify the origins of our findings. We describe this in a *review protocol*, published on the UKERC website. Relevant materials were also posted on the website as work progressed, including the project scoping note and working papers. The approach aims to provide a comprehensive, transparent and replicable assessment of *the balance of evidence* on the role of levelised costs in policy and investment decisions.

1.2 Report structure

Ch. 2 considers the reasons policymakers intervene in electricity markets, the range of instruments available to them, and how both have changed over time. It explains why some policies will seek to shape the direction of investment and/or to promote certain technologies or categories of technology. The chapter also reviews the role that unit cost estimates have historically played in policy making, and assesses the contribution that such estimates can make in informing future policy.

Ch. 3 discusses the role of risk in the investment decision process, and examines why and how, in liberalised markets, price and revenue risks are key determinants of investment. This chapter therefore explores factors other than technology costs that are relevant to investment decisions, and why these matter when devising the means to intervene in electricity markets.

Ch. 4 discusses the relationship between policies and investment. In particular it considers how policies may either mitigate investment risks or create risks, depending upon policy design. The chapter makes recommendations as to how UK policy might respond to those factors which drive investment electricity markets.

2. Intervention in electricity markets: technology specific policy instruments and the role of costs estimates in policy analysis

2.1 Introduction

This chapter considers the role of policy in shaping the direction of investment in electricity markets. It has two main areas of focus.

First, it seeks to explain why policymakers acting in liberalised electricity markets, where investment decisions are made by private companies, may attempt to affect the volume and direction of investment. In particular we explore why *some* policy objectives are linked to support for particular technologies and how policies in general are informed by cost estimates. In order to do this the chapter considers the reasons that policymakers intervene in electricity markets, how policy objectives have evolved over time and the policy instruments available to deliver policy goals.

Second, given the high profile afforded to levelised costs in policy analyses it is important to understand the relationship between policy goals, incentives to invest in particular technologies (or technology types), and estimates of cost. The chapter reviews the role of levelised costs in formulating policy, particularly technologically specific intervention, and the value and limitations of levelised costs as a policy tool.

The chapter addresses the following issues:

- The basic rationale for intervention in electricity markets.
- The effect of historical developments, changing energy policy priorities and changing models of intervention on policy instruments.
- Why some policies are technologically specific.
- Levelised costs in policy analysis including the rationale for intervention in electricity markets, the level of financial support for technologies and the design of policy instruments.

2.2 Background

In British electricity markets, as in many others, privatisation and liberalisation have reduced the influence of policy over investment decisions relative to the days of central planning by state owned utilities (PIU 2002). Investment decisions are made by private companies seeking to maximise return on investment, subject to acceptable levels of risk and regulatory constraints. However, governments continue to play a role in electricity markets, and take a keen interest in the level and nature of investment. For example the British government has recently emphasised the need to encourage both adequate investment and a diversity of fuel/resource in the generation mix, and recent government analyses discuss the possibility of interventions to ensure that both are delivered (DTI 2003; DTI 2006d).

The policy framework can have a profound impact on investment. For example during the 1990s a large amount of new gas generation capacity was built in Britain, largely in response to high electricity prices and the market structure of the time, created by privatisation. Changed market regulations also played a role when interest in building new generation declined (DTI 2003). Moreover, several recent policy developments are intended to influence the *direction* of investment in energy markets. Some, such as the Renewables Obligation (RO), seek to direct investment in a highly specific way, directly incentivising renewable sources of energy. Other policies seek to shape the *overall* direction of investment, but in a less specific way, a prominent example being the EU carbon emissions trading scheme. Governments (or at least the British government) generally prefer to avoid 'picking winners', and intervening in a technologically prescriptive way (DTI 2006d; PIU 2002). In meetings and workshops held to inform this project, investors signalled a desire to understand policy developments and why it is that policy is in some instances technology blind yet in other instances explicitly favours certain technologies or technology types. The chapter therefore discusses how and why governments sometimes intervene in a technologically prescriptive way.

Where government intervenes, estimates of technology cost (and levelised costs) have played a substantive role in policy analyses. Examples include the supporting analysis and consultation documents for the RO and other renewables policies, the PIU Energy Review and the DTI Energy Review (DTI 1999; DTI 2000b; DTI 2002; DTI 2006a; DTI 2006b; DTI 2006d). It is notable that the examples above include those where financial incentives *have* been provided by policy (the RO, capital grants for offshore wind, etc) and where government has decided that financial intervention is *not* required to deliver a policy objective (the case of nuclear power in (DTI 2006d)). Government estimates of levelised costs appear to have played a key role in such decisions. Levelised costs are also collated and published by the International Energy Agency (IEA) and by energy ministries and regulators in other countries. Since unit cost estimates are so prevalent in policy analyses this report seeks to explain their role in energy policy design and implementation, and how these estimates relate to investment decisions.

2.3 Intervention in electricity markets

The basic rationale for intervention in electricity markets

Policymakers have intervened in electricity markets from the earliest days of electricity generation. It is possible to identify three principal rationales for intervention in electricity markets, reviewed in Box 2.1. (PIU 2002):

- Market failure, such as the 'natural monopoly' status inherent in electricity networks, or environmental damage such as acidification and climate change.
- Social/equity issues.
- Geopolitical and security of supply concerns (which may also include support for domestic resources or technologies).

Box 2.1: Rationale for intervention in electricity markets

1. Market failure of three main kinds (monopoly, environment, innovation)

- 'Natural monopoly'; the 'network' characteristics of electricity systems preclude the operation of wholly competing power systems. At different points in history this has been justification for monopoly regulation, for nationalisation and for policies to create and maintain competitive markets in power generation and supply.

- Negative environmental externalities; since in many cases the damage costs of pollution associated with energy production are not captured in costs of generation these may also be viewed as market failures. Environmental problems have been tackled in a range of ways over time. Historically regulation was the preferred route (and with some notable successes such as controls on SO_2 emissions); more recently fiscal incentives and market based instruments have been introduced (see below).

- Positive externalities of innovation; there is a long standing economic rationale for public investment in RD&D that relates to the public good characteristics of innovation. For example, investment made now in a new technology may lead to future cost reductions in that technology – which will benefit future investments. Private investors may not be able to fully capture the benefits to society of developing new products, hence under-invest in innovative effort. Recent academic work and policy documents have focused on innovation in the context of energy policy, particularly the development of low carbon options (Anderson et al. 2001; DTI 2006d; PIU 2002; Stern 2007).

2. Equity/distributional effects

- Energy policy may need to address issues linked to social equity, including the potential for both geographical and economic exclusion from access to energy services. Policy may therefore use direct or cross subsidy to provide access to energy services for poorer consumers and/or to finance connection for those in remote locations.

3. Security/geopolitics

- Energy policy may need to impose measures to ensure security of supply, and a degree of resilience to threats resulting from geopolitics, technical faults and natural phenomena (severe weather or natural disaster). This is often linked to the promotion of diversity (both technology and locational diversity) in the electricity generating mix, and may include measures to ensure adequate levels of reserve generation capacity are available on the system.

- In the specific case of nuclear power, governments also intervene for reasons of safety and with respect to concerns about proliferation of weapons-usable materials (IAEA 1970; SDC 2006).

Historical developments and changing energy policy priorities

The principles outlined above and in Box 2.1 have sustained through time over many decades and have relevance to energy policy irrespective of market arrangements or ownership structures. However, they have been interpreted and acted upon in very different ways at different points in history. The resulting policy mix is complex, and it is useful to consider how and why different objectives and different delivery mechanisms have emerged over time.

The idea that electricity systems are a 'natural monopoly' played a predominant role in regulation and policy from an early stage in the industry's development. The view that state ownership of such monopolies was in the public interest underpinned the nationalisation of the electricity industry that took place in many countries from the 1950s (Hannah 1982). In many countries state ownership and/or regulated monopoly status helped finance the large investments needed to achieve economies of scale, allowing a planned expansion of electricity output intended to fuel economic growth and provide universal, affordable and reliable service (Chesshire 1996; Helm 2003). For many decades, at least until 1979, this industrial structure seemed 'normal' and was not challenged politically (Helm 2003). Yet in the late 1980s the approach to monopoly changed, from state ownership to the facilitation of competitive markets. This occurred in large part for ideological reasons[2], but also reflected a shift in emphasis as electricity systems matured; from system expansion to improving economic efficiency, partly through competition (Surrey 1996). Changes to policy have also occurred as a reaction to fuel price volatility and environmental problems, or concern about increasing import dependence and the impact of market developments on the fuel supply mix used in generation. However by the late 1990s there was widespread consensus on the need to tackle such problems through the operation of private markets.

The relationship between liberalisation and energy policy objectives

Throughout the 1990s the predominant focus of energy policy was market liberalisation, increasing the amount of competition in the emerging electricity generation market. Environmental problems were addressed through regulation such as the Large Combustion Plants and Integrated Pollution Prevention and Control Directives (EC 2001; HMSO 2000). A number of interventions served to address particular political concerns, or difficulties related to liberalisation[3]. It has been observed that during the 1990s liberalisation served most policy objectives simultaneously (PIU 2002). More recently however, market drivers and policy imperatives appear to have diverged. Some

2 The belief that markets and private investment are in general more efficient at delivering goods and services and that state involvement in all markets ought to be kept to a minimum was highly significant when electricity industries were privatised (Helm 2003; Hutton 1996).

3 E.g. The non-fossil fuel obligation and temporary moratorium on gas fired generation (Mitchell & Connor 2004; Select Committee on Trade and Industry 1998)

commentators even suggest that energy policy goals are no longer fully compatible with market imperatives (Helm 2003). In particular, increasing concern about climate change has given rise to new policy measures and a reformulation of policy goals. Hence in 2000, UK Energy Policy was summarised as follows (DTI 2000a):

"To ensure secure, diverse and sustainable supplies of energy at competitive prices"

By 2003, the Energy White Paper recast energy policy[4] with a specific focus on climate change, as follows (DTI 2003):

- *"to put ourselves on a path to cut the UK's carbon dioxide emissions - the main contributor to global warming - by some 60% by about 2050, as recommended by the RCEP, with real progress by 2020*
- *to maintain the reliability of energy supplies*
- *to promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity*
- *to ensure that every home is adequately and affordably heated."*

Changing policy goals have led to new policies such as the Renewables Obligation and a range of policies linked to climate change (see below). Since 2003, concerns related to overall levels of generating capacity and concentration of investment in gas-fired generation have also played a prominent role in policy analyses (DTI 2006d). Whilst the 'four pillars' of policy introduced in 2003 have not changed, their relative importance may have shifted – with security/reliability of supply becoming a higher priority (DTI 2006d). Since supply-security is linked to diversity, hence encouraging investment in technologies other than gas, it too has the potential to drive policy away from technology neutral measures. Despite the oft-stated aversion to 'picking winners' (see above and (DTI 2006d; PIU 2002)), it seems that some policy goals are best served by technology or resource specific interventions. Part of the reason lies in the nature of different interventions, and the economic rationale for particular types of policy instrument, which we now explore.

The impact of changing models of intervention on policy instruments

As policy goals change the targets for and means of intervention shift. However, policy changes can also reflect changing models of intervention, for example the emergence of economic concepts related to pollution abatement (Pearce 1991). An influential set of economic arguments has led to increasing use of market based instruments (MBIs) such as permit trading schemes in areas that might historically have been dealt with through direct regulation, notably environmental problems (The Royal Society 2002). In addition, policy has engaged to some degree with the argument that policymakers need to actively promote innovation (DTI 2006d; PIU 2002; Stern 2007). Support for Research and Development (R&D) is well accepted on grounds of public good, but more recent attention has focused on the

4 The remit of energy policy is wider than the electricity industry but electricity plays a major role in energy policy debates.

Table 2.1: Policy instruments, high level objective and technological specificity

Option/intervention	High level objective (Stern 2007)			Technology specific?
	Price carbon	Overcome non market barrier	Promote innovation/new technologies[5]	
Cap and Trade (e.g. EU ETS)	Yes	No	~	No
Carbon tax	Yes	No	~	No
RPS schemes (e.g. the RO)	No	No	Yes	Yes *
Fixed price revenue support (e.g. German Feed in Tariff)	No	No	Yes	Yes
Capital subsidies (e.g. grants for offshore wind)	No	No	Yes	Yes
Grants for RD&D	No	No	Yes	Yes
Direct regulation (e.g. pollution abatement regulations, LCPD etc) (electricity supply)	No	No	?	?
Regulation (electrical appliances)	No	Yes	?	?
Labelling (electrical appliances)	No	Yes	?	?

Key to table 2.1

Yes = positive impact: No = zero or very limited impact: ~ Limited/secondary effect:

? Possible depending on policy design

* Degree of specificity depends upon design – for example the RO is technology neutral but within category of technology/resource (renewables), and could be more specific if banded by technology.

importance of learning by doing, which can be encouraged by niche markets created by policy (Anderson et al 2001; Foxon 2003; Kemp et al. 1998). Regulation continues to play a strong role in many aspects of electricity supply markets and in the markets for domestic and commercial electrical appliances.

A classification of intervention and why some policies are technologically specific

Although policymakers generally prefer to avoid being technology prescriptive this needs to be set against both the possibility that some policy goals may be best served by technology based intervention, and that some policy instruments cannot be technology neutral. The Stern Review provides a classification of interventions that links policy objectives to policy instruments. This is specific to climate policy, but it has wider application in the environmental arena, and indeed may be applied to other energy policy goals. It helps to explain why some policy goals and instruments tend to be technologically prescriptive. For example, several important measures to promote innovation

5 Innovation is indirectly induced by most policies, including carbon pricing and regulations – however some policies are intended to promote innovation directly and these are the object of this column.

are inherently technologically prescriptive (see below).

The Stern Review classification of different forms of intervention is threefold (Stern 2007):

1. Measures to price carbon (including taxes, levies and permit trading schemes).
2. Measures to overcome non-price or behavioural barriers (regulation, information provision)
3. Measures to promote innovation (RD&D, measures to create niche markets)

Table 2.1 illustrates the importance of technology specific interventions in several policy areas, notably in promoting innovation.

Analysis in support of technologically specific policy goals/instruments

Given the importance of technology specific interventions/policy goals it is interesting to consider examples of recent analysis undertaken by policymakers in order to explore the need for intervention and design policies. Such analysis needs to address three factors:

1. Is there a rationale for intervention in terms of meeting policy goals?
2. Is financial support needed to promote particular options, if so how much?
3. What is the most appropriate mechanism to deliver financial support for particular options?

The current policy mix includes interventions that are technology specific and those that seek to be technology neutral (as far as possible). Recent policies relevant to the electricity sector include (DTI 2003; DTI 2006d):

- The Large Combustion Plants Directive and other pollution control regulations.
- Support for renewable energy through the Renewables Obligation (RO).
- Political support for nuclear power and consultation over measures to address barriers to new build.
- The EU Emissions Trading Scheme.
- The Climate Change Levy.
- A commitment to the development or demonstration of carbon capture and storage.
- New funding for RD&D in energy technologies.

