Electricity cost estimates: How accurate are they, and are they fit for purpose in policy analysis?

A thesis submitted for the degree of Doctor of Philosophy

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Acknowledgements

Firstly I would like to thank my supervisor Rob Gross for his guidance and support, and his continuing encouragement for me to carefully consider the evidence and think more deeply about the implications before forming conclusions. I would also like to thank my other colleagues who, together with Rob and I, co-authored the UKERC Technology and Policy Assessment research reports and associated journal papers that relate most closely to the subject of this thesis: Chiara Candelise, Arturo Castillo Castillo, Tim Cockerill, Philip Greenacre, Grant Harris and Felicity Jones. Their cooperation during those projects and generous assistance in developing my understanding are very much appreciated. Thanks also to Paul Westacott and Ajay Gambhir for helping me to understand the development of PV technologies and policy. Particular thanks go to Jamie Speirs for his continued practical support. My final thanks go to Gill Hardy for proof reading drafts of the thesis, and for providing the love, support and encouragement that allowed me to finish this work.
Declaration of originality
I declare that this thesis: ‘Electricity cost estimates: How accurate are they, and are they fit for purpose in policy analysis?’ is my own work. Any material presented in this thesis that is not my own is appropriately cited and referenced.

Philip Heptonstall, April 2015

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NE/H013326/1

Much of the data collection work was undertaken as part of the research effort for UK Energy Research Centre (UKERC) Technology and Policy Assessment (TPA) projects. This thesis also draws upon several research outputs which I have co-authored, including the five UKERC research reports, seven journal papers, one UKERC working paper, and one book chapter identified below. Chief among these were:
UKERC TPA Project No. 6, which investigated the costs of offshore wind in the UK and produced the research report ‘Great Expectations: the cost of offshore wind in UK waters – understanding the past and projecting the future’ (Greenacre et al. 2010), and a journal paper based on elements of the work (Heptonstall et al. 2012).

UKERC TPA Project No. 9 which researched the history of cost estimates for a range of electricity generation technologies and analysed the methodologies that have been used in the past to estimate and forecast costs and produced the research report ‘Presenting the Future: An assessment of future generation costs estimation methodologies in the electricity generation sector’ (Gross et al. 2013), and a journal paper which was in part informed by that work (Harris et al. 2013).

As is the case with most UKERC TPA work, these two projects were a collaborative effort involving a small team of researchers. For the offshore wind project (UKERC TPA Project No. 6) I carried out the tasks involving the reviewing, cleansing, normalisation and plotting of the data, and led the work on the costs sensitivity analysis and the resultant journal paper. The identification of potential data sources, the qualitative assessment of the drivers of costs and the drafting of the main project report was carried out jointly by myself and my colleagues Philip Greenacre and Robert Gross.

The project that analysed the history of electricity cost estimates and forecasts for several different generation technologies and the methodologies that have been used to arrive at those estimates and forecasts (UKERC TPA Project No. 9) was also carried out by a team, although in this case production of the technology-specific data was assigned to team members (see the ‘Data collection’ section in Chapter 2). In addition to producing the offshore wind and nuclear costs data, my tasks were to manage the costs data historical currency exchange rate
conversion process (to ensure consistency between technology datasets), consolidate and normalise the data from the six case studies, build the summarised datasets and charts, and review and summarise the economic and policy literature underpinning cost estimates and their use. Drafting, review and revision of the final synthesis report was undertaken by myself, Philip Greenacre and Robert Gross. The work on the nuclear case study that formed one of the inputs to the UKERC 2013 report also informed a journal paper exploring the potential for increases in costs for this technology (Harris et al. 2013). The levelised costs analysis for that paper was carried out by my colleague Grant Harris. I reviewed the levelised cost analysis, including running the assumptions through an alternative levelised cost model to confirm the results, with the final paper drafting being undertaken by Grant Harris and I.

The nature of the PV case study in this thesis differs to the offshore wind and nuclear case studies since it first draws upon the extensive literature on the evolution of PV costs, including the working paper (Candelise 2012b) produced by my colleague Chiara Candelise for the UKERC 2013 report, to inform a review of the key issues in the history of estimates and forecasts for this technology. This review is used to provide the context and background for an examination of the (frequently changing) UK policy to encourage PV deployment, which forms the latter part of the PV case study in this thesis.

My work on other UKERC projects which has helped to inform this thesis includes research into the investment proposition for power generation with carbon capture and storage in the UK (Watson et al. 2012, Boot-Handford et al. 2014), work on the generic challenges posed by investment in power generation and the limitations of cost estimates commonly used in policy analyses (Gross et al. 2007, Heptonstall 2007, Gross et al. 2010), and the additional costs and wider implications of integrating intermittent power generation technologies into electricity systems (Gross et al. 2006, Gross and Heptonstall 2008, Skea et al. 2008, Steggals
et al. 2011). Lastly, my work for (Gross and Heptonstall 2010) contributed to my understanding of the history of UK policy with regard to electricity generation from renewable sources.
Abstract
This thesis is concerned with the history of electricity generation costs, how they have changed over time, and the accuracy of forecasts of future costs. These costs are a critical input to policy, yet both estimates and forecasts have frequently proved to be wrong or have changed dramatically over relatively short timescales. The thesis presents evidence from three technology case studies (offshore wind, nuclear power and solar PV), supported by a review of the range of cost measures used in the economic, business and policy spheres, and the methodologies used to understand the factors that bear upon cost trajectories and approaches to forecasting future costs. Drawing upon the evidence from the case studies, the thesis examines how cost forecasts have changed over time, the (frequently wide) range of forecasts, the sources of errors, and how policy has responded to uncertainty and changes in both cost estimates and forecasts.

The findings address the limitations of commonly used cost metrics, challenge assumptions that costs will necessarily fall, discuss the meaning of regulatory certainty in the face of uncertain future costs, and emphasise the importance of context (why estimates are commissioned, and by whom, and also who they are undertaken by). The evidence suggests that the co-presentation and use of estimates and forecasts for technologies with very different technical and financial characteristics implies significantly more comparability between them than is wise, and can convey the message that the underlying uncertainties are similar, when in fact the reasons may be fundamentally different in character. This highlights how important an understanding of technology characteristics is when deriving estimates and forecasts, not simply because those characteristics bear upon the numerical values of the results, but because of the influence they have on the nature of the uncertainty of those results.
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<tr>
<td>AACE</td>
<td>Association for the Advancement of Cost Engineering</td>
</tr>
<tr>
<td>AFC</td>
<td>Average Fixed Cost</td>
</tr>
<tr>
<td>a-Si</td>
<td>amorphous silicon</td>
</tr>
<tr>
<td>ATC</td>
<td>Average Total Cost</td>
</tr>
<tr>
<td>AVC</td>
<td>Average Variable Cost</td>
</tr>
<tr>
<td>BERR</td>
<td>Department for Business, Enterprise and Regulatory Reform</td>
</tr>
<tr>
<td>bn</td>
<td>billion</td>
</tr>
<tr>
<td>BoS</td>
<td>Balance of System</td>
</tr>
<tr>
<td>CAGR</td>
<td>Compound Annual Growth Rate</td>
</tr>
<tr>
<td>CAPM</td>
<td>Capital Asset Pricing Model</td>
</tr>
<tr>
<td>CCC</td>
<td>Committee on Climate Change</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon Capture and Storage</td>
</tr>
<tr>
<td>CdTe</td>
<td>cadmium telluride</td>
</tr>
<tr>
<td>CfD</td>
<td>Contract for Difference</td>
</tr>
<tr>
<td>CIGS</td>
<td>copper indium gallium di-selenide</td>
</tr>
<tr>
<td>CO$_2$</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>c-Si</td>
<td>crystalline silicon</td>
</tr>
<tr>
<td>DECC</td>
<td>Department of Energy and Climate Change</td>
</tr>
<tr>
<td>DTI</td>
<td>Department of Trade and Industry</td>
</tr>
<tr>
<td>EBPP</td>
<td>Evidence-Based Policy and Practice</td>
</tr>
<tr>
<td>EMR</td>
<td>Electricity Market Reform</td>
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<tr>
<td>EPC</td>
<td>Engineering, Procurement and Construction</td>
</tr>
<tr>
<td>EPR</td>
<td>European Pressurised Reactor</td>
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<tr>
<td>FCR</td>
<td>Fixed Charge Rate</td>
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<tr>
<td>FID</td>
<td>Final Investment Decision</td>
</tr>
<tr>
<td>FiT</td>
<td>Feed-in Tariff</td>
</tr>
<tr>
<td>FOAK</td>
<td>First-of-a-kind</td>
</tr>
<tr>
<td>GBP</td>
<td>GB Pounds (Sterling)</td>
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<td>GDA</td>
<td>Generic Design Assessment</td>
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<tr>
<td>Abbreviation</td>
<td>Full Form</td>
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<tr>
<td>GW</td>
<td>Gigawatt</td>
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<tr>
<td>IDC</td>
<td>Interest During Construction</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>kW</td>
<td>kilowatt</td>
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<tr>
<td>kWh</td>
<td>kilowatt-hour</td>
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<tr>
<td>LCF</td>
<td>Levy Control Framework</td>
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<tr>
<td>LCOE</td>
<td>Levelised Cost Of Energy</td>
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<tr>
<td>LR</td>
<td>Long-run</td>
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<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
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<tr>
<td>LWR</td>
<td>Light Water Reactor</td>
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<tr>
<td>m</td>
<td>million</td>
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<tr>
<td>MC</td>
<td>Marginal Cost</td>
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<tr>
<td>MCC</td>
<td>Marginal Cost of Capital</td>
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<td>MFEC</td>
<td>Multi-Factor Experience Curve</td>
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<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt-hour</td>
</tr>
<tr>
<td>NEA</td>
<td>Nuclear Energy Agency</td>
</tr>
<tr>
<td>NETL</td>
<td>National Energy Technology Laboratory</td>
</tr>
<tr>
<td>NOAK</td>
<td>n&lt;sup&gt;th&lt;/sup&gt;-of-a-kind</td>
</tr>
<tr>
<td>NRC</td>
<td>(US) Nuclear Regulatory Commission</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Operations and Maintenance</td>
</tr>
<tr>
<td>OECD</td>
<td>Organisation for Economic Co-operation and Development</td>
</tr>
<tr>
<td>PIU</td>
<td>Performance and Innovation Unit</td>
</tr>
<tr>
<td>PTC</td>
<td>Production Tax Credit</td>
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<tr>
<td>PV</td>
<td>Photovoltaics</td>
</tr>
<tr>
<td>PWR</td>
<td>Pressurised Water Reactor</td>
</tr>
<tr>
<td>R&amp;D</td>
<td>Research and Development</td>
</tr>
<tr>
<td>RD&amp;D</td>
<td>Research, Development and Demonstration</td>
</tr>
<tr>
<td>REA</td>
<td>Rapid Evidence Assessment</td>
</tr>
<tr>
<td>RO</td>
<td>Renewables Obligation</td>
</tr>
<tr>
<td>ROC</td>
<td>Renewables Obligation Certificate</td>
</tr>
<tr>
<td>SFEC</td>
<td>Single-Factor Experience Curve</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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</tr>
<tr>
<td>SR</td>
<td>Short-run</td>
</tr>
<tr>
<td>TC</td>
<td>Total Costs</td>
</tr>
<tr>
<td>TFC</td>
<td>Total Fixed Costs</td>
</tr>
<tr>
<td>TFEC</td>
<td>Two-Factor Experience Curve</td>
</tr>
<tr>
<td>TPA</td>
<td>Technology and Policy Assessment (a research team within the UKERC)</td>
</tr>
<tr>
<td>TVC</td>
<td>Total Variable Costs</td>
</tr>
<tr>
<td>UCRF</td>
<td>Uniform Capital Recovery Factor</td>
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<tr>
<td>UKERC</td>
<td>UK Energy Research Centre</td>
</tr>
<tr>
<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
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1 Introduction

1.1 Introduction

This thesis is concerned with the history of electricity generation costs, how they have changed over time, and the accuracy of forecasts of future costs. The term *cost estimates* is used here to define estimates for notional plants to be built at the time the estimate was made, and the term *cost forecasts* is used here to define projected costs for notional plants to be built at some point in the future, relative to the time when the forecast was made\(^1\).

Electricity costs are a critical input to policy analysis, and have a strong influence over both the overall direction and goals of policy and the detail design of policy to achieve those goals, yet both estimates and forecasts have frequently proved to be wrong or have changed dramatically over relatively short timescales (Gross *et al.* 2013). Against this backdrop, achievement of the UK Government’s decarbonisation targets is forecast to create significantly increasing demand for renewable and low carbon electricity generation, since the relative cost and difficulty of decarbonising other sectors of the economy means that it is expected that electricity generation will have to bear a proportionally greater share of this target than other sectors, coupled in the longer term with the increased electrification of those other sectors (CCC 2008, DECC 2011f).

Adopting a UK focus, the thesis examines the history of electricity cost estimates and forecasts, identifying when and why they have turned out to be wrong or have diverged from previously forecast trajectories, and discusses the implications for policy makers, to address the central question: *How accurate are electricity cost estimates and forecasts, and are they fit for purpose in the context of policy analysis?*

---

\(^1\) The potential for semantic confusion over the terminology used to describe costs is discussed in more detail in Chapter 2.
A number of subsidiary questions flow from the overarching question, including:

- What is the role of electricity cost estimates in policy?
- What methods and metrics\(^2\) are used to estimate and forecast electricity costs, and what are their strengths and weaknesses?
- What are the most important aspects or issues of costs which are not typically included in those metrics commonly used in policy?
- To what extent have technology costs diverged from previous cost estimates and forecasts, and how has this differed between generation technologies?
- How has policy responded to uncertainties over cost estimates and forecasts?

There are therefore two strands to the analysis underpinning this thesis – the first is concerned with how the limitations of commonly used cost metrics bear upon their usefulness, and the second is concerned with how the degree of accuracy of those metrics may influence their use in policy making. A key challenge for policymakers is how to develop approaches and mechanisms that are robust in the face of these uncertainties. The overall aim of this thesis is to inform and contribute to the debate as to how policymakers should respond to this challenge.

1.2 The use of power generation costs in policy

It is clear that electricity cost estimates and forecasts have played a central role in the policy formulation process, aiding in the identification of viable options and the assessment of the economic impact of a range of electricity generation mixes e.g. (DTI 2003, DTI 2006, DTI

\(^2\) The word ‘metric’ has its roots in the decimal measuring system but is now used across a wide range of disciplines and spheres of activity, including its use here as a collective noun for quantitative measures of costs.
2007, HM Government 2008, DECC 2011f). Cost data are also at the core of international publications such as the IEA’s World Energy Outlook series e.g. (IEA 2004, IEA 2010b, IEA 2014c), and key inputs to influential reports such as the IEA’s Experience Curves for Energy Technology Policy (IEA 2000). The different cost characteristics of the range of electricity generation technologies are also essential to analyses undertaken using cost-optimising energy system models which have been used extensively to create scenarios of future UK energy systems. The outputs and the insights gained from such scenario modelling exercises feature prominently in policy documents such as the White Papers and Energy Review referred to above, and in other inputs to policy formulation (Stern 2006, HM Government 2009, UKERC 2009, CCC 2010).

The perception of opportunities for future cost reductions in low carbon electricity generation technologies has played a key role in analyses of the affordability of achieving CO₂ emissions reduction targets. More specifically, assumptions over technology ‘learning rates’³ and the resultant cost reductions has led to the conclusion that CO₂ emissions can be abated at relatively low cost and that policy is required to drive deployment so that those cost reductions can be realised (Stern 2006, IEA 2010b, CCC 2011b). The IEA’s World Energy Outlook, for example, emphasises the role of government policy action in influencing the future energy landscape and argues that increasing deployment levels and achieving the cost reduction aspirations of renewables and carbon capture and storage (CCS) technologies will be heavily reliant on strong government support (IEA 2010b). The Stern Review makes a similar point, arguing that ‘the ambition of policy has an impact on estimates of cost’ (Stern 2006) pg. 247.

³ The term used to describe the relationship between increasing production and deployment of a technology which leads to learning how to reduce the unit cost of that technology. This, along with the closely related term of ‘experience curve’, is discussed in more detail in Chapter 4.

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Closely aligned to this is the importance of judgements and assessments that suggest costs will fall over time, and the implications for the economy-wide costs of reducing CO\textsubscript{2} emissions and, in particular, the costs of decarbonising the electricity sector. There is, therefore, an important link between cost analyses and government interventions with estimates of costs helping to set the direction and shape of policy, and policy also influencing costs. Where analysis is investigating possible government intervention and the design of potential policies, three factors in particular need to be addressed. These are: firstly, whether there is a rationale for intervention in terms of policy goals; secondly, the degree of financial support needed; and thirdly, an assessment of the most appropriate mechanism to deliver on policy goals (Gross et al. 2007). Cost estimates and forecasts represent key inputs to any analysis which addresses these questions.

Forecasts of the future trajectory of costs, through engineering assessment and especially via experience curve\textsuperscript{4} analysis, are also heavily influenced by contemporary and historic costs data. Many commentators, including the International Energy Agency (IEA), suggest that experience curves (extrapolations of existing data combined with assumptions about deployment rates) offer ‘powerful tools for formulating low-cost strategies to reduce and stabilise CO\textsubscript{2} emissions’ and ‘to set targets and design measures to make new technologies commercial’ (IEA 2000) pg. 9. Importantly, they can (at least in theory) be used to show how much technology deployment is required in order to achieve a specific cost level at some point in the future (ibid.).

Views of the likely future of electricity costs are therefore to a very considerable degree shaped by data from the past and present, and these views feed into the formulation of

\textsuperscript{4} See Chapter 4 for a detailed discussion of engineering assessment and experience curve analyses.
policies which then go on to influence future cost out-turns. For example, cost estimates played a central role in the design of the 2002 Renewables Obligation (RO), and the UK Government Department of Trade and Industry’s (DTI) ‘resource cost curves’ were instrumental in defining both the level of the Obligation itself and the RO buy-out level (Gross et al. 2007). More recently, the Committee on Climate Change’s assessment of optimal decarbonisation strategies, which form part of its advice on the UK Carbon Budgets, is based on considerations of technology costs (along with carbon price, demand growth, and capital stock turnover), and the 2011 assessment (CCC 2011b) used cost forecasts to construct scenarios out to 2020 and 2030.

There are a number of characteristics of the electricity generation sector that create additional challenges for policymakers and those actors who policymakers may wish to influence such as power generation companies, project developers and the equipment manufacturing, installation and maintenance supply chain. The electricity generation sector is characterised by very large investment requirements and very long-lived assets. This means that, to be effective, policy must provide an investment climate that is conducive to attracting these very large sums (Blyth et al. 2014), and that once investment is made, it may be ‘locked-in’ to the generation mix for, potentially, several decades (Chignell and Gross 2013). This means that the uncertainties or errors in estimating and forecasting electricity costs which are discussed below can have large, long-term financial implications for electricity bill payers and/or taxpayers.

1.3 Problems with estimating and forecasting power generation costs
Since the mid-2000’s cost estimates for many large scale electricity generation technologies have increased significantly (Heptonstall et al. 2012). To illustrate this, Figure 1.1 below
brings together the LCOE (Levelised Cost of Energy\textsuperscript{5}) 2011 estimates produced for the UK Government by Parsons Brinckerhoff and Arup (Arup 2011, Parsons Brinckerhoff 2011) and the corresponding estimates made for the analysis underpinning the UK Government’s 2006 Energy White paper (DTI 2006).

Whilst estimates would inevitably be expected to change over time as technology costs responded to real technical and economic conditions, what the data represented in Figure 1.1 highlights is the difficulty facing policy makers where there is both a considerable range of technology cost estimates \textit{at the time that those estimates were made} (represented by the wide ranges associated with each estimate), and uncertainty over \textit{how those costs will change over time} (represented by the differences between the 2006 and 2011 estimates for each of the technologies shown below).

A further difficulty for policymakers is that estimates for notional plants to be built at the time the estimates are made may represent differing aspects of uncertainty depending on the technology. For example, the capital costs of a CCGT (Combined Cycle Gas Turbine) plant can be known with some accuracy since there is a relatively transparent market with multiple equipment manufacturers – so the range of cost estimates largely reflects different assumptions over fuel and CO\textsubscript{2} emissions costs. By contrast, estimates for nuclear plants would be expected to have a much wider range of capital costs because there is no recent track record or market prices on which to base the estimates – so it is prudent for the estimates produced for policymakers to explore the effects of different assumptions over those capital costs.

\textsuperscript{5} See Chapter 3 for a detailed discussion of the LCOE approach to the representation of costs.
The comparison in Figure 1.1 also reinforces the point that costs can change considerably even over relatively short periods. For example, over the five years separating these two sets of estimates, CCGT costs had risen by approaching 80%, nuclear by around 75%, and onshore wind by over 40% (on an inflation adjusted basis, using the midpoint of the central ranges). The wide range of cost estimates, and the largely unexpected cost increases within the last decade emphasise the considerable uncertainties in accurately forecasting the future trajectory of those costs.

In addition to these uncertainties, the cost metrics commonly used in policy analyses such as the LCOE (Levelised Cost of Energy) have a numbers of limitations which potentially affect their usefulness (Gross et al. 2010). These can be broadly categorised as limitations in extent.

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6 The cost analyses on which this chart is based typically calculate a range of levelised costs based on a central set of assumptions and an extended range based on wider variations in the input parameters. In this chart, the former set is represented in the central blocks and the latter set in the black lines extending from each block. A more detailed explanation of what these ranges represent is provided in Section 8.2.
(such as the inability to capture all economic externalities), limitations in methodology (such as determination of the appropriate discount rate or the assumed plant load factor), and limitations in applicability (such as the degree to which they are able to indicate how market participants will act). Key issues remain over how these limitations can be addressed, and in determining the appropriate policy response. This thesis will explore these uncertainties and the implications for policy analysis and policymakers.

1.4 Thesis structure

Chapter 2 of this thesis describes the approach adopted for the research, the methodology used to collect the costs data and explains how the case study approach helps to answer the research questions set out in this chapter.

Chapter 3 explains the range of cost measures used in the economic, business and policy spheres, and provides a critique of those measures which feature most prominently in electricity policy analyses. Chapter 3 also deals with a further aspect of cost uncertainty (and one which is becomingly increasingly important as the electricity generation mix changes) – that of how the additional costs associated with variable renewable generation are most appropriately represented in cost estimates.

Chapter 4 reviews the very rich academic literature that discusses how costs change over time, the methodologies used to understand the factors that bear upon cost trajectories, and approaches to forecasting future electricity generation costs.

Chapters 5, 6 and 7 present the findings from the technology case studies, explaining the history of cost estimates for each of the electricity generation technologies considered
(offshore wind, nuclear and PV respectively). These chapters also discuss how cost forecasts have changed over time, the (frequently wide) range of forecasts, and how policy has responded to uncertainty and changes in both cost estimates and forecasts.

Underpinned by the reviews in Chapters 3 and 4, Chapter 8 discusses the findings from the case studies in Chapters 5, 6 and 7. Finally, Chapter 9 draws together the key overall conclusions that emerge from the discussion.
2 Approach and methodology

2.1 Introduction
The research objectives identified in Chapter 1 are addressed through a set of electricity generation technology case studies (see Chapters 5, 6 and 7). These case studies draw upon electricity cost data and historical narratives, with costs data sources and qualitative assessments of the history of costs identified through a targeted systematic review. To properly understand the role of cost estimates in policy, a review of the academic and grey literature that addresses the economic theory underpinning electricity cost estimates and their application in a policy context was also undertaken, as well as a review of the academic literature underpinning theories of technology learning and cost reduction (see Chapters 3 and 4 respectively). This chapter describes the systematic review and case study approaches (see Sections 2.2 and 2.3 respectively), the data gathering and consolidation exercise (see Section 2.4), and discusses why these approaches were adopted.

2.2 The systematic review approach
To collect the costs data and qualitative history for each technology in the case studies, a targeted systematic review approach was adopted. Whilst the systematic review methodology has its roots in the field of medical research and the concept of Evidence-Based Policy and Practice (EBPP), the UKERC Technology and Policy Assessment (TPA) research team have adapted the approach so that it can be used to address a range of questions in the energy policy sphere (Sorrell 2007, UKERC 2012).

The adapted approach involves the careful specification of search terms (including a clear description of the Boolean logic used to combine multiple terms) and setting out in advance the journal databases and other potential evidence sources. Potential items of evidence (for
example a journal paper or report in the grey literature) are then screened, typically on the basis of the document title and abstract to eliminate any clearly irrelevant sources. The remaining set of evidence items is then inspected, categorised, aggregated, summarised and synthesised as required to address the research question. As Sorrell noted in his 2007 paper, successful application of the systematic review approach is not always practical, which is why the TPA research team apply the following criteria to potential research questions:

- Does the question reflect the concerns of users?
- Is the question relevant to the current energy policy debate and/or the objectives of the UKERC and UK energy policy?
- Are there important areas of conflict or confusion that a TPA assessment could help overcome?
- Can the question be made sufficiently concise to allow it to be addressed within the resource constraints?
- Is the question amenable to a synthesis assessment based on existing evidence? For example, is the question sufficiently tightly defined? Is an adequate evidence base both available and accessible?