This list is not exhaustive. It is notable in addition that the British electricity and gas regulator (Ofgem) has an overarching obligation to protect consumers and encourage competitive markets. Also that the government has been obliged, and prepared, to intervene in the market directly on occasion to ensure security of supply, for example in providing emergency financial assistance to British Energy.

In what follows we review the published analysis undertaken in support of two example policy decisions: The development of the Renewables Obligation; and discussion of the case for new nuclear power stations in the DTI Energy Review (2006).

In the case of the RO cost estimates appear to have played a central role in the design of policies. For example DTI 'resource cost curves' were instrumental in defining the level of the buy out price of the Renewables Obligation, and indeed the level of the Obligation itself (DTI 1999; DTI 2000b). However, at the time the Obligation was announced the government did not examine in detail the investment implications of the differing maturity of various renewables. Nor did it consider the risk-reward ratios that investors might seek in return for managing the various price risks associated with RO. Such risks are additional to the technology/cost risks of the less developed options such as energy crops and offshore wind. As we explore in Chs. 3 and 4 these issues are highly relevant to subsequent progress with different renewable technologies and proposals to reform the RO (DTI 2006c; DTI 2006d).

In 2006 the UK government was explicit in its contention that the economics of nuclear power 'look more positive'. This conclusion is based upon an analysis of the relative levelised costs of nuclear power and other options under a range of fuel price, carbon price and capital cost assumptions undertaken for the 2006 Energy Review (DTI 2006a; DTI 2006d). In its analysis, DTI explicitly considered relative levelised costs, costs per tonne of carbon and the welfare balance of nuclear and other generation options (DTI 2006a). DTI estimated levelised costs and reviewed a range of studies of levelised costs (DTI 2006a). It took a scenario approach to gas and carbon prices and capital costs for nuclear power (DTI 2006a), concluding that except in a scenario of high nuclear capital costs, low gas prices and no carbon price, new nuclear appears to offer economic benefits. However DTI explicitly avoided an assessment of the financial proposition offered by new nuclear, stating that would be for private investors to consider (DTI 2006a). Hence assessment of costs appears to provide a rationale for the government's current view (Spring 2007), that nuclear power does not need financial support from the government over and above that provided by the EU ETS, provided there is concerted EU action to ensure the long term continuation of the EU ETS (DTI 2006d).

The overwhelming conclusion that emerges from a review of the analysis carried out in support of both the Renewables Obligation and for the UK government's current position on nuclear power is that 'economic viability' is assessed largely (if not solely) in terms of levelised costs. One of the difficulties that arises in the use of levelised cost for policy analysis is the wide range of costs that are derived in different studies for the same technology. Before proceeding to a discussion of how levelised costs are used in policy analysis, it is useful to provide a quantification of the range of costs that exists in the literature and the importance of key assumptions used in calculating them.

2.4 Levelised cost estimates

Levelised costs are an attempt to capture the full lifetime costs of an electricity generating installation, and allocate those costs over the lifetime electrical output with both costs and outputs discounted to

Box 2.2: Levelised cost calculation methods

There are two basic approaches to calculating levelised costs. Both require:

- An assessment of the costs (and the timing of those costs) that will be incurred in building and operating a plant during its lifetime i.e. the cost stream.
- An assessment of the electrical output (and timing of that output) of the plant during its lifetime i.e. the output stream.

The first calculation method (as used by the IEA) involves discounting the future cost stream and future output stream and dividing the present value of lifetime costs by the present value of lifetime output.

The second method (known as the 'annuity' method) involves calculating the present value of the cost stream (giving a lump sum value), which is then converted to an Equivalent Annual Cost (EAC) using a standard annuity formula. Dividing the EAC by the average annual electrical output (not the discounted present value of the output) results in a levelised cost.

Provided the discount rate (used in calculating the present value of the total costs) and 'levelisation' rate (used in the annuity formula) are the same then the results will be the same for both methods.

their present values (see Box 2.2). Estimates of levelised cost of electricity generation originated under conditions where electricity networks were operated as monopolies, either in public ownership (the pre-liberalisation UK model), as closely regulated private utility companies (the US model), or as local municipal undertakings (common in parts of mainland Europe). They were used by electricity utilities/companies and their regulators to provide a first indication of the relative costs of plant. The approach was sometimes also applied to all investments collectively to obtain an average system cost, as a basis for submissions to finance ministries and regulatory commissions in the setting of prices.

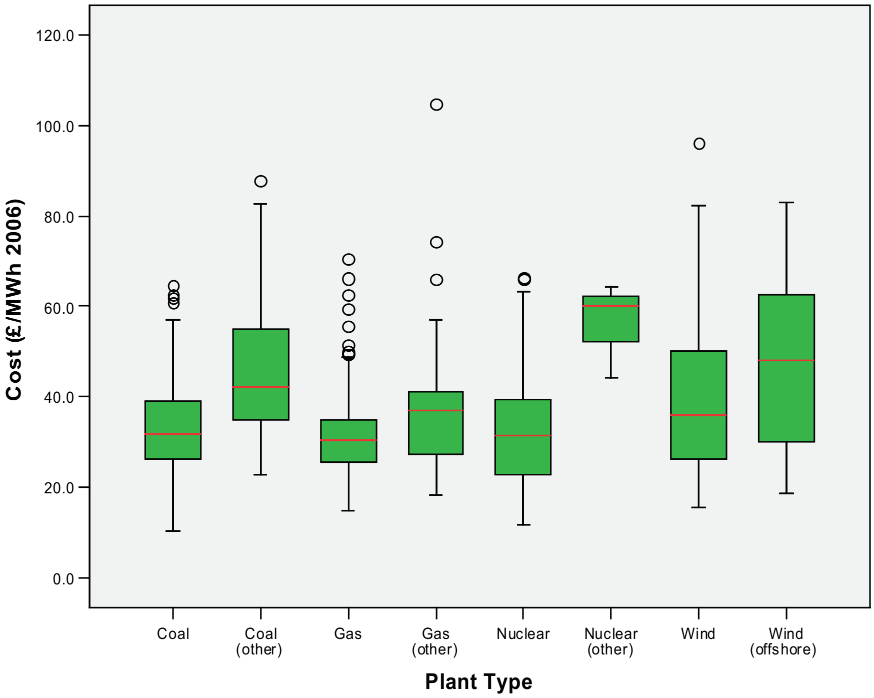
Levelised costs are widely reported in government, IEA and other studies. Examples include:

- The 'Projected Costs of Generating Electricity' series of IEA reports, published in 1983, 1986, 1989, 1998 and 2005.
- UK government White Papers and reports including the 2000 Renewables Obligation Consultation document, the 2002 Energy Review and 2003 Energy White Paper, and the 2006 Energy Review.
- The US Department of Energy's 'Annual Energy Outlook' series.

Ranges of levelised cost estimates

To inform this report UKERC undertook a systematic review of the literature on levelised cost estimates (See Working Paper 4). Using an agreed set of search

Figure 2.1: Cost ranges for leading electricity generation technologies



N.B. The 'Coal (other)' and Gas (other)'groups include a range of technologies which are either at less advanced stage of commercial development (such as Integrated Gasification Combined Cycle, Oxycombustion, and CO_2 capture), or have performance characteristics that make them suitable for specific roles in the electricity generation mix (such as Open Cycle Gas Turbine). They have been grouped separately from the standard coal and gas technologies to avoid skewing the results. The 'Nuclear (other)' group has a very small sample size, which would suggest that drawing conclusions for this category would have little value. Costs do not include the net effect of support mechanisms or carbon pricing. Full details are in Working Paper 4.

terms and databases, more than 140 documents were revealed that either present data on unit costs for one or more technologies or discuss the issues surrounding unit cost estimates. The project team categorised each reference (e.g. by the generating technologies covered and the country or region that findings were relevant to), and ranked them according to relevance and comparability. Almost 1,200 data points were extracted from the sources which were assigned the highest relevance rating by the project team.

Cost estimates were captured for 18 technology categories. For the sake of brevity the cost ranges presented in Figure 2.1 are for coal, gas, nuclear and wind

Table 2.2: Statistics for leading electricity generation technologies

	Coal	Gas	Nuclear	Wind	Wind (offshore)
Mean	£32.9/MWh	£31.2/MWh	£32.2/MWh	£39.3/MWh	£48.0/MWh
Median	£31.9/MWh	£30.5/MWh	£31.3/MWh	£35.9/MWh	£47.9/MWh
Inter-quartile range	£13.1/MWh	£9.5/MWh	£16.5/MWh	£24.2/MWh	£33.6/MWh
Standard deviation	£9.7/MWh	£8.9/MWh	£10.5/MWh	£16.6/MWh	£20/MWh

generation technologies. The green box for each technology represents the inter quartile range (i.e. the central 50% of values), and the median value is denote by the red line. The lines from each box extend as far as the highest and lowest values. Outliers (values further than 1.5 times the inter-quartile range from the box boundaries) are represented with individual circles.

The mean, median, inter-quartile ranges and standard deviation for the main technologies are shown in Table 2.2.

The components of levelised costs can be broadly classified into two groups; the engineering-led estimates of plant construction and operation costs, and the assumptions about variables such as discount rate, fuel prices and utilisation (i.e. the plant load factor). Using worked examples, sensitivities to these assumptions are demonstrated (Figures 2.2, 2.3 and 2.4).

The examples consider two technologies – low capital cost, high fuel cost (e.g. CCGT), and high capital cost, low fuel cost (e.g. nuclear). Estimates for capital and running costs, plant efficiency, and plant life are taken from (DTI 2006d). Base case values for discount rate, plant load factor and fuel costs are taken from (DTI 2006d) and (Holt 2005). The base case results are within 3% of the median values reported in Table 2.2.

Figures 2.2, 2.3 and 2.4 clearly illustrate that a relatively high capital cost, low fuel cost technology is sensitive to variation in discount rates and plant load factors, and insensitive to fuel price variation. The

Figure 2.2: Sensitivity to discount rate

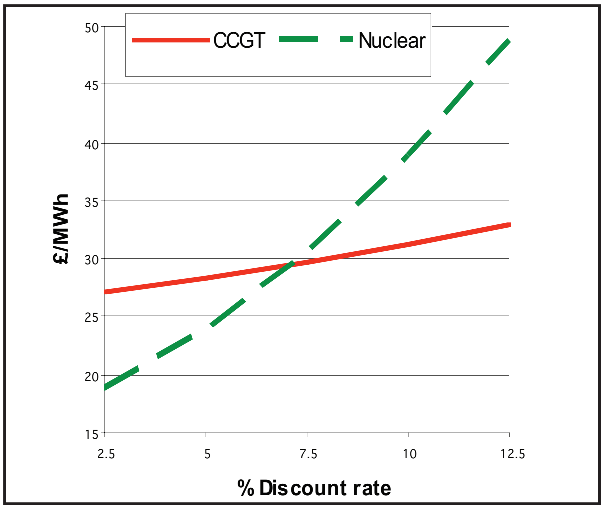


Figure 2.3: Sensitivity to load factor

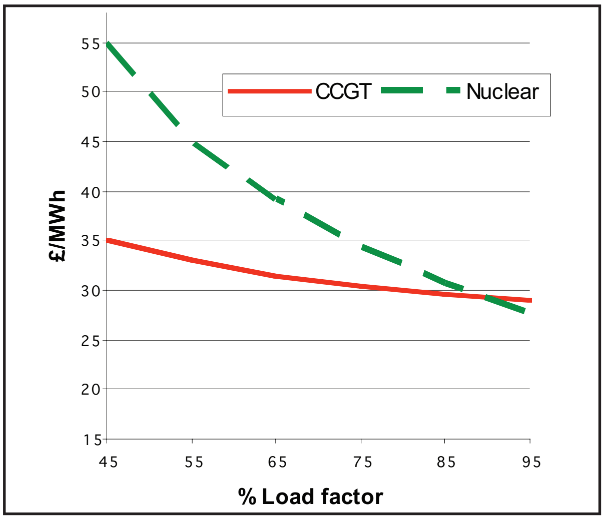
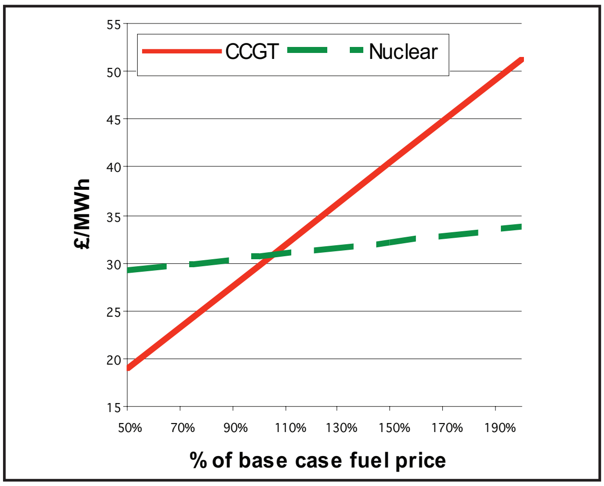


Figure 2.4: Sensitivity to fuel price



opposite is true for a low capital cost, high fuel cost technology. The key message however, is that even if there is some agreement over the physical construction and operating costs of particular technologies, wide variations in levelised cost estimates can result from the other factors – and that these factors will affect cost estimates in different ways depending on the characteristics of the technologies.

Box 2.3: The evolution of cost estimates in utility planning

Estimates of levelised cost of electricity generation originated under conditions where electricity networks were operated as monopolies, either in public ownership (the pre-liberalisation UK model), as closely regulated private utility companies (the US model), or as local municipal undertakings (common in parts of mainland Europe). The estimates were often used to assist in the identification of the least cost option for investment, seeking to optimise the technical and economic development of electricity networks. Under public ownership the approach was also sometimes applied to all investments collectively to obtain an average system cost, as a basis for submissions to finance ministries and regulatory commissions in the setting of prices.

Estimates were also used by electricity utilities and their regulators under public ownership to provide a first indication of the relative costs of plant. In a series of papers and books in the 1950s and 1960s utility economists and engineers addressed a number of limitations to the approach, see (Turvey & Anderson 1977) for a detailed review of this literature. The sophistication of these models allowed planners to optimise investment taking into account factors such as:

- Diurnal, weekly and seasonal fluctuations in demand, when the idea of using the load duration curve for cost analysis was introduced.
- Seasonality in supply, for example in systems with hydro plant.
- Changes in the plant factors of plant already on the system when new plants were introduced. In turn:
- Changes in plant factors over a new plant's lifetime as it too was shifted down the merit order following the introduction of further new plant on the system.
- Uncertainties as to plant availability and future demands; and, more recently:
- The analysis of investments under uncertainty using portfolio analysis and options valuation.

The models became increasingly used by the electricity generation industry around the world in the 1960s up to the era of market liberalisation beginning in the 1990s, and still are used in countries where electricity markets are publicly owned. They were also used by economists for the analysis of the marginal costs of supply to provide a better basis for pricing policies, for example to move away from the (monopolistic) approach of average cost pricing and to support the case for peak-load, off-peak and seasonal pricing.

2.5 Cost considerations in policy analysis

Historically, when the UK electricity industry was in public ownership, levelised costs were used to provide an approximate estimate of the relative merit of different technologies. Cost-minimisation was a key driver, so levelised costs were often the starting point for the analysis of technology choice. Many other factors could then be incorporated into the system design for achieving cost-minimisation, and increasingly sophisticated optimisation models were used to determine optimal investment (see Box 2.3). Similarly, closely regulated utilities (the model followed in parts of the US and elsewhere) also work towards cost minimisation, and put greater emphasis on an optimisation type approach in negotiations with their regulators.

Box 2.4: Diversification in Investment and Portfolio Theory

It is well known that in financial markets, investment in a number of securities carries less risk for a given expected return than investment in a single security. This is because stock prices do not move perfectly in 'lock-step' with one another. For example, when the price of stock A moves up, the price of stock B is unlikely to change by exactly the same amount. Therefore a portfolio of stock A and stock B does not change in value as rapidly as either stock A or stock B alone. A portfolio that includes every stock in the market is completely diversified, and is only exposed to market risk; the expected variability of the market as a whole. Therefore diversification can only eliminate a portion of investment risk called unique risk, or diversifiable risk, whilst the risk that diversification cannot eliminate is termed undiversifiable risk. Research has shown that a very large portion of diversifiable risk can be eliminated by creating a portfolio of only a few stocks (Brearly & Myers 2003).

In 1952 Harry Markowitz developed the basic principles of portfolio construction, which sets out how to build an efficient portfolio of stock such that expected return can be maximised for a given level of risk (or risk can be minimised for a given expected return). Markowitz added the possibility of borrowing and lending at the risk-free rate into his model, and proved that a rational investor would hold a particular risky portfolio of stocks, and then borrow or lend money at a risk-free rate in order to obtain an exposure to risk that is suitable for the investor (Luenberger 1998).

The influence of diversification and the ideas behind portfolio theory apply to investment in energy related assets. For example, in the electricity sector, a set of generation assets that run on different fuels will be less exposed to risk than a set of generation assets that run on the same fuel. Indeed there exists an efficient mix of primary fuel types that, based on historical data, should provide the best return for a given level of risk. In a national policy context, the use the portfolio theory can therefore help to minimise the economic risk related with meeting the country's energy needs (Awerbuch 2006b);(Wiser & Bolinger 2006).

System-wide optimisation is now assumed to be achieved through the disaggregated decisions of individual competing agents in the market. But, 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. An important example is the issue of diversity in generation mix, discussed in Box 2.4. Benefits from increased diversity accrue to the system as a whole, since diversity reduces exposure to a range of risks (Awerbuch 2006b), and may not be fully captured by individual investors (individual companies may also consider their generation portfolio – see Ch. 3). Hence, public policy oriented analysis of technologies must take a view of technologies as a portfolio of options and the social benefits offered in terms of diversity and security represent an externality.

Market externalities provide an important rationale for policy intervention. In this respect levelised costs are useful. They 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. £/tonneC) for different technologies, 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 current policy choices (DTI 2003; PIU 2002).

Clearly, levelised costs may be used for assessing 'ball park' levels of, or need for, subsidy for particular technologies relative to established options. They provide an approximate view of the level of subsidy or transfer payment (if any) needed. The extent to which levelised costs provide data accurate enough for this task is affected by the range of estimates that abound in the literature (see Figure 2.1 and Working Paper 4). Moreover, some commentators have argued that levelised costs should be adjusted to reflect the technologically differentiated exposure of different technologies to a range of risks (Awerbuch 2006a; Awerbuch 2000).

Whilst noting these important limitations on using levelised costs to assess technologies, we do not explore them further here. In terms of the ability of policies to deliver investment, there is

Box 2.5: Factors that may not be captured in levelised costs

- Changes in demand and supply conditions, including: variations in price by time of day, week, month and season; changes in dispatching schedules as new plants are introduced on a system; changes in supply availability e.g. for wind, which shows significant seasonal as well as hourly and weekly variation, and hydro, which is seasonal.
- External costs and benefits, including: the environmental costs of pollution damage; benefits such as the value of learning to future generations of investors.
- The effects on prices and the rate of return arising from public policies toward: external costs of pollution damage and the incentives (such as the value of emissions trading schemes) on prices; technology development (e.g. R&D and development grants, the Renewables Obligation); residual insurance responsibilities that fall to government (e.g. nuclear waste).
- System factors*, including: transmission costs and other network costs such as impact on system balancing and system security requirements; impact on state/system level energy security; flexibility/controllability of power station output; suitability for different operating modes e.g. baseload or balancing services; relative impact of demand variation.
- Business impacts, including: the option value that investment in a particular technology may give a utility (Awerbuch et al. 1996) and see Working Paper2, Annex 2; the costs of information gathering (i.e. the information required to inform an investment decision); fuel price volatility (distinct from expected cost inflation); future revenue volatility (electricity volume and prices); future changes to: tax regimes, environmental legislation, government support mechanisms; portfolio value, whereby investment in generating technologies whose costs do not co-vary with other technologies can reduce overall costs at any given level of risk (Awerbuch 2000).

* System wide levelised costs may also be assessed, and some system costs may be added to generating costs (see Gross et al, 2006)

another important point of note. That is the interaction between the level of support needed to facilitate investment in particular technologies and the design of policy instruments. This is because policy design has implications for the level of risk attached to investment. Hence levelised costs may not be sufficient to determine how to intervene, and when levelised costs are the primary tool used to assess whether policy instruments will deliver investment problems may arise. Quite apart from the uncertainties and sensitivities discussed above there are several factors which levelised costs may not properly reflect (see Box 2.5).

Arguably most significant of the factors that levelised costs cannot capture is the relationship between electricity price variation/uncertainty (including the prices that pertain to tradable certificates for carbon or renewable energy) and investment risk. Private investment is concerned not with levelised costs but with the rate of return to investment and the level of risk associated with it. This is affected not just by cost and cost risk, but by revenues, prices and price risks, and how government policies bear on these quantities.

2.6 Summary

1. The range of drivers for policy intervention in liberalised markets are well understood – to address market failure of one form or another, equity issues, or security concerns. The relative weight attached to these drivers has changed over time and has led to a complex (and shifting) policy mix.

2. Policy makers, at least in the UK, are very averse to technology prescriptive interventions ('not picking winners'). However in practice some policy objectives are best met by the characteristics of certain technologies, and some policy instruments cannot be technology neutral – they are, to a degree, inherently prescriptive.

3. Cost estimates have played a central role in the formulation of policy instruments. They help indicate the cost of meeting public policy objectives such as reducing CO_2 emissions, and/or whether there is therefore a rationale for such support (for example based on cost effectiveness or net welfare gains). They give an initial indication of the scale of support required for particular technologies, and cost projections may be used to assess the value of support for innovation.

4. However, cost estimates have limitations, in part because there is a range of plausible estimates for any given technology and market/operating assumptions, and also because cost estimates cannot capture the other factors which influence investment decisions in liberalised markets. These include price and revenue risks and rates of return. The result is that cost estimates alone are not a reliable guide to how investors will act in liberalised electricity markets.

Ch. 3 therefore moves beyond levelised costs to consider returns on investment and the factors that bear on this quantity. It looks at a range of risks that affect the kinds of calculations and analysis undertaken by private investors, and the thinking behind them. Ch. 4 discusses the resulting implications for the analysis of policies.

3. Investment appraisal and risks in liberalised markets

3.1 Introduction

This chapter considers the role of different sources of risk in investment appraisal. It explains why a range of factors additional to cost 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. Returns depend on revenues as well as cost, so the price of electricity becomes an important risk factor in the investment decision. 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. Risk is therefore an important component of investment decision-making.

The chapter discusses the following issues:

- The sources of risk, focussing in particular on electricity price risk, and how this can affect financial appraisal of power generation investments.
- How investment decision-making takes risk factors into account.
- How risk can affect financing of projects and the cost of capital.

3.2 Sources of risk, price risks and implications for power generation investment choices

Introducing risk

Different studies use different definitions of risk. Some aim to distinguish between uncertainty and risk, by ascribing the term uncertainty to a situation where it is not possible to parameterise the variability of outcomes, and using risk when outcomes are variable within some expected probability distribution which can be parameterised. For example, the UK Climate Impacts Programme (Willows & Connell 2003) adopt a widely used definition of risk – that it is the product of the likelihood of a consequence and its magnitude. They refer to uncertainty as describing the quality of our knowledge concerning risk. In this report, we use the term 'risk' in a more general sense to mean a factor that creates uncertainty in the financial returns of an investment.

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 2003b)). These range from the general (e.g. macro-economic, political and force majeur risks) to the more project-specific (see Table 3.1).

Revenue and price risks

These risk factors affect different technologies in different ways. They 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 (IEA 2003a). 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 3.1. 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.

This section focuses on the role of electricity price risk. Although all generation technologies within a given market are subject to largely the same time of day price of electricity[6], the level of exposure to this price risk varies considerably between generating technologies. As a result, electricity price risk turns out to be an important risk factor affecting technology choice in investment appraisal.

Table 3.1: Risks directly affecting a company's cash-flow calculation

	Price Risks	Technical Risks	Financial Risks
Costs	Fuel price CO_2 price	Capital cost Operating and maintenance cost Decommissioning and waste Regulation	Weighted cost of capital Credit risk
Revenues	Electricity price	Utilisation levels (and timing of utilisation, which can be important for price) Build time	Contractual risk

The origins of price risks in competitive markets

If electricity prices were fixed or extremely stable then it would be possible to capture many of the issues in Table 3.1 using levelised costs and the simulation models referred to in Ch. 2. Under monopoly conditions many of these risks could be passed through to consumers. The level of financial risk in competitive markets is likely to be high when compared to pre-liberalised conditions, but in theory it ought to be possible to capture the implications of this through adjustments to the finance assumptions used to generate levelised costs. Indeed recent analysis of levelised costs undertaken to inform policy generally uses 'private sector' discount rates By assumption these are higher than those used under public sector conditions or to represent 'social' discount rates (Leach et al. 2005).

6 Some generators may receive additional payments for the provision electricity system services, based on contracts issued by the System Operator see http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/

However in many countries, and certainly in Britain, electricity prices are not fixed or insulated from risk, hence levelised costs cannot capture electricity price risks. Price risks arise because of uncertainties about future prices for electricity. These in turn arise for a range of reasons, from large scale economic events or political changes, to volatility in fuel prices or problems with power stations. Market structures under liberalised markets differ between countries and are subject to change over time, either as a result of regulatory changes or through merger, consolidation or new market entrants. Markets may be highly competitive, with many companies competing within separate functions (e.g. generation, supply, distribution) or dominated by an oligopoly (or even monopoly) of vertically integrated generation and supply companies. The degree of 'unbundling' of functions (e.g. generation from transmission) will affect the levels of competition. However merger and consolidation activity may at least partially offset regulatory unbundling, as at least some functions are reintegrated. For example, in the British market merger activity has created 'reintegrated' generation and supply companies and resulted in the exit of most 'merchant' generators. Many supplier/generators also own distribution networks. These factors affect price volatility. To understand the implications of price uncertainty and fluctuation for investors it is first necessary to understand how wholesale electricity prices are formed, and what sets them.

Price formation under liberalised markets

In Britain electricity is bought and sold under a complex set of regulatory arrangements known as BETTA (British Electricity Trading and Transmission Arrangements)[7]. Its central principles consist of:

- Forward and futures markets that allow contracts for electricity to be struck up to several years ahead.
- Power exchanges which give participants the opportunity to 'fine tune' their contract positions or trade energy forward as appropriate.
- A balancing mechanism, which operates at Gate Closure (1 hour before real time), in which bids and offers for electricity can be made to enable the system operator (National Grid Plc) to balance the supply and demand on the transmission system. The system operator also contracts for various forms of reserve plant to cope with unexpected variations.

7 The operation of this mechanism is not described in detail here. For a brief overview see http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10081_2605.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/betta/betta02

- A settlement process for charging or paying participants whose notified contract positions do not match their actual volumes of electricity.

The arrangements result in bilateral trading of large volumes of energy between suppliers and generators, and much smaller trades closer to real time through power exchanges and the balancing mechanism. Nevertheless, electricity prices include a 'time of day' component, since generation must be increased and decreased as demands fluctuate – as illustrated in Figures 3.1 and 3.2 (in Box 3.1). The result of this is that the market determines the 'dispatch' of plants according to their cost characteristics and the spot price of electricity at any given time of day is 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. These are the system marginal plant, and for that particular time of day will set the price of electricity (i.e. acting as price makers) and all other plant on the system will be price takers.

Price makers and price takers

Short-run marginal costs include all variable costs, including fuel costs, variable operating and maintenance costs, CO_2 and other environmental costs borne by the electricity producer. They exclude fixed costs such as capital depreciation and fixed operating and maintenance costs. Hence, the lowest short run marginal cost plants are used first, and most of the time. Such plants, often referred to as 'baseload' generators, are usually high capital cost but low or zero fuel cost technologies such as nuclear power and renewables. The newest and most efficient fossil fuel plants may also run on 'baseload'.

Fuel prices and plant efficiencies for the system marginal plant(s) determine the short run price of wholesale electricity. This also implies that fuel price volatility is reflected in wholesale electricity prices and indeed fuel price increases are eventually passed through to consumers. Hence, to an extent, fossil fuel generators have a degree of natural 'hedge' against fuel price fluctuations because changes in fuel prices are reflected in changes to electricity prices.

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 reasons that long term fixed price contracts are rare appear complex and are not fully documented, but possible reasons include the potential mobility of the customer base, which militates against long term supplier liabilities. Nevertheless the result is that significant long-run fuel price uncertainty, such as that is represented in the different Energy Review scenarios (DTI 2006d), will not usually be hedged through contractual arrangements.

Box 3.1: The position of coal and gas generation in the UK merit order

The position that coal and gas plant appear in the merit order[8] depends on the prices of gas, coal, and CO_2. Under high gas prices and modest CO_2 prices, gas will tend to be on the margin. 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 position 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. It is possible to see this happening in practice in the UK market response to changes in gas prices.

The shifting in relative positions in the merit order of gas and coal generation in response to changes in the relative prices of each is illustrated by figures 3.1 and 3.2. Figure 3.1, represents how demand was met on a typical winter day in 2002/3, when gas prices were low relative to the winter of 2005/6. Gas is above coal in the merit order (so is 'dispatched' before coal and therefore appears in the chart next to the baseload nuclear generation). Figure 3.2 represents a typical winter day in 2005. Coal is above gas in the merit order so therefore appears in the chart next to the baseload nuclear generation. In 2002/3 gas was traded at 0.69p/kWh, by 2005/6 the price had risen by 83% to 1.262p/kWh. By contrast the price of coal was relatively stable across the two year period at 0.394p/kWh and 0.487p/kWh respectively.