(UKERC 2012)

In practice, the TPA research team typically adopt a hybrid approach that involves a targeted systematic review element where it is applicable and practical, combined with other more traditional analysis approaches as required. This hybrid approach was adopted for the TPA projects which inform this thesis (Greenacre et al. 2010, Gross et al. 2013). One of the drawbacks of the systematic review approach is that it is relatively time-consuming, which has recently led the TPA research team to investigate how the approach could be further
adapted to condense the time taken, whilst still retaining the important elements of the approach. This further adaptation is inspired by the increasing attention being paid in the literature to the technique of Rapid Evidence Assessment (REA) (Civil Service 2014, Collins et al. 2014).

2.3 The case study approach

A case study approach was adopted because it can answer the question ‘What is going on?’ (Bouma and Atkinson 1995) pg. 110, and ‘the case study method allows investigators to retain the holistic and meaningful characteristics of real-life events’ (Yin 2009) pg. 4. Yin goes on to explain that there are three key conditions that should be considered when selecting an appropriate research method, which are:

- The form of the question being asked by the research.
- The degree of control that the researcher has over the events being researched.
- The extent to which the focus is on contemporary events.

Of these three, Yin proposes that the first is the most important, and suggests that the case study method is most applicable where the following three conditions are met:

- The research is attempting to answer how and why events occurred (a point also supported by (Ellet 2007).
- Where the researcher has no control over those events.
- Where the focus is on contemporary events.
Applying these three conditions to this thesis, it is clear that the first two are aligned. The third condition (of focus on contemporary events) is partly aligned since the thesis examines both contemporary data and events but also historic data and events. However, Yin acknowledges that there is a considerable degree of overlap between research methods, and it is clear that the ‘descriptive history’ method could also have been used, which fits with Yin’s observation that there are ‘situations in which two methods might be considered equally attractive’ (ibid. pg. 13). In practice, the approach adopted in this thesis also has elements of a longitudinal comparison (Bouma and Atkinson 1995) since it analyses how technology-specific data has changed over time, and compares between different technologies.

There is a rich literature on case study methods and approaches e.g. (Easton 1992, Ellet 2007, Yin 2009) and it is useful to recognise two particularly important principles. The first is to ensure that there is a direct link between the research questions, sources of evidence and the research findings – what Yin calls the ‘Chain of Evidence’ (Yin 2009) pg. 122. The second is concerned with the quality of the analysis by ensuring that the evidence set is as complete as possible, that alternative interpretations of the case studies evidence are recognised, that the analysis should focus on the most important issue or issues, and that the researcher undertaking the case study draws upon and demonstrates their existing knowledge of the subject matter (ibid.).

A case study approach was therefore selected as being the most appropriate for this thesis since it is concerned with the complex interaction of contemporary and historic costs data, the evolution of cost forecasts, and the policy responses to changing estimates and forecasts. Taken together, these characteristics of the research subject and material appear to be closely aligned with those circumstances under which a case study approach is likely to be effective.
The three case studies were selected to examine policy responses to unexpected rising costs (in the case of offshore wind), policy ambitions in the face of uncertainty and contestation over costs (in the case of nuclear power), and the reaction to costs falling more quickly than anticipated by many forecasts (in the case of solar PV). The case studies were informed by qualitative assessments of the history of costs for each technology, exploring the reasons why costs estimates and forecasts have changed over time. As described previously, the case studies are supplemented by a discussion of the wider issues surrounding cost estimates, such as their usefulness as a guide to real investment decisions and the challenges of correctly apportioning the additional system costs imposed by electricity generation from variable renewable resources.

The case studies draw their quantitative evidence on costs from publicly available analyses (see Section 2.4 below) and their qualitative evidence from the observed history of UK governments and other actors’ responses to changes in cost and policy. The decision was taken to restrict the evidence for this thesis to that which is in the public domain, partly because of the time required to access additional evidence through, for example, interviews with government and industry representatives, but also because of the danger of introducing a degree of subjectivity or ex-post rationalisation of previous events and decisions. This allowed the focus to be retained on the facts about what was being published in regard to cost estimates and forecasts, and how policymakers and industry were observed to respond to those facts. Nevertheless, the potential for alternative perspectives or insights that may have been possible if interviews with key actors had been conducted is acknowledged, and this is recognised as a potential area for future research – see Section 9.10.
For two of the case studies (see Chapter 5 and 6) sensitivity analyses using levelised cost models (see Chapter 3) were also conducted. For offshore wind the main purpose of the sensitivity analysis was to identify the major drivers for the future trajectory of costs in a UK context, form a view as to the plausible medium-term range of those costs, and compare these with the other cost forecasts in the literature. The main purpose for nuclear power cost sensitivity analysis was also to highlight the drivers of costs and, more specifically, to highlight the degree of uncertainty over cost outcomes implied by observations of the underlying reasons for previous cost increases. The starting assumptions, sensitivities and results for the offshore wind and nuclear levelised cost analyses are described in the respective case study chapters.

2.4 Data collection

The electricity cost data was consolidated and normalised from reviews of existing costs data for a range of electricity generation technologies, undertaken by a project team (see below) as part of the UKERC ‘Cost Methodologies’ project (Gross et al. 2013). The technologies covered were:

- Combined-Cycle Gas Turbine (CCGT)
- Nuclear power
- Onshore wind
- Offshore wind
- Carbon Capture and Storage (CCS)
- Solar photovoltaics (PV)
Production of the technology-specific data was undertaken by individual team members. The data for offshore wind and nuclear was collected by myself and Philip Greenacre, PV data was produced by Chiara Candelise, Felicity Jones produced the CCS and onshore wind data, with CCGT data being produced by Arturo Castillo Castillo. Building the summarised data sets and charts was carried out by myself.

The searches of data sources were designed to capture evidence from both the academic and grey literature. The grey literature was particularly important in this instance since much of the publicly available costs data is produced outside of the academic arena. These sources include country-specific analyses (often commissioned by national governments), technology-specific analyses (often produced by industry bodies), and international analyses bringing together data for a range of countries and technologies (such as the IEA’s long-running ‘Projected Costs of Generating Electricity’ series). Once identified, data sources were recorded in an EndNote reference management system. The sources were then reviewed to confirm their appropriateness and to identify, where possible, any potential duplication of data (for example through later sources re-using earlier data) and to ensure that numbers were genuinely comparable (for example, that the definition of what was and was not included in capital cost estimates was understood).

The data that has been collected can be split into two major categories. The first is data of historical cost estimates (i.e. estimates for notional plants built at the time the estimate was made), and the second is data of cost forecasts (i.e. estimates for notional plants to be built at some point in the future). There are of course time dimensions to both these types of estimates. In the case of historical estimates the time dimension will reflect the year the estimate was made, and in the case of cost forecasts there are two time dimensions, with the
first dimension being the year the forecast is made, and the second being the point in the future that the forecast applies to.

These two categories can give rise to a semantic confusion since data in both categories are often estimates in the sense that they are not observed real costs from actual power projects or market prices. Whilst it may be argued that historical cost estimates should be more accurately described as contemporaneous estimates, this seems a rather awkward term (and certainly not one that is used in the literature) so this thesis uses the term 'cost estimates’ to describe those estimates for notional generation projects to be built at the time the estimate was made. The term ‘cost forecast’ is used to describe those estimates for notional generation plant to be built at some point in the future (relative to the time when the forecast was made).

For each technology, the minimum set of attributes that were recorded for each data point were:

- The unique reference ID from the EndNote reference management system database, to identify the data source.
- The currency that the data was presented in.
- The year of publication for the data source, used to determine the appropriate historical exchange rate to be used (unless this was explicitly different to the publication date, see below).
- The currency ‘rebase’ year, used to determine the appropriate historical exchange rate to be used where the data source identified this as being different to the publication year (see above).
• The year that the historical estimate data relates to. This is often the same as the year of publication but was noted separately to allow for any data sources where this was not the case.

• The year that the forecast data relates to.

• Costs data captured usually included either total capital costs and/or LCOE. If considered useful (and available) this was supplemented by additional data such as operating costs, fuel costs, assumed plant lifetime and discount rate, and the country which the data was applicable to. Units were normalised to MW (for capital and fixed operation and maintenance costs) and MWh (for LCOE and variable operation and maintenance costs).

Other information relating to each data source, such as the publishing and commissioning organisation, was recorded in the EndNote reference management system database. The datasets in Excel spreadsheet format are available in the following Dropbox folder:

https://www.dropbox.com/sh/co6221ecjlni85g/AAA6jEgm5qSTwIjwRK2Q8Fh8a?dl=0

Figure 2.1 below shows the number of distinct data rows that were collected for each technology, and compares the number of data rows for each technology to the size of the total dataset. In practice the number of individual data points captured is higher than represented on the chart because each distinct data row may contain both capex and LCOE numbers, and also the additional data identified above. In total, over two and a half thousand distinct data rows were collected.
To allow comparison, the values for each technology were normalised to a consistent year and currency. This was done by converting all values to GB Pounds using the rate that was applicable at the time of the estimate (see above for how the appropriate year was identified), and then inflating the subsequent GB Pounds figure to 2011 values. The currency conversion was done using the ‘spot exchange rate against £ Sterling’ from the Bank of England Statistical Interactive Database and the values were then inflated to 2011 using inflation data from the UK Office of National Statistics Consumer Price Indices (CPI). The CPI is an ‘internationally comparable measure of inflation which employs methodologies and structures that follow international legislation and guidelines’ (ONS 2010) pg. 1, and since 2003 has been the measure used by UK governments to monitor general inflation targets (ibid.). It represents a measure of the overall level of inflation experienced by consumers, and was therefore considered to be an appropriate index to use since it is consumers and/or taxpayers who must ultimately pay the costs of power generation. The effects of inflation

Figure 2.1 Number of distinct cost data rows collected for each technology
could have been captured using alternative indices, for example, the Producer Price Indices (PPI), and exploring the sensitivity of the results to the application of other indices would be an interesting area for future research – see Section 9.10.

It is recognised that any normalisation process has the potential to introduce conflating factors, but such a process is required to allow meaningful comparison. Where movements in currency exchange rates are a significant factor in changes in cost (such as was the case for offshore wind in the UK) or where currency conversion may introduce a potentially misleading result (such as was the case for PV), these concerns are discussed in the relevant case study.

2.5 Summary

Figure 2.2 below provides an overview of the approach to this thesis in schematic form, summarising the linkages between the research components described above.
The findings from the qualitative assessments and contextual material were drawn together and combined with summaries of the costs data sets, identifying the overall trends and the main drivers for the observed technology cost trajectories. The technology-specific data sets were also consolidated to present summarised and comparative analyses in the discussion in Chapter 8. The final stage of the thesis synthesises the findings from the case studies and discussion of the wider issues, together with additional analysis of the costs database, and discusses what lessons can be learnt for the future use of electricity cost estimates in policy.
3 Measures of costs

3.1 Introduction
This chapter describes the range of different electricity cost measures and the economic concepts that underpin them. Focusing on the UK, the chapter discusses the use of cost estimates in the policy context, including the implications of the move from a centrally planned, state-owned electricity generation and supply system to a liberalised, privately-owned system where the delivery of policy aspirations faces different challenges. The chapter then goes on to discuss the limitations of the cost measures most frequently used in policy analyses, including the challenge of incorporating additional system-wide costs in plant-level or technology-specific estimates.

3.2 Cost estimates and policy
Estimates of electricity costs, whether historic, contemporary or future, feature prominently in energy analysis undertaken by academia, commercial consultancies and government, all of which may influence policy interventions. These estimates have played a substantive role in the analysis that underpins policy, with examples in the UK including:

- Successive Energy White Papers and Reviews (DTI 2006, DTI 2007, DECC 2011f)
- Supporting analysis and consultation documents for policy development such as the Renewables Obligation (RO) (DTI 2002, DTI 2003, DTI/Ernst&Young 2007)
- Key economic analyses such as the Stern Review (Stern 2006), and The Renewable Energy Review (CCC 2011a)
- The 2008 Climate Change Act (HM Government 2008)
• The Electricity Market Reform (EMR) process (DECC 2013c, DECC 2013g, DECC 2013i, DECC 2013j)

As Chapter 1 identifies, cost data are also an essential input (and sometimes output) of international publications such as the IEA’s World Energy Outlook series e.g. (IEA 2004, IEA 2010b), and Experience Curves for Energy Technology Policy (IEA 2000).

The different cost characteristics of the range of electricity generation technologies have also formed key inputs to analyses undertaken using cost-optimising energy system models such as MARKAL and TIMES7, which have been used extensively to create scenarios of future UK energy systems. The outputs and the insights gained from such scenario modelling exercises feature prominently in policy documents such as the White Papers and Energy Review referred to above, and in other inputs to policy formulation (HM Government 2009, UKERC 2009, CCC 2010).

Chapter 1 also highlighted the somewhat circular relationship between cost estimates (which influence decisions over policy design and which technologies are deemed to be deserving of support) and policy (which can influence future costs by driving deployment or by more specifically targeted research and development funding). The range of technology cost forecasts also bears upon policymakers expectations of the future costs of achieving policy goals, but also influence decisions as to what technologies are supported, the size of such support, and for how long it will be required (Stern 2006, Gross et al. 2007, IEA 2010b). In this regard, the role of cost forecasts using the experience curve, engineering assessment and expert elicitation approaches is key, and these are reviewed in Chapter 4, with the case

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7 MARKAL (MARKet ALlocation) is a least-cost optimisation model of energy use, which represents the entire energy system, from primary resources to demands for energy services. See (UKERC 2009) for a more detailed description, and (Hawkes 2014) for a description of the TIMES model.
studies and Chapter 8 discussing the extent to which these have turned out to be accurate guides to future costs.

Examples where UK policy has been clearly shaped by cost estimates and forecasts include their role in the design of the 2002 Renewables Obligation (RO), with the UK Government Department of Trade and Industry’s (DTI) ‘resource cost curves’ being a key factor in deciding on the level of the Obligation itself and the RO buy-out level (Gross et al. 2007).

Changes in UK government policy towards nuclear power also provide a salient example. A little over a decade ago, the view set out in the 2002 Energy Review (PIU 2002) was that the focus for energy policy should be energy efficiency and a substantial increase in electricity generation from renewables, with the option for new nuclear power ‘kept open’ but with ‘no current case for further government support’ – a view based in part on an assessment of the cost of new nuclear relative to other power generation technologies. However, analysis undertaken only four years later as part of the 2006 Energy Review compared the levelised cost of nuclear power and other electricity generation options (see Figure 3.1) and concluded that the economics of the technology had improved, to the extent that it was economic without subsidy, and that ‘new nuclear power stations would make a significant contribution to meeting our energy policy goals’ (DTI 2006, Kennedy 2007). This was followed by a White Paper on Nuclear Power (BERR 2008a) which confirmed the UK Government’s view that ‘nuclear power has a key role to play as part of the UK’s energy mix’.

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8 See Chapter 6 for further details on the UK Government’s current position on nuclear power.
Further examples include the Committee on Climate Change’s assessment of optimal decarbonisation strategies, which form part of its advice on the UK Carbon Budgets, and is based on considerations of technology costs (along with carbon price, demand growth, and capital stock turnover), and the 2011 assessment (CCC 2011b) which used cost forecasts to construct energy system scenarios out to 2020 and 2030. Some of the most recent examples include the Contracts for Difference (CfD) ‘strike price’ analyses by the UK Department of Energy and Climate Change, and the electricity cost estimates that informed those analyses (DECC 2013b, DECC 2013i).

Policymakers have historically focussed on cost numbers such as the levelised cost of energy (LCOE) and, to a lesser extent, capital cost (capex) because these were (and remain) particularly important cost measures that matter from a societal perspective. These two measures are discussed in detail in Sections 3.4 and 3.5 below, but to first put them into their
proper context, the following section describes the other measures of costs and costs terminology.

### 3.3 Cost definitions and terminology

This section identifies the main definitions of costs, starting with the definitions used in economic theory. Economists distinguish between total variable costs (TVC, those costs that vary with respect to output) and total fixed costs (TFC, those costs that do not vary with respect to output), with total costs (TC) being the sum of total fixed and total variable costs. Average fixed cost (AFC) is the total fixed cost divided by the number of units of output and average variable cost (AVC) is the total variable cost divided by the number of units of output, with average total cost (ATC) being the total costs divided by the number of units of output. Marginal cost (MC) is the additional cost of increasing production by one unit of output. (Parkin 2008, Lipsey and Chrystal 2011)

Economic theory uses the concept of the short-run (SR) and the long-run (LR) with respect to these definitions of cost. In this context, the short-run is defined as the ‘time frame in which at least one factor or production is fixed’ and the long-run as the ‘time frame in which all factors of production’ can be varied’ (Parkin 2008) pg. 220. These time frames are typically denoted by prefixing each of the cost acronyms described above with SR (short-run) or LR (long-run) as appropriate. These distinctions have important implications for both the investment decisions that firms make and decisions on how a particular plant is operated once it is built. Parkin (2008) describes anticipated long-run average costs as a planning tool, to guide a firm in the selection of the most efficient mix of plant size and other inputs, with

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9 ‘Factors of production’ is the term used to describe all the inputs, including labour, materials and equipment, that are used in the production processes (Stiglitz and Walsh 2006).

10 The ‘R’ is sometimes omitted from the acronym so that, for example, short-run average variable cost would be denoted as SAVC, see (Begg et al. 2014).
anticipated short-run costs guiding decisions on how a particular plant should be operated once it is built. This differentiation between short-run and long-run costs has very important implications for what electricity generating plant is actually built and what plant is actually run to satisfy demand at any given time – a point that is discussed further below.

Strictly speaking, marginal cost is the derivative of total cost with respect to quantity but since fixed costs do not change with respect to quantity, then marginal cost can be defined as the derivative of variable cost with respect to quantity. It must also be recognised that, in practice, a power plant output will be varied in discrete units (such as MWh), not the infinitesimally small change implied by a derivative function (Stoft 2002, Rothwell and Gomez 2003, Weyman-Jones 2009). A useful alternative description of the concept of marginal cost is provided in (Weyman-Jones 1986) in which it is described as ‘part of the information discovered by trying to find the least expensive way of meeting some future change in output’ (pg. 71-72).

As well as these economists’ definition of costs, there are other ways of categorising costs, based on the physical ‘thing’ (or activity) that they represent. In the context of power generation these include the cost of building a power station (capital costs), the costs incurred in running and servicing a power station, such as fuel and staff costs (operational and maintenance costs), the cost of delivering units of electricity to consumers (transmission and distribution costs), other costs of running a business such as the cost of providing metering and billing (sometimes known as retailing costs), and the cost of dismantling a power station at the end of its life (decommissioning costs). There is also a particular variant of capital costs, known as ‘overnight costs’ which can be defined either as the capital costs of a notional power plant if it is assumed that no interest charges are incurred during construction
i.e. it is constructed ‘overnight’ and all capital costs are incurred instantaneously (Short et al. 1995), or alternatively as the present-value cost of a plant that would have to be paid as a single sum before the project begins, to pay completely for a plant’s construction (Stoft 2002).

A further differentiation should be made between accounting balance sheets and economic interpretations of costs. For example, a sunk cost (one that cannot be recovered, or ‘any cost incurred by a prior decision that cannot be affected by the current course of action’ (Short et al. 1995) pg. 96 is, in accountancy terms, still a cost and will appear on a balance sheet until it is written off. However, it is of less importance to an economist because a sunk cost should not, in traditional economic theory, bear upon subsequent decisions (Rothwell and Gomez 2003) and is ‘irrelevant to the firm’s current decisions’ (Parkin 2008) pg. 220. It should be noted, however, that some argue that it may be rational to take sunk costs into account, particularly where there are financial or time constraints on the options available to firms or other actors (McAfee et al. 2007).

Each of these categories of cost have specific uses and applications, for example the short-run marginal cost which a power station owner faces will determine the electricity price at which they are prepared to run the plant and sell the output over a short term time horizon, but the long-run average cost (relative to long run average electricity prices) is a much more important influence on the decision to build a new power station, and also on whether the owner of an existing power station continues to operate their plant over the long term – or chooses to exit the market, sell the plant and do something else with their capital (Stoft 2002). Economists and utility planners have in the past used approaches such as ‘screening curves’ as a tool for preliminary comparison between electricity generation technology options.
These curves plot annualised total cost per unit of capacity installed (e.g. kW or MW) as a function of plant load factor\textsuperscript{11}, and help ‘establish the envelope within which a supply option will be economic’, and so ‘serves to screen out options that cannot possibly be economic’ (Koomey \textit{et al.} 1989), pg. 3. Figure 3.2 below shows an example screening curve for three technologies, demonstrating how the annual revenue required varies depending on the plant load factors (actually described as ‘Capacity Factor’ in Figure 3.2) – and, crucially, that it varies differently between technologies. This is because the slope of the screening curve for a particular technology represents the variable costs of operating the plant, and the y-axis intercept represents the annualised fixed costs of the plant (Stoft 2002).

![Screening curves for electricity generation technologies](image)

\textit{Figure 3.2 Example screening curves for electricity generation technologies (Koomey \textit{et al.} 1989)}

A key point is that a screening curve shows the average cost of using a unit\textsuperscript{12} of generation capacity, not the average cost of a unit\textsuperscript{13} of electrical output. As explained in Section 3.4 below, the latter is typically defined as the levelised cost of energy (LCOE) and is expressed

\textsuperscript{11} Note that load factor is the anticipated actual plant output, expressed as a percentage of its theoretical output if it were to run at full rated load all the time – so a notional 1MW capacity plant that generated 7,008 MWh in one year would have an 80% load factor.

\textsuperscript{12} In this context, a ‘unit’ is a single generating set of a power station.

\textsuperscript{13} In this context, a ‘unit’ is a quantitative measure of electrical energy, for example a MWh.
in units such as £/kWh or £/MWh. Building on the screening curve approach, it is also possible to plot the LCOE of a generation technology against plant load factor and the result is what Stoft describes as ‘hyperbolic screening curves’ (Stoft 2002) pg. 37. Examples of such curves can be found in (Heptonstall 2007), as shown in Figure 3.3 below, and also in (IEA 2010a). The key point is that the intersection of the curves for different technologies will be at the same load factor on both screening curve and LCOE curve diagrams because the intersection represents the point (in terms of load factor) when one plant becomes more or less economical than the other.

Figure 3.3 LCOE as a function of discount rate, load factor and fuel cost (Heptonstall 2007)
However, whilst the approach described above may provide useful insights for a monopoly provider or a central system planner, it may not necessarily give a clear indication of how firms operating in liberalised markets will actually behave in terms of their decisions to invest in electricity generation plant. This may, for example, be because their decisions on when and what to invest in will be based on their view of how their own actions will be responded to by their competitors, on their perception of the value of a particular investment as part of their generation portfolio, or the option value of waiting for more information (Bazilian and Roques 2008).

Furthermore, none of the cost categories described above will on their own identify what plants should actually be operated to satisfy system demand for a particular period. The answer to that question requires a solution to the ‘unit commitment problem’ i.e. given a particular mix of available generating plant (i.e. units), what is the actual mix that should be operated (i.e. committed) that will satisfy demand for a defined demand period at minimum cost? Solving the unit commitment problem is an optimisation process using data from all available generating plants on fuel cost curves, maintenance cost curves, unit start-up costs, unit ramping rate limits, unit capacity limits, and unit minimum up and down times (Sheble and Fahd 1994). The issue is further complicated because in liberalised markets such as the UK with no (or very limited) central dispatch of generation it is not the system operator’s job to decide which plants will actually run. Instead, policymakers and regulators must try to design and structure a market which delivers investment in, and efficient dispatch of, a mix of actual generation capacity which approaches the theoretical least-cost solution to the unit commitment problem (Stoft 2002).
3.4 Levelised cost of Energy

The levelised cost of energy (LCOE) calculation incorporates all the costs incurred during the life of an electricity generation project, including capex, O&M (operations and maintenance), fuel and decommissioning costs, and divides the discounted sum of those costs by the discounted lifetime output from the power station, resulting in a lifetime average (levelised) cost per unit of electricity from the power station. A standard formulation of the LCOE calculation, from (IEA 2005) is shown in equation [1] below:

\[ LCOE = \frac{\sum [I_t + O&M_t + F_t] (1 + r)^{-t}}{\sum [E_t (1 + r)^{-t}]} \]

where:

\( I_t \) = Investment costs in year t (£)

\( O&M_t \) = Operation and maintenance costs in year t (£)

\( F_t \) = Fuel costs in year t (£)

\( E_t \) = Electricity generation in year t (usually denominated in MWh or kWh)

\( r \) = Discount rate (%)

The resulting LCOE value is typically expressed in £/MWh or p/kWh

An alternative formulation relies on the transformation of the total investment (i.e. capital) costs into an annualised amount using a capital recovery factor and dividing the annualised investment cost and annual operations and maintenance costs by the average annual output. A standard form of this, from (Short et al. 1995) is shown in equation [2] below:
\[ LCOE = \frac{I \cdot FCR}{E} + \frac{O&M}{E} \]

where:

I = Initial investment (£)

E = Average annual electricity generation (MWh or KWh)

O&M = Average annual operation and maintenance costs (£)

FCR = Fixed Charge Rate (see below)

The Fixed Charge Rate (assuming no tax and that the O&M figure includes all fixed and variable annual costs) is equal to the Uniform Capital Recovery Factor (UCRF), shown in equation [3] below:

\[ \text{Uniform Capital Recovery Factor} = \frac{r(1 + r)^t}{(1 + r)^t - 1} \]

where:

r = Discount rate (%)

t = Economic life of project (years)

This second LCOE formulation is in fact a shorthand approach which is analytically less time consuming than the first but which relies on the assumptions that the project under consideration has constant annual output and O&M costs over its lifetime, and that all investment costs occur in year 1. This limitation can have a significant impact on any calculated results if, for example, the output from a generator is expected to decline as the
plant ages\textsuperscript{14}, a phenomenon which has been observed to affect many device types (Staffell and Green 2014). Another key limitation of the approach using equations [2] and [3] is that the results will increasingly diverge from the results using equation [1] where the capital costs of a project are expected to be incurred over several years, such as in the case of nuclear power, see Chapter 6.