Figure 3.1: Typical winter 24 hour load profile on National Grid system 2002[9]

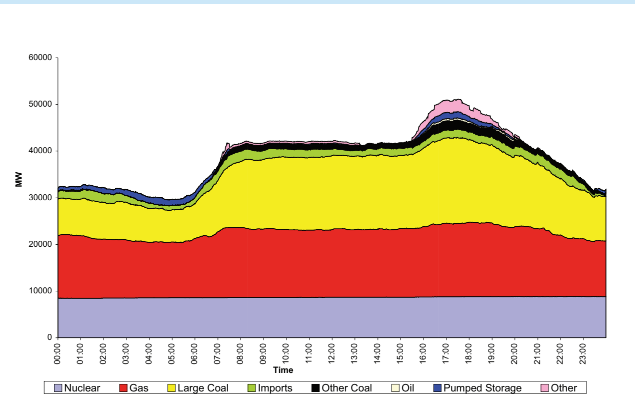
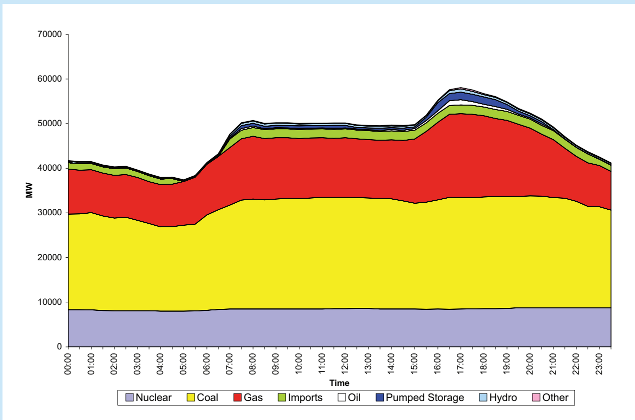


Figure 3.2: Typical winter 24 hour load profile on National Grid system 2005[10]

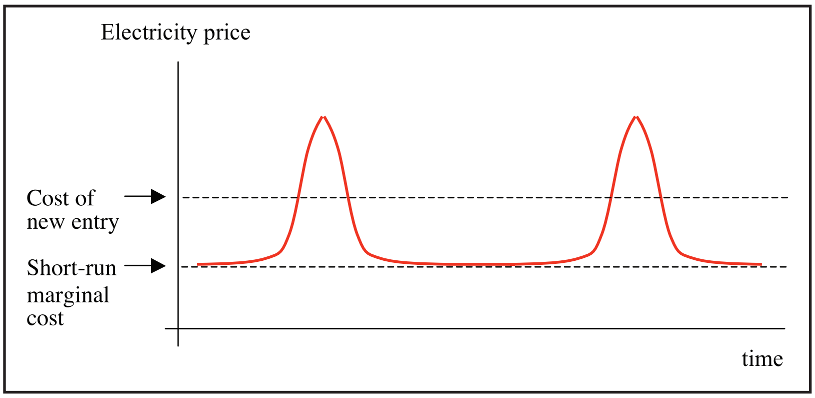


8 Strictly speaking, there is no 'merit order' in the UK's electricity market – generators are free to trade as they see fit within the constraints of their operating characteristics (such as output ramping rates) and the regulatory framework. The term is however a useful shorthand to describe what typically happens in the market – i.e. that low variable cost plant will operate whenever it is physically able to do so and progressively higher variable cost plant will operate to follow seasonal and diurnal demand variation.

9 From NGC Seven Year Statement 2003 (Typical winter demand, England & Wales), chart provided by National Grid.

10 From NGC Seven Year Statement 2006 (Typical winter demand, GB), chart provided by National Grid.

Figure 3.3: Investment and price cycles in a competitive market



Long-run price risks in competitive markets

Another important source of electricity price risk results from the long run (years to decades) investment dynamics that arise in competitive electricity markets. These may tend towards a boom and bust cycle, hence price risks also come into play over longer timescales. In competitive markets, producers receive a signal to invest through the product price. When electricity supply is becoming tight relative to demand, and this reflects a shortage of generating capacity, prices[11] should rise creating the incentive to invest in new capacity.

Because it takes several years to bring a new power plant online, this process requires some judgement in advance of likely impending shortfalls in the market. Timing of investment can be critical. (White 2005) describes how price behaviour in competitive markets could lead to periods of several years of low prices (close to short-run marginal cost). These prices are too low to encourage new entry. As plant retires or demand increases, the market gradually becomes tighter until average prices 'spike' up above the threshold for new entry. At this point, there may be a race to bring new plant on-line to make the most of the higher prices, which once again returns the market to a period of low prices and low investment until the next price spike (shown schematically in Figure 3.3, following the form in (White 2005)).

Such pricing behaviour for a competitive market can be considered as a dynamic equilibrium as long as a sufficiently long time perspective is taken. A mathematical treatment of this behaviour is given in (Dixit & Pindyck 1994). However, this type of 'herding behaviour' creates challenges both for companies and policy makers. Given such uncertainties, investors will require large discount rates, effectively driving average long-run prices higher than would be the case without this source of uncertainty. This has led commentators to question whether competitive markets will provide timely investment in new capacity e.g. (Finon et al. 2004; White 2006).

Given the particular characteristics of electricity, capacity shortfalls can even lead to interruptions to supply as well as price spikes. The threat of these cycles also challenges policy-makers, who may face political pressures due to consumer

11 We refer here to 'prices' in a broad sense, encompassing a range of different price changes - time of day, contracted and wholesale price, etc - the central point being that overall/average short run marginal prices rise in response to shortage.

dissatisfaction with price spikes, and/or in the face of prospective capacity shortages in future years. An expectation of policy intervention in market may create additional uncertainty and in the long-run create additional barriers to investment (Antoniou & Pescetto 1997; Robinson & Taylor 1998).

On the other hand, others would argue that competitive markets are well suited to providing appropriate investment signals (IEA 2005). In any case, in most real markets, these boom and bust cycles are dampened somewhat by actions taken by companies to restructure and consolidate market power as a direct response to the market risks (Bower et al. 2001). Despite the 'unbundling' carried out as part of the liberalisation process, the UK electricity industry is now dominated by several large, vertically integrated power companies whose operations cover generation, supply and retail business. These companies also own local distribution networks. Whilst most supply businesses are not protected from competition, this arrangement does provide something of a buffer at least against shorter-term market variations because there is some friction in the market against switching suppliers. Vertical integration therefore increases a company's ability to plan capacity additions. In principle, long-term contracts would also provide a market-based solution to these problems, but so far a long term (longer than 1 – 3 years) forward market has not developed to any great extent.

Illustrating the Effects of Price Risk

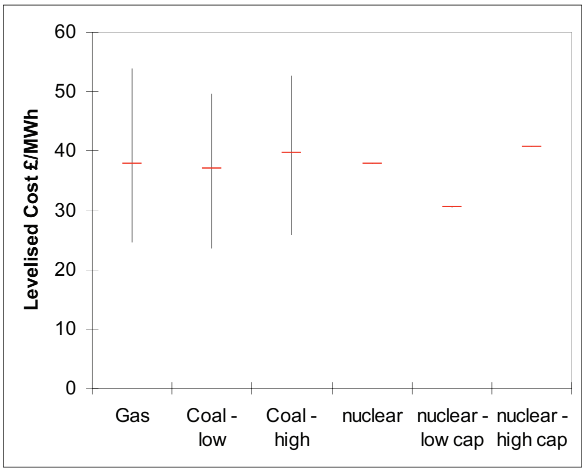
Regardless of whether coal or gas generation is the price maker, high fixed cost and low/zero fuel cost plant such as nuclear power and renewables are almost always price takers. They are highly unlikely to be marginal plant[12], and always take the prices set by plant that are marginal. Hence they benefit when prices are relatively high (as gas and electricity prices were during 2006), but may suffer when prices are low (for example during 2001). In what follows we explain the significance of this for the ranges of cash flows that might be calculated for the three main types of electricity generation – coal, gas and nuclear power[13], compared to the ranges of levelised costs for these generators.

The implications of price uncertainty for investment are explored in detail in Working Paper 2, which is summarised here. Figure 3.4 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

12 This is a generalisation relevant to systems with a mix of fossil and non-fossil plant. Different conditions may apply in systems with very high penetrations of high capital low fuel cost technologies e.g. nuclear power in France or hydro in Norway.

13 Note that the factors relevant to nuclear power would also apply to wind, hydro and other renewables, except biomass plant, which might be regarded as more akin to a fossil fuel generator.

Figure 3.4: Spread in levelised costs arising from different CO_2 and fuel price scenarios taken from (DTI 2006d) See Working Paper 2 and Annex 2



price scenario. There are four CO_2 price scenarios, £0/tCO_2, £10/tCO_2, £17/tCO_2, and £25/tCO_2.

The levelised cost representation simply represents the costs of generation, and does 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.

Working Paper 2 also provides an illustration of how the implications of electricity price risk for cash flow and hence investors 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 (DTI 2006d), and put into a simple cash-flow model. This 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 3.5. This essentially takes the same projects shown in Figure 3.4, 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. 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

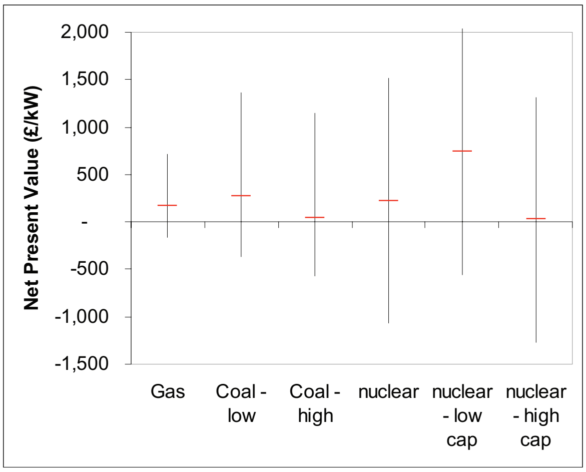
The present value of the capital costs of the plant, plus the annual maintenance costs, plus the output of the plant times its fuel and other variable costs.

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.[14]

3.3 Incorporating risk into decision-making

Investment decision-making includes (but does not entirely comprise of) financial appraisal. The basic principles of how investors financially appraise investments will be familiar to a wide audience of project development, economic and finance professionals. In simple terms, investors consider the net present value (NPV) and derive the internal rate of return (IRR) of an investment. Box 3.2 describes how risk is represented within an NPV calculation, using a risk-adjusted discount rate. IRR calculations avoid having to calculate the risk-adjusted discount rate by simply choosing a value of the discount rate that sets the NPV to zero. The IRR therefore measures the cost of capital that the project could bear and still be expected to breakeven. This metric is often used in quite a simple fashion by comparing a project's expected IRR with a given hurdle rate that the company uses for that class of project. Projects considered to have different classes of risk may be ascribed different hurdle rates (we note that this is

Figure 3.5: Net present value representation of the spread of returns arising from different CO_2 and fuel price scenarios taken from (DTI 2006d) See Working Paper 2 and Annex 2



a simplification and that some risks are relevant throughout a project's lifetime whereas others apply for specific timeframes). The hurdle rate may be linked to the cost at which a company can raise capital. It also represents the amount of risk a company can be exposed to without reducing its credit rating.

The range of NPVs illustrated in Figure 3.5 provides a simplified indication of a spread of possible returns, hence risks. In reality any investment proposition will be further complicated by a range of other factors that affect the cost of capital and hurdle rate. These may reflect, for example, the size of investment, timescales and qualitative factors.

Many companies run a detailed model of the electricity system they are considering making an investment into, with major

14 The y-axis is related to the profit per MW that could be achieved from the projects, for illustrative purposes this is expressed neglecting the effects of tax.

generation plant represented. Such models may be used to assess possible financial outcomes, hence risks, by either generating a set of NPVs from a set of discrete scenarios 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 RO. The impact of investment behaviour of other players in the market may also be incorporated. A range for each of these variables would be considered in the modelling:

- A scenario approach would 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, see e.g. (Feretic & Tomsic 2005).
- 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.

Given a certain risk profile in terms of a spread/range of NPVs, how do companies then factor this into their investment decisions? Companies will have different ways of assessing the importance of the distribution of potential project returns. They may simply put a value on the down-side risks, and compare 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, as this would affect their cost of borrowing. Alternatively, companies may use the distributions to classify the risk rating of the project, and hence help determine the appropriate hurdle rate to use within an IRR-type approach. This may be most appropriate when considering projects with well-understood risks. It is important to note that the criteria that different investor groups (lenders, equity investors, companies investing 'on balance sheet) will apply to developing and assessing the spread of NPVs will differ. Whilst these factors are too complex to examine in detail here we return to the relative appetite for risk from different categories of finance below (Sect. 3.4).

Techniques also exist to explicitly quantify the effects of different sources of risk based on real option theory (see Box 3.3). There is quite a substantial literature developing on the use of these techniques.

Box 3.2: NPV and IRR (following Trigeorgis 1996)

Ignoring uncertainty, and assuming that money for the investment can be borrowed at a risk-free rate r, a single up-front capital investment cost I and annual cash inflows ct in period t, the NPV is calculated as:

$$NPV = \sum_{t=1}^{T} \frac{c_t}{(1+r)^t} - I$$

In reality, many elements of the project finances will be uncertain. In principle, each uncertain element of the cash inflow ct should be replaced with a certainty-equivalent amount ?t. The value of ?t in year t is chosen such that it has the same present value (PV) as the uncertain cash inflow when they are discounted at the appropriate (risk-adjusted) rate, i.e.

$$PV = \frac{\hat{c}_t}{(1+r)^t} = \frac{E(c_t)}{(1+k)^t}$$

Where E(ct) is the expected (mean) value of the uncertain cash inflow ct, and k is the opportunity cost of capital (or risk-adjusted discount rate) for projects of that class of risk. Then the NPV under uncertainty can be written as:

$$NPV = \sum_{t=1}^{T} \frac{\hat{c}_t}{(1+r)^t} - I$$

This certainty-equivalent approach disaggregates the effects of time value of money under certainty from the effects of risk. Equivalently, one may define a risk premium as the expected value of the cash flow in a given year minus the certainty equivalent cash inflow. This risk premium should reflect the overall market risk premium for that class of project. In general, the cash inflows in each period may be subject to a different level of risk, requiring a different risk premium to be used for each period. This would be the case if project uncertainty were resolved in a 'lumpy' manner rather than being gradually resolved in a smooth way over time. It may also be important for different elements of the cash-flow to be discounted using different risk premiums – for example gas prices may be deemed more risky than coal prices. In practice, it is difficult to determine the correct adjustments that should be made to the different elements of the cash-flow in each period. A simplifying assumption is often made in order to allow both the time value of money and the project risks to be represented by a single risk-adjusted discount rate k for the project as a whole:

$$NPV = \sum_{t=1}^{T} \frac{E(c_t)}{(1+k)^t} - I$$

Use of an internal rate of return (IRR) avoids the need for a detailed assessment of the value of k by choosing its value such that the NPV becomes equal to zero. The IRR measures the effective cost of capital that the project could be charged, and still be expected to break-even. This can then be compared to a hurdle rate to give a simple indication of whether the project is financially viable. The hurdle rate companies use would then incorporate their assessment of the project's risk. This is a reasonable approximation to the more rigorous certainty-equivalent approach as long as risks are well understood and are assumed to resolve smoothly over time.