Regardless of the LCOE formulation, a key consideration is the discount rate, which represents the time value of money, and allows a future cost (or revenue) to be converted into a present value (Parkin 2008). The discount rate can be represented as either including the effects of inflation (thereby giving a result in nominal terms) or excluding the effects of inflation (thereby giving a result in real terms). Discount rates are generally assumed to be annual and to apply at the end of each year (Short \textit{et al.} 1995), but in principle there is no reason why the levelised cost formula cannot discount more frequently (e.g. monthly or quarterly), provided the rate applied is adjusted accordingly. This approach will however yield different results as the effects of compounding of the discount rate will be more pronounced.

Selection of the appropriate discount rate can be notoriously problematic, as (Khatib 2003) observes ‘all the effort in estimating investment and operational costs is rendered worthless by a deviation in the choice of discount rates’ pg. 43. In part this is because different classes of investors (for example private firms or governments) may have genuinely different views on the time value of money. One approach to deriving an appropriate discount rate for appraising private-sector projects is to use the cost of capital as a proxy. In theory at least, a

\textsuperscript{14} A consequence of the LCOE calculation is that factoring in such declining performance (which is only possible if equation [1] is used) may have a varying impact on the LCOE of some technologies, depending on whether the decline is a result of reduced availability or reduced conversion efficiency. For example, the effect of reduced availability on the LCOE of a CCGT plant will be less than for reduced conversion efficiency because if a CCGT plant is unavailable it does not require fuel (and fuel is a large component of a CCGT plant’s LCOE). The effect of reduced conversion efficiency will be greater because this will mean that more fuel is required for each unit of electrical output.
competitive firm should use its Marginal Cost of Capital (MCC) rather than the average current ‘embedded’ cost but it is more typical to use a firm’s weighted average cost of capital (WACC) which takes into account the current capital structure of the firm and the different rates of return (interest or dividend payments) associated with each component of total capital, rather than the marginal cost associated with a prospective new project (Short et al. 1995). The relative shares of the different sources of financing can vary significantly between companies and countries, and this in turn can affect both the overall cost of capital that an organisation faces and also how responsive that organisation may be to market conditions or other external pressures (IEA 2014c).

Levelised costs can be calculated on either a pre or post-tax basis. From a company’s perspective taxes are a cost, shifting the marginal cost curve upwards, and are likely to bear upon the investment decision, but at the societal level they can be considered to be transfer payment to fund redistributive government spending (Parkin 2008, Lipsey and Chrystal 2011) rather than a true economic cost. An exception is any taxes which are directly linked to the power plant emissions (for example those which attempt to address negative externalities) – and these are in any case usually straightforward to incorporate into LCOE analyses. Nevertheless, taxes can potentially introduce a confounding factor when comparing LCOE results between different tax jurisdictions, and for these reasons they are excluded from many LCOE analyses e.g. (IEA 2010a). Another reason may be that including the effect of taxation introduces more complexity and requires additional information on asset depreciation rates and periods, marginal (effective) tax rates, tax credits, and the nominal discount rate to be applied to the tax calculations (because tax must be calculated in nominal, not real, values). A further complication is that effective tax rates will vary between projects and companies (KPMG 2013), which may reduce the comparative analysis value of LCOE estimates.
Estimates of LCOE can provide insights from a range of analyses including:

- A high level comparison of generating technologies in terms of the relative performance and prospects of each, and also provide an approximate view of the level of subsidy needed to promote individual technologies, or technology types.
- An 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.).
- An 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.
- Input to technology based economic models of the electricity system, as used for energy scenarios that can inform policy (as described above).

(Gross et al. 2010)

The prevalent use of LCOE in recent inputs to UK policy making is illustrated in Figure 3.4 which summarises LCOE estimates in analysis commissioned by both DECC and CCC around the start of the current decade, and Figure 3.5 and 3.6 which shows the most recent cost estimates and near-term forecasts published by the UK Government.
Figure 3.4 Range of recent cost estimates for large-scale electricity generation in the UK. Note that these estimates are for projects starting around the time the analyses were published (i.e. these are not forecasts for projects starting some years into the future). (Mott MacDonald 2010, Arup 2011, Mott MacDonald 2011, Parsons Brinckerhoff 2011)

Figure 3.5 Range of cost estimates and sensitivities for projects starting in 2013 (DECC 2013b)
LCOE estimates are also a central feature in the consultations around the level of support to be offered to low carbon generators through the strike price set by the Feed-in-Tariff Contracts for Difference under the Electricity Market Reform process (DECC 2011f, DECC 2013g), and in technology specific cost reduction aspirations, such as the drive to reduce the cost of offshore wind (Offshore Wind Cost Reduction Task Force 2012, The Crown Estate 2012). They also feature in international analyses and comparisons undertaken on behalf of the European Union (Alberici et al. 2014), the US Department of Energy (DoE 2015), and the International Renewable Energy Agency (IRENA 2015).

3.4.1 Limitations of LCOE
One key limitation of levelised cost with regard to policy, which is linked to the fuel price and revenue volatility issue in the list below, is that investors will typically prefer to invest in power generation projects whose cost and revenue characteristics tend to minimise
investment risks and will tend to favour such projects even if the levelised costs of other potential projects are similar. Electricity generation technologies can be broadly characterised as ‘expensive machines for converting free or low cost energy into electrical energy or else lower cost machines for converting expensive fuels into electrical energy’\textsuperscript{15} (Mott MacDonald 2010) pg. 8, and in practice investors will typically prefer the latter (such as Combined Cycle Gas Turbines (CCGT)) over the former (such as renewables and nuclear power). This is because in many liberalised electricity markets, CCGT plants are normally ‘price-makers’, able to pass fuel price movements (which constitute a large fraction of their costs of production) onto customers, so largely removing fuel price and revenue risks (at least from the perspective of the individual generator).

In contrast, high fixed cost nuclear and renewable plants are ‘price-takers’ which remain more exposed to revenue risk because even in times of low electricity prices, these plants have little option but to continue to produce in order to cover as much of their (already incurred) fixed costs as possible. Figures 3.7 and 3.8 illustrate this by comparing a range of LCOE and Net Present Value (NPV)\textsuperscript{16} spreads for gas, coal and nuclear technologies. An examination of the spread of LCOE values (Figure 3.7) suggests that in this instance the costs of nuclear power are both broadly comparable with coal and gas, and that those costs are not sensitive to fuel and CO\textsubscript{2} cost fluctuations. Whilst this may indeed be the case, the LCOE analysis does not reveal the significantly greater risk of a negative NPV for nuclear projects (Figure 3.8) – which would occur if low gas or coal prices led to lower electricity revenues through the price-maker mechanism described above (Gross \textit{et al.} 2010).

\textsuperscript{15} An exception to this is electricity generation with Carbon Capture and Storage (CCS) which, depending on the fuel and technology, can have both relatively high capital costs and relatively high fuel and operating costs – a characteristic which presents this technology with potentially unique challenges (Boot-Handford \textit{et al.} 2014).

\textsuperscript{16} In investment appraisal terms, the NPV is the sum of discounted revenues of the project over the project life minus the sum of discounted costs of the project (Parkin 2008). Leaving aside any other considerations such as limitations on access to finance, a project with a positive NPV should be taken forward, whilst a project with a negative NPV should not.
Figure 3.7 Spread in levelised costs arising from different CO2 and fuel price scenarios (Gross et al. 2010), input values taken from (DTI 2006)

Figure 3.8 Net present value representation of the spread of returns arising from different CO2 and fuel price scenarios (Gross et al. 2010), input values taken from (DTI 2006)
The consequence is that policy which aims to deliver investment in high fixed cost, price-taker technologies must do more than simply equalising levelised costs (net of support) across technologies, and ensure that there are sufficient incentives to overcome the investment risk described above. It must also ensure that operators are incentivised to run their generation plants in the most economically rational manner (i.e. to achieve ‘efficient dispatch’ of the generation fleet described in Section 3.3 above.). (Woodman and Mitchell 2011) contend that one of the justifications for the Contract for Difference mechanism described in the EMR proposals (DECC 2010a, DECC 2011f) over a more traditional straight Feed-in-Tariff was that the UK Government wanted to ensure that low-carbon generators remained exposed to the wholesale electricity market (since they would still need to find a buyer for their output).

Whilst this does not by any means automatically ensure ‘efficient dispatch’, the logic was that the market would place greater value on output at times of high demand, providing an incentive to low carbon generators to do what they can to ensure that they are able to generate at such times. In practice, this may have a rather limited effect since most low carbon generation is either constrained by the temporal availability of the resource (such as in the case of wind) or by the operational inflexibility implicit in their cost profiles (such as in the case of nuclear or wind, and described above) – which means that the owners of these plants will typically want to run them whenever they are available, almost regardless of wholesale electricity prices.

It is certainly the case that other countries (Germany, for example) have experienced problems where a large amount of renewable generation is incentivised by a Feed-in-Tariff to operate regardless of demand or other system constraints. This is because it may undermine
the business model of incumbent thermal generators, who are still required to provide reliability and system balancing services but whose plant load factors are reduced to the point where they become uneconomic to operate (Clark 2014), or it may require very substantial investment in transmission capacity – leading to the question of how those additional costs should be allocated (see Section 3.6).

A further criticism of the LCOE calculation as formulated above is the argument that it does not correctly differentiate between cost streams which have different risks. In his 2000 paper, Awerbuch suggested that if generating companies were to correctly value risk then seemingly high cost but zero fuel price risk technologies would appear more competitive in LCOE analyses. Awerbuch argued that investors should place a higher value on less risky costs/income streams so different discount rates should be used, depending on the risk of the future stream with relatively risky or unpredictable costs being discounted at a lower rate than more predictable cost streams. For example, Awerbuch suggested that future Operation and Maintenance (O&M) costs are more predictable than future fuel costs so fuel costs should be discounted at a lower rate than O&M costs.

The key point is that a high risk/unpredictable cost stream is (in Awerbuch’s view) a worse proposition than a lower risk cost stream and so therefore should have a larger present value – so must have a lower discount rate. Awerbuch suggested that the Capital Asset Pricing Model (CAPM) should be used to derive the appropriate discount rate for cost streams, and applying this model to future fuel costs suggests that the discount rate used should be 1-3%, which is much lower than the discount rates typically used in levelised cost estimates. Since fuel costs are the major component of total costs in the case of (for example) CCGT plants, and are incurred throughout the lifetime of the plant, applying a lower discount rate to this cost...
stream will significantly increase total costs in present value terms (Awerbuch 2000). The analysis in (Albrecht 2007) built on Awerbuch’s proposal to show how, using a combined CAPM/portfolio method, PV generation can lower the total risk of an electricity generation portfolio. This approach was also used as part of the risk-adjusted portfolio cost minimisation analysis in (Krohn et al. 2009), and as expected significantly increased the apparent attractiveness of renewable technologies that have no fuel costs.

However, there is a danger that this approach could potentially disadvantage an individual company which correctly values the contribution that an alternative (higher unit cost but no fuel price risk) technology can make and invests in it – because their short run costs will be higher than a generator who doesn’t invest in the technology (assuming that the fuel price risk does not materialise), so they will be at a short run competitive disadvantage. Others (e.g. Anderson) have argued that applying different discount rates to cost streams with different risk profiles is the wrong approach in principle, and that “the proper way to treat uncertainties in any component of costs, such as capital or fuel costs, is to address them explicitly by feeding their means, ranges and variations directly into the analysis…..The discount rate should be varied for only one reason, which is that the discount rate is uncertain…..It is true that companies may raise the threshold rate of return for risky projects, but the right thing to do as a point of principle is to combine the variances of all quantities that are uncertain.”

In addition to the issues described above, the further limitations of levelised costs can be broadly categorised as commercial factors, economic externalities, and system factors (IEA 1989, Awerbuch et al. 1996, Awerbuch 2006). The commercial factors and economic externalities not captured by LCOE are summarised below. The system factors are discussed

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17 Personal communication with Professor Dennis Anderson, Imperial College, February 2007
separately in Section 3.6 of this chapter because they bear upon cost estimates more generally, and are becoming increasingly important in discussions over the use of electricity cost estimates in policy.

Commercial factors not captured in LCOE:

- The actual plant lifetime may well be longer than the assumed ‘economic’ life.
- The unpredictability of fuel price (costs) and revenue volatility (electricity volume and prices) – see above.
- The impact of project size/scale/modularity.
- The option value that investment in a particular technology may give a utility.
- The costs of information gathering (i.e. the information required to inform an investment decision).
- Future changes to tax regimes, environmental legislation, government support mechanisms.
- Corporate level taxes – both the absolute level and the details of the tax regime e.g. some tax rules allow the accelerated depreciation of assets – which may affect choices between capital intensive and less capital intensive technologies.
- 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.

Economic externalities which may not be reflected:

- Residual insurance responsibilities that fall to government.
- Any un-priced externalities e.g. CO₂ costs in the absence of a CO₂ tax or permits.
• External benefits such as the value of learning to future generations.

• Inter-temporal and inter-generational cost issues, such as where a power plant may impose costs on future generations (but where the benefits are realised now).

An additional limitation of LCOE numbers is that they have limited usefulness unless the assumptions for load factor and, as discussed above, discount rate (neither of which are in themselves costs) used in the LCOE calculation are known. In the case of load factor, this is because the levelisation formula (see above) apportions total costs across total units of output, and these units of output are in turn a function of plant capacity and load factor. In the case of discount rate, it is because both cost and output streams are converted to present values using the discount rate, and varying the discount rate can have dramatic effects on the resultant LCOE (Heptonstall 2007, Heptonstall et al. 2012). This point is reinforced by (Borenstein 2011) who argues that much of the range (and discrepancies) between LCOE estimates is driven not by differences of opinion of the component cost of a technology but by ‘assumptions about inflation rates, real interest rates, how much the generator is used, and future input costs, including fuel costs’ pg. 4.

Despite these criticisms, LCOE estimates remain a powerful indicator and continue to play a key role in many policy analyses. The limitations described above are also increasingly recognised. For example, the IEA’s 2010 report on projected electricity costs having a section devoted to the limitations of LCOE, and DECC’s electricity cost estimates reports now discussing explicitly the limitations and uncertainties of levelised costs (IEA 2010a, DECC 2013b, DECC 2013c). This can be compared with earlier work such as the 2006 Energy Review which dealt with the uncertainties over costs by presenting a sensitivity analysis but
was much less explicit about the limitations of LCOE estimates (DTI 2006). The treatment of these uncertainties is discussed further below and in Chapter 8.

3.5 Capital expenditure

Whilst capital expenditure cost (capex) estimates feature less prominently in headline policy outputs they do however continue to play a role in inputs to policy analyses and wider debates over costs in the energy sector. This is particularly the case for nuclear and many renewable generation technologies where the capital cost can be the overriding determinant of cost out-turns (Greenacre et al. 2010, Harris et al. 2013), and where, as a result, the capital costs frequently take centre stage in discussions of the merits or otherwise of particular technologies e.g. (Barker and Clark 2014).

Capex estimates also feature in analyses of the scale of investment required to replace the UK’s aging electricity generation fleet, transmission and distribution infrastructure, and achieve the UK’s decarbonisation targets (DECC 2014b), and also help draw attention to the disparity between the implied capex requirements of policy aspirations (see Figure 3.9) and the size of investments being made by the existing generating companies (see Figure 3.10). Other analyses such as (IEA 2000, Nemet 2009b) estimate the total capital expenditure that may be needed to deploy sufficient capacity of a developing technology to bring its costs down to a level that is comparable with existing technology options, based on an extrapolation of observed experience curves (see Chapter 4).
Analyses with an international focus, such as (IEA 2014c) also use aggregated capex values to track historical investment trends (see Figure 3.11), and illustrate the future global energy investment requirements (see Figure 3.12).
The type of forecasts shown in Figure 3.12 help to bring investment requirements into sharp focus and emphasise the scale of those requirements, with the IEA’s latest analyses suggesting that globally around $40 trillion of capital investment will be required in the period up to 2035, $2 trillion of which will be required in the European power sector.
3.5.1 Limitations of capex

Some economists feel that the lack of a time dimension for capex figures is unhelpful because ‘the true (but unstated) units are £/kW-lifetime’, which leads to the conclusion that ‘This cost provides useful information but only for the purpose of finding fixed costs that can be expressed in $/MWh. No other useful economic computation can be performed with the overnight cost of capacity given in $/kW because they cannot be compared with other costs until levelised’ (Stoft 2002), pg. 30. Stoft goes on to explain that capital costs must implicitly always have a time dimension by comparing two hypothetical generators using the same technology but where one is older than the other so has a shorter expected lifetime, and therefore has less value. This leads to his conclusion that generation capacity costs should be expressed as rental rate, which imposes an explicit time dimension – which can then be expressed in the same units as LCOE such as £/MWh.

A further complication encountered when using capex is the wide range of definitions used, based on what elements of a project are and are not included and the approach taken to representing the flow of costs over time in a single number. The US National Energy Technology Laboratory, for example, describe five different definitions of capital cost in their guidelines for cost estimation methodologies for power plant performance (NETL 2011), summarised in Figure 3.13.
The potential for misunderstandings over what exactly a single capex number represents was illustrated in the discussions following the publication of the Carbon Connect report on nuclear power (Leveque and Robertson 2014), where EdF Energy argued that the Carbon Connect analysis had wrongly interpreted the capex value published by EdF Energy as being inclusive of interest during construction (Carbon Connect 2014, de Rivaz 2014). It is interesting to note that this was an instance of a project developer being apparently anxious to emphasise the high capital costs of its preferred technology\footnote{This may have been because this reduced the implied level of profitability of the project and the developer was keen to reassure policymakers that the level of support being negotiated was not more generous than required.}, a point to which this thesis returns in the discussion in Chapter 8.

Also what is not evident from the capex number on its own is the proportion of total costs which it represents. This varies considerably between technologies with some, such as nuclear power and most renewable technologies, having a very high ratio of capital to running costs and others, such as gas-fired power stations, having relatively low ratio of capital to running costs. This makes comparisons between technologies based on capex alone...
of very limited value, unless the availability of capital is so constrained that it becomes an overriding factor and does not take account of the differential impact that the cost of capital can have (see below).

### 3.6 System-wide costs

This section focuses on an issue identified in Section 3.4 above – i.e. the extent to which estimates capture the full costs which a generating plant imposes on the electricity system to which it is connected. Traditionally, cost analyses using measures such as LCOE have incorporated the full lifetime costs associated with the generation of electricity from a plant, but have drawn a notional boundary at the point where that plant is connected to the wider electricity grid. Any costs outside that boundary have not normally been included in LCOE figures, even though a particular generating plant (or fleet of similar technology generator types) may, because of their size, operating characteristics or location, impose additional costs on the electricity system as a whole.

The debate over whether traditional electricity cost metrics should attempt to capture the additional system-wide costs which a particular plant or generation type imposes on an electricity system is not a new one. However, the increasing share of electricity generation that is provided by intermittent\(^\text{19}\) generators which rely on the availability of a fluctuating resource such as wind or insolation has meant that there is an increased focus on this issue. It is recognised that any generation plant that is connected to a grid imposes some system costs, because any such plant needs physical connection to the electricity network. For example, much of the current UK transmission grid is a result of the desire during the post-Second

\(^{19}\) The debate over the most appropriate generic term to use for ‘intermittent’ generation has continued for some time (Gross \textit{et al.} 2006, Poyry 2011a). Although the term ‘Variable Renewable Energy’ appears to be used with increasing frequency e.g. (Hirth 2013), this thesis uses ‘intermittent’ as well because it is still very widely used.
World War decades to connect the main centres of demand to large coal-fired powers stations whose sites were typically selected on the twin requirements of ready access to the fuel source and cooling water. Plants may also have an impact on the amount of short-term reserves required to guard against the unexpected loss of very large generating units. In the UK for example, the system operator ensures that there are sufficient generation reserves to maintain security of supply in the event of the loss of the largest single in-feed (known as the N-1 criteria). Nevertheless, this section focusses on those costs which arise as a result of the variability and location-specific nature of renewable resources because it is these characteristics which in large part are driving the debate as to how system costs should be represented.

3.6.1 Intermittency costs
Less than ten years ago the cost impacts of intermittent generation were considered to be relatively small, for the level of renewables penetration then envisaged in the short to medium-term for many countries. For example, the analysis in (Gross et al. 2006) focussed on the technical impacts of intermittent generation on the UK electricity system and in particular the ability of the system to reliably meet demand during peak periods (‘reliability impacts’) and the ability to balance supply and demand over timescales ranging from seconds to hours (‘balancing impacts’). The work concluded that for penetrations of intermittent generation up to around 20% (on an energy basis), reliability impacts would add £3-£5/MWh to each MWh generated from intermittent sources, and balancing impacts would add £2-£3/MWh\(^{20}\) on the same basis, resulting in a total cost impact of between £5 and £8/MWh.

\(^{20}\) The additional costs imposed at low renewable penetration levels are typically much lower than these figures, with some analysts suggesting that actual system balancing costs for the UK in 2011 (with around 3GW of wind installed) were around €0.5/MWh (Swinand and Godel 2012).
These figures are relatively small (although certainly not trivial) but the costs of providing system reliability and balancing are dependent on the costs of the technology that would be expected to provide those services. Since this is frequently assumed to be large-scale gas fired generation in the form of CCGT plants, and as shown in Figure 1.1 in Chapter 1, CCGT costs have risen significantly since the mid-2000s, the implication is that the costs associated with intermittency may also have risen. By way of illustration, Figure 3.14 below updates the sensitivity analysis of UK system reliability costs in (Skea et al. 2008) with more recent CCGT costs from (DECC 2013c). The dashed lines show the reliability costs using mid-2000s CCGT costs and the continuous lines show the range of reliability costs associated with 2013 estimates for CCGT plant. As expected, the higher cost of CCGT plant results in significantly increased reliability costs with increasing impact in absolute terms as capacity credit (the extent to which intermittent generation capacity can replace dispatchable capacity without compromising system reliability) falls.

Figure 3.14 Reliability cost sensitivity analysis results, using 2006 and 2013 costs
The results reinforce the point made in (Milligan et al. 2011) which discusses the difficulties in correctly calculating integration costs and which concludes that, whilst the calculation methodologies are well developed, the resultant integration costs are very dependent on the ‘balancing’ technology chosen by the analyst. Whilst this thesis is not primarily concerned with the magnitude of additional system costs but rather with how those values are represented in electricity costs, the combination of an increasing penetration of intermittent generation and rising costs for the plants which would be expected to provide balancing and reliability services helps to explain why the issue is of increasing concern.

3.6.2 Incorporating intermittency costs in electricity cost estimates

One of the most widely adopted approaches to the representation of the additional system costs imposed by intermittent generators can be broadly categorised as the ‘enhanced LCOE’ approach. This method, of which the (Gross et al. 2006) analysis described above is a partial example, takes as the starting point the traditional LCOE as described in Section 3.4. It then seeks to determine the total additional costs which a particular level of intermittent generation will impose, converts that cost into per MWh value by apportioning it over the expected output from the intermittent generation, and then adds that MWh cost onto the base LCOE figure. A variation of this approach starts with a ‘system price’ for each unit of electricity generated and then subtracts the costs which intermittent generators should bear as a result of their operating and location characteristics (which could also be described as revenue reductions). Examples of this range of approaches include (Borenstein 2011, Joskow 2011, Taylor and Tanton 2012, Hirth 2013, Holttinen et al. 2013, Ueckerdt et al. 2013), and each of these are discussed below.
Both the Joskow and the Borenstein analyses focus on the ‘production profiles’ of intermittent generation and the impact that these profiles have on the market value of electricity from these sources. Based on the premise that the market value of the output from an electricity generator can vary considerably depending on when that output is produced, both argue that the value of electricity from intermittent generators will be overvalued (or more specifically, undercosted) by traditional LCOE analyses when compared to dispatchable technologies if there is a mismatch between the availability of the variable resource and typical demand peaks. However, Borenstein does also point to the earlier work of (Fripp and Wiser 2008) which found that where the available resource was particularly well matched to demand, such as in the case of PV in California, then the value of output from such generators could exceed average power prices, a result which Joskow also identifies, and which is broadly consistent with one of the conclusions from (Gross et al. 2006) in that intermittency costs are to a large degree dependent on the characteristics of the electricity system to which the intermittent generators are connected. Joskow acknowledges that the market value approach requires an assessment of future electricity prices, over which there is likely to be ‘considerable uncertainty’ pg. 23, whilst Borenstein also identifies the difficulty in correctly costing the full system impacts of any new transmission capacity required to connect intermittent generators because of the potential knock-on impact on the usage of existing line capacity.