The approach is described in textbooks such as (Dixit & Pindyck 1994; Trigeorgis 1996). Applications of the approach are described widely in the literature, including for example (Edelson & Reinhart; EPRI 1999; Frayer & Uludere 2001; IEA 2007; Ishii & Yan 2004; Lambrecht & Perraudin 2003; Laurikka & Koljonen 2006; Reedman et al. 2006; Rothwell 2006; Sekar et al. 2005).

Industry interviewees and other contributors suggest however that real options techniques are not widely used in a commercial setting within the electricity industry. However, electricity industry analysts and project developers indicated that the expertise and qualitative perceptions of corporate decision makers play an important role in assessing projects and such factors may be implicit in strategic judgements. Strategic considerations are discussed in the following section.

For reasons discussed in more detail in Ch. 4 below, policies are themselves a source of risk that companies must consider – since policies are both changeable and largely outside corporate control. Hence markets created by policy may be viewed as inherently risky, at least until companies have gained confidence and experience in them. Moreover policy design can affect risk; some policy types create new price risks whilst others reduce (or even remove) this element of risk. Again, we explore these issues in Ch.4.

Strategic investments

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 effect investment; we review a few examples below.

In some 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. Portfolio techniques can be used to assess how individual projects add value in addition to their own expected returns, by balancing risks within a broader portfolio of generation types, since different generation types have risk profiles (Awerbuch & Berger 2003); (Wiser et al. 2004). Companies will often apply similar concepts in a less formal way by aiming for diversification of their generation portfolio as part of their overall corporate strategy. Industry experts stressed the importance placed upon a strategic view of portfolio issues, though it appears that this is done in a largely qualitative way.

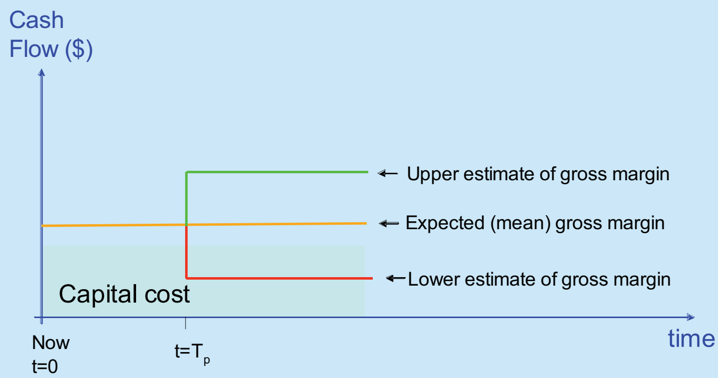
Strategic considerations relative to competitors may also be important. For example a company may want to break into a new market, or to acquire plant to consolidate market position (which may or may not be linked to a desire to diversify the technology base of its generating portfolio). Such considerations are more likely to become important where the companies active in a market are relatively large, able to put equity directly into particular projects, or where the market is concentrated enough for large companies to seek market power.

Box 3.3: Option value and Real Options

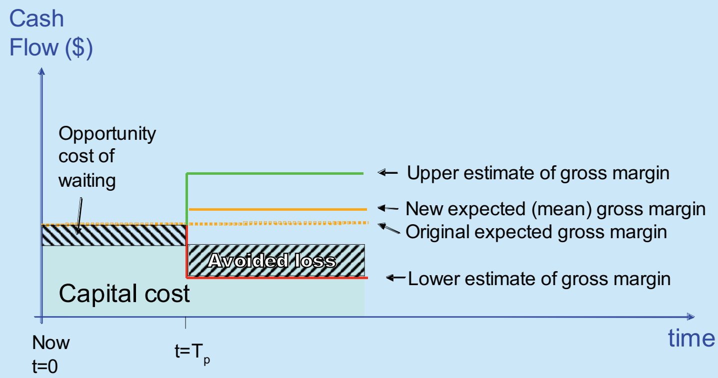
For a company faced with uncertain future costs or revenues, there may financial benefits to reducing the range of these uncertainties by gaining new information prior to investment. Since the expected value of the NPV is a probability-weighted mean, by avoiding some of the worst outcomes, the expected value of the project will go up. Figure 3.6 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 Tp. 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.

Figure 3.6: The value of waiting for regulatory information

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



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



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 Tp 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 Tp.

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.

Companies will need to take a view on the likely timing of new capacity additions being made by their competitors and the potential for policy support by government for particular types of investment. For example, 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. If all (or most) companies decide to wait then additional support becomes more necessary. The potential to 'second guess' the actions of competitors and/or to deliberately manipulate policy has been referred to as 'gaming' – meaning that companies act in order to influence the behaviour of other players as well as assessing an investment or other action on its merits, see (Green & Newbury 1992; Powell 1993; Varian 1992) This is discussed further in Ch.4.

Investment that builds knowledge or provides information may also have additional strategic value that will feed into the investment decision. This may be important when investing in new technology areas which are expected to be an important part of the future generation mix but which currently have a degree of uncertainty over costs (e.g. offshore wind, nuclear, CCS). Industry contributors to this project suggested that strategic investment considerations such as this may be reflected in the hurdle rate expected of projects. Hurdle rates may be lower for strategic projects and/or more 'relaxed' assumptions may be permitted in the estimation of returns. Moreover, the size of a particular investment may affect the ability of a company to invest for strategic reasons. Small projects, such as many renewable energy schemes, may be financed 'on-balance sheet' using the company's own capital. This permits companies to internalise some the risks associated with such projects; risks may be higher than debt investors would accept. Hence small, risky projects that meet some other strategic objective may be more likely to go ahead than large risky projects.

These considerations have important implications for some of the technologies that policymakers are seeking to support. 'Pilot' projects may be more attractive than full scale utilisation. Whilst the technology risks of well proven technologies (such as wind power) may be lower than those at a more 'experimental' stage (such as wave power) the need to raise external finance for large scale developments may increase the returns companies seek and/or require greater risk mitigation. The relationship between finance and risk is explored in the next section.

3.4 Impact of risk on investment finance

This section draws upon Working Paper 3, which reports upon a number of investor workshops held between 2004 and 2006, focusing on finance for renewable energy technology and policy.

Debt, equity and risk – the cost of capital

Risk and return are fundamental to private sector finance decisions: how much to lend, to whom and for what, or how much to invest in a company or project.

Financing can be broadly divided into two types, debt and equity. Debt providers lend money to companies in exchange for an agreement to pay back at a pre-determined rate for a given length of time. Debt can either be raised through lenders, banks for example, or through issuing bonds. In both cases, the key concern of lenders or bond traders is the ability of the borrower to be able to service the loan repayments. Credit risk is therefore a key driver of the cost of debt – companies or projects that are deemed to be highly credit-worthy will have lower repayments (i.e. lower interest rates) than companies or projects that have significant risk of financial distress.

Equity investors (usually the power companies themselves on behalf of their shareholders) are entitled to a share of any profits once the debt repayments have been made. These investors will focus on estimating the risk-adjusted returns – and whether these are commensurate with the risk they are taking putting capital into the endeavour. Because there is no guaranteed level of return, the risks for equity investors are higher, and the returns they expect are correspondingly larger. Therefore, from the perspective of the project developer, equity is a more expensive form of financing than debt.

The share of debt and equity (known as 'gearing') are fundamental to the overall cost of capital and the level of return expected of an investment. 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 required return on the firm as a whole and, as such, it is often used internally by company directors to determine the economic feasibility of new investments as it represents a minimum value for the IRR of a new project.

The same goes for individual project financing. Because of the lower cost of capital associated with debt, project developers 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.

As capital is mobile, investors, and lenders, will favour the sector, project, or location where they get the best return. The ratio of return to risk offered by the electricity market will therefore determine the extent to which and under what conditions financiers and lenders will be interested in electricity generation projects. Lenders will be concerned with the ability to repay over the whole business cycle. Both debt and equity investors will assess the spread of potential revenues, based for example on the probability of a range of utilisation levels and scenarios for future wholesale prices. Equity investors will be prepared to bear a higher risk profile of returns (for example a debt investor may consider the returns to a wind farm based on 90% of the distribution of expected wind speeds, whereas equity may consider a narrower, more risky share of the wind speed distribution). Market fluctuations such as those described in Figure 3.3 may lead to concerns about the ability to repay during extended periods of low prices and will tend to increase the cost of debt, and reduce debt gearing levels compared to markets with a smoother price profile.

Since liberalisation, investment in UK electricity generation has been through a number of stages, reflecting changing market conditions and regulatory actions. It is not possible to provide a thoroughgoing review here, although it is worthwhile noting that during the 1990s relatively high margins (electricity price relative to fuel prices), low capital costs of gas-fired CCGT and the low cost of gas encouraged the 'dash for gas'. New entrants in the form of 'merchant' generators were able to attract a large share of debt finance for new CCGT projects. The competitive behaviour of these new entrants (combined with regulatory changes) led to a dramatic fall in electricity prices and in the early 2000s margins reached very low levels. Since 2003 electricity prices have increased due to rising gas prices, but margins are still modest compared to the mid 1990s. Low margins in the UK electricity market have been accompanied by considerable consolidation and market concentration, combined with vertical integration between generators, distribution network owners and suppliers.

Investment in a 'price maker': gas-fired electricity generation

In the UK electricity market, margins rose during 2006 and early 2007 (Tendance Carbone 2007), having been low for a number of years previously (White 2006). Views on why margins dropped in the early 2000s differ. (Evans & Green 2003) argues that it was largely due to increased competition following introduction of NETA, whereas (Bower 2002) argues it was due to structural changes in the market which were taking place independently of the new regulatory framework. It is also not clear whether margins have now recovered sufficiently to prompt wide scale investment. Irrespective of the current situation, or the causes of earlier low margins, the history is relevant to investors' view of risk. Investors are of course aware of the very low fuel and electricity prices experienced in the early 2000s, the very high gas prices more recently and of a range of policy developments. This suggests that investment will only take place in technologies that are robust in the face of a range of uncertainties (or when conditions are such that future uncertainties may be passed through to customers).

It is therefore interesting to note that investments are taking place with seven new CCGT plants (representing a total of over 8GW of generating capacity) currently seeking DTI consent[15]. A typical investment proposition in the electricity sector would entail an 80/20 debt/equity split; a relatively low risk investment. 'typical' at present generally means gas-fired generation and it is interesting to note the reasons for this:

- For the reasons discussed above (Sect. 3.2) gas fired-generation is able to pass through fuel price uncertainties to consumers – it is the price maker and therefore has a natural 'hedge' against both very low and very high fuel prices.
- Gas-fired generation is relatively low capital cost, so the total finance (hence risk) required to develop a project is smaller than it is for equivalent size coal, nuclear or renewables projects.
- Gas-fired generation has short construction times which both reduces capital required and the risk of radical changes to market conditions or policies prior to the completion of a new plant.
- Gas-fired generation is affected less by uncertainties about future carbon prices induced by the EU ETS than coal fired generation.
- Gas-fired generation is flexible and depending on market conditions may be profitable at a range of load factors/positions in the 'merit order'.

This may not hold for all companies and all investment propositions. The portfolio effects and other strategic considerations described above may of course drive investment in other directions. Perhaps as a result, some companies are actively progressing new coal-fired plant[16].

Investment in a 'price taker': capital intensive power generation

When, for a variety of reasons, electricity prices collapsed at the end of the 1990s the implications for generators with high fixed costs became clear to investors – as demonstrated by the problems that beset British Energy in the early 2000s. Exposure to revenue risks limits the amount of debt that can be secured, increasing the requirement for (more expensive) equity finance. In what follows we illustrate this point with reference to nuclear power. 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. We focus upon nuclear generation here for illustrative purposes and because, at the time of writing, nuclear power is believed to have similar levelised costs to gas- and coal-fired generation and the UK government have ruled out subsidy or premium payments to promote it (DTI 2006d). By contrast renewables, which in principle face similar difficulties, have support through the Renewables Obligation. We therefore return to renewables in Ch.4.

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 (interest that could be paid once other variable costs have been covered) if electricity prices were to fall to the low levels experienced in 2000 – 2003 (White 2006). This limits the debt share of a new

15 As of May 2007, see DTI section 36 consent website for details: (http://www.dti.gov.uk/energy/markets/consents/applications/page23224.html). Note this does not necessarily mean that these plants will actually be built, but generating companies are, at the very least, investing in an option to build.

16 See http://www.eon-uk.com/pressRelease.aspx?id=1045&month=0&year=0&p=2 for an example.

£1.3 billion nuclear power station to less than £300m 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. Given the high expected returns associated with such a large equity stake and the low margins that appear typical of a competitive electricity market White concludes that new nuclear generation is not financially viable.

The debt-equity scenario described by White might be improved upon in a number of ways. First it is possible that a large utility may be able to borrow money against its wider portfolio or to explicitly value the portfolio diversity added by nuclear power. Second it is possible that the 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). Thirdly, it is possible that 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 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). Alternatively, 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). Finally it is conceivable that the government could take an equity stake itself, perhaps in the form of a Private Finance Initiative (PFI). We return to some of these issues in Ch. 4.

Implications of price risk for investment

We may now make two, linked, observations about the market risks associated with nuclear power and other high capital cost projects: First that a wide spread of NPVs are generated by the risk to revenues associated with the variability of electricity prices. Second that these risks imply that such a project would only be able to secure a low share of debt relative to equity. Hence, new nuclear generation would be unlikely to attract finance under current UK market conditions, or it would at least require the unusual financing arrangements discussed above. None of these issues is reflected in the cost estimates for nuclear power reviewed in Ch. 2. Hence policy analysis that only considers costs may be extremely misleading; giving the impression that nuclear power is 'competitive' with gas generation. Yet in fact, on a project finance basis, a nuclear scheme is exposed to greater price risks, has greater uncertainty over cash flow and is not likely to be able to secure an attractive share of debt financing when compared to a gas fired alternative. These issues are in addition to the more frequently discussed cost risks associated with nuclear power, such as build time over-runs and cost escalations (MacKerron et al. 2006).

As noted above, revenue risks and their linkage to gearing are not unique to nuclear power. The implications of electricity price risks for finance apply equally to any high capital cost, low fuel cost investment, such as wind power, tidal barrage or a hydro-electric scheme. Indeed it is notable that in the UK much wind power development that has taken place under the Renewables Obligation (RO) has been undertaken ‘on balance sheet’ (See Working Paper 3). Large utilities put in equity, and hence internalise the risks associated with both wholesale prices and the RO system. This requires a strong company with significant asset base, internal cash-flow, and where additional debt can be raised against the creditworthiness of the company rather than against the specific project. Box 3.4 discusses investment patterns under the RO. Since renewables development takes place as a result of a specific policy – the RO – we return to the issues that surround it in Ch. 4.

Box 3.4: Investment in Renewable Energy

Renewable energy is attracting significant capital: New Energy Finance, together with the Sustainable Energy Finance Initiative* estimate that, in 2006, a total of $70.9billion worth of clean energy financing transactions were completed worldwide (higher if M&A activity is included). Total renewable generation in the UK is relatively low compared to many other countries, coming 15th out of the EU-27 countries (EEA - European Environment Agency 2007), but is growing quite quickly. Total power generation from RO eligible renewables sources increased from approximately 10,000 GWh in 2004 to over 13,000 GWh in 2005. This increase compares reasonably well with growth rates in Spain and Germany between the years 2000 and 2003 (3,400 GWh/year and 4,500 GWh/year respectively), two countries that have seen perhaps the most rapid recent expansion of non-hydro renewable electricity generation (Stenzel et al. 2003). Expansion rates in the UK have been constrained by the planning process, particularly for onshore and offshore wind. Supply-chain issues have also affected deployment rates. The high global rate of growth in the renewables sector, together with the recent strong prices for basic materials has lead to increases in costs compared to the original engineering estimates.

The largest sources of the increase between 2004 and 2005 are from co-firing (1,500 GWh), on-shore wind (770 GWh) and hydro-power (461 GWh) (DTI 2006). Resource constraints are expected to limit future growth of generation from landfill and hydro sources. Given these constraints, future growth of renewables in the near-term is expected to come largely from biomass and wind generation, with other more advanced technologies (e.g. wave and solar) possibly making a contribution in the longer-term.

There is a large potential resource for further co-firing of biomass, but this source is capped under the current RO mechanism as it is a much lower cost option than most other renewables, and steps have to be taken to ensure it does not ‘drown out’ the development of other sources. There is still a large potential for further on-shore wind in the UK – the British Wind Energy Association estimates over 30,000 GWh (9% of UK electricity supply) would be feasible by 2020, but additions thereafter would be resource constrained. The BWEA estimates that offshore wind could deliver a similar amount by 2020 under the right economic conditions, and would not be resource constrained (BWEA 2006).

The UK currently has one of the most active off-shore wind sectors in the world, with planned projects representing 3006 MW of capacity compared to 2480 MW of capacity in Germany and 1190 MW capacity in all other countries put together (reNews 2006). Much of this activity has been driven by strategic expectations that off-shore wind will be an important part of the UK’s mix of renewable energy in the future. However, whilst many of these projects are proceeding through planning and consent stages, current prices under the RO are not sufficient to bring many of the planned projects to the build stage. This is one of the key reasons why the structure of the RO is currently being reviewed.

* New Energy Finance, is a trade specialist in renewable energy information and analysis for investors www.newenergyfinance.com; UNEP’s Sustainable Energy Finance Initiative was established to provide tools, support and a global network for investors in sustainable energy, www.sefi.unep.org.

3.5 Summary

1. Under liberalised markets investment is driven by expected returns, which are assessed in the light of a range of risks related to both costs and revenues. An important category of revenue risks are associated with electricity price fluctuations. These risks cannot be captured in levelised cost figures.

2. In some cases, technologies that appear competitive or low risk in terms of costs may be an unattractive investment proposition because of revenue risks. If price risks are large then the spread of returns to investment for a given technology may be much wider than the range of levelised cost estimates for that option.

3. Exposure to price risks differs by technology because some options (usually fossil fuel generators) act as 'price makers'. This means they are able to influence system prices and can also pass fuel cost fluctuations through to consumers. As a result, even if fuel and power prices are uncertain, returns on investment are relatively secure. Others, so called 'price takers' (nuclear, renewable and hydro plants), have high fixed costs but little or no control over system prices. Price takers benefit when electricity prices are high, but during a period of sustained low prices they may be unable to cover their fixed costs. If prices are volatile then revenue risks are higher for the latter class of technologies, which may discourage investment irrespective of their relative costs.

4. In practice, the extent of electricity price volatility, hence price risk, is a function of market conditions and structure. The UK market has experienced considerable volatility in recent years, and the margin between fossil fuel and electricity prices has tended to be low. This typically favours low risk investments that can secure a high debt/equity ratio (currently gas-fired generation).

5. The risk of a sustained period of low electricity price suggests that 'price takers' will not be able to secure debt/equity ratios commensurate with the level of return that is likely to be available. Such projects are unattractive to investors in the absence of any additional incentives.

6. In addition to assessment of risk and return, investment decisions will also be affected by a range of strategic considerations. These include portfolio effects, market share considerations and PR benefits.

7. Investment by electricity companies may be undertaken to reveal information or gain market advantage, and it may be delayed for the same reasons. 'Option value' captures these issues. In the case of new technologies or where new policies are expected, option value may be attached to waiting. In such cases policy may have to provide additional remuneration to bring forward investment and reveal information about costs and risks.

4. Conclusions: Implications for policy

4.1 Introduction

This section considers the implications of the issues articulated in Ch. 2 and Ch. 3 for policy[17]. In those chapters we sought to explain how consideration of investment appraisal and risk provides policy analysts with a different lens through which to view generating technologies. Options that may appear competitive in terms of levelised cost may nonetheless appear unattractive when viewed in terms of risk and returns. Policy incentives that appear sufficient to deliver policy goals when viewed in terms of levelised cost may not offer enough support to 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.

This chapter therefore discusses the relationship between policy developments and electricity price risk. It also considers how policy might respond to issues related to project finance, information flow in private markets and corporate strategy, as discussed in Ch. 3. Finally it provides some recommendations for future policy development, which seeks to define a more 'investment aware' policy environment.

The chapter covers the following issues:

- How investment risks might be explicitly factored into policy analysis.
- How policy affects risk, with a focus on revenue support schemes and revenue risks.
- Issues for policy raised by analysis of information flow, corporate strategy, and appraisal optimism.
- A case study in risk and policy: offshore wind.
- Conclusions and recommendations.

4.2 How investment risks might be addressed in policy analysis

Ch. 2 highlighted two key issues for policy. First, that although UK policymakers prefer to avoid 'picking winners' some policy goals and instruments, particularly those related to innovation, are linked to investment in specific technology or resource types. We discuss the risk and investment characteristics of different types of policy instrument and a range of technology types in section 4.3, below.

The second key issue is that estimates of levelised costs cannot capture the full range of risks relevant to investors. Cost estimates are appropriate for some policy purposes, such as undertaking cost benefit analyses of different technologies, but are 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. However, whilst policy 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

17 This chapter draws, in part, upon Working Paper 3, commissioned by UKERC for this project, see Annex 2.

complex. Industry experts interviewed in the course of this project emphasised the importance to potential investors of exploring a range of electricity price scenarios as part of investment appraisal. 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, they can also be assessed (as in many companies) 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.

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, for the reasons explained in Ch. 3, different companies may make different investment decisions even when faced with the same market conditions. However policy analysis could undertake simple assessment 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. Policymakers consulted in the course of this project emphasised that levelised costs are used only to indicate 'ballpark' differences between technologies. A simplified investment analysis could provide a similarly approximate level of information about the prospects for investment in response to different forms of incentive. We return to this suggestion in the recommendations section below.

Since the way in which premium payments are delivered is particularly relevant to revenue risk, we explore this in more detail in the next section.

4.3 How policy affects risks

Policy itself can affect investment risk. A range of factors are relevant:

- Political changes can affect markets, particularly if incoming political parties have a different view of energy policies and change or remove support mechanisms or introduce new schemes. The extent to which 'grandfathering' to protect extant investment is accepted by all political parties may differ between countries.
- Governments may 'change the rules' – for example in moving from the electricity trading arrangements set up in the early 1990s (the 'pool') to the England and Wales trading arrangements (NETA) and then British trading arrangements (BETTA). Such changes can impact on electricity prices, price volatility and risks.
- The approach that regulators take to market governance – e.g. to breaking up companies to reduce market concentration – 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 intervene directly to prevent investment – for example in the moratorium on new gas generation imposed in Britain during the late 1990s and legislation against new nuclear power stations in several other EU countries.
- Governments provide incentives and support schemes, which are discussed in detail below.

Hence a range of risks related to the perceived stability of the policy environment will affect the cost of financing for a project. Policy induced risks can also directly increase costs – for example, through fees for grid connection and through delays to construction caused by consenting or grid connection hold ups[18]. However policy can also create markets, through a variety of support or incentive mechanisms. These provide an important focus for the remainder of this section, since they can increase returns or reduce risks.

Technology support schemes and revenue risks

This section considers the risk associated with a particular class of policy – premium price or subsidy schemes that have been set up with the objective of promoting certain categories of technology (such as renewable energy). Such support mechanisms generally aim to increase revenues, improve cashflow, and enable these energy sources to compete for capital with other investment options.

However, a policy-created market itself poses a risk: policy or regulatory change resulting from a change in government, or other circumstance, which is outside the control of project developer or investor. Unlike other more technical risks, these are very difficult to mitigate, yet can undermine revenue streams built into business models, and have a serious impact on projects or firms. Moreover, the nature of a support mechanism can affect the risk profile of the returns it generates. Price (and hence revenue) risk is a function of the way in which support is provided. Some policies will reduce the spread of possible returns whereas others increase them – even when the amount of support (in total or per MWh) is the same. The discussion that follows is focused upon renewable energy policies, as these are the most widely used revenue support policies currently in play in electricity markets. However, similar principles apply to investment risk created by the EU ETS, and its impact on other low carbon technologies such as nuclear power and carbon capture – see Working Paper 2. Any new measures aimed at particular technologies, whether low carbon or otherwise, would be subject to the same considerations. The UK government and EC are both considering measures to promote the development of carbon capture and storage (CCS), which

18 Financiers quoted in Working Paper 3 place some emphasis on policy conditions in the round – including planning, consenting and connection issues as well as levels of subsidy.

has particular characteristics such as the need for new infrastructure. An assessment of the issues explored below, and application of the kind of analysis we describe in section 4.2 and recommend below would be a valuable activity in support of any future CCS policies.

A range of policies exist to promote the development of renewable energy technologies. The list includes:

- Revenue support schemes. There are several variants; current examples include:
  - Renewables Portfolio Standards with renewable electricity certificate trading (E.g. the UK RO).
  - Fixed price schemes (feed in tariffs).
  - Premium prices (on top of electricity sales).
- Capital grants.
- Governments taking equity stake through PFI (public private partnership).
- Public procurement rules.
- Tax incentives.
- Direct ('command and control') regulation.

We explore the implications a range of policy options for different categories of risk in Box 4.2. In what follows we focus solely on revenue support schemes, in order to illustrate the key issues for policy. 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 prices for renewables output for a fixed period of time (Feed in Tariffs as in use in Germany and many other countries). Payments per MWh are fixed for particular technologies at a particular rate for a particular time period (or number of operating hours).
2. A fixed 'uplift' over and above average electricity prices, again fixed by technology (an option available to wind farm developers in under current Spanish legislation for example).
3. A market exists for renewable energy certificates (The UK RO and Renewables Portfolio Standards in place in parts of the US for example). Such markets may be differentiated by technology or encompass all forms of renewables generation.

The amount of revenue risk that developers are exposed to increases as we move from mechanisms 1 through 2 to 3. In case 1, 'pure' feed in tariffs provide a fixed price, and revenue risks associated with electricity price movements are effectively removed from the developer's investment decision. Whilst in most countries tariff rates are adjusted regularly by regulators, existing projects are 'grandfathered' (guaranteed payment at the rate pertaining when the project was commissioned). In case 2, developers are exposed to electricity price movements, although they are guaranteed a minimum payment. However in case 3 developers are exposed to price risks in both electricity markets and the market for renewables certificates. The UK RO has no 'floor' price on Renewable Obligation Certificates (ROCs) so at least in theory the

Box 4.1: Financier perspectives on the Renewables Obligation and German Feed in Tariffs

A range of financier consultation outcomes on policies to promote renewables are reviewed in Working Paper 3. These include a finance roundtable held in 2005 on the EU review of its Renewables Directive which discussed the relative merits and challenges of the UK's RO scheme and the German feed-in fixed tariff. Below is a summary of key points, drawn from Working Paper 3:

UK market (Renewable Obligation Certificate):

- The relative sophistication of the RO involves investors having to take a 'future' view of different elements (e.g. value of recycling fund) to arrive at the value of the ROC. These price uncertainties are currently driving investment into the arena of strong sponsors that can both manage this risk and access the necessary level of capital: the bigger utilities. This was explained in more detail in a 2003 survey of investor attitudes to the RO, a year or so after its introduction. An independent wind developer stated: 'Longer term PPAs are hard to obtain….The result is that small developers struggle to gear projects higher than 70%, well below target gearing of 80-85% they need to justify returns..” (Carbon Trust 2003)
- Market growth more generally has been steady and the regime has driven investment towards good quality wind sites with good output (ie strong revenue);
- 'One size fits all' pricing in the ROC market has created a strong incentive for mature and lower cost technologies, and does not foster uptake of new or more expensive technologies. Some see a 'gap in economics' for offshore wind, which in turn is raising questions about both the attainment of the 2010 goal, and the need for additional support or modification to ensure a diversified portfolio in the marketplace. At least one view was expressed that the Renewables Obligation is not yet working properly.
- On offshore wind specifically, there is interest from banks and fund managers, they will be looking for: performance of the first round of offshore wind projects; higher returns; off-take contracts or some kind of security of revenue; and the issue of capital grants for Round Two to make the financing equation work. In the Carbon Trust 2003 survey, one project financier explained: “…We need to offload market risk on ROCs and trading risk, and won't back any project where there remains technology risk.”
- In general, there is money and interest in UK renewable energy investment, but not enough 'decent sized' projects (roughly, over 50MW) with attractive enough returns coming forward, at a scale to interest commercial banks.

German market (feed-in tariff):

- Fixed-tariffs, over a clear timeframe, provide certainty of income – a key issue for investors – reflected in the number of deals done, and have encouraged entrepreneurs and smaller scale investors to enter the market; differentiated tariff incentives, by technology, has promoting diversification;
- During the 2004 roundtable, 'below the line' local and national tax issues, together with planning complexities, were noted;
- Development of 'low quality' wind sites that attain commercial viability because of the feed-in tariff, has occurred. Although financiers prefer the clear price structure, there is a concern that if the output is too low (e.g. 15% capacity factor) this will not be sustainable for the sector in the long term – raising the prospect of public or political pressure for change due to unacceptable cost;
- Risk associated with regular government review of tariff premiums is an important issue. A six month 'chill' on investment occurred during a recent German tariff review.

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 in Ch. 3, a period of low average electricity prices poses a particular risk for capital intensive investments. A project's exposure to period of low average prices would be explored as part of investment appraisal. 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

Box 4.2: Policy options and price risk

Different mechanisms have different implications for risks. Table 4.1 attempts to provide an overview of the relationship between the main options for policy support and different categories of risk. Categories of risk are defined and explained in Ch. 3 and Working Paper 4.