The Hirth 2013 analysis\textsuperscript{21} follows a similar approach to the two analyses described above, and focuses on the effects of intermittency on the market value of renewable energy, finding that the value of wind generation in Europe may fall to between 50\% and 80\% of the European market average power price with a modelled 30\% of electricity being supplied

\textsuperscript{21} The paper provides a summary of the substantial body of literature covering the ‘market effects’ of intermittent generation.
from wind power, with the effects on the value of output from PV being even more pronounced. The approach separates the effects into the three categories of costs (or revenue reductions) shown in Figure 3.15 below.

![Figure 3.15 System base price and the market value of wind power (Hirth 2013)](image)

The ‘Profile Costs’ identified in Figure 3.15 reflect the value of electricity generation varying depending on when it is produced relative to demand, the ‘Balancing Costs’ reflect the impact of errors in forecasting the output from renewable generators (errors which must be corrected for by increasing or reducing output from other generators or adjusting demand), and the ‘Grid-related Costs’ reflect the impact of variable renewable resources not being located close to centres of demand and therefore requiring additional transmission grid investments. Depending on the market design and regulation, and the support mechanisms employed, the impacts modelled by Hirth could have significant implications for the projected revenue stream of renewable generators, with the paper concluding that ‘Electricity systems with limited inter-temporal flexibility provide a frosty environment for variable renewables like wind and solar power’ (ibid.) pg. 233.
The focus of the analysis in Taylor and Tanton 2012 is on what they describe as the ‘missing costs’ of wind power in traditional LCOE figures. They have a similar (although not identical) categorisation of these costs to Hirth, with their additional costs being grouped into reliability and balancing impacts, the cost implications of the higher fuel consumption of conventional plant (due to increased cycling, steeper ramping rates and plant running part-loaded), and the additional transmission costs (and associated transmission losses). Their analysis calculates that the ‘missing’ costs would add over 80% to the LCOE of US-based onshore wind if CCGT plant is assumed to be the comparator plant. The authors attribute what they argue is a failure to fully reflect system-wide costs to a combination of reporting conventions, a paucity of reliable data and a history of socialising these costs across all generators.

In their 2013 paper, Ueckerdt et al. propose a new metric of ‘system LCOE’ that is designed to capture technology-specific generation costs and the system integration costs that should be associated with that technology (although they acknowledge the considerable complexity of isolating the technology-specific integration costs). Their modelled results for wind power in Europe, shown in Figure 3.16 below, show how the ‘system LCOE’ is calculated to rise as the penetration level increases – results which are consistent with other recent analyses e.g. (Holttinen et al. 2013). The authors also make the point that they expect integration costs per MWh will be lower in the longer term as power systems adapt to high penetrations of renewables.
The Holttinen *et al.* study collates the findings from work across many countries conducted under the auspices of the IEA, with the underlying analyses typically calculating a total balancing cost impact and then converting that into an additional cost per MWh of output from wind with values presented by country or system control area. The study does not go on to add these costs onto the base cost of wind but in principle this could be done, although the base LCOE of wind would of course vary from country to country. The authors also reinforce the point made in other studies concerning the challenges inherent in allocating new grid investment costs across wind generation because new grid capacity may benefit all system users, not just the wind generators.
An example where additional costs are not apportioned to new variable renewable generation is the analysis by (Strbac et al. 2012) which used a cost-minimising electricity system simulation model to assess the relative costs of different system balancing technologies in Great Britain in the period to 2050, with results presented in terms of total cost savings per year for each of the pathways modelled, relative to a baseline. The results demonstrated the potentially wide cost range for the integration of intermittent renewables, depending on the balancing technologies adopted.

Other analysts have argued that LCOE is ‘no longer a useful concept’ and that ‘technology value is best judged by its ability to reduce total system cost’ (ERP 2014) slide 9, because electricity systems need a range of services, not just units of electricity and intermittent generators generally tend to be consumers of those services rather than providers. They suggest that technologies that can provide those services should have their value adjusted upwards. The results from the total system cost modelling approach adopted by the authors suggest that achieving the UK’s decarbonisation targets would generally be more cost effective with a higher proportion of nuclear generation than is often seen in other modelled futures of the UK energy system. Arguably, one conclusion that could be drawn from this is that the models typically used for UK policy analysis do not represent very well the additional costs which intermittent generators impose.

In summary, any grid-connected electricity generator will inevitably impose costs on the system to which it is connected, even if those costs are simply to cover the physical connection. The additional system costs created by a particular generator or technology type must be borne regardless of whether those costs are attributed to the generator or not, but in the past in the UK when the large majority of electricity was supplied from conventional
thermal generators with a broadly complementary range of operating characteristics, this was a largely uncontentious area. What is changing now is that the increasing share of electricity that is supplied from variable renewable sources, and policy aspirations for very large contributions from renewables in the medium and long-term, are bringing the additional system costs which intermittent generators impose into sharper focus. This increased scrutiny is further explained by the fact that almost all analyses find that the costs of integrating variable renewable generation into an electricity system will rise as the share of total supply from those sources increases, and because the costs of the conventional thermal plant that would normally be expected to facilitate that integration have also risen considerably in the last decade\textsuperscript{22}.

\subsection*{3.7 Conclusion}

It is clear that whilst there are a wide range of cost definitions, the estimates and forecasts of LCOE, and to a lesser extent capex, have played and continue to play a key role in policy analyses. LCOE and capex are not the only important measures of costs for policy makers. In part this is because of the inherent limitations discussed in this chapter, but also because the types of costs described above that historically were only of interest to system planners and designers of centralised generation dispatch algorithms now matter to policymakers because for policy to be effective in liberalised markets it must not only influence what power stations \textit{are built} but also which power stations \textit{are operated} – and the answer to that question might not be found in headline LCOE or capex figures.

\textsuperscript{22} Some commentators suggest that facilitating the integration of variable renewables with conventional thermal plant such as large-unit CCGTs imposes greater costs than are necessary and that using smaller units would be more economically efficient in practice, primarily because the very high thermal efficiency of conventional large CCGT plants can only be attained under a narrow range of operating regimes (Sharman 2014).
An increasing number of analyses explicitly recognise the degree of uncertainty in their estimates of electricity costs e.g. (Parsons Brinckerhoff 2011), a point reinforced in (Mott MacDonald 2011) which particularly emphasised both the high degree of uncertainty in cost estimation and analysis – in terms of capex, operation and maintenance costs, and potential cost reductions from learning – and also the significant impact that the cost of capital (i.e. interest on debt and dividend payments for equity holders) has on the relative costs of different generating technologies. If a lower cost of capital is assumed this will favour technologies that are relatively capital intensive with relatively low running costs (such as nuclear). A higher cost of capital will favour technologies with relatively low capital cost and relatively high running costs (such as CCGT). The importance of the cost of capital is further reinforced because electricity generation technologies tend to be grouped towards each end of the relative capex/opex spectrum (see Section 3.4).

In their 2011 report for DECC, Parsons Brinckerhoff are clear that ‘In using the estimates prepared by PB the inevitable uncertainties need to be recognised. Costs should be considered in the light of the AACE International Recommended Practice 18R-97’ (Parsons Brinckerhoff 2011) pg. 6. A summary of that recommended practice is included in their report, and reproduced below in Figure 3.17. It is implied in the 2011 report that those cost estimate ranges summarised in Figure 3.18 below (a variant of Figure 1.1 in Chapter 1) are ‘Class 5’ category i.e. those with the largest degree of uncertainty with an expected accuracy range between minus 50% and plus 100% (with a potentially smaller range for more mature technologies). It should be noted however that this degree of uncertainty is partly due to the generic nature of the estimates, and that the AACE classifications are more usually applied to specific projects, and also that the guidance was later revised slightly with the suggestion that
estimates generally lay in the ‘Class 4’ or ‘Class 5’ categories (Parsons Brinckerhoff 2012, Parsons Brinckerhoff 2013).

![Table and Diagram]

**Figure 3.17** AACE cost estimate classification matrix (AACE International 2005)

![Graph]

**Figure 3.18** Comparison of 2006 and 2011 cost estimates
Figure 3.18 brings together the 2011 estimates commissioned by DECC (Arup 2011, Parsons Brinckerhoff 2011) and the estimates made as part of the analysis underpinning the UK Government’s 2006 Energy White paper (DTI 2006). Estimates would inevitably be expected to change over time as technology costs responded to economic and market conditions and technology changes but the figure highlights two key points. The first is the considerable range of estimates for each technology at the time that those estimates were made, and the second point is that cost estimates can vary considerably even over relatively short periods. This thesis returns to this theme of uncertainty in the discussion in Chapter 8.

With regard to the calculation and apportionment of integration costs, the only way to calculate them is at a system level – and some analysts take the view that this is as far as it is sensible to take the analysis. Others go on to allocate those costs across the units of electricity generated from variable renewable sources, and some take the further step of then adding those cost/MWh values to the LCOE of a selected technology (or applying essentially the same logic but from a market price perspective, adjusting the value of generation from renewable sources downwards by the calculated system integration costs). A potential concern with the ‘enhanced LCOE’ approach is that it masks the fact that individual variable renewable energy plants may in reality impose different system costs, but similar plants will have similar ‘enhanced LCOE’ costs. This stems from the fact that the approach implicitly treats similar variable renewable plants as an homogenous fleet, which may be acceptable if the purpose of the exercise is to gain a broad-brush understanding of how the ‘full’ costs of intermittent plants compare to the alternatives, but is of much less value if the purpose is to compare one project with another.
The use of LCOE in relation to variable renewable generation is under pressure from at least two perspectives. The first is based on the criticism that the measure does not capture all the costs which a particular plant or plant type will impose on the system to which it is connected. Whilst this is certainly true for traditional LCOE analyses, it is also true that attempts to enhance the analysis to do so accurately is problematic and contested (both in terms of the mechanics of how to go about such enhanced analysis but also as to whether such analyses are appropriate at all if applied to variable renewable generation). Some analysts suggest that this limitation may fatally undermine LCOE as a reliable metric for electricity systems with large amounts of variable renewable generation. The second source of criticism is from those analysts who argue that the correct method is to adopt a ‘market value minus integration costs’ approach, but this again is not without its own challenges, not least in that for forward-looking analyses it requires an accurate assessment of future electricity prices – which can be notoriously difficult to predict. These criticisms create a significant potential challenge for policymakers since they call into question the reliability of those comparative cost measures which feature prominently in policy analyses – an issue which is taken up in the discussion chapter.

The relatively large intra-year cost ranges and inter-year cost increases shown in Figure 3.18 demonstrate the sensitivity of levelised cost estimates to the input assumptions, a theme which is explored in more detail in the offshore wind and nuclear case studies in Chapters 5 and 6. The case studies, and the discussion in Chapter 8, also explore the underlying reasons for the cost increases from the mid-2000s onwards, and address the implications for policymakers.
4 Methodologies for cost forecasting

4.1 Introduction

This chapter discusses the reasons why costs of products or processes are often expected to fall over time as the cumulative volume of production increases, and how this expectation of declining costs bears upon cost forecasting. Whilst estimates of current costs typically rely on ‘engineering assessment’, ‘expert elicitation’, observation from recent or current projects, and analyses of prices in component markets, forecasts for costs at a point in the future can in principle draw on both these approaches and ‘experience curve analyses’. Since the principal methodologies used to make forecasts and projections of future costs in power generation are experience curves and engineering assessments (sometimes augmented by expert elicitation), this chapter examines these approaches and discusses their potential limitations.

4.2 Sources of cost reduction

The tendency for technology costs to decline as cumulative production volume increases is well established, and the sources of such cost reductions are typically grouped into the four classifications described below (Arthur 1994, Foxon 2002):

- Economies of scale result from the reduction in average costs per unit of output as fixed costs are spread over increasing production volumes. The cost reductions, if passed on to consumers in the form of lower prices, may also then increase demand and create the conditions for further cost reductions. Focusing on electricity generation, economies of scale can be delivered on per unit of installed capacity basis and on a per unit of electrical output basis through increasing the total installed size of a power station and/or the major components. Examples of the latter include the scaling up of UK coal-fired steam turbines during the 1960s and 1970s, albeit not without significant challenges (Hannah 1982), and
wind turbines increasing in size from less than 200kW in the 1980s to the multi-MW scale devices that dominate today (Arantegui et al. 2012). Economies of scale may also arise at a company level, for example as firms are able to spread the costs of centralised administrative functions over a larger total output.

- Network externalities describe the effect that the use of a good or service by one person or entity has on the value of that product to others. Also described as co-ordination effects (Pierson 2000), these often occur where technologies are linked and need to be compatible, interoperable, or where devices must be operated as part of a system. When a positive network externality occurs, the value of a product or service increases as more people use it. Typical examples include computer hardware and software, data storage formats and devices, and road vehicle and refuelling systems.

- Adaptive expectations explains that as a leading design emerges consumer uncertainty is reduced and more consumers are encouraged to adopt the leading design, further encouraging its adoption and feeding back into yet more widespread use – and in the process also reducing any competing design’s ability to benefit from adaptive expectations.

- Learning effects reflect product or system improvements and cost reductions as experience is gained in the development, production, deployment, and application of a technology. There are several categories of learning effects including learning-by-researching, learning-by-doing, learning-by-using, and learning-by-interacting (Schaeffer et al. 2004), and these are discussed in more detail below.

Learning-by-researching\(^{23}\) is, as its name suggests, the process through which research and development (R&D) activity results in more efficient, lower cost products and/or production

\(^{23}\) (Schaeffer et al. 2004) and Junginger et. al (2008) also describe this as ‘learning-by-searching’.
processes. Junginger et. al (2008) characterise these as improvements related to the innovation process and suggest that they are important not only during the invention stage of a product but also during the later stages of the product life cycle. The concept of learning-by-doing was first articulated in (Wright 1936) who observed that the labour cost of producing an aircraft frame declined with the number of frames produced. This was followed by (Arrow 1962) who proposed that learning was the product of experience and of problem solving i.e. that ‘learning can only take place through the attempt to solve a problem and therefore only takes place during activity’ pg. 155. Isoard and Soria (2001) report that previous commentators had suggested that there are actually two types of output from a firm, one of which is the product or service itself and the other is gradually accumulating experience. Learning-by-using refers to the knowledge derived from the use of the product by consumers, helping manufacturers to understand the actual performance of the product and to learn more about the users’ needs, which in turn may lead to modifications or improvements to the product (Junginger et al. 2008). Learning-by-interacting refers to the interactions between researchers, industry, consumers, users and policy makers that can assist with the diffusion and exchange of knowledge (Junginger et al. 2008), which can then lead to product or process improvements and cost reductions (Foxon 2003).

There is, therefore, a substantial body of evidence to support the view that future costs can fall, through the range of mechanisms described above – at least until some fundamental constraints are reached. The remaining sections of this chapter discuss the methodologies used to forecast the magnitude and trajectory of future cost reductions.

24 (IEA 2000) suggests that ‘learning-by-producing’ is a more accurate term.
25 The issue of ‘cost floors’, below which costs cannot realistically be expected to fall is discussed in Section 4.3.2.
4.3 Experience curves

4.3.1 Overview
An experience curve expresses the relationship between the unit cost of a product or process and its cumulative production or deployment over time. As noted above, (Wright 1936) observed that not only did the labour cost of producing an aircraft frame decline with the number produced but that the rate of reduction remained constant with each doubling of cumulative production (Coulomb and Neuhoff 2006, Weiss et al. 2010). This was formalised by (Arrow 1962) who proposed that declining labour costs (per unit of output) is a result of growing experience, and that the productivity of a firm increases as the cumulative output for the industry grows. Although ‘experience curve’ and ‘learning curve’ are often taken to be interchangeable, some commentators distinguish between the two terms, using ‘learning curve’ to refer specifically to workers learning how to produce more efficiently, and ‘experience curve’ to include the combined effects of learning, specialisation, investment and scale (Isoard and Soria 2001, Nemet 2009a). The concept of learning has therefore been extended to include changes in total production costs as a function of cumulative production (including research, capital, administration and marketing, and not simply manufacturing labour costs), and it is this definition that is usually referred to as the experience curve approach (Junginger et al. 2008, Weiss et al. 2010). This thesis uses this wider term of experience curve over learning curve throughout, except where the latter is quoted directly from other sources.

Traditional experience curves are known as ‘one-factor’ because they use cumulative production as the single proxy for the combined effects captured in the definition above, with changes in cost being the dependent variable (Nemet 2006). In an attempt to address some of the criticisms of experience curves, ‘two-factor’ approaches which disaggregate the
explanatory variables have also been adopted by some analyses, and these are discussed in more detail in Section 4.3.2. Notwithstanding this, the fundamental characteristic of an experience curve is that costs reduce as cumulative production increases, and that, in theory at least, unit cost declines by an approximately constant percentage with each doubling of cumulative production or deployment (Ferioli and Van Der Zwaan 2009). The relationship between cost and deployment is therefore a straight line when shown on a log-log scale (Schaeffer et al. 2004). The same authors also highlight a potential source of confusion relating to the terms ‘learning rate’ and ‘progress ratio’ – with the former being the percentage reduction in costs achieved per doubling of cumulative production, and the latter being the new (lower) cost expressed as a percentage of the previous cost – so for example if the cost of a wind turbine has reduced from £1.5m/MW to £1.35m/MW as cumulative production has doubled, the learning rate is 10% and the progress ratio is 90%.

The experience curve approach can be used as a purely explanatory model, describing what has happened to unit costs as actual cumulative production has increased. However, if it is to be used as predictive tool for estimating future cost reductions over a specified time period then assumptions must be made regarding the rate of future production or deployment of a product or technology (to convert from cumulative production to time) and the anticipated learning rate during the forecast period (IEA 2000). The difficulties in selecting the appropriate values for these variables are discussed later in this chapter.

A key conclusion from experience curve analyses is that new technologies with relatively higher costs may become cost competitive with incumbent ones as cumulative deployment of the new technology rises. This may particularly be the case if the market for the emerging technology is growing quickly (perhaps as result of being a clearly superior product or
encouraged by strong policy support) because this will create the ‘space’ for the required increases in cumulative production volumes. Progress towards cost competitiveness may be further assisted where the market size for the incumbent technology is growing relatively slowly or is stagnant because this will limit the opportunity for the incumbent to increase cumulative deployment – since even if learning rates are constant, cost reductions will get progressively harder (and/or take longer) to achieve in practice because of the logarithmic nature of the relationship between deployment and cost – see Section 4.3.2. However, some commentators suggest that the gap between incumbent and emerging technology costs may not close if incumbent technologies experience cost reductions of their own, or that the competitive response from the incumbents may delay the achievement of cost parity for longer than a pure experience curve analysis might suggest (McVeigh et al. 1999, Contestabile et al. 2014), as illustrated in Figure 4.1 below. Furthermore, the existence of learning and experience effects does not necessarily mean that costs are guaranteed to fall, regardless of technology – a point that is discussed in Chapter 8.

Figure 4.1 Conceptual framework of power technology transitions, incorporating the levelised cost of energy and overall system operational and integration costs into the levelised effective cost of system (Contestabile et al. 2014).
As far as learning rates for power generation technologies are concerned, the range of findings from the literature has led to the use by some analysts of a rate of 20% for the energy sector as a first approximation, with the exception of nuclear power (IEA 2000, McDonald and Schrattenholzer 2001, Jamasb and Kohler 2007). There are, however, a wide range of results with Kromer (2010) finding a range of between less than 3% and over 35% in the literature. Kahouli-Brahmi (2008) finds an even greater range of 1% to 41.5% for learning-by-doing rates and observes that well established technologies such as coal (with already high global market penetration) show relatively low average learning rates of 4%. The same author finds that average learning rates for solar PV are around 20%, and Jamasb and Kohler (2007) also suggest that solar PV has achieved faster learning rates than other renewable technologies. The observation that learning rates appear higher in the earlier stages of technology deployment is supported by the example of coal power which had significantly better learning rates (in the US at least) from 1948 to 1969 than between 1960 and 1980 (ibid.). Declining learning rates were also reported for gas turbine and wind power in Albrecht (2007). However, this is not a view supported by Jamasb & Kohler (2007) who contend that ‘wind energy has demonstrated a wide range of learning rates with no obvious pattern across either locations or time periods (early versus late development stages)’ pg. 4. It would seem that it is wrong, therefore, to assume that cost reductions will always follow a smooth trajectory, even for those technologies where the overall direction has been unequivocal, such as in the case of PV (see Chapter 7).

Regardless of the precise value of the learning rate, the existence of the potential for learning has become one of the main rationales for government support for low carbon technologies and the so-called ‘buying down’ of costs (Gross et al. 2012), and also forms the basis of key assumptions in models that analyse the potential costs of moving to lower carbon economies.
(Coulomb and Neuhoff 2006). They can also provide insights into the relative allocation of resources for innovation or deployment (Jamash 2007) and facilitate the evaluation of the cost effectiveness of policy support.

In principle, and notwithstanding the concerns discussed later in this chapter, they can also be used to indicate the likely deployment level and therefore investment needed to make a technology competitive (Junginger et al. 2008, Ferioli and Van Der Zwaan 2009), although forecasting when a technology will break-even also requires an assumption over future deployment rates (IEA 2000) i.e. how long it will take for cumulative deployment to reach the level where the assumed learning curve suggests that the technology will be competitive. Figure 4.2 below draws attention to the potentially large differences in cumulative deployment (and hence costs) that must be incurred to achieve targeted cost reductions, even with apparently small differences in the assumed progress ratio (given that the axes are on log scales).

![Figure 4.2 Break-even point and learning investments. This example is for PV modules with a progress ratio of 80%. The shaded area indicates remaining learning investments to reach the break-even point. The figure also shows changes in the break-even point for progress ratios of 78% and 82% (IEA 2000)](image-url)
In summary, Nemet (2006) suggests that experience curves have a number of attractive characteristics:

- The central concept of technical improvement is consistent with the idea that organisations learn from experience.
- The availability of cost data and production/deployment data allows the model to be tested.
- Many experience curve analyses produce results with a good fit to the observed cost trajectories, assisted by the fact the approach captures the changing rate of the change in costs over time.
- The aggregation of all the factors described above into a single variable means it can be included relatively easily in energy and economic system models.

Experience curve analysis provides a potentially very powerful tool for cost forecasting, and one that numerous empirical studies have shown is supported, at least in part, by the available data. Despite these positives, the use of experience curves is not without challenges, and the following section addresses the main criticisms and limitations of the experience curve approach.

4.3.2 Limitations of experience curves
There are a number of criticisms of the experience curve approach, which can be broadly divided into two groups, with the first being those criticisms and limitations which are intrinsic to the learning curve approach and methodology (categorised as Intrinsic limitations below, and the second being criticisms and limitations which are related to the quality or applicability of the empirical data inputs, or the wider input assumptions,
categorised as **Data input and assumption limitations** below. It is recognised that there is a degree of overlap between these groupings but they are used since they provide a useful structure for understanding and categorising the criticisms described in the remainder of this section.

**Intrinsic limitations:**

**(1) Variable learning rates**

Some analysts have questioned the assumption that learning rates remain broadly constant, given that historical experience curves depict the aggregated effect of many factors that are likely to have varied over time. The trend may be subject to fluctuation depending on the period examined and the stage(s) of development a technology is passing through during the period being analysed (Kromer 2010), and there may be periods when a downward trajectory is interrupted. It may also be the case that there is no absolute or unique learning rate for a given technology (Jamalb and Kohler 2007, Yu et al. 2011). (Ferioli and Van Der Zwaan 2009) suggest that the learning rate may change over time depending on the data set considered, with (Nemet 2006) observing that assessing the timing of future cost reductions is sensitive to even small changes in learning rates (see Figure 4.2 above).

Many analyses suggest that costs tend to fall relatively swiftly during the earlier stages of product development and that, in the absence of a subsequent radical innovation, the learning rate will change to a lower level (i.e. a slowing of cost reductions) when a technology enters the more mature phase (Junginger et al. 2008, Ferioli and Van Der Zwaan 2009). Moreover, in the early years of a technology’s deployment, successive doublings of cumulative production are likely to be more easily achieved than in later, more mature stages because much greater absolute volumes are required to double cumulative production at higher production levels. On the other hand, others have suggested that this may be offset by the
larger market for suppliers to manufacturers of a mature technology leading to greater competition amongst those suppliers, in turn leading to lower input costs (Söderholm and Sundqvist 2007).

Experience suggests that in fact competitive pressures can move costs in ways that are difficult to predict. Whilst the degree of competition to supply input factors to firms may well increase with greater deployment, the degree of competition amongst manufacturers or project developers for those input factors may also increase. There is therefore the potential, at least in the short term or where supply chain confidence is relatively low, for the supply of key raw materials or components to be constrained, as was evident with PV silicon prices in the mid-2000s\textsuperscript{26}, onshore wind turbines in Germany during 1995-2001, and in the UK offshore wind sector in the late 2000s\textsuperscript{27} (Junginger \textit{et al.} 2008, Greenacre \textit{et al.} 2010).