Table 4.1: Which policies reduce exposure to which categories of risk?

	Cost risks relevant to RE developers and financiers*				**Revenue risks relevant to RE developers and financiers**			
Risks ameliorated by policy	**Technical Risks**		**Financial Risks**		**Price Risks**	**Technical Risks**		**Financial Risks**
Policy type	O&M	Capital cost	Cost of capital	Credit risk	Electricity price and CO_2 price	Build time+	Utilisation levels	Contract. risk
RPS schemes					?		✔	
Fixed price schemes			✔	✔	✔		✔	✔
Capital subsidy or PFI		✔	✔	✔				

* Fossil fuel developers will also be exposed to fuel and CO_2 price risks on the cost side, these are neglected here on the basis that most renewables have 'free' fuel – we note that biomass plants which may face fuel price risks but neglect these here in for illustrative purposes. Note also that the effect of fuel prices on wholesale electricity prices are incorporated into electricity price risks.

+ Build time overruns effect revenues, we note that they may also add to capital costs but assume that this is captured in the cost columns as capital cost risks.

? RPS schemes provide partial mitigation of electricity price risks – insofar as separate market exists for ROCs. However electricity sales price still affects total revenues, by contrast many feed in tariffs are entirely insulated from electricity price movements.

technology risks under the RO than they would under fixed tariff arrangements. This is because overall risk exposure will be higher under the RO.

In practice, developers must take a view of expected volatility in various markets and how these compare to other factors such as exposure to regulatory risk (see Box 4.1). It is perfectly possible that developers and investors will perceive a particular market as stable, offering good prices, and as relatively low risk. As noted in Box 3.4 and 4.1, the RO has accelerated the development of onshore wind in Britain. Moreover, other factors may have a more significant impact in investment. For example Working Paper 3 notes that wind power developments in Greece have been hindered by planning procedures despite a generous fixed tariff payment scheme. Nevertheless, the RO adds a dimension to revenue risk whilst feed in tariffs remove price volatility from the revenue risk equation.

It is important to note that fixed tariff schemes do not remove price risks altogether, they simply remove them from project developers. Simple economic theory suggests that under competitive conditions prices for renewable electricity will be determined by the market, which should result in the delivery of a given target for renewables at least cost. 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.

However it is also important to avoid overly simplistic representations of economic 'efficiency' based upon assumptions about markets efficiently moving to equilibrium. In practice if development cannot proceed because of grid limitations or planning, or if the obligation is simply set too high relative to feasible levels of renewables output, then consumers will pay a high price. Since government is responsible for setting the level of the obligation, 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. 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.

Assumptions that markets can move swiftly to equilibrium may also be unrealistic, given the time needed to build renewables capacity. Markets may be out of equilibrium for a long time (targets not met), resulting in high prices for renewables. This may not be politically acceptable, and lead to criticisms based on 'overpayment' relative to feed in tariffs or developers getting 'supernormal' profits (high returns on investment) (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 2006d).

For all these reasons overly simplistic assertions that an MBI such as the RO is the most economically efficient approach needs to be treated with some caution. Nevertheless the underlying point that fixed prices transfer rather than remove risk is valid. An important question for policy is under what conditions might this risk transfer be a desirable thing for policymakers to do?

The case study of offshore wind below (Section 4.5) suggests that the price risks associated with the RO were a factor in the slow progress with investment in offshore wind in Britain relative to experience in Denmark, where a fixed price regime exists for offshore wind. As we explain below, despite similar costs and lower levels of revenue support, Danish developments are largely on track whereas British developments have proceeded more slowly than policymakers intended. It may therefore be that using fixed prices to transfer risk away from developers is likely to be most desirable in instances where technology risks are also high. However a range of other factors also come into play. These relate to the flow of information and companies' strategies in operating in markets where information is limited.

4.4 Decision making where information is poor or asymmetric: Policy responses to appraisal optimism, 'gaming' and poor information

Three further factors are relevant when considering the link between incentives and investment in new technologies. All three relate to the amount and quality of information about technology costs and risks available to policymakers and market participants.

Appraisal optimism

First, developers of new technologies commonly exhibit 'appraisal optimism', whereby in the absence of data derived from commercial experience the costs of a new development are underestimated and returns exaggerated. In Section 4.5 we discuss the possibility that this phenomenon was manifest in the case of offshore wind in the UK. Appraisal optimism is well documented in the literature on technology development, particularly for large and complex projects (MacKerron et al 2006). Similar effects may have been exhibited by the Finnish nuclear reactor under development at Olkiluoto (Bream 2006). Industry interviewees indicated that companies take account of this through a range of means, including the (high) rate of return that is required of innovative or unproven technologies. However, it appears that such appraisal optimism is not always recognised by policymakers. In Box 4.3 and Section 4.5 we discuss the cost estimates put forward for offshore wind, and compare these to the costs that occurred in reality. We discuss how policy support for offshore wind was based upon what turned out to be unrealistically low estimates of cost and understatements of investment risk – hence how policies failed to deliver the scale of investment expected, or needed to meet targets.

Information asymmetry, corporate strategy and 'gaming'

The second issue is where there is asymmetry of information between policymakers and market participants, and the latter have the better information. In such conditions market participants may have an interest in misrepresenting the costs of technologies. Evidence of deliberate 'gaming' by companies seeking policy support is difficult to substantiate (though game theory has been applied in electricity market analysis (Green & Newbury 1992; Powell 1993). HoWever, a compelling story (however hypothetical) of companies 'low balling' policymakers has been conveyed to the authors of this report by several industry experts. The story runs as follows:

- Companies that wish to secure subsidy or regulatory support for their technology will have an interest in persuading policymakers of the cost effectiveness of their technology. In short, costs are underestimated or understated, which may reflect appraisal optimism on the part of the companies concerned.
- However, once political commitment is secured and the technology in question secures a place in policy goals it becomes difficult for policymakers to 'back out' of support for it.
- Hence when costs rise relative to early estimates (whether by accident or design), or risks turn out to be higher than expected, investors are unconvinced or market conditions change, policymakers are obliged to find ways to provide augmented support.

In other words, the 'game' is to draw policymakers into political support by presenting attractive sounding levelised cost estimates, and paying little attention to other investment criteria. Either because costs are understated or for other investment related reasons this early promise and political commitment translates into a requirement for additional economic support when experience reveals true costs and risks.

Option value and the 'price of waiting'

In reality the distinction between appraisal optimism, poor information and deliberate attempts to understate costs is both blurred and probably impossible to quantify. However for policy purposes the motivation of market participants is not relevant, the implications for policy are what matter. A third information related issue is where data on costs and risks is limited for all concerned. This may give rise to an option value attached to waiting, and encourage developers to invest in order to hold a stake in future developments, whilst waiting for others to make the first moves and reveal costs.

The implications of appraisal optimism, poor information and misrepresentation of costs are as follows:

- Policymakers may have relatively poor information about costs for emerging technologies, since unlike the pre-liberalised central planners who purchased or developed technologies they are not able to secure such information 'first hand'.
- 'Appraisal optimism' is a common feature in the development of new technologies. Technology developers or equipment suppliers may also have incentives to play up or play down costs and potential according to circumstance.
- Where new or unproven technologies are being utilised for the first time, information about costs may be limited for all concerned.
- Costs (and the accuracy of ex ante estimates) 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. Policy will also need to take account of appraisal optimism and the interests of market participants. Hence;
- 'Over-remuneration' relative to levelised cost estimates may be needed for early stage or unproven technologies.

It is important to note that corporate strategy can be aligned positively with policy interests. For example several industry experts highlighted the value to their business of holding a diverse portfolio of generation assets. If companies seek diversity for strategic reasons and policy seeks to promote diversity there may be common interest that can be served. There may also be linkage here with work on 'transition paths' in the innovation systems literature, particularly the Dutch experience with building a shared understanding of change between government and industry (Foxon 2003; Kemp & Loorbach 2005). Detailed exploration of this issue is outside the scope of this report; however the innovation literature places considerable emphasis on the role of expectations of future policy in driving corporate investment (Foxon et al. 2005). It is 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.

4.5 The British offshore wind experience: a case study of policy viewed in terms of risk, return and corporate strategy

Limited progress with offshore wind has been noted by the government and is part of the rationale for the proposed 'banding' of the RO (DTI 2006d). Higher than anticipated costs due to high steel prices and demand for turbines are cited as the primary reason that cost are higher and offshore wind development has proceeded more slowly than expected (DTI 2006d).

Yet several large Danish offshore wind developments proceeded according to schedule despite offering total payments to wind developers lower than that offered by the RO (see Box 4.3). One reason for this lies in the risks associated with the RO[19] itself, as well as the technologies utilised in offshore wind schemes. Financiers point to a 'gap' in finance for offshore wind in the UK – risks are too high to secure a high proportion of debt finance and offshore wind projects will require a significant share of equity relative to debt – certainly higher than that of a typical electricity generation project. Yet returns are too low to finance a high share of equity (see Ch. 3 and Working Paper 3). This is because two categories of risk are combined for UK offshore wind:

- Technology risks are perceived as being relatively large, since global experience with offshore turbines is limited.
- Revenue risks are also significant, due to uncertainties over future electricity and ROC prices.

Hence the investment proposition offered by offshore wind is not attractive to developers other than large utilities able to finance projects with their own equity and attach strategic benefit to the projects (PR, portfolio, corporate learning) – and even then not at the scale required to deliver targets. The effects of this have been to delay the development of the majority of Round 1 offshore wind sites and may be particularly profound for Round 2, since the size of Round 2 developments is such that finance on balance sheet is likely to be more difficult.

It is also interesting to review the analysis that underpinned the level of support provided to offshore wind, the decision initially not to band the RO, and the amount of capital grant offered to Round 1 sites.

During 2002 the UK govt made £60m available for capital grants to offshore wind developers. DTI officials involved in setting the level of the capital grant available per project had concerns about the need to avoid a 'deadweight' loss for the Treasury, whereby more subsidy is provided than is needed to bring forward investment, giving a 'windfall' gain to wind developers. The level of support was therefore set to the minimum level believed to be commensurate with the expected costs of the technologies – a 10% of capital costs limit on each development. This was based upon an analysis of capital and levelised costs. These cost estimates were based upon engineering models used to estimate the additional costs of 'offshoring' wind turbines, data provided by the aspiring offshore wind industry, and experience from Denmark (at that time restricted to the relatively small and sheltered Middelgrunden offshore wind farm and a number of other relatively small, inshore, developments).

Consideration of the issues discussed in this report suggests that a more sophisticated analysis ex ante could have revealed that the cost estimates used in

19 Some of the investor views on the RO discussed in this chapter are drawn from a finance roundtable event run under the auspices of the Renewable Energy Finance-Policy project at Chatham House, see Working Paper 3.

the planning of the combination of capital grants and RO support for offshore wind were too low. Moreover that the level of risk imposed by the RO itself would combine with technology risks and costs to make the scale of development envisaged by the DTI difficult to deliver in financial terms:

- Appraisal optimism was not factored into the cost estimates at all.
- The attitude of more commercially oriented investors (relative to Denmark) to technology risk was not taken into account.
- The effects of market and revenue risk (RO and electricity price uncertainty) were not considered.
- The 'option value' for individual developers of securing sites and then waiting for competitors to reveal uncertain costs and risks were not factored in.

A more 'investment oriented' assessment might have factored in the need to:

- Ameliorate the revenue risk associated with the RO, given the higher technology risk associated with offshore developments relative to onshore wind.
- Consider the ratio of risks and returns in the light of the share of debt and equity that such innovative projects might have required.
- Include an explicit premium for 'information', possibly based on the cost that could be attached to the option value of waiting.
- Include a 'contingency' for first of a kind risks.

Nevertheless actual costs for the four largest offshore wind farms in the world appear to be lower than the DTI's current estimate (see Box 4.3). Moreover, Danish farms have been built and financed with a level of remuneration per MWh lower than the 'optimistic' cost estimates from the DTI in 2002. By contrast, most of the offshore wind sites leased in Britain's first round of consents are yet to be constructed, despite levels of support under the RO that appear more than adequate relative to costs of existing UK waters farms (see Box 4.3). This suggests that although load factors and recent rises in turbine prices are also relevant, the ability to secure finance at advantageous rates is important to the financial feasibility of offshore wind. This is likely to be more achievable under the fixed price and guaranteed sales that are a feature of the Danish support regime.

Box 4.3: Offshore wind facts and figures

Estimates and out-turns of delivered cost of electricity from offshore wind farms vary markedly. Table 4.2 shows how estimated capital costs of wind power compare with out-turns from early UK and Danish farms. Several factors come into play; discount rate assumptions and load factors feature heavily in the differences in levelised costs. Early studies may have been optimistic. Nevertheless the price paid for offshore wind output in Denmark, under which large wind farms are operating successfully, is around 50% of the cost per MWh estimated for UK offshore wind (DTI 2006). This is partly due to cost escalations since 2003 and load factor differentials (the LF assumed in DTI 2006 is very low relative to evidence from UK and Danish farms). However it also suggests that Danish developers have been able to attract finance with a relatively low cost of capital. Danish support mechanisms for offshore wind offer a fixed tariff and guarantee of power purchase. The Danish wind industry estimate costs using a 5% real discount rate. Our calculations suggest that Horns Rev and Nysted would not be financially viable, given Danish payments for offshore wind, unless a discount rate of less than 8% (nominal) were used. In contrast, although costs appear to be attractive relative to levels of support using a 10% discount rate, few UK offshore developments have taken place. Whilst the reasons are complex, and include strategic and option value considerations (see main text), it is also likely the combination of technical and ROC price risk pushes up the cost of capital. 10% may be lower than actual rates of return required for investment.

Table 4.2: Cost estimates and real costs for offshore wind

Development/estimate	Capital cost (£m/MW)	O&M* (£/kW)	O&M* (p/kWh)	Life (years)	Cost of capital %	Load factor (%)	Levelised cost (£/MWh)
Future Offshore (DTI 2002)	1000	-	1.2	20	10	35	51[a]
Energy Review (DTI 2006d)	1500	46	-	20	10	33	79[a,c]
Danish Wind Industry (see footnotes)	1100	-	0.7	20	7.5	47[0]	33[b]
Horns Rev (DK)	1310[1]	-	0.7[2]	20	7.5	45[3]	40[a]
Nysted (DK)	1190[1]	-	0.7[2]	20	7.5	37[3]	42[a]
North Hoyle (UK)	1350[4]	35[5]	-	20	10	37[4]	60[a]
Scroby Sands (UK)	1250[6]	25[6]	-	20	10	34[6]	58[a]

Table 4.3: Danish and British support payments available to offshore wind

Support scheme	**Payment (£/MWh)**	**Basis**
Renewables Obligation	70 - 80	ROC market + electricity wholesale price (fluctuating). Assumes ROC price of £40 - 45 and electricity at £30 – 35/MWh
Danish offshore wind subsidy for turbines financed by electricity utilities[7]	42	Rates are fixed for 42,000 operation hours at 46 øre/kWh, 36 øre/kWh thereafter. Subsidy avail for 20 years.