\textbf{(2) Absence of cost floors in experience curves}

Some commentators caution that experience curve analyses which do not include a cost floor in forecasts could result in excessively high cost reduction estimates (Alberth 2008). If a market is saturated, demand is limited to the replacement of existing products which have reached the end of their service lives, which limits the opportunities for learning-by-doing and cost reduction may slow significantly or stop (Ferioli and Van Der Zwaan 2009). Technologies may also be constrained by the availability of natural resources and when those resource constraints are reached the costs of the technology may level off (ibid.). Imposing a cost floor on an experience curve analysis may guard against forecasting costs that are below the minimum costs of the inputs, but doing so does then raise the question of how such a floor should be determined.

\textsuperscript{26} See the PV case study in Chapter 7.
\textsuperscript{27} See the offshore wind case study in Chapter 5.
(3) Disproportionate influence of early trends
Cost data from the pre-commercial and early-commercial phases in technology development may be uncertain and/or unrepresentative of subsequent trends and this can have a potentially disproportionate influence over experience curve analyses (Schaeffer et al. 2004). Early cost estimates based on pre-commercial and early-commercial stage plants may be lower than for later fully commercial plants as unanticipated problems emerge and experience from these early plants feeds back into design changes (Kromer 2010).

(4) Compound systems
Technologies are typically composed of multiple elements and hence the learning system is an aggregation of different sub-systems including product manufacture and performance (Neij et al. 2003, Junginger et al. 2008). These sub-systems are each affected by different learning and cost-reduction factors but an aggregated experience curve ignores the complexity of the sub-systems and their individual potential for evolution and cost reduction (Nemet 2006). A wind turbine for example includes blades, generator, nacelle, tower and foundation, each with its own experience curve. Learning can also occur in, for example, site acquisition and preparation, installation, connection infrastructure, and improved O&M regimes to increase generator availability. Similarly in photovoltaic systems cost reductions in modules may occur more rapidly than those for installation or balance of systems components such as invertors. In theory then, learning systems can be disaggregated into multiple experience curves to give a more detailed and accurate picture of the trends involved – although in practice they are often not, largely because studies are constrained by data availability or the time involved in collecting and analysing such multiple experience curves.
(5) Application of experience curves to modular versus large-scale technologies
Some analyses suggest that learning rates and the fit of experience curves to the observed data depends on the technology considered, with more modular technology such as PV and onshore wind following the historical trend closely, while larger scale plants such as coal, gas and offshore wind show greater deviations from the trend (Junginger et al. 2008). This is supported by Neij (1997) who observes that there is an important distinction between power technologies that require extensive on-site construction, and technologies that can be mass-produced by centralised factories i.e. modular technology production can learn more quickly and have greater cost reduction potential than large plant technologies. In addition, (Junginger et al. 2008) also suggest that the greater variability and lower learning rates of larger scale plant arise, in part, from them often being very site-specific and largely custom-built (the authors also suggest that this applies particularly strongly to nuclear plants).

(6) Assumption of spillovers
Experience curve theory generally assumes that each firm in an industry will benefit from the learning-by-doing and experience of all firms i.e. that there will be a degree of knowledge ‘spillover’ between firms in the same industry. Closely linked to this is the assumption that there will be potential for spillovers from related technologies and industries, and spillovers from both within an industry and from related sectors have been included in analyses (Alberth 2008). However, in practice, firms may be expected to try to defend their intellectual property and commercial advantage, and (Nemet 2006) identifies this as one of the potential weaknesses of experience curve analysis. The assumption, therefore, of significant benefits from spillovers may therefore lead to overly optimistic conclusions regarding possible future learning rates and cost reductions.
Multi-factor experience curves

The role of economies of scale relative to learning effects are discussed in a number of recent papers (Wilson and Grubler 2011, Grubler et al. 2012, Wilson 2012) and the interaction between scale, unit size, market growth rates and policy is complex, with Neij et al. (2003) suggesting that the degree of connection and overlap makes any disaggregation very difficult. However, one of the most important criticisms of typical single-factor experience curve (SFEC) analysis has been the potential for neglect of other explanatory variables that also impact on cost (Neij et al. 2003, Pan and Köhler 2007, Yu et al. 2011). Jamasb (2007) argues that the consequence of this is to give undue weight to the effect of cumulative production or deployment, especially for emerging technologies, and therefore to produce inaccurate estimates of learning rates.

Some commentators therefore suggest that sources of cost reduction should be assessed individually and propose the inclusion of one or more additional explanatory variables to produce ‘two-factor’ experience curves (TFEC) or ‘multi-factor’ experience curves (MFEC) (Neij 2008, Yu et al. 2011), although others raise concerns over the availability of the data required (Junginger et al. 2006). The chief additional explanatory variables which commentators have suggested for inclusion in TFECs or MFECs are learning-by-researching, scale, influence of policy, competition and time, and these are discussed in turn below.

Learning by researching whereby R&D leads to technical progress and cost reduction may be accounted for in two-factor experience curves by incorporating cumulative R&D spending or the number of patents as proxies for increases in knowledge (Jamasb and Kohler 2007, Kahouli-Brahmi 2008, Mukora et al. 2009). (Jamasb and Kohler 2007) reported that comparisons of electricity generation technology learning-by-doing rates for single factor curves (based only on cumulative output) with learning-by-doing rates in two factor curves
which also include learning-by-research concluded that there are considerable differences between single and two-factor curves, and that single-factor learning curves tend to give too much weight to the effect of learning-by-doing for early-stage technologies (and therefore the effect of learning-by-researching is not recognised) and that, in some cases, the effect of learning-by-research may be more significant than that of learning-by-doing – a finding which may have important policy implications in terms of the relative importance of policies to expand capacity and investment in R&D. There is a recognition that incorporating learning-by-researching into two-factor experience curves is not widely used, partly because whilst the approach provides a potentially good fit for the innovation stage it cannot capture well the ‘learning-by-continuous research’ that takes place in the later stages of deployment (Pan and Köhler 2007) pg. 753, and also that separating the effects of R&D and cumulative deployment can be problematic (Ferioli and Van Der Zwaan 2009).

*Scale effects* are treated by most analyses as an inherent part of the experience curve and not disaggregated, but their absence as a distinct factor may have an impact on the accuracy of learning rates (Söderholm and Sundqvist 2007, Kahouli-Brahmi 2008). Hall and Howell (1985) suggest that cost reductions may be just as closely correlated with the current scale of production as they are with accumulated output to date which, if correct, would imply that cost reductions in the later years of a technology may be driven by economies of scale effects rather than long-term learning effects. Some studies such as (Isoard and Soria 2001, Yu *et al.* 2011) have attempted to separate learning effects from returns to scale effects and (Söderholm and Sundqvist 2007) argue that not including the effects of returns to scale in analyses of nuclear generation costs means that the impact of learning effects is overstated. Nemet (2006) also stresses the contribution of manufacturing economies of scale to the observed cost reductions of PV modules.
Policy measures, some analysts contend, should also be assessed to determine their influence, with Soderholm and Sundqvist (2007) suggesting, for example, that fixed feed-in tariffs may reduce the incentive for innovation (and therefore have an influence on the speed of cost reductions), whilst Junginger et al. (2008) suggest that there is no clear evidence that policy support manifested through publicly funded R&D activities directly influences cost reductions.

Competition may also be a factor to incorporate into cost reduction analyses. Soderholm and Sundqvist (2007), for example, argue that mature technologies may benefit from increased competition amongst their suppliers (and therefore lower input costs). Supporting this proposition, (Greake and Lund Sagen 2008) found that competition was the most significant factor in their study of the falling cost trend for liquefied natural gas (LNG) plant.

Time, it is argued, may need to be explicitly included in analyses of costs and future estimation, and that ‘accounting for time improves the understanding and use of learning curves’ (Ferioli and Van Der Zwaan 2009) pg. 4002. In support of this, the same authors also contend that experience as measured by cumulative production or deployment should not be the only explanatory variable, and that the existence of a good fit between costs and capacity does not necessarily mean that a constant learning rate can be assumed – and that learning rates may vary over time.

The additional factors of learning-by-researching, scale, influence of policy, competition and time described above may have relatively more or less influence at different stages in the evolution of a product or technology. Using the example of solar PV development, (Yu et al. 2011) suggest that at the technology’s emerging stage neither learning-by-doing or
economies of scale played a significant part in cost reductions, and the factors that drove the cost decline were input prices (primarily silicon) and other factors such as learning-by-researching and government subsidies. At the diffusion stage, economies of scale were beginning to play a role in cost reduction, as was learning-by-doing, whilst input prices were still important. The authors found that at the mature stage, learning-by-doing and the returns to scale effect were the dominant factors. This is consistent with analysis by Kahouli-Brahmi (2009) who suggests that early stage, emerging technologies have low learning rates, evolving technologies show high learning-by-doing and learning-by-researching rates, and established technologies display low learning rates but increasing returns to scale.

Data input and assumption limitations:

(1) Inadequate, inappropriate, and incomplete data

Experience curves rely on analysis of historical cost data, but obtaining suitable data may be difficult (Sharp and Price 1990), and this has led some commentators to suggest that the absence of such data over sufficiently long time periods is a key drawback in the use of experience curves (Mukora et al. 2009). This problem is particularly acute for energy technologies that are still in an emergent phase because the availability of data is likely to be limited. An example which highlights this problem can be seen in attempts to forecast future costs of UK offshore wind energy where, until recently, there was little primary data from which to construct experience curves because there was very limited deployment of the technology. In an attempt to circumvent this problem early assessments of the future costs of offshore wind used as a proxy ‘borrowed’ learning rates from the onshore wind sector (Greenacre et al. 2010) despite the wide variation in onshore wind learning rates (McDonald and Schrattenholzer 2001) and the differences in costs breakdown between the onshore and offshore sectors (Blanco 2009, Feng et al. 2010). In the event, costs did not follow the expected downward trajectory, the reasons for which are explored in the offshore wind case
study in Chapter 5. Constructing forward-looking cost trajectories based on experience curves is also very sensitive to the initial costs data, and selecting the level of cumulative capacity at which cost reduction is anticipated to begin is also important, particularly because costs may not fall during the early stages of a technology’s deployment (Mukora et al. 2009).

A limited data series may not reveal important trends and, in response to this, (Ferioli et al. 2009) suggest that cost data should span ‘several orders of magnitude of cumulative production’ pg. 2530. The issue of what constitutes a sufficient level of data can also be addressed in terms of time, with Schaeffer et al. (2004) suggesting that a period of at least ten years’ worth of historical data should be available if experience curves are to be used to produce cost forecasts.

(2) Costs, prices, currency conversion and inflation

In principle, experience curves should be constructed from cost data but since such data may be commercially sensitive they may not be available outside of the firms actually producing the technology. The solution is often to use price data but this may not be an accurate reflection of true underlying costs (IEA 2000, Kromer 2010), not least because profit levels will tend to fluctuate as market and competition conditions vary which makes adjusting price data to reflect costs by removing ‘normal’ profits problematic. This concern is also raised by (Schaeffer et al. 2004) who suggest that results will be misleading if experience curve data is drawn from a period which does not adequately reflect the full degree of fluctuating market conditions, compounded by the fact that the ratio of cost to profit may vary quite significantly during different phases of a technology’s development (Junginger et al. 2008).

Currency conversions and corrections for inflation can also introduce errors into experience curve analysis, especially when using data from a country which may have experienced
significant currency fluctuations or periods of high inflation (Schaeffer et al. 2004). This problem is not unique to experience curves, as is recognised in the discussion of data collection for this thesis in Chapter 2 but the relatively long time periods required to make experience curve analysis robust do increase the risk of these factors having a material effect on the findings.

(3) **Input costs**

Whilst historical technology cost data will reflect past fluctuations in input costs such as raw materials, a number of studies note that experience curves used to forecast future costs cannot forecast any future variability in those input costs (Junginger et al. 2008, Greenacre et al. 2010). This issue is particularly relevant to the experience of the major UK generating technologies in recent years where potential learning effects and other sources of cost reduction have sometimes been overwhelmed by ‘exogenous shocks’, especially in the form of commodity and fuel feedstock price increases (Gross et al. 2013).

(4) **Deployment assumptions**

Experience curves typically reflect cost changes relative to cumulative deployment so to forecast costs for some point in the future, assumptions must be made about deployment rates over time. These assumptions are subject to uncertainty and may turn out be inaccurate, which in turn may lead to inaccuracy in the level and timing of possible future cost reductions (Junginger et al. 2008).

(5) **System boundaries**

Whilst learning rates and experience curves originated at the firm level, the system boundary has since been expanded to take in entire industrial sectors at a national, regional or global level, and the learning rates of each may vary. For example, (Junginger et al. 2008) observe
that whilst global experience curves have generally been produced for PV modules, studies for wind turbines tend to be country-specific. The rate and range of learning and cost reduction may also depend on the extent to which a technological development is associated with a specific geographical area. Furthermore, some commentators have argued that country-specific experience curves may not be a good guide to the actual global rate of cost reduction of a technology (ibid.).

The body of literature reviewed in this section suggests that there is convincing (although by no means uncontested) evidence to support the use of experience curves, either to provide an explanation of observed historical cost reductions, or as a tool for forecasting the future trajectory of a technology’s costs. Whilst the limitations of experience curve analyses are recognised, they have played, and continue to play, a key role in underpinning policy, providing a rationale for interventions to increase deployment and drive down costs, and also as a tool for estimating how long such policy interventions may be required for. The following section goes on to discuss the alternative approaches of engineering assessment and expert elicitation, recognising that these approaches are sometimes used to complement, or in tandem with, experience curve analyses.

4.4 Engineering Assessment and expert elicitation

4.4.1 Overview
The first stage of the engineering assessment approach to cost estimation and forecasting is to break down a technology into its component parts and then, in the second stage, draw on engineering and other expert advice to assess the potential for technical changes and possible cost and efficiency improvements separately in each component. The third stage then aggregates the findings for each component (using different weighting factors if appropriate)
to give an overall estimate for the technology in question (Mukora et al. 2009). A part of such assessments may also be to identify other key drivers such as changes in raw material costs to build a ‘composite cost index’ (Arup 2011) pg. 8. Typically, technologies are assessed and placed on a spectrum that ranges from ‘emerging’ to ‘mature’ with emerging ones considered to have the greatest potential for further development and cost reduction through innovation and returns to scale (Chapman and Gross 2001). Analysis of future cost or performance may combine a degree of qualitative review, often based upon expert judgement, with quantitative evaluation based on findings from previous estimation or parametric modelling (discussed below), or by comparison with other technologies which are thought to share some characteristics, and for whose cost trajectories there may be better data available (Mukora et al. 2009).

Engineering assessment therefore has the potential to provide a detailed analysis over a range of time periods, and can provide an understanding of the engineering and technical factors that drive cost reduction, help identify the scope for technical progress, and provide insights into how any limitations of current designs can be overcome. A key advantage of engineering assessment is that it need not rely on previous trends in cost reduction – trends that may not be repeatable, are uncertain because market experience is limited, or are judged to be not indicative of the future cost reduction potential of the technology under consideration. (Mukora et al. 2009) also highlight a related strength – the potentially greater ability of engineering assessment, compared to experience curves, to provide insight into possible discontinuities (i.e. step changes and transitions) in the trajectory of technological development and therefore to anticipate and factor in radical as opposed to incremental change.
The approach of expert elicitation builds on the process of seeking input from experts described above, but is refined into ‘a systematic process of formalizing and quantifying, typically in probabilistic terms, expert judgments about uncertain quantities’ (EPA 2011) pg. 1. The approach can therefore ‘inform decisions by characterising uncertainty and filling data gaps where traditional scientific research is not feasible or data are not yet available’ (ibid.) pg. 1. Expert elicitation is intended to be a more rigorous, systematic approach than individual expert judgement alone and can be used to produce distributions of the values for an uncertain parameter, and is particularly useful where the values of that parameter are difficult to measure or where the available data sets are insufficient (ibid.).

There are numerous examples of the use of expert elicitation for forecasting future electricity technology costs, including (Bosetti et al. 2012, Anadon et al. 2013, Usher and Strachan 2013, Ricci et al. 2014). The Usher and Strachan 2013 work used the approach to address uncertainties in a number of key inputs to an energy system optimisation model, including expert views on the levelised cost of energy in 2030, aggregating the results mathematically (and arriving at a range of results that were similar to the range presented in (Heptonstall 2007)). Whilst there are several mathematical techniques which can be used to aggregate expert elicitation results, a simple average is often used, as in (Usher and Strachan 2013) because it is straightforward and has been shown to produce adequate results (EPA 2011). (Anadon et al. 2013) and (Bosetti et al. 2012) focused on expert views on the effects of research, development and demonstration (RD&D) investment for future nuclear and PV technologies costs respectively, with (Anadon et al. 2013) in particular finding marked differences in results depending on the sector and geographical region of the experts. (Ricci et al. 2014) focussed on expert views on the range of energy penalties associated with different carbon capture technologies, feeding the results of the elicitation process into an
integrated assessment model. Interestingly, one of the justifications used for the expert elicitation approach by (Bosetti et al. 2012) was that it was a response to the difficulties (and attendant criticisms) of extrapolating future costs from past experience curves, particularly where there were discontinuities in the trajectory, or ‘non-reproducible events’ as the authors put it (pg. 315).

4.4.2 Limitations of engineering assessment and expert elicitation

As (Mukora et al. 2009) acknowledge, ‘Satisfactorily representing and forecasting technical change for early-stage technologies is a formidable challenge’ pg. 157. The main limitations with engineering assessments that are based on expert opinion is that those opinions can differ, and may be open to interpretation and manipulation or excessive optimism (Chapman and Gross 2001, Schaeffer et al. 2004). Assessments are also open to straightforward error, both in terms of how to parameterise the costs of a product or process and in terms of the data input for each parameter (Koonce et al. 2007). For new technologies in particular, cost estimates may vary considerably and estimating costs for technologies still in the early stages of development is particularly difficult (Mukora et al. 2009).

The expert elicitation approach is, in part, an attempt to address some of these limitations by seeking to determine the range and distribution of views, and identifying any areas of bias, but the engineering assessment approach can also be refined through the use of parametric cost modelling, a technique which is applicable to products or technologies in many stages of development, and which uses functional ‘cost estimation relationships’ to define links between a specified set of characteristics and cost. The approach builds a set of relationships that reflect the mathematical link between the characteristics of a component and its cost, which are in turn derived from past experience and from engineering expertise (Koonce et al. 2007).
2007). (Mukora et al. 2009), however, caution that this approach is not as applicable to forecasting over longer time horizons as other methods, that it cannot incorporate the potential effects of radical changes, and that it is, of course, dependent upon being able to correctly define the functional forms of the cost estimate relationships on which the technique relies.

A significant concern associated with the expert elicitation approach is the need to prevent bias, or at least acknowledge where it exists. In recognition of this, ‘best practice’ for expert elicitation would normally be expected to ensure that the mechanism for the selection of experts is very clear, and that the background and basis of qualification of each expert is understood so that any bias which emerges in the results, such as in (Anadon et al. 2013) described above, can be explained (EPA 2011). Whilst there are a range of techniques to account for bias, some related to the process design and others related to the statistical analysis of the results, it is recognised that bias cannot be eliminated completely, and indeed in some cases the skewing of results based on the background of the experts can be an important research finding in its own right. Finally, it is important to recognise that the expert elicitation process does not remove the uncertainty but the approach can at least help to characterise and quantify that uncertainty (ibid.).

The engineering assessment and expert elicitation approaches discussed in this section provide alternative and somewhat complementary methods to the experience curves-based analyses described in the previous section. Whilst neither approach is without limitations, the evidence suggests that they are able to yield useful insights into the trajectory of future costs, particularly where there is insufficient data to construct reliable experience curves or where the data that is available is not considered to be a good indicator of future trends.
4.5 Cost reduction forecasting techniques in recent policy analysis

It is perhaps tempting to view the methodological approaches described in this chapter as competing tools but in recent years several of the electricity cost analyses conducted for the UK Government have adopted a mixed approach which draw lessons, insights and data from a range of approaches (Mott MacDonald 2010, Arup 2011, Parsons Brinckerhoff 2011, Parsons Brinckerhoff 2012, Parsons Brinckerhoff 2013). The Mott MacDonald work, for example, explicitly addressed concerns over the reliability and applicability of the available cost data and assumptions over the degree of learning that would be expected to occur in moving from ‘first of a kind’ (FOAK) to ‘nth of kind’ (NOAK), acknowledging that their analysts were ‘forced to make informed judgements’ where there was insufficient or unreliable data (Mott MacDonald 2010) pg. 7.

The (Parsons Brinckerhoff 2011) work was based on a review of costs data sources with each source reviewed by the analysis team to assess its credibility (effectively benchmarking them to the analysis team’s expert views). An interesting aspect of this work was that the experience curves which were used to forecast cost reductions were not universally assumed to start at the date of the analysis, so for some technologies any downward cost trajectory did not begin until a date in the future – a point of particular relevance in the light of the lessons from the offshore wind and nuclear case studies (see Chapters 5 and 6). Also in 2011, Arup combined assumptions about global technology deployment levels and experience curves with data drawn from ‘industry literature’ and consultation with stakeholders (Arup 2011) pg. ix. The (Parsons Brinckerhoff 2012) analysis followed a similar approach, using a combination of published experience curve data and their own expert judgement (although with no formal stakeholder consultation). An interesting aspect of this analysis was that it recognised the problems inherent in basing experience curves for a particular technology on
an apparently similar technology, noting that where the technologies are very similar then most of the learning and cost reduction may have already occurred and if the technologies are not similar, then the validity of using such proxy experience curves may be limited – a point which resonates with the UK experience of offshore wind discussed in Chapter 5. The work also made an interesting point when it notes that ‘due to the unavailability of a robust source of learning rates for new nuclear an indicative rate of 5% was used’ (Parsons Brinckerhoff 2012) pg. 19. Chapter 6 discusses the degree of evidence available to support assumptions over learning and cost reductions for nuclear power. The concerns raised in all these analyses are clearly recognised in recent UK Government electricity cost reports with (DECC 2012b) and (DECC 2013c) acknowledging the considerable degree of uncertainty in data on current costs28, in the application of experience curves, and in determining when technologies can be assumed to start moving down the costs curve from FOAK to NOAK plants.

4.6 Conclusion

The discussion presented in this chapter suggests that the explanatory power of learning curves can provide useful insights for the historical aspects of technology cost trajectories, helping to answer the ‘what is going on?’ question (see Chapter 2). However, it appears that the predictive power of the learning curve approach is more contested, and the uncertainties are clearly recognised. Nevertheless, experience curves have the useful characteristic of being relatively straightforward to model (in their traditional single-factor form at least), and therefore lend themselves to forecasting rather than being limited to the examination of the drivers of past trajectories, but a particular challenge that remains for long-term forecasts is that even relatively minor variations in learning rates can lead to significantly deviating cost estimates over the (frequently long) time periods that apply to energy policy and investments.

28 See also Chapter 3 on the characterisation of uncertainty in cost estimates.
The limitations of experience curves described in this chapter (both those that are intrinsic to the approach and those that relate to input data and assumptions) have led some commentators to the conclusion that experience curves as a predictive tool may only be suitable for medium-term forecasts of established technologies under ‘conditions of low uncertainty and for a series of incremental innovations’ (Neij 2008) pg. 2201, and that the further into the future an estimate is based, the more inaccurate it is likely to be. Furthermore, it may be difficult or impossible to predict accurately when the factors which drive cost reductions could be overwhelmed by supply-side constraints such as increasing commodity prices, labour shortages, and lack of manufacturing or installation capacity, a theme that this thesis returns to in the case studies and the discussion. Whilst recognising the limitations, others argue that the evidence does provide support for the use of experience curves, that the limitations do not fatally undermine their use, and that ‘the evidence for some degree of experience-based cost reduction is overwhelming’ (Jamasb and Kohler 2007) pg. 12. It is also clear that they continue to play a key role in electricity cost forecasting for policy analysis, providing a justification for support aimed at increasing the deployment of emerging technologies, and helping to predict how long such support may be required for.

The engineering assessment and expert elicitation approaches offer the advantage, especially in the early stages of technology deployment, of not being reliant on past trends, and so can be particularly useful where such data is absent, limited or considered to be an unreliable predictor of the future. The disaggregated assessment of sensitivity to change in key cost parameters can also provide useful insights for policy, identifying the most promising areas for future cost reduction (and therefore where policy may best be focussed). Neither approach, however, can completely eliminate any bias (whether conscious or not) in the views of the engineers and other experts on whose analysis and opinion these methods are
based. The absence of reliance on historical trends does give the potential for the effects of discontinuities or disruptive events (both positive and negative) to be assessed, although of course doing so does then rely on opinions over the nature, likelihood and timing of any such events.

The electricity cost estimates and forecasts which underpin UK policy increasingly draw upon a combination of the approaches discussed in this chapter, recognising that all can provide valuable insights but also that no single approach is without drawbacks or limitations. In this respect, acknowledgement of the inherent uncertainties discussed in both this chapter and Chapter 3 is key, and this thesis returns to the theme of uncertainty (and the policy response to that uncertainty) in the case studies and the discussion.
5 Offshore wind case study: Increasing policy ambitions and rising costs

5.1 Introduction

This chapter describes the divergence between cost expectations and reality for offshore wind from the mid-2000s onwards and discusses the reasons why costs rose considerably, against a backdrop of rising policy ambitions. The chapter then goes on to describe the results from a levelised cost model developed by the author and colleagues to demonstrate sensitivities to the major cost drivers, form a view as to the plausible range of medium-term cost forecasts and compare these to more recent forecasts from other sources. The chapter draws upon offshore wind costs research undertaken by the author for the UK Energy Research Centre (Greenacre et al. 2010), later work on electricity cost estimates (Gross et al. 2013), and a journal paper (Heptonstall et al. 2012).

Offshore wind is expected to play a key role in meeting the UK Government’s ambitious targets for electricity generation from renewable sources during the current decade. Whilst the UK’s national target under the EU 2008 Renewables Directive is for 15% of total energy consumption to come from these sources by 2020, it is anticipated that more than 30% of electricity will have to be generated from renewable sources by 2020 if the Renewables Directive target is to be met (BERR 2008b) compared with an actual figure of around 11% for 2012 (DECC 2013h). Although there is no specific target for the share of this generation that will come from offshore wind, it is expected that it will make a major contribution, partly because of the excellent offshore wind resources which the UK has (BCG 2010), and partly because moving offshore avoids some (but not all) of the issues which have led to public opposition to onshore wind farms. Analysis for DECC’s Electricity Market Reform Delivery Plan suggests that 8-15GW of offshore wind generation could be installed by 2020 (DECC 2013d), with the potential for further substantial increases in installed capacity beyond this.
date. Current (June 2014) installed capacity for UK offshore wind is around 3.7 GW, compared to around 7.2 GW of onshore wind (RenewableUK 2014). An indicator of the scale of the potential is the development rights which have been awarded to date – for offshore wind in the UK these are awarded by the Crown Estate (the owner of the seabed) and these rights have been awarded in 3 rounds. Rounds 1 and 2 granted rights for a total of around 8 GW of development, and Round 3 rights, awarded in early 2010, were for over 30 GW of potential development (The Crown Estate 2010a, The Crown Estate 2010b).

5.2 Cost forecasts and outcomes
As Figure 1.1 in Chapter 1 shows, electricity generation cost increases are not confined to offshore wind and since the mid-2000s costs for all the major electricity generating technologies have risen considerably. That notwithstanding, by 2009 the costs of offshore wind had risen very substantially, at a time when aspirations for deployment of this technology were very high. This section highlights the divergence between cost expectations and reality from the mid-2000s and summarises the factors that drove those cost increases.

5.2.1 Expectations of future costs
Figure 5.1 below presents a summary of the forecast capex values reported in the literature, and shows the in-year average forecast costs for two groups, one consisting of those forecasts made up to 2005 (shown with diamonds), and one of those forecasts made from 2005 through to 2009 (shown with circles). Amounts have been converted from the original reported currency into GBP at the exchange rate prevailing at the year of the estimate, and inflated to 2009 values.
The data presented in Figure 5.1 reinforce the message that analysts have consistently expected costs to fall over time. What changed in the mid-2000s is that forecast costs in the relatively near future were higher, but were still expected to fall in the longer term, returning to broadly the same level as earlier forecasts. Since this implies a higher rate of cost reduction, it raises the question as to what is influencing these expectations. There may be good reasons to expect or hope that long run costs can be reduced a great deal, but it is important to understand the basis of such expectations.

5.2.2 Contemporary estimates
Cost estimates had increased significantly by the mid-2000s with inflation-adjusted capital costs in 2010 centred around £3m/Megawatt (MW) installed, compared to around half that
less than 10 years earlier (see Figure 5.2). The typical 2010 capex estimate of around £3m/MW translates into a levelised cost of around £140-150/MWh, depending on other input assumptions, a figure that is broadly consistent with the ‘administered’ Contract for Difference strike prices published in (DECC 2013i).

![Average actual CAPEX (per MW, 2009 GBP)](image)

**Figure 5.2** Offshore wind in-year average, minimum and maximum actual capex, adapted from (Greenacre *et al.* 2010)

### 5.2.3 Cost trend drivers

The drivers of these cost increases include (in approximate descending order of impact):

- Rising materials, commodities and labour costs
- Adverse currency movements (particularly the fall in value of Sterling compared to the euro)
- Rising costs of offshore turbines due to supply chain constraints and additional engineering issues associated with operating in the marine environment
- The increasing depth and distance from shore of some projects (which affects installation and operation and maintenance costs)
- Constraints in the availability of installation vessels and suitable ports
- Planning and consenting delays

The principal factors are discussed in more detail below.

**Turbine prices and component supply squeeze**

Several drivers contributed to an increase in turbine prices though evidence that disaggregates their individual effects is limited. Together with the increasing cost of commodities, the rise in turbine prices was due in part to the cost of engineering/marinisation improvements in the face of poor availability experience. In addition, (Gordon 2006) noted that by the mid-2000s rapid growth in the US onshore wind industry caused by the US Production Tax Credit (PTC) scheme was resulting in a global shortage of turbine components, delaying European offshore projects and forcing up prices.

By 2007, turbine supply was the dominant bottleneck with the UK offshore sector squeezed by onshore turbine demand from China, India, and elsewhere in Europe as well as the US (BVG Associates 2007). Reinforcing this, (Douglas-Westwood 2008) reported that the combination of a strong market and constrained supply drove onshore turbine prices upwards by 30% between 2006 and 2008, whilst (Ernst & Young 2009) studied the evolution of
turbine costs over time for a range of UK Round 1 and Round 2 projects and suggested that offshore wind turbine costs were likely to increase 67% from an average of £0.9m/MW to around £1.5m/MW over the five year period to 2011.

Since offshore turbines have occupied a small niche relative to onshore turbine markets it is perhaps understandable that a ‘niche premium’ would attach to the offshore market (Greenacre et al. 2010). Whilst the cumulative global installed capacity of offshore wind has more than doubled in the four years to the end of 2014 (to almost 9 GW), the size of the global market is still small relative to onshore wind, with just under 50 GW installed onshore during 2014 and less than 2 GW installed offshore in the same period (GWEC 2015). Commentators have also speculated on the possible impact on competition given the limited number of companies engaged in turbine manufacturing for the UK offshore wind industry (BWEA 2008, Carbon Trust 2008, Ernst & Young 2009, RAB 2009, Offshore Wind Cost Reduction Task Force 2012). Until relatively recently the offshore wind market has been completely dominated by Siemens and Vestas who together accounted for 98% of offshore turbines installed in the UK up to 2009 (Ernst & Young 2009), and have therefore been in a position to pass on high commodity and component costs, although new market entrants are now appearing, see below.

- Depth and distance
UK Round 2 projects are more distant from shore and in deeper waters than Round 1 projects with Round 2 projects often being nearly double the depth and more than double the distance from shore of Round 1 projects (4C Offshore Limited 2010). Unsurprisingly, an increase in depth and distance can have a significant impact, influencing construction, installation, electrical infrastructure, and operation and maintenance costs. Depth is a primary factor in engineering design and foundation size during the construction and installation phase. For
example, foundation costs can rise from approximately £0.4m - £0.5m per MW for 20m depth to £0.5 - £0.625 per MW for 35m depth (Ramboll Offshore Wind 2010). Of particular relevance to later UK Round 2 and 3 sites, the Carbon Trust found that foundation costs for sites in 40 to 60m of water were 160% greater than for sites in 0 to 20m of water (Carbon Trust 2008).

Distance from shore is a factor both at the installation stage and also during operation because of maintenance and repair requirements. It also impacts on electrical infrastructure costs, in particular the amount of transmission cabling required. (Ernst & Young 2009) analysed the evolution of electrical infrastructure costs versus distance from shore for a range of Round 1 and Round 2 projects and found that infrastructure costs doubled from around £0.3m - £0.4m per MW for projects less than 5km from shore to £0.8m per MW for projects 20km from shore.

- **Operation and maintenance costs**

Operation and maintenance (O&M), costs for UK Round 1 sites were greater than expected, in part due to the inadequate marinisation of onshore machines (ODE Limited 2007) leading to higher than anticipated levels of breakdown and repair, and consequent non-availability (which in turn affects load factor, see below). In addition, O&M costs have been increasing, at least since the mid-2000s, as projects have been built further from shore. Additional factors, according to (Ernst & Young 2009), include more preventative but costlier maintenance strategies, higher labour and logistics costs, a stronger Euro, and some re-estimation of previously under-estimated O&M budgets in the light of experience gained from earlier projects.
- **Availability/reliability and load factor**

The load factor of a wind farm is primarily dependant on wind conditions and the availability of turbines and related equipment\(^{29}\). Offshore wind speeds are generally higher and more stable than onshore sites with (Snyder and Kaiser 2009) suggesting that moving onshore to offshore should lead to an increase in the load factor from roughly 25% to 40%. However, some early UK offshore farms experienced lower than expected availability resulting from gearbox failure (especially bearings), generator failures, subsea cable damage and operator access limitations (BVG Associates 2007). (Feng et al. 2010) reported that UK Round 1 projects experienced only 80.3% average availability with an annual average load factor of 29.5% – higher than the average value of 27.3% reported in 2007 for UK onshore wind farms but lower than the expected 35.0% for UK offshore, and significantly lower than the reported capacity factors of at least 40% for some Danish offshore wind farms (Wind Stats 2009b, Wind Stats 2009a).

- **Commodity prices**

In the offshore wind sector, the most significant commodity is steel which had typically accounted for around 12% of total project cost (BWEA and Garrad Hassan 2009). From 2002 to 2007 the steel index Compound Annual Growth Rate (CAGR) was 47% although in 2008 it fell by 58% returning to the long-term historic trend (Ernst & Young 2009). This increase in steel prices from the early 2000s was a contributing factor to turbine costs rising from £0.9m to £1.5m/MW (67%) in five years (RAB 2009). Steel price rises played an even greater role in the escalating costs of foundations, increasing from around £0.25m to £0.7m/MW (a 180% increase) over the five years to 2009 (Ernst & Young 2009).

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\(^{29}\) Maximising load factor may not, in isolation, deliver the maximum return on investment because of the non-linear relationship between turbine size, cost and actual output at a given site (Krohn et al. 2009).
The cost of other relevant commodities, such as copper, also increased. Between 2002 and 2006 commodity prices grew at 19% CAGR. However, between 2007 and 2009 with the onset of the global credit crisis the commodity prices index fell by 5% CAGR, although it remained substantially above the historical trend line. Analysis by The Carbon Trust in 2008 suggested that if commodity and materials prices were to return to 2003 levels, overall offshore wind power costs would fall by 11% (Carbon Trust 2008).

- **Euro/Sterling exchange rate**

The Euro/Sterling exchange rate also contributed significantly to the rise in costs borne by UK offshore wind developers. At the time, around 80% of the value of a typical UK offshore wind farm was imported and was either priced in Euros or priced in a currency tied to the Euro (Greenacre et al. 2010). Since 2000 when the exchange rate was approximately €1 = £0.60, the Euro gradually increased in value against the pound, reaching almost one-for-one parity in December 2008, with UK developers experiencing increases in component costs as a result. However, recent analysis suggests that over 40% of the costs incurred during the lifetime of a UK wind farm are now spent in the UK, with significant potential to further increase the UK-based share of the supply chain (OWIC 2014).

O&M costs were also affected by the strength of the Euro. In addition, vessels and support services have been largely sourced from continental Europe, hence installation costs also rose (Ernst & Young 2009). The overall effect was that, whilst prices for commodities had fallen from 2008 as a result of the global downturn, any positive effect on turbine prices had until recently been more than offset by the appreciation of the Euro against Sterling (Ernst & Young 2009).
- **Cost of finance**

In principle, if an offshore wind developer were to use project finance, then the increasing experience in construction and operation would be expected to gradually reduce the risk premium for offshore installations resulting in a decreasing cost of capital. However, utility developers, who were responsible for the majority of capacity installed during the period, typically used balance sheet financing. The consequence of this was an increase in funding costs because of the 2007/2008 crisis in the global credit markets, with the marked rise in spreads for utility bonds from mid-2007 onwards resulting in a higher cost of corporate debt (Ernst & Young 2009).

5.2.4  *The policy response to rising costs*

The 2006 Energy White Paper (DTI 2006) was largely positive about the prospects for offshore wind in the UK but concerns were being raised as to whether the policy support via the Renewables Obligation (RO)\(^{30}\) mechanism then in place would be sufficient to bring forward the scale of projects implied by UK Government aspirations (EAC 2006). At the time, the RO was intended to provide ‘technology neutral’ support for renewables, leaving it to the market to decide on the most cost-effective technology mix to meet the obligation level.

In 2006 the Environmental Audit Committee called for support to be differentiated by technology (EAC 2006) through a revised RO mechanism known as ‘ROC banding’, where multiple Renewable Obligation Certificates (ROCs) per MWh are awarded to generation

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30 The RO is a certificate trading-based scheme which imposes an obligation on electricity suppliers to source a percentage of their electricity from renewable sources, leaving it to the market to decide how that obligation is met. A ‘buy-out’ mechanism gives suppliers the option (at a cost) to under-deliver on their obligations, in the process creating a fund which is then shared amongst holders of ROCs to reward them for each MWh or renewable electricity they have sourced. The buy-out price is capped, protecting consumers from potentially excessive costs. A more detailed description and critique can be found in (Gross and Heptonstall 2010). The RO scheme is being replaced by the Contracts for Difference scheme introduced as part of the Electricity Market Reform process.
from those technologies deemed to have higher costs, with reductions for particularly low
cost renewable technologies. However, it was not until 2009 when support for offshore wind
projects was increased, initially by awarding 1.5 ROCs per MWh. The level of support was
soon increased to 2 ROCs per MWh in response to analysis which concluded that projects
would not be taken forward even at 1.5 ROCs per MWh (Ernst & Young 2009).

These increases in support were enacted in the context of sharply rising aspirations for
offshore wind deployment with prospective project developers bidding for over 30GW of
Crown Estate Round 3 sites. Successful bids for sites totalling 32GW were announced in
early 2010 and these were further augmented by extensions to Round 1 and 2 sites (often
referred to as ‘Round 2.5’), also awarded in 2010. Against this backdrop, the policy decision
was to respond very positively to the evidence of rising costs, by substantially increasing the
level of support available. Initially, the increased ROC multiple was intended to be relatively
short term, available for projects accredited up to early 2014. However, the support level
available from 2 ROCs was also reflected in the strike prices available under the ‘Final
Investment Decision (FID) Enabling for Renewables process’ (DECC 2014g).

5.3 Levelised cost model input assumptions and cost sensitivity
Taken together, the direction of the cost drivers in the mid-2000s created the conditions for
the large cost increases shown in Figure 5.2. Nevertheless, the expectation that offshore wind
costs would still fall substantially at some point in the future has sustained (see Figure 5.1)
which leads to the question as to whether or not these expectations are plausible and/or likely.
This section uses a levelised cost model developed by the author and colleagues (Greenacre
et al. 2010, Heptonstall et al. 2012) to demonstrate sensitivities to the major cost drivers and
derive a range of medium-term cost forecasts so that these can be compared and contrasted to more recent forecasts from other sources (BVG Associates 2012, The Crown Estate 2012).

At a minimum, a levelised cost model requires starting assumptions about the capital (investment) costs, operation and maintenance (O&M) costs, expected project lifetime, expected output and the discount rate (see Chapter 3). There are, of course, no direct fuel costs for renewable generation such as wind power. The approach used for (Heptonstall et al. 2012) required a more disaggregated set of inputs so that the sensitivity to the various cost drivers could be explored. This involved breaking the total capital cost down into the major components (such as turbine and foundations), and separating the O&M costs into those costs related to physical maintenance and those costs related to non-physical services such as insurance.

The data used for the ‘base case’ calculation were drawn from (Carbon Trust 2008, BWEA and Garrad Hassan 2009, Ernst & Young 2009) and are shown, together with the resultant levelised cost per MWh, in Table 5.1 below.

<table>
<thead>
<tr>
<th>Component/input parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine (including tower)</td>
<td>£1.5m/MW (47% of capex)</td>
</tr>
<tr>
<td>Foundations</td>
<td>£0.7m/MW (22% of capex)</td>
</tr>
<tr>
<td>Electrical infrastructure</td>
<td>£0.6m/MW (19% of capex)</td>
</tr>
<tr>
<td>Planning and development costs</td>
<td>£0.4m/MW (12% of capex)</td>
</tr>
<tr>
<td>(O&amp;M) (physical)</td>
<td>1.6% capex pa</td>
</tr>
<tr>
<td>O&amp;M (non-physical)</td>
<td>1.4% capex pa</td>
</tr>
<tr>
<td>Project life</td>
<td>20 years</td>
</tr>
<tr>
<td>Load factor</td>
<td>38%</td>
</tr>
<tr>
<td>Discount rate</td>
<td>10%</td>
</tr>
<tr>
<td>Proportion of total costs exposed to currency risk</td>
<td>80%</td>
</tr>
<tr>
<td>Steel costs contribution to total costs</td>
<td>12%</td>
</tr>
<tr>
<td>Base case calculated levelised cost</td>
<td>£144/MWh</td>
</tr>
</tbody>
</table>

Table 5.1 Offshore wind base case assumptions and result
Sensitivity to changes in the cost of key factors

The model takes the base case values from Table 5.1 and then allows the application of a percentage multiplier (either positive or negative) to individual cost components, and recalculates the overall levelised cost (and also the revised percentage contribution that each category makes to overall levelised costs). Starting from this base case, the sensitivity to the most significant cost drivers was explored by adjusting their values within the ranges shown in Table 5.2. There are, of course, other cost drivers such as the availability of installation and maintenance vessels, port facilities, wider macroeconomic conditions, cost of commodities other than steel, and labour costs, as well as the more intangible effects of planning and consenting issues and the level of confidence in the supply chain. This analysis, however, is focused on those cost drivers which were considered to have the greatest impact on total costs.

The ranges selected are based upon previous analysis, principally (Carbon Trust 2008, BWEA and Garrad Hassan 2009, EWEA 2009, RAB 2009, BCG 2010, Mott MacDonald 2010). Where there is clear evidence to suggest that the plausible range for a particular cost driver is asymmetric, such as in the case of turbine costs, then this is reflected in the sensitivity range. Where there is no clear view, then a symmetrical sensitivity range is used, such as in the case of currency exchange rate movements.

<table>
<thead>
<tr>
<th>Cost driver</th>
<th>Sensitivity range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine costs</td>
<td>-40%, +10%</td>
</tr>
<tr>
<td>Foundation costs</td>
<td>-30%, +20%</td>
</tr>
<tr>
<td>Depth and distance</td>
<td>0%, +22% (absolute change in total capex of going to a deep, distant site)</td>
</tr>
<tr>
<td>Load factor</td>
<td>-3%, +7% (percentage point changes in load factor)</td>
</tr>
<tr>
<td>O&amp;M costs (physical)</td>
<td>-25%, +25%</td>
</tr>
<tr>
<td>Currency movements</td>
<td>-20%, +20%</td>
</tr>
<tr>
<td>Steel costs</td>
<td>-50%, +50%</td>
</tr>
</tbody>
</table>

Table 5.2 Offshore wind cost sensitivity ranges. Note that these cost drivers are not wholly independent
The results are shown in Figure 5.3 below, where the longest bars indicate the highest sensitivity. They demonstrate clearly the critical importance of maximising turbine availability (and therefore load factor), reducing turbine costs, and the consequences of going further offshore and in deeper water. There may also be the potential to reduce currency risk by locating more of the supply chain within the UK. It is also recognised that these factors are interdependent, that there are many ways of categorising costs, and that in practice there is a considerable degree of overlap and interdependency between any such categories and the cost drivers represented here. The categories used in Figure 5.3 are not simplistically additive, partly for the reasons described above but also because the plausible range of variation for a particular category takes into account the possible impact of variation in other relevant categories (for example, currency movements may bear upon the cost of turbines for delivery to UK projects, and steel prices may bear upon foundation costs and turbine costs). The purpose of presenting the results as shown is to make clear the relative magnitude of the effect of different factors – the overall effect on total costs is discussed below.

Figure 5.3 Offshore wind levelised cost sensitivities (Heptonstall et al. 2012)
It is of course possible to take a different view on what the plausible range for each of these cost drivers is likely to be. For example, a more optimistic view could be taken about the potential for £/MW cost reductions in the turbine, perhaps reflecting a much more competitive supply market, increasing turbine size and/or a move to simpler designs. On the other hand, a more pessimistic view could be taken on the likely costs of foundations as future offshore wind farms will be developed in sites with much greater water depths (where the currently favoured monopile foundation approach becomes either impractical or prohibitively costly). An extended range of sensitivities for these two factors is shown with the dotted lines in Figure 5.3, corresponding to a 50% reduction in turbine costs and a 50% increase in foundation costs respectively. Achieving this extended cost reduction in the turbine would result in a reduction in levelised costs of almost 19%, making turbine costs the single largest potential area of cost reduction. Increasing foundation costs by 50% from the base case results in an almost 9% increase in the levelised cost and raises the potential impact of this factor above that of steel price movements, but still substantially below the potential impact of currency movements.

5.4 Views on future UK costs

There is a range of competing drivers for the future costs for offshore wind in the UK. As noted above, some factors have the potential to move costs equally in either direction whereas others are more likely to lead to either cost increases, or cost reductions. Upward pressure on costs may come from a range of factors, not least of which is the increasing water depth and distance from shore of the Round 3 development sites. This move will drive capital cost increases through larger and more complex foundations, increased grid connection costs, and a more challenging installation environment. It is also likely to increase O&M costs as a result of more difficult access arrangements. There is also a risk that the supply chain
constraints noted above persist, or that competition with other markets (for example, with offshore wind developments in Germany, and with the offshore oil and gas industry for vessels) will drive up costs. These factors may bear upon the cost of turbines, but also upon installation, foundation and O&M costs. These factors are reflected in the two ‘worst case’ projections below. The potential for O&M cost increases is also reflected in the ‘best guess’ projection to take account of enhanced O&M regimes intended to increase reliability (and therefore load factor), and also the increased costs of maintaining more distant Round 3 sites. The ‘worst case’ projections also represent the possibility that load factors may stay persistently low due to ongoing issues with reliability and limited access for maintenance.

There also remain the continued risks of commodity price rises driven by wider macro-economic factors, and a currency risk posed by the large share of the value of an offshore wind development that is imported into the UK, typically from within the Euro zone. Whilst expanding the value share of an offshore wind development that is sourced from within the UK would reduce overall exposure to currency risks, this factor is not directly included in the projections below. Currencies can move in either direction and exploring macro-economic sensitivities is beyond the scope of this analysis.

Downward pressure on costs may come from increasing competition throughout the supply chain but particularly in turbine manufacture, aided by the new market entrants such as REpower, Multibrid (now Areva), GE, Clipper and Mitsubishi (Heptonstall et al. 2012). The dramatically increased scale of the UK offshore wind industry implied by the Round 3 developments would be expected to engender increased confidence in the supply chain, and also create opportunities for innovation and learning, in installation and O&M approaches, foundation and turbine design, and standardisation and scale effects, all of which have the
potential to bear down upon costs. Improving reliability, and therefore technical availability and load factor, may come at a cost, in either enhanced O&M procedures as noted above or through more robust designs but, as demonstrated above, improving load factors can have dramatic effects on cost per MWh. The beneficial effects of improving load factor are even more marked as projects advance further from shore where wind speeds are generally higher. These factors are reflected in the two ‘best case’ and the ‘best guess’ projections below.

Taking these factors into account, and the sensitivity to key factors described above, Figure 5.4 below compares the results from three consolidated views to the base case to show ‘best guess’, ‘worst case’ and ‘best case’ projections for the levelised cost of UK offshore wind power in the mid-2020s. The values used for each case are summarised in Table 5.3, and are based on an assessment of the factors described above. The dotted lines show the relatively small effect of the extended ranges discussed above on the ‘worst case’ and ‘best case’ projections.

![Offshore wind levelised cost projections (mid 2020s)](image)

**Figure 5.4 Offshore wind cost projections (Heptonstall et al. 2012)**
<table>
<thead>
<tr>
<th>Projection</th>
<th>Assumptions (changes from base case values in Table 5.1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>‘best case’</td>
<td>Load factor increased by 7 percentage points to 45%, turbine costs reduced by 40%, foundation costs reduced by 30%, O&amp;M costs reduced by 25%</td>
</tr>
<tr>
<td>‘best case’ with further reduction in turbine costs</td>
<td>Load factor increased by 7 percentage points to 45%, <strong>turbine costs reduced by 50%</strong>, foundation costs reduced by 30%, O&amp;M costs reduced by 25%</td>
</tr>
<tr>
<td>‘best guess’</td>
<td>Load factor increased by 5 percentage points to 43%, turbine costs reduced by 25%, foundation costs reduced by 5%, O&amp;M costs increased by 10%</td>
</tr>
<tr>
<td>‘worst case’</td>
<td>Load factor reduced by 3 percentage points to 35%, turbine costs increased by 10%, foundation costs increased by 20%, O&amp;M costs increased by 25%, plus an additional 10% increase in total capital costs to allow for extremes of depth and/or distance</td>
</tr>
<tr>
<td>‘worst case’ with further increase in foundation costs</td>
<td>Load factor reduced by 3 percentage points to 35%, turbine costs increased by 10%, <strong>foundation costs increased by 50%</strong>, O&amp;M costs increased by 25%, plus an additional 10% increase in total capital costs to allow for extremes of depth and/or distance</td>
</tr>
</tbody>
</table>

Table 5.3 Values used for offshore wind cost projections in Figure 5.4

The projections from the levelised cost modelling described above and in (Heptonstall et al. 2012) cover a range from £89/MWh for the extended ‘best case’ to £193/MWh for the extended ‘worst case’, with corresponding capex values of £2.2m/MW to £4m/MW. This wide range reflects the level of uncertainty over future costs in what is still a developing industry. However, the ‘best guess’ values of £116/MWh and a capex of £2.8m/MW suggest that it may be reasonable to expect a gradual fall in the costs of offshore wind in the period to the mid-2020s. The main reasons are as follows:

- Increasing competition amongst suppliers within the turbine market as the scale of developments rises
- Greater supply chain confidence, again resulting from the increased scale of Round 3 developments
- Innovation, efficiency gains, scale effects and standardisation, especially in turbine size and technology and in foundation design, but very radical changes are not envisaged within this timescale
- Improvements to O&M regimes, enhancing reliability, availability and therefore load factors
There were certainly some signs that costs had levelling off by 2010 (Vattenfall 2010) and future cost reductions greater than the ‘best guess’ are of course possible, although the analysis above suggests that this would require most, if not all, of the major drivers to move decisively in the right direction over the period to the mid-2020s.