Notes:

Exchange rates: £1 GBP = 10.9766 DKK

Discount rate

a. 10% nominal (DTI 2003) and (DTI 2006d)

b. 5% real, assumed to be 7.5% nominal (as quoted in Danish Wind Industry 2003 and by assumption for Horns Rev and Nysted)

c. All costs in this table calculated 'overnight' – for simplicity neglecting interest during construction. DTI 2006 published levelised costs include interests during construction, and on this basis their central estimate of costs is £83/MWh.

Technical data

0. Approximation implied by data published by Danish Wind Industry – see http://www.windpower.org/en/tour/econ/offshore.htm

1. From (Garrad Hassan 2003)

2. From Danish Wind Industry (see above)

3. Operational data. Published by Wind Stats Newsletters (Vols. 18 – 20, 2005 – 2007 – see http://www.windstats.com), quoted figure averaged from the following quarterly data: Winter 2005 (0.57 Horns Rev, 0.5 Nysted), Spring 2005 (0.40, 0.33), Summer 2005 (0.30, 0.27) Autumn 2005 (0.54, 0.4), Winter 2006 (0.45, 0.35), Summer 2006 (0.27, 0.23), Autumn 2006 (0.58, 0.54)

4. npower 2006 report to DTI - http://www.dti.gov.uk/files/file32843.pdf

5. Long run estimate from npower's second report to DTI http://www.dti.gov.uk/files/file32844.pdf.

6. Scroby Sands report to DTI, 2005: http://www.dti.gov.uk/files/file34791.pdf

7. Danish Wind Ministry http://www.ens.dk/sw23781.asp

* O&M costs may be annualised, capitalised or expressed per unit. We have used two conventions here following the relevant studies. In principle each convention can be converted to the other.

4.6 Conclusions and recommendations

The principal issues for policy highlighted in this report pertain to how policies affect investment risk. Policy analysts have traditionally focused on cost related risks to do with technology, but important revenue risks are associated with electricity price movements. These risks may have a fundamental impact on investment. Indeed we have shown that technologies that appear to be attractive in terms of comparative costs may be a highly uncertain investment because of their exposure to various price risks. Moreover, policies that appear appropriate when measured against estimates of levelised cost may not be able to deliver investment because of price risks that are either neglected from analysis or even created through the design of policy. There is a clear need for further research on the relationship between policy, risk and investment. However, the following key issues for policy emerge from this analysis:

1. **Policy needs to actively engage with investment risk.** This means understanding where risk originates and how it affects investment. Policy analysis needs to actively model investment scenarios and incorporate revenue risk, rather than focusing largely on costs.

   Policymakers should develop a 'shadow investment appraisal' model, to test proposed policies against a range of price risks created by electricity markets and policies as well as cost uncertainties related to technology. The model should be open, to allow prospective investors and independent analysts the opportunity to comment on assumptions and parameters. There may be a trade off between model sophistication and transparency. Developing such a model is complex, and requires further research and consultation with investors and policy analysts.

2. **Policy design can affect price risks. The choice between fixed price tariffs and market-based schemes is really a choice about risk allocation.** Policy-makers need to make a judgement about what the risks are and who is in the best position to handle them. For example fixed price schemes or price 'floors' reduce or remove the risks associated with electricity prices falling below a level sufficient to sustain debt servicing. They may, however, expose consumers to greater risks in terms of an uncertain level of total expenditure, and may fail to incentivise developers to reveal true costs. Market schemes allocate more risk to the developer, and could provide greater competitive pressure to reduce costs, but if the risks are too large, the market may simply fail to deliver the investment needed for learning. When defining the nature of revenue support schemes, and deciding between revenue support and capital subsidies, policymakers should weigh the risks created by policies against the potential for market forces to reduce costs. The choice will depend on the specific case being considered, and will include consideration of the state of technical development and the degree of confidence in cost estimates.

Hence there is a 'risk hierarchy' linking policy to technology maturity:

- *Capital subsidies and/or PFI equity stakes are most likely to be appropriate for wholly new technologies emerging from R&D,* and/or for unproven and large scale 'lumpy' investments where there is limited prospect of incremental learning through small scale early commercial units. E.g. CCS and possibly wave power.

- *Fixed price tariff schemes may be most appropriate for initial roll out of emerging technologies;* i.e. those that are demonstrated, but are yet to be used on a large scale, are subject to considerable technology risk and have yet to benefit from extensive 'learning by using'. E.g. offshore wind, also possibly CCS.

- *Market based schemes are generally most suited to proven technologies,* or to incentivise least cost means for short term carbon reduction. E.g. onshore wind.

  Policies that are designed to support investment in high risk, early stage options will be most effective if in addition to providing remuneration they also seek to reduce or remove revenue risks associated with price volatility. Very early stage options may benefit from capital subsidies, as these can also mitigate technology risks.

3. **Information about costs and performance for new technologies is often revealed through market activity.** Policymakers may have poor information, and policies that rely on such information may be subject to both appraisal optimism and deliberate gaming by market participants. Where information is scarce, investments are needed to reveal it; policy may need to pay for this, overcoming the option value associated with waiting, therefore:

   Policy must be prepared to make explicit provision for premium payments to 'first movers', since these higher risk investors will reveal cost and risk data for the wider market.

   Policymakers should also undertake qualitative assessments related to corporate strategy and the potential for appraisal optimism and gaming.

To the extent to which it is feasible to do so government should build a shared understanding of policy goals, as this will shape expectations, an important driver of strategic investment in industry.

These conclusions and recommendations seek to equip policymakers to respond to the overarching conclusion of this investigation of policy and investment risks:

If policy goals depend upon investment in particular technologies then policy must be designed with investment risks, not just technology costs, in mind. This is not because concern with costs is wrong but because costs are only one part of the equation. Policymakers cannot determine which technologies get built, they can only provide incentives to encourage a diverse and/or low carbon generation mix. And if incentives are to deliver such investment, they must first understand how investment decisions are made.

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Annex 1: Project team, expert group and contributors

Project team

The team was drawn from ICEPT at Imperial College, with inputs from experts from the Business Council on Sustainable Energy, the RIIA and the London Business School, operating under the management of ICEPT, who run the TPA function of the UKERC. The team is as follows:

Director: Jim Skea, UKERC Research Director
Project Manager: Robert Gross, TPA Manager
Authors: Robert Gross, Phil Heptonstall, William Blyth
Contributors: Dennis Anderson, Derek Bunn, Kirsty Hamilton, Adam Hawkes
Researcher: Lazaros Exarchakos

Expert group

The expert group was chosen for its combination of energy industry, finance, academic and policy expertise. It met twice during the course of the project, providing input to the initial framing of the issues, literature search, synthesis and drafting. Several members of the group made additional contributions in the form of reference provision, invited submissions on particular issues and through bilateral discussions and brainstorming on specific areas of expertise.

Shimon Awerbuch (SPRU)
William Blyth (RIIA Associate Fellow)
Andy Boston (E.ON)
Adrian Gault (DfT)
Kirsty Hamilton (Business Council for Sustainable Energy & RIIA Associate Fellow)
Nick Hartley (Oxera)
David Kennedy (DTI)
Peter Pearson (Expert Group Chair), ICEPT
Richard Ploszek (RAEng)
Ian Temperton (Climate Change Capital)

Peer reviewers

Aviel Verbruggen (University of Antwerp)
Tony White (Climate Change Capital)

Industry interviewees

Ravi Baga (EDF Energy)
Jon Boston (RWE npower)
Andy Boston (E.ON)
John Campbell and Jamie Wilson (Scottish Power)
Alan Moore (former CEO National Wind Power and former BWEA Chairman)
Rhys Stanwix (Scottish and Southern Energy)
Simon Wills (Centrica)

Annex 2: Working papers commissioned for this project

1. Electricity Generation Costs and Investment Decisions: An Historical Perspective (Dennis Anderson)
2. Factoring Risk into Investment Decisions (William Blyth)
3. Investment: Risk, return and the role of policy (Kirsty Hamilton)
4. A Review of Electricity Unit Cost Estimates (Phil Heptonstall)

Note: These working papers will be published on the UKERC website.

Annex 3: Search terms and full list of documents revealed by literature search for working paper 4

Box A3.1: Databases and other research sources for working paper 4

Annual Reviews
Elsevier 'Science Direct'
'ESTAR' (British Library)
IEEE Explore
IEE Inspec
ETDA (Energy Technology Data Exchange)
IEA documents and publications
DTI documents and publications
EU documents and publications
US DoE documents and publications
Industry associations (e.g. World Nuclear Association, World Coal Institute)
Research groups (e.g. SPRU, ICEPT, UMIST, Environmental Change Institute, Strathclyde University)
Energy consultancies (e.g. Future Energy Solutions, Oxera, Ilex)
Specific recommendations from UKERC members
Google

Search terms

Unit costs + electricity generation
Unit costs + power generation
Unit costs + electricity
Unit costs + electricity prices
Unit costs + electricity generation mix

Levelised costs + electricity generation
Levelised costs + power generation
Levelised costs + electricity
Levelised costs + electricity prices
Levelised costs + electricity generation mix

Future costs + electricity generation
Future costs + power generation
Future costs + electricity
Future costs + electricity prices
Future costs + electricity generation mix

Modelling future costs + electricity generation
Modelling future costs + power generation
Modelling future costs + electricity
Modelling future costs + electricity prices
Modelling future costs + electricity generation mix

Risk + electricity generation
Risk + power generation
Risk + electricity
Risk + electricity prices
Risk + electricity generation mix

Cost projections + electricity generation
Cost projections + power generation
Cost projections s + electricity
Cost projections + electricity prices
Cost projections + electricity generation mix

Learning curves + electricity generation
Learning curves + power generation
Learning curves s + electricity
Learning curves + electricity prices
Learning curves + electricity generation mix

Projected costs + electricity generation
Projected costs + power generation
Projected costs + electricity
Projected costs + electricity prices
Projected costs + electricity generation mix

Portfolio effects + electricity generation
Portfolio effects + power generation
Portfolio effects + electricity
Portfolio effects + electricity prices
Portfolio effects + electricity generation mix

Full list, sorted by author and year – see Working Paper 4 for details of how these were ranked for relevance.

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DTI	2006	The Energy Challenge	94
DTI	2006	Quarterly energy prices	71
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Author	Year	Title	Ref
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Annex 4: Summary of key points emerging from industry interviews

As part of the Investment Decisions project, the UKERC TPA team undertook a series of semi-structured interviews with representatives from the UK electricity industry. These interviews were conducted on a non-attributable basis. This annex summarises the main themes discussed together with the broad messages which emerged.

Industry interviewees

Ravi Baga (EDF Energy)
Jon Boston (RWE npower)
Andy Boston (E.ON)
John Campbell and Jamie Wilson (Scottish Power)
Alan Moore (former CEO National Wind Power and former BWEA Chairman)
Rhys Stanwix (Scottish and Southern Energy)
Simon Wills (Centrica)

Headline points

The relevance, or otherwise, of unit cost estimates to investment decisions

Government and academic estimates of levelised costs of different generation options are of limited relevance to investment by electricity generators/suppliers.

Companies tend not to undertake their own analyses of levelised costs, indeed it would be unusual to see a levelised cost estimate in an investment appraisal. They may be used to provide a 'first order' comparison of different technologies.

Government estimates might be more accurate than they used to be but they still cannot capture all the issues that drive investment. However, they are interesting and important to the extent that they can shape policy and market intervention mechanisms.

The degree to which government incentives effectively address the drivers of commercial investment decisions

There is a degree of disconnect between policies and the realities of investment decisions. One example cited was the tension between the support available under the RO and the barriers presented by the planning and consenting process.

Whilst policymakers may have some understanding of the drivers for investment, this is not reflected in policies, in particular the impact of risk on the investment process. Governments should not be surprised that market based instruments create winners and losers because that is what markets do. Similarly, policymakers should not be surprised if markets create a period of high returns since this is what is required to attract new investment. Several interviewees expressed concern that policymakers appeared to be minded to 'change the rules' before market mechanisms (particularly the RO) had been given a chance to work.

The effect on investor confidence of 'meddling' with policy instruments should not be underestimated. Several interviewees expressed concern about the frequency with which the Renewables Obligation has been amended. There is a trade off between the need to amend policies that are not delivering, and avoiding a perception that the policy environment is of itself risky, due to a propensity for 'rule changing'.

Risk assessment, finance and investment decisions

Companies and investors are interested in the IRR and NPV of prospective investments under a range of scenarios for electricity price, volume of sales/utilisation and levels of support from policy (e.g. ROC price projections).

Companies are likely to explore sensitivity to a period of low electricity prices and/or low ROC and/or low ETS prices. This price risk assessment will affect the relative attractiveness of different investments. In particular it can affect the amount of debt that can be attracted to a particular project, since debt coverage must be sustained when revenues are low.

Finance for new power stations needs to be highly geared – a typical debt/equity ratio might be 80/20. Since this is difficult or impossible to secure for riskier projects, such projects are unlikely to go ahead unless they bring additional benefits – see below. Relatively small projects might be financed 'on balance sheet', but it is not easy for companies to finance large projects against their wider asset base and such projects must be able to 'stand alone' in terms of risk and return.

The role of strategic considerations in investment decisions

Investment decisions are not informed by NPV/IRR calculations alone. The impact of a particular investment on a company's portfolio mix, the strategic value, the degree of fit with the organisations' core competencies, may all also be considered.

Some projects may have a particularly favourable (or unfavourable) impact on a brand image, or may be avoided if the 'management overhead' of delivering the project is considered too high. Projects may also be avoided if they conflict with corporate governance standards – for example on social responsibility.

Projects may be considered more favourably if they allow organisations to acquire knowledge about emerging technologies, or they fit with perceptions of government aspirations (because it is anticipated that this will drive future policies).

The extent to which risks can be represented in the analysis which underpins investment decisions

Most but not all risks can be represented in scenarios or other forms of analysis. It is particularly difficult to do so where there is a complex mix of interrelated risks. In such circumstances even very sophisticated modelling can be of limited value and qualitative judgements are inevitably required.

Political and geopolitical risks are very hard to represent meaningfully in quantitative analysis.

The availability and accuracy of information about costs and risks

Equipment manufacturers, generating companies and industry consultants generally have the best information about actual costs.

For emerging technologies cost and risk information may not be readily available to any market participants and in these circumstances it may be that companies have to invest in projects so that information can be revealed, or purchase options to invest in projects so that decisions can be made when better information is available.

Revealing such information may incur additional costs, for which investors need to see a return, or they will wait for better information to become available.

Policymakers need to understand that where there is uncertainty over costs it is often more likely that costs will turn out to be higher than anticipated – not lower.

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