Nevertheless, some analyses are bullish about cost reduction opportunities and the projections in Figure 5.4 make for interesting comparison with other sources. Figure 5.5 below, for example, shows the cost reduction pathways developed by the Offshore Wind Cost Reduction Task Force in 2012 (a joint initiative by the industry, the UK government and the Crown Estate), with cost estimates for projects with a final investment decision (FID) in 2020 ranging between approximately £90 and £120/MWh. The task force report focussed on the improvements required in the key areas of supply chain, innovation, contracting, planning and consenting, grid and transmission, and financing to deliver these cost reductions – reinforcing the message that substantial cost reductions require progress in many areas (Offshore Wind Cost Reduction Task Force 2012).

![Exhibit B: Offshore wind levelised cost of energy by story](image)

**Figure 5.5 Offshore wind cost reduction pathways (BVG Associates 2012, The Crown Estate 2012)**
The pathway in Figure 5.5 that is most consistent with the ‘best guess’ projection shown in Figure 5.4 is ‘Slow Progression’ characterised as ‘slow market growth and limited supply chain maturation and technology development’ (The Crown Estate 2012) pg. viii. In practice, the most optimistic pathway in Figure 5.5 ‘Rapid Progression’ is even more positive than the ‘extended best case’ projection from (Heptonstall et al. 2012) since it suggests a cost of around £90/MWh by 2020 whereas the Figure 5.4 projections are for the mid 2020s i.e. several years later. However, an understanding of the context for these projections is important since they are a direct response to a challenge from the UK Government that offshore wind costs should reduce to £100/MWh by 2020 (DECC 2011g). The pathways are described as tool to ‘test the achievability of the £100/MWh ambition’ (The Crown Estate 2012) pg. vii, and the analysis explicitly recognised the direct link between achieving substantial cost reductions and the continued growth of (and by implication, policy support for) the offshore wind industry.

These pathways can also be compared with the ‘administered’ CfD strike prices for offshore wind in (DECC 2013i). These are set at a level of £155/MWh for 2014/15, reducing to £140/MWh for the 2018/19 period (at 2012 prices). Whilst CfD strike prices are not directly interchangeable with LCOE estimates for the reasons described in (DECC 2013c) these values are still substantially greater than even the highest numbers from the Crown Estate pathways in Figure 5.5 above, and well above the ‘target’ set by DECC (see above). DECC modelling suggested that these strike prices were consistent with achieving 10GW of UK offshore wind deployment by 2020 (DECC 2013i), which compares to the 12GW in the Crown Estate ‘Slow Progression’ pathway, and 23GW in their ‘Rapid Growth’ pathway (The Crown Estate 2012). In this respect there does appear to be a degree of mismatch between views on deployment rates and associated cost reductions since DECC’s 2020 deployment
figure of 10GW is associated with a strike price that is well above the Crown Estate’s cost pathway for a similar, albeit slightly higher, deployment level. Other commentators have also drawn attention to the interdependencies and delicate balance required between deployment rates, supply chain confidence and cost reductions – highlighting concerns that cost reduction targets are only likely to be delivered under conditions of a stable deployment trajectory (Spencer and Andrews Tipper 2014).

Most recently, the results of the CfD auction process announced in late February 2015 (DECC 2015) suggest that progress on cost reductions has indeed been more rapid than previously forecast, with some industry analysts suggesting that the winning bids for offshore wind translate into an LCOE of around £100/MWh, assuming that these projects reach the Final Investment Decision (FID) stage in 2016 (BVG Associates 2015). Whilst this would certainly represent considerable progress, it does perhaps remain to be seen whether the winning projects can secure the required financing at these bid prices, and whether these and future projects can be successfully built and operated at these implied costs. They should also be compared with the findings published in the offshore wind Cost Reduction Monitoring Framework report which found that costs for projects completed by 2014 had declined to £131/MWh, and that costs for later projects currently at the FID stage were expected to be £121/MWh (ORE Catapult et al. 2015).

5.5 Conclusion
By 2009 the UK Government had found itself in a position where the clear evidence for increasing costs was appearing at the same time as the aspirations for offshore wind (and the degree to which achieving policy goals were dependent upon it) were increasing dramatically, which perhaps left very limited room for manoeuvring with respect to
deployment aspirations. There is a counterpoint to this in that there is an element of circularity in the relationship between industry cost forecasts and policy support because the accepted (and increasingly explicit) bargain between policymakers and the industry is that support is available now because there is an expectation that increasing deployment will lead to cost reductions (for the reasons described in Chapter 4). It is perhaps not surprising therefore that industry forecasts continue to predict substantial cost reductions over relatively short timescales, because to do otherwise may potentially jeopardise the level of support available.

Reconciling the scale and pace of development desired for offshore wind with the growth rate that the supply chain can sustain is a potentially delicate balancing act. The scale of planned offshore development creates the opportunity to bring in new capacity and reduce costs, but the pace of growth implied by meeting UK and EU targets has the potential to create upward pressure on costs. A key challenge for policymakers is to balance the need to provide sufficient support to bring forward projects whilst at the same time sending a clear signal to the industry that costs must fall, a balance that has been apparent in the discussions over the CfD strike prices (The Crown Estate 2012, DECC 2013i).

The cost trajectory of offshore wind is particularly important for the UK because it is anticipated to make such a large contribution to meeting the country’s renewable energy targets, and this is coupled with the increased scrutiny of the cost and effectiveness of providing support for all low-carbon generation options resulting from the Electricity Market Reform process (DECC 2011f). Furthermore, it is the difference between offshore wind costs and electricity prices that affects the additional cost of meeting targets (DECC 2013d), and the gap between onshore and offshore wind costs suggests that, in the absence of cost
reductions, an increasing reliance on offshore wind may significantly increase the cost of meeting the UK’s targets, or mean that a larger share of the Levy Control Framework budget is used up for a given volume of renewably-sourced electricity.

The dramatic cost rises from the mid-2000s onwards were driven by a range of factors that all exerted an upward pressure, although the most recent signs suggest that costs are now on a downward trajectory. In the medium and longer term, the potential for cost reductions arising from greater competition and from increased supply chain confidence, along with innovation, learning and economies of scale in key areas, has the potential to outweigh the cost increases resulting from greater depth and distance of future offshore wind projects. However, expectations that costs will fall as rapidly as they have risen may be overly optimistic, and substantial cost reductions require all of the key drivers to be aligned.

Two clear messages relating to costs forecasting also emerge from the experience of offshore wind in the UK. The first is that there is a risk that the learning curve-based forecasts of the type discussed in Chapter 4 are applied to a technology at too early a stage in its development and deployment. In the case of offshore wind, this meant that the starting point for the earlier cost reduction forecasts did not necessarily reflect the true costs of the technology at the time, or were overly reliant on data from early projects which may not have been fully representative of the site conditions for more typical later-stage projects. This may be a particularly important lesson for technologies where a significant fraction of the total costs are location specific (which is much more so the case with offshore wind than with a CCGT plant for example). A rather unfortunate conclusion from this is the possibility that analysts and policymakers can only become fully confident about the application of experience curves at a point when there may be a less critical need for them.
The second message is that even if cost reductions can be achieved they may be overwhelmed by other factors. Some of these may be largely outside the control of the industry such as adverse currency and commodity price movement, and others not, such as supply chain bottlenecks or a limited numbers of major suppliers (which is a particular issue where those suppliers have alternative, lower risk, markets for similar products that can be manufactured in the same facilities). This thesis returns to these issues in the discussion in Chapter 8.
6 Nuclear case study: Policy ambitions in the face of uncertainty over costs

6.1 Introduction

This chapter draws upon research undertaken by the author for the UK Energy Research Centre (Gross et al. 2013), and a related journal paper (Harris et al. 2013). The chapter describes the history of cost estimates and forecasts for nuclear power, explores the sensitivity of current estimates to the observed key drivers of previous cost increases, and discusses the policy response to the uncertainty over the anticipated costs of new nuclear power plants in the UK.

In the early 2000s, the view of the UK Government was that the option of new nuclear power should be ‘kept open’ but with no direct support, which in effect precluded any new nuclear build in the UK (PIU 2002). By the mid-2000’s however, the UK Government’s disposition towards new nuclear power was much more positive, with the 2006 Energy Review concluding that the economics of the technology had improved and that, ‘new nuclear power stations would make a significant contribution to meeting our energy policy goals’ (DTI 2006). This was followed by the 2008 White Paper on Nuclear Power (BERR 2008a) which confirmed the UK Government’s view that, ‘nuclear power has a key role to play as part of the UK’s energy mix’.

Since the change of heart towards nuclear from the mid-2000s onwards, projected costs for new nuclear plants have risen considerably, as have costs for many other electricity generation technologies (see Figure 1.1 in Chapter 1). That notwithstanding, the most recent cost projections for electricity from nuclear power in a UK context are centred around £90/MWh (DECC 2013c) which, if realised, puts this technology towards the lower end of
costs for low-carbon generation. The following section identifies the trajectory of cost estimates and forecasts for nuclear power and discusses the UK Government’s response to rising cost estimates from the mid-2000s onwards.

6.2 Cost forecasts and outcomes

This section analyses how forecasts of future costs compare with contemporary estimates of cost outcomes i.e. comparing past expectations about the future with the reality of costs at a given time. The analysis for this section focuses predominantly on capital rather than levelised costs. In part, this is because there is more data on capex in the evidence reviewed, but also because nuclear capital costs account for the majority (60% - 75%) of the levelised costs of electricity generation (MacKerron et al. 2006, Grimston 2012b). By contrast, the costs of the feedstock fuel for example is a very small proportion of the overall costs (typically of the order of 2%) which means that the effects of even quite large changes in fuel costs on the cost of nuclear-generated electricity are relatively small (Grimston 2012b).

6.2.1 Expectations of future costs

Figure 6.1 below presents a summary of worldwide capex forecasts for (future) years between the late 1980s and the early 2040s. It shows the in-year average forecast costs for two data groups, one consisting of those forecasts made up to 2005, the other consisting of forecasts made from 2005 onwards. The year 2005 was chosen because the mid-2000s appears to have been a turning point when estimates of contemporary costs began to rise significantly. Figure 6.1 demonstrates how nuclear capital costs have in the past been expected to fall over time, and how they are still expected to do so, albeit from a higher

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31 The evidence base for contemporary costs are typically estimates from academic and governmental analysts, industry bodies and other observers, because of the limited availability and clarity of costs data from actual projects and vendors.
starting point averaging over £3.5m/MW in 2010. In the mid-2000s, cost forecasts for the relatively near future were revised significantly upwards, reflecting the new reality of rising contemporary cost estimates. However, costs are still expected to fall in the longer term, though to a level significantly higher than expected by the earlier pre-2005 forecasts. This contrasts with the offshore wind forecasts shown in Chapter 5 where costs rose (reflecting the experience at the time) but were still forecast to fall in the future back to the previously forecast level.

Figure 6.1 Nuclear forecast capex worldwide, comparing pre and post 2005 estimates (Gross et al. 2013)
6.2.2 Contemporary estimates

Turning to cost outcomes over the last four decades and how this data compares with expectations, (Cooper 2009) provides a useful insight into the comparison between expectations and outcomes for the early years of commercialised nuclear power in the U.S. Figure 6.2 shows Cooper’s analysis that compared the increase in projected and actual costs of reactors from the mid-1960s to the mid-1970s, with values shown relative to an index of 100. Cooper denoted the two data series shown in Figure 6.2 as ‘1966-67 Projected’ and ‘1966-76 Actual’ to reinforce the fact that all values are indexed to the projected costs for reactors in 1966-67.

![Figure 6.2 Actual and projected capital costs by date of commencement of construction, completed reactors (Cooper 2009)](image)

Cooper’s two key points were that cost projections and actual outcomes were increasing during the decade and that outcomes were increasing at a faster rate than projections – as demonstrated by the steeper trajectory of the ‘Actual’ data series when compared to the ‘Projected’ data series. It appears therefore, that both capital cost containment and forecast
performance deteriorated over the decade. Furthermore, forecasting accuracy did not improve over subsequent decades, as a comparison between Figure 6.1 showing past projections of expected future costs and Figure 6.3 below demonstrates.

![Figure 6.3 Estimated nuclear capital cost outcomes worldwide over the last four decades (Gross et al. 2013)](image)

Figure 6.3 presents worldwide estimated capex outcomes between 1972 and 2011. From the early 1970s costs rose gradually before a slightly steeper escalation in the early 1980s which peaked around the late 1980s and early 1990s. In France, for example, real capex rose 40 to 50% between the early 1970s and early 1980s (Thomas 1988), and between 1970 and 2000 overnight costs increased by at least a factor of three (Grubler 2009). In Germany between

\[\text{Note that all the outlier data points in Figure 6.3 above £6m/MW are from one source (Grubler 2009) and apply only to US reactors. These data points reflect Grubler’s calculation of the effects of extended construction times (on higher financing costs in particular). Whilst dramatic, the outliers do not have a large effect on the trend line because there are many more data points with lower values.}\]
1969 and 1982 pre-construction estimates of overnight cost rose 9% annually i.e. a tripling in 13 years (Thomas 1988). In the US, a Department of Energy study showed that predicted construction costs of US$45 billion for 75 reactors had risen to an actual cost of US$145 billion, a cost overrun of more than 220% (Harris et al. 2013).

Comparing Figures 6.1 and 6.3, it is clear that for a period of time between the late 1980s and the mid to late 2000s, forecasts were broadly correct in identifying an upward trend of contemporary costs followed by a downward trend. However, the contemporary cost trend turned sharply back up in the second half of the 2000s, and throughout the period examined actual cost levels have been considerably higher than originally anticipated. Capital costs were expected to peak in the 1990s at an average of around £2.5m/MW and were projected to decline to approximately £1.5m/MW by 2010. In fact, the evidence indicates that actual costs around 1990 were estimated to be anywhere from approximately £1.5m/MW to more than £14m/MW (recognising the earlier caveat over the outliers in Figure 6.3).

(Grimston 2012b) reported that in 2004 estimated capital costs for nuclear new build in the US were around $1.4/MW and that subsequent NOAK plants were expected to have capital costs of approximately $1m/MW. However, by the second half of the decade, costs had increased considerably with one 2007 report estimating an overnight cost of almost $3m/MW for a new nuclear plant (or between $3.6m/MW and $4m/MW when interest was included). Also in 2007, Moody’s Investor Services estimated a range of between $5m/MW and $6m/MW for the total cost of new nuclear. Meanwhile Florida Power and Light estimated the total cost of one of its proposed projects as being between $5.5m/MW and $8m/MW (ibid.). In Europe, the still on-going Olkiluoto project in Finland had been expected to cost under €2m/MW and to be completed in May 2009 but by 2010 was running three years behind
schedule with projected final costs of nearly €3m/MW. Meanwhile in France, the costs of the Flamanville reactor were restated at €2.3m/MW in 2008, up more than 17% from a year earlier (ibid.)\textsuperscript{33}. According to (Parsons Brinckerhoff 2010), between 2008 and 2010 estimates of nuclear generation costs in the UK rose by 40% whilst (Mott MacDonald 2010) suggested that realistic (then current) 2010 prices for a new build were around £2.4m/MW to £3.6m/MW in the US or Western Europe and a lower figure of around £2.3m/MW for a non-OECD country.

In broad terms, therefore, costs rose from the early years up until around 1990, seemingly declined until the early to mid-2000s, and then started to escalate again. The most significant drivers that have influenced nuclear cost trends are described in the section below and grouped by these three periods.

\subsection*{6.2.3 Cost trend drivers}
\subsubsection*{The 1960s to 1980s}
\textit{Environmental and safety concerns}

Many analysts and commentators have observed that the escalation in costs from the start of commercial reactor construction in the mid-1960s through the 1970s to the late 1980s in very large measure stems from the effects of a changing regulatory environment, see, for example, (Cantor and Hewlett 1988, Hultman \textit{et al.} 2007, Neij 2008, Rai \textit{et al.} 2010). This is especially so in the US to which much of the evidence and cost data relates. By the late 1960s nuclear safety and waste disposal was the subject of increasing public focus and had become a predominant theme for the environmental movement (Rai \textit{et al.} 2010). Public and political opposition to nuclear power continued to grow through the 1970s and became more

\textsuperscript{33} At the time of writing (February 2015), the final costs and completion dates of the Olkiluoto and Flamanville projects was still far from clear.
widespread after the accidents at Three Mile Island in 1979 and Chernobyl in 1986. Direct action, political lobbying and use of legal action introduced major delays into projects and interrupted operations (Grimston 2012b). This helped to ‘foster an unstable regulatory climate in which the rules kept changing in apparently arbitrary ways’ (MacKerron 1992) pg. 645. The consequence through much of the 1970s and 1980s was the repeated call for design changes, with regulators demanding more safety features in such areas as fire protection and seismic criteria (NEA 2000). In many cases these had to be fitted after construction had already begun, causing additional material, equipment and labour costs, together with significant delays which added to the costs of finance (Tolley and Jones 2004, Rai et al. 2010, Grimston 2012b).

Between the early and late 1970s in the US, tightening Nuclear Regulatory Commission (NRC) regulations led to a 41% increase in the quantity of steel required for a similar rated plant, a 27% increase in concrete, a 50% increase in piping, and a 36% increase in electrical cabling (Cohen 1990). According to (Tolley and Jones 2004), regulation was responsible for approximately a 70% increase in capital costs from 1967 to 1974. Whilst there was already an underlying pressure for more stringent regulation, a number of crises during this period increased the uncertainty and upward pressure on nuclear costs (Grubler 2010, Grimston 2012b). In the US, these were the 1975 Browns Ferry incident and the 1979 Three Mile Island accident, and in the Ukraine, the 1986 Chernobyl disaster. After the accident at Three Mile Island, the industry was subjected to even more intense scrutiny. The result was that construction costs after Three Mile Island but before Chernobyl were 95% higher than those completed before Three Mile Island, with construction costs after Chernobyl around 90% higher than those completed between Three Mile Island and Chernobyl (Harris et al. 2013).
- Reactor design and construction time

The Nuclear Energy Agency (NEA) observed that US plants built before 1979 took an average of five years to build and licence whilst those built after Three Mile Island averaged almost 12 years. In the latter cases, financing and other time-related cost escalations could represent as much as half the total cost (Spangler 1983, NEA 2000). According to (Cohen 1990), the increase in US construction time from 7 years in 1971 to 12 years in 1980 plus the increase in labour and materials costs contributed to a quadrupling of capex. For Germany, (Thomas 1988) noted a clear trend towards longer construction periods and higher costs between 1967 and 1977, with the predominant explanation being the interaction of regulatory and technical factors, especially reactor type. Similarly, regarding the French nuclear programme, (Grubler 2010) argues that the move towards a new French reactor design in the 1980s (as well as deviating from the tested Westinghouse license by redesigning reactor components) caused lengthening construction times and consequent cost escalations.

In addition to management inexperience or inadequacy (Ahearne 2011) and regulatory uncertainty, another reason for prolonged construction was what has been termed ‘stretching out’. In the 1980s, utility financial planning was, in part, derailed by lower trending electricity demand. Utilities therefore sometimes chose to deliberately ‘stretch out’ the construction time of plants that it appeared would be loss-making once on-line (Thomas 1988, Cohen 1990), with a consequent increase in interest charges during construction (IDC).

- Design change, lack of standardisation and diseconomies of scale

Despite the unstable regulatory environment, the 1970s saw a rapid growth rate in deployment characterised by competitive reactor pricing, coupled with optimistic cost projections (MacKerron 1992, Rai et al. 2010). The result was that manufacturers frequently changed reactor designs, not only in response to regulatory pressures but also in order to offer
customers increased generating capacities. In the US during this time, over 50 utilities began separate procurement programmes involving at least 6 vendors, 20 architects/engineers, and 26 construction contractors. The result was 110 plants, most having unique design and operating characteristics and, over time, increasing reactor capacities (Rai et al. 2010).

In the mid-1960s, the industry scaled up from a reactor capacity of around 400-500MW to about 800MW. Then, before these were completed, 1100MW plants were being constructed. Although this was done in the expectation that economies of scale would bring costs down, in practice the frequently changing designs precluded the standardisation that may have delivered these benefits (MacKerron 1992, Rai et al. 2010). It has also been suggested that increased complexity led to diseconomies of scale and had a negative effect on morale and productivity (due to lengthening construction horizons), and imposed greater demands on management (Cantor and Hewlett 1988). Lack of standardisation and scale economy issues were not confined to the US. In France, (Grubler 2010) attributes the worst of the cost escalation to reducing standardisation and instead trying to upsize and ‘frenchify’ (as Grubler puts it) the nuclear reactor design late on in the programme. This involved replacing the 900-1300MW reactors that had been relied upon for the majority of the programme with 1500MW ‘N4’ reactors. The result was a ‘negative learning’ process as a result of inadequate standardisation and additional learning and first of a kind (FOAK) costs.

The rapid rate of deployment of nuclear plants hampered the industry’s ability to apply learning from earlier projects to later ones because projects were evolving simultaneously, albeit at different stages (MacKerron 1992, Rai et al. 2010). Moreover, (Neij 2008) points out that nuclear plants are individually designed and built according to local conditions which restricts the opportunities for cost reduction related to experience. Experience sharing and
spillover have been limited by design diversity and customisation as well as being undermined by long lead times in planning, construction and commissioning periods (Thomas 1988).

- **Labour**
According to (Thomas 1988), construction delays and retro-fitting of design changes increased both skilled and semi-skilled labour costs and also tended to lower morale and productivity, and the growth in reactor orders in the 1970s created a skills shortage in the US – where labour costs were a smaller proportion of total costs than materials costs in 1976 but by 1988 this situation had been reversed. During this period, nuclear costs increased at a compound average rate of 13.6% per annum, whilst labour costs increased at 18.7% and materials costs only 7.7% (Cohen 1990).

- **Interest rates**
In the early 1980s, (Spangler 1983) reported that the economics of nuclear power were affected by recent high interest rates, especially when construction schedules were also subject to significant delays. In 1976/77 US Federal prime rates ranged between approximately 6% and 8% per annum but by 1980/81 rates had hit a record high of around 21%, were still 11% or more in 1983 and remained relatively high during most of that decade (FedPrimeRate.com 2012). In addition, after the 1979 Three Mile Island accident, financial markets reduced the bond ratings of US utilities. This meant that their borrowing costs rose, thereby increasing the interest component of total cost (Thomas 1988). Thomas also suggested that nuclear project financiers elsewhere in the world also took note of this, affecting financing costs worldwide.
- Methodological factors

In 1970 none of the US reactors ordered during the first wave of commercial orders in the 1960s had yet begun operating. Therefore most of the available information in the early 1970s when the volume of sales escalated rapidly was based upon expectation and estimates rather than actual experience. Moreover, at the time, cost analysis was almost exclusively produced by industry or governments, and there were few financial analysts and independent energy consultancies expressing scepticism and higher cost estimates (Cooper 2009). Subsequent experience from actual construction projects meant that cost estimates then had to be increased considerably.

This problem of lack of real costs data persisted over at least the next two decades. (Thomas 1988) commented that few countries published actual costs containing clear assumptions, suggesting that, in his view, much of the data were hypothetical and substantially underestimated and that, furthermore, whilst such estimates might incorporate past cost increases, they assumed there would be no future increases and ignored trends to the contrary. (MacKerron 1992) also argued that much of the data made public came from agencies which tended to be positive about nuclear power, assuming that ‘past problems are always solved and new problems will not emerge’ pg. 642, i.e. significant appraisal optimism anticipating large cost savings compared to previous projects, and ‘projecting surprise-free futures’ as Mackerron puts it pg. 644.

Alongside this perhaps natural optimism, deliberate under-estimation (‘low-balling’) in order to win contracts or to provide a justification for investments also played a part. (Grubler 2010) identified ‘concerns about the strategic misuse of cost forecasts’ pg. 5184 and it has been suggested that in the 1960s both Westinghouse and GE offered turnkey contracts with
artificially low prices in order to penetrate markets. Only a few years later, cost estimates had risen by 80% (Kern 2011).

The 1990s to mid-2000s
- Non-OECD country data
Using the data collated for (Gross et al. 2013) and comparing the average capex figures for 1989 onwards for the developed countries of North America, Western Europe and Japan on the one hand, versus the developing countries of South America, Eastern Europe and Asia (minus Japan) on the other, reveals a noticeable difference. The developed country group averages capex of approximately £2.6m/MW whilst the developing country group averages £2.3m/MW, a difference of a little over 10%. In 1992, the same comparison results in an average of approximately £2.5m/MW (developed countries) versus £1.8m/MW (developing countries), a difference of nearly 30%. In 1998, the result is an average of around £2.4m/MW (developed countries) versus £2.1m/MW (developing countries), a 12.5% difference. And in 2005, the developing country estimates are one third cheaper at approximately £1m/MW on average versus £1.5m/MW for the developed countries. In 2010 the difference in averages was even greater though by then both averages had risen dramatically (to over £3.1m/MW for developed countries including Eastern Europe and over £1.5m/MW for developing countries).

It is clear that the generally lower estimates from developing countries contributed significantly to the overall declining trend. However, it is also striking that developed country estimates were also declining even though there was little or no actual construction activity going on. In the US, for example, no reactors had been approved for construction since 1978 (Hultman et al. 2007). (Grimston 2012a) suggests the downward trend was due to a combination of lower input costs, especially labour, in part due to a slowing down of the
world economy, less regulatory pressure and a greater incidence of command-and-control type economies likely to ensure stable electricity prices which therefore lowered the risk premium on capital financing (or where financing was available at lower public sector rates).

Construction times also played an important role, with (Tolley and Jones 2004) observing that the nuclear plants in construction since the early 1990s – mostly in Asia – were built in shorter construction times than in the US and even in France, and with less cost variability. Up to the late 1970s when the last US plant began construction, the average construction time in the US was nearly ten years. For plants beginning construction between 1993 and 2001, the global average was just over five years.

As noted above, the contemporary estimates of developed countries were also coming down. Some commentators suggested that estimates of cost from the group of countries where little or no construction was occurring were being influenced by the numbers emerging from the lower cost environments where construction was actually taking place (Grimston 2012a). (Tolley and Jones 2004) also point to the experience in Asia as offering a ‘basis for optimism regarding future construction in the US’ pg. 2-1, especially with regard to reduced construction times. In the UK, (MacKerron et al. 2006) reported that recent UK-applicable estimates appear to have been derived from studies designed to apply to other countries. The authors of that report also argued that appraisal optimism was still a significant risk for future UK nuclear projects. What this suggests is that the downward cost trend during the 1990s and early 2000s reflected both the reality of lower costs in developing countries coupled with the appraisal optimism of developed countries where cost estimates were perhaps not adjusted sufficiently upwards to take account of differing national conditions.
- Additional considerations
From 1990 onwards, several new reactor designs with advanced safety features and operation characteristics became commercially available (Junginger et al. 2008). After the cost escalations of previous decades, it is possible that a high water mark had been reached with safety-driven costs now fully ‘priced in’. In addition, the Nuclear Energy Agency (NEA) was finding cause for optimism in what it saw as the ‘managerial and operational process transformations’ that the US nuclear industry had undergone in the previous decade (NEA 2000) pg. 13.

Increasing standardisation was also a possible factor, characterised by the growing dominance of light water reactor (LWR) designs, and especially the pressurised water reactor (PWR) variant. Worldwide (excluding the then Soviet Union), of the more than 100 reactors under construction in 1986 and completed in the 1990s, 80% were LWRs and this pattern has since continued (Kern 2011). For example, until late in France’s nuclear power programme it relied on only three standard designs which were reproduced at different locations to enable cost savings. The standardisation of design apparently led to a reduction in capital costs of 10-15% (Grubler 2010).

Mid-2000s to present
- Commodities and competition
Despite the global financial crisis in 2008/2009 and the ensuing recession, increased estimated costs over the last decade have been partly attributed to worldwide competition for resources and commodities (such as steel and cement) and for manufacturing capacity (Harris et al. 2013). Strong demand for generation plant has resulted in cost increases, supply chain issues and longer delivery times as manufacturers have struggled to meet demand, and
nuclear construction projects have also been ‘competing with oil, petrochemical and steel companies for access to resources’ (Grimston 2012b) pg. 323.

- Specialist components, supply chain bottlenecks and skills shortages
Some commentators have suggested that construction times could increase due to supply chain bottlenecks affecting the availability of key parts – in particular special forgings where there are only two companies globally that are able to manufacture some of the very large components for nuclear plants (Grimston 2012b, Harris et al. 2013). Competition with the petrochemical industry and new refineries as well as other electricity generation projects for ‘production slots’ in these facilities may also increase costs and introduce delays if worldwide nuclear activity expands, according to (Grimston 2012b).

A shortage of skilled labour has also caused cost estimates for major construction projects worldwide to rise. In North America, skills shortages in both nuclear design and construction personnel have been expected to delay construction schedules and drive up projected costs (Ahearne 2011, Grimston 2012b). At the EU level, it has been estimated that demand for skilled labour will increase by up to 170% by 2018 if all planned new nuclear builds were to be built (Harris et al. 2013).

- Recent experience in Finland and France
The cost and time overruns at the projects in Olkiluoto in Finland and Flamanville in France may also be influencing current estimates. Finland lacked both recent construction experience and technology experience in the EPR reactor design, and there have been reported problems with the quality of work and materials, communication and management issues, and delays and changes in design (Harris et al. 2013). Delays at Flamanville have been attributed to construction accidents, changes in project management, and additional stress tests following
the Fukushima crisis in Japan. Flamanville is the first EPR reactor to be built in France, it is also the first reactor to start construction in 15 years, and (Grubler 2010, Harris et al. 2013) suggest that the project’s problems exemplify how knowledge obsolescence has resulted from an extended period of no nuclear construction experience.

- Other drivers
(Harris et al. 2013) point to political and commercial incentives for vendors and contractors to ‘lowball’ cost estimates at the bidding stage – political in order to prove that government R&D policies have been working, and commercial in order to secure business. If this is indeed the case it is possible that, as projects have developed over time, the true costs have become more apparent, thus contributing to the upward cost trend. A related factor is better cost transparency. According to (Parsons Brinckerhoff 2010), the reason that nuclear generation cost estimates in the UK rose 40% between 2008 and 2010 was, in part, because preparing for new nuclear build resulted in clearer costs, and that tendering for plant internationally meant that up-to-date cost data were more widely available, thus enabling more realistic estimates.

6.2.4 The policy response to rising costs
From the mid-2000s onwards the UK Government’s view on the potential contribution from nuclear power was increasingly positive, albeit with the clear proviso that ‘it will be for the private sector to initiate, fund, construct and operate new nuclear plants’, with the role of Government limited to ‘addressing potential barriers’ (DTI 2006) pg. 17. This position was informed, at least in part, by an assessment of the relative costs of the range of large-scale low-carbon electricity generating technologies available to the UK, and in particular a cost-benefit analysis conducted for the 2006 Energy Review which assessed the welfare balance
for nuclear power under the range of gas and CO₂ prices shown in Table 6.1 below (DTI 2006, Kennedy 2007). These assessments were inevitably informed by the cost estimates and forecasts shown in Figures 6.1 and 6.3 which suggested that nuclear costs were falling in the late 1990s and early 2000s (albeit in the relative absence of new-build data from OECD countries).

<table>
<thead>
<tr>
<th>Carbon price = ( £0/tCO₂ )</th>
<th>Low gas price</th>
<th>Central gas, high nuclear</th>
<th>Central gas price</th>
<th>Central gas, low nuclear</th>
<th>High gas price</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>-2100</td>
<td>-1400</td>
<td>-400</td>
<td>900</td>
<td>1400</td>
</tr>
<tr>
<td>Carbon price = ( £15/tCO₂ )</td>
<td>-1500</td>
<td>-900</td>
<td>200</td>
<td>1400</td>
<td>2000</td>
</tr>
<tr>
<td>Carbon price = ( £25/tCO₂ )</td>
<td>-1100</td>
<td>-500</td>
<td>600</td>
<td>1800</td>
<td>2400</td>
</tr>
<tr>
<td>Carbon price = ( £36/tCO₂ )</td>
<td>-700</td>
<td>0</td>
<td>1000</td>
<td>2300</td>
<td>2800</td>
</tr>
</tbody>
</table>

Table 6.1 Nuclear generation welfare balance under alternative gas price, carbon price and nuclear cost scenarios, £m/GW (DTI 2006)

The 2008 White Paper on Nuclear Power (BERR 2008a) went on to confirm the UK Government’s supportive view on the role for nuclear power in the electricity mix. Two years after the Nuclear White Paper, the UK Government’s position was that it would support new nuclear power projects, ‘provided that they receive no public subsidy’ (Cabinet Office 2010) pg. 17. At the time, the position of the nuclear industry was that new nuclear would need no subsidy provided that carbon emissions from fossil fuel plants were priced appropriately (de Rivaz 2009). Since then, nuclear cost estimates have risen substantially and, whilst the position of no public subsidy is still government policy, the Electricity Market Reform (EMR) process offers support for new nuclear power stations (and other low carbon generation options) through a Feed-in Tariff (FiT) via a Contract for Difference (CfD) and an underpinning of the price of CO₂ emissions (DECC 2011f, HM Government 2012). This is in
addition to a range of facilitative actions such as the Generic Design Assessment (GDA) process (BERR 2008a).

Taken together, these policy measures represent a substantial package of support, and were a response to the sharply rising costs discussed above and shown in Figure 1.1 in Chapter 1. Whilst there is perhaps a semantic debate to be had over whether the measures constitute a subsidy, they also need to be seen in the context of continuing high levels of support for offshore wind (see Chapter 5), still substantial support for onshore wind (DECC 2013i), and the fact that the costs for almost all the large-scale generation options (both low and high carbon) have also increased significantly, with the notable exception of solar PV (see Chapter 7). In this context, the £92.50/MWh strike price agreed for the Hinkley Point C project (see Section 6.4 below) represents a cost towards the lower end of the spectrum for low carbon generation technologies, which helps to underpin the UK Government’s continuing commitment to nuclear power. A further element of the policy response to the evidence that nuclear cost estimates were rising can be seen in the desire to lock-in the current estimates by offering a very long-term (35 year) contract period, albeit with allowances for indexation.

6.3 Levelised cost model input assumptions and cost sensitivity

The results from levelised cost projections, whatever the technology, depend on the set of assumptions around variables such as capital cost, construction times, the expected plant life, operational and maintenance costs, fuel costs, plant availability, load factor and discount rates (Heptonstall 2007), but this section focuses in particular on the length of the pre-construction and construction phases and how capital costs can change over these phases, drawing on evidence from US and European nuclear programmes. The pre-construction phase typically involves securing operating licenses, reviewing technical designs, conducting public
enquiries, performing site acquisition/preparation and completing financing negotiations. The construction phase includes the engineering, procurement and construction (EPC) of reactors, associated infrastructure development, grid connection and the first fuel loading.

The analysis presented in this section compares the experience of US and European nuclear projects with the assumptions that feed into recent UK nuclear levelised cost estimates and uses values based on the observed experience to examine the effect that these may have on the projected costs of nuclear power. This permits analysis of the plausible upper ranges of nuclear cost out-turns, if costs incurred during the pre-construction and construction phases rise as they have been observed to do in the past. The results are presented in Section 6.4 below, and compared with cost estimates and forecasts from other key UK-specific sources.

The LCOE model is similar in principle to that employed for the offshore wind analysis in Chapter 5 and the generic approach described in Chapter 3. In order to maintain comparability with most other studies, the assumptions and calculations focus on ‘busbar’ costs (i.e. up to where the power station connects to the transmission grid) and ignores any items such as losses in transmission and distribution or additional system balancing costs (Gross et al. 2006, Strbac et al. 2012) – see also Chapter 3.

6.3.1 Pre-construction period
Recent analyses for the UK estimate that the pre-construction phase will take between 4 years (Mott MacDonald 2011) and 5-6 years (Deloitte 2010). This compares with the World Nuclear Association estimate of a global average pre-construction phase of approximately 3-7 years (World Nuclear Association 2011). As far as cost changes during this phase are concerned, analysis of publicly available information on US projects (chosen because this
market has similar labour costs, licensing procedures and reactor technologies to the UK), indicates that, on average, overnight construction cost estimates in the pre-construction phase increased at 14.2% per annum on a real compounded basis between 2005 and 2011 (Harris et al. 2013).

6.3.2 Construction period
The IAEA-PRIS database (IAEA 2012) of nuclear plant construction times shows that, since the 1970s, the median global construction time including reactors constructed in Asia is 7.7 years, with the median figure excluding Asia being 8.3 years (Harris et al. 2013). Whilst EdF Energy estimated a 5.5 to 6 year construction period for the Hinkley point plant (EdF 2011) and the current assumption for DECC’s cost estimates is a 6 year construction period (DECC 2013b), the analysis below uses a value of 8 years, based on the global median construction time of 7.7 years.

As far as cost changes during the construction phase are concerned, the analysis in (Harris et al. 2013), based on data from Koomey and Hultmann (2007), suggests that annual cost escalation for US reactors was 8.1%. Grubler’s review of the cost trends of the French build programme suggested that overnight costs had increased by more than a factor of three between the first and last reactor generations built (Grubler 2010), which represents a cost escalation of approximately 5.6% per annum (Harris et al. 2013), whilst Komanoff calculated a cost escalation rate of 3.6% per annum for the French build programme (Komanoff 2010).

The levelised costs analysis presented below use an annual escalation rate of 5.4%, which represents the weighted average real escalation rate of the 58 reactors in the French build programme between the 1970s and 1990s, the 99 reactors in the US new build programme
between the 1970s and 1990s and the IHS/Cambridge Energy Research Associates (CERA) European Power Capital Cost index (IHS 2011). Applying this 5.4% escalation rate to the current EPR and AP1000 reactor estimates in the US and Europe increases the average cost estimate from £3,238/kW to £4,613/kW (Harris et al. 2013).

Sensitivity of UK cost estimates to observed costs escalations
In December 2010, the EdF Energy-led consortium was reported to have estimated costs of ‘more than’ £9bn for building two 1600MW EPR reactors in the UK (Hollinger 2010). It has subsequently been reported that this cost has escalated to £14bn (The Times 2012). Since there was a degree of ambiguity over what this cost includes, for example, whether this is the full capital cost of the plants including financing charges and interest during construction or if escalation rates are included, the analysis in (Harris et al 2013) investigated a range of options to determine which gave the best fit with the post-escalation estimates described above.

The lowest cost option assumed that the £9bn figure was the final ‘all in’ capital cost (i.e. a similar definition to the ‘total as spent cost’ used by the NETL in Figure 3.13) so interest during construction was deducted from this figure to reach the overnight cost, calculated from an assumed profile of the timing of costs incurred during the construction period, and assuming that this figure includes any potential cost escalations. The higher cost options were arrived at by applying an assumed 5.4% cost escalation during a 5.5 year pre-construction and a 7.5 year construction phase. This analysis suggested that an overnight cost estimate of £4,885/kW was most closely aligned with the post-escalation cost range identified above, and this value was therefore used in the levelised cost model in (Harris et al 2013). It is also worth noting that the disagreement over what the total capex figure represents was still ongoing in 2014 with EdF revising their total capex figure upwards to £16bn excluding
interest during construction, suggesting an overnight cost of £5,000/kW (Carbon Connect 2014, de Rivaz 2014).

6.3.3 Other key input assumptions

- Plant operating life
Although the intended technical lifetime of both the AP1000 and EPR reactors is 60 years, operating experience for nuclear power stations beyond 30 years is limited. According to (Schneider et al. 2011) the average age of the 130 nuclear units that are no longer in service is around 22 years. Recent UK experience suggests life extensions are certainly possible (Nuclear Engineering International 2012) and it seems reasonable to expect that newer reactors will indeed have longer lives than early designs from the 1960s, but it remains the case that 60 year plant lives are currently unproven. Therefore, the analysis presented below uses the same assumptions as DECC for a ‘generic PWR’ in (DECC 2011h), the Worldwatch Institute (Schneider et al. 2011), and the Massachusetts Institute of Technology (2009) by assuming operating lifetimes of 40 years for new plants. The effect of extending (or reducing) the operating life of a plant is, nevertheless, explored in the sensitivity analysis shown in Table 6.3 in Section 6.4 below.

- Plant load factor
The EPR reactor has a target availability of 90% (EdF 2009), although since reactors of this design have not been operated yet it is impossible to know whether this target will be met in practice. However, Citibank and HSBC estimates suggest that there is approximately a 5% difference between availability and load factors reported by EdF for their currently operated plants with an average load factor of 76% (Citigroup 2009, HSBC 2010). Whilst French nuclear load factors may be affected by the partial load following role that nuclear performs in the French energy market, it seems reasonable to rely upon EDF’s actual operating
experience. Therefore, the assumption for the analysis below is that reactors will have an average load factor of between 76% and 85% (and a central figure of 80.5%), with the higher figure calculated by subtracting the difference between load factors and availability factors described above from the target load factor for the UK new build programme (90%). This assumption is supported by a study which found that only the top 100 out of the 414 plants which had been operating for at least one year had a lifetime load factor of more than 80% (Thomas et al. 2007). As is the case for assumptions over plant operating life, the effect of varying load factor is shown in Table 6.3 below.

---

**Financing costs and structures**

The relatively high capital cost of nuclear plants means that their overall economics, and the feasibility of their financing, depend greatly on the cost of that capital, and more accurately the Weighted Average Cost of Capital (WACC), which is essentially the weighted sum of the interest rate on loans and the rate of return on equity investment (Gross et al. 2010, NEA 2010). A report prepared by Oxera for the UK Committee on Climate Change (Oxera 2011) assessed the cost of capital required for the UK’s new nuclear build programme by conducting a survey of market participants to ascertain expected rates of return. This survey produced a range of between 9% and 13% (on pre-tax basis). Providing support for figures towards the mid-point of this range is the estimate provided by Areva, whose view in March 2010 was that liberalised markets would require a 11% (also, pre-tax) WACC (Gautrot 2010). The analysis presented in Section 6.4 below uses a WACC figure of 11% but it should be recognised that there is also some (albeit contested) evidence that their actual cost of capital is less than has been assumed (Leveque and Robertson 2014).
6.4 Views on future UK costs

The assumptions used for key variables in the levelised cost model, drawn from the observed experience discussed above, are summarised in Table 6.2 below together with the resultant LCOE. Figure 6.4 below demonstrates the relative impact of each of the key assumptions, starting from a base case figure drawn from (Mott MacDonald 2010). The right hand bar of Figure 6.4 shows that the main driver is the application of the 5.4% escalation rate to current utility overnight cost estimates. The remaining five bars of Figure 6.4 show the impact of each of the other assumptions described above, before the application of a 5.4% escalation rate, with the decrease in plant operating life having the least impact and the increase in the cost of capital having the second greatest impact after the overnight cost escalation rate.

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-construction period</td>
<td>6 years</td>
</tr>
<tr>
<td>Construction period</td>
<td>8 years</td>
</tr>
<tr>
<td>Plant operating life</td>
<td>40 years</td>
</tr>
<tr>
<td>Load factor</td>
<td>80.5%</td>
</tr>
<tr>
<td>WACC</td>
<td>11%</td>
</tr>
<tr>
<td>Pre-construction cost</td>
<td>£197/kW</td>
</tr>
<tr>
<td>Overnight construction cost</td>
<td>£4,885/kW</td>
</tr>
<tr>
<td>Levelised cost</td>
<td>£164/MWh</td>
</tr>
</tbody>
</table>

Table 6.2 Major assumptions for nuclear cost analysis and LCOE result, adapted from (Harris et al. 2013)

The sensitivity of the results to variations of the key input assumptions of overnight cost, length of construction period, operating life of the plant and WACC are also shown in Table 6.3 below. Because the levelised cost calculation attributes proportionally greater present value to costs and output that occur closer to the calculation start year, reducing plant operating lifetime has a greater (negative) impact on levelised costs than increasing plant operating lifetime by the same amount. Any increase in the construction phase timeline results in lower total (discounted) costs because the impact of discounting the cost stream by a further year offsets the increase in interest and other costs that result from an extended construction timeline. However, because the generating phase is also delayed, the impact of
discounting the power output by a further year more than offsets this cost reduction, resulting in an increase in the overall LCOE.

![Figure 6.4 Levelised cost estimates for nuclear power, assuming 2013 project start (Harris et al. 2013)](image)

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Sensitivity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Overnight cost</strong></td>
<td>% change</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>-20%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>-16%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>-15%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>-13%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>-10%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>-8%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>-5%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>-4%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>0%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>0%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>+5%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>+4%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>+10%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>+8%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>+15%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>+12%</td>
</tr>
<tr>
<td>LCOE (£/MWh)</td>
<td>+20%</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>+16%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Construction period</strong></th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
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<td>£145</td>
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<td>£178</td>
<td>£189</td>
<td>£206</td>
<td>£226</td>
</tr>
<tr>
<td>LCOE % change</td>
<td>-22%</td>
<td>-18%</td>
<td>-11%</td>
<td>-4%</td>
<td>0%</td>
<td>+9%</td>
<td>+16%</td>
<td>+26%</td>
<td>+38%</td>
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<table>
<thead>
<tr>
<th><strong>Plant operating life</strong></th>
<th>20</th>
<th>25</th>
<th>30</th>
<th>35</th>
<th>40</th>
<th>45</th>
<th>50</th>
<th>55</th>
<th>60</th>
</tr>
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<tbody>
<tr>
<td>LCOE (£/MWh)</td>
<td>£185</td>
<td>£175</td>
<td>£169</td>
<td>£166</td>
<td>£164</td>
<td>£162</td>
<td>£161</td>
<td>£161</td>
<td>£160</td>
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<tr>
<td>LCOE % change</td>
<td>+13%</td>
<td>+7%</td>
<td>+3%</td>
<td>+1%</td>
<td>0%</td>
<td>-1%</td>
<td>-1%</td>
<td>-2%</td>
<td>-2%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>WACC</strong></th>
<th>%</th>
<th>7%</th>
<th>8%</th>
<th>9%</th>
<th>10%</th>
<th>11%</th>
<th>12%</th>
<th>13%</th>
<th>14%</th>
<th>15%</th>
</tr>
</thead>
<tbody>
<tr>
<td>LCOE (£/MWh)</td>
<td>£100</td>
<td>£114</td>
<td>£129</td>
<td>£145</td>
<td>£164</td>
<td>£183</td>
<td>£204</td>
<td>£227</td>
<td>£252</td>
<td></td>
</tr>
<tr>
<td>LCOE % change</td>
<td>-39%</td>
<td>-30%</td>
<td>-21%</td>
<td>-11%</td>
<td>0%</td>
<td>+12%</td>
<td>+25%</td>
<td>+39%</td>
<td>+54%</td>
<td></td>
</tr>
</tbody>
</table>

Table 6.3 Nuclear levelised cost sensitivities, adapted from (Harris et al. 2013)
Most of the LCOE results in Table 6.3 are well above the £92.50/MWh CfD strike price for the Hinkley C project that has been agreed between the UK Government and EdF Energy (DECC 2013j) – and other analyses go on to suggest even lower costs for ‘n\textsuperscript{th}-of-a-kind’ (NOAK) plants built after the first wave of new plants, with projections commissioned by DECC in 2011 suggesting a levelised cost for electricity from nuclear plants of around £65/MWh (in 2010 prices) for a notional NOAK plant with a 2017 project start date (Parsons Brinckerhoff 2011). Given the history of nuclear cost forecasts and out-turns described above, and the question as to whether a UK nuclear project starting in 2017 would benefit from substantial learning opportunities of earlier plants (which could not have been completed by then), these forecasts may appear to strain credulity almost to breaking point. However, they also need to be seen in the context of an industry that was bullish over both the current costs and the opportunities for future cost reductions, and policymakers who were effectively engaged in a process of early-stage negotiation with the industry over the support required to bring forward nuclear projects – a point to which the discussion chapter returns.

Newer cost estimates and forecasts for nuclear projects were published in DECC’s 2012 and 2013 analyses (DECC 2012b, DECC 2013c), both of which published values in 2012 prices. The 2012 report’s central estimate for a project starting in 2012 was £81/MWh with a sensitivity range between £72/MWh and £93/MWh. Forecasts for a project starting in 2018 had a central value of £73/MWh with a sensitivity range between £64/MWh and £86/MWh. Just over a year later, the 2013 report concluding that the central estimate for a project starting in 2013 was £90/MWh (see Figure 6.5 below) with a sensitivity range between £78/MWh and £107/MWh, so by this stage the analysis was closely aligned with the final negotiated figure for the CfD (see above).
The 2013 analysis also concluded that the central estimate for a project starting in 2019 was £80/MWh with a sensitivity range between £70/MWh and £94/MWh, values which corresponding closely to the same report’s forecasts for projects commissioning in 2030. These forecasts were reduced slightly when the analysis took technology-specific investment hurdle rates into account, with a central estimate of £77/MWh and a sensitivity range between £67/MWh and £89/MWh.

### 6.5 Conclusion

The UK Government believes that nuclear power can play a key role in reducing CO₂ emissions and maintaining security of supplies (DECC 2011f), and policy has been informed by cost estimates that suggest that electricity from new nuclear power stations will be competitive with alternative low carbon generation options. Recent estimates in analyses for
DECC suggest that the levelised cost of nuclear power are well towards the lower end of the range of low carbon generation alternatives, with some analyses projecting even lower costs for so-called ‘nth of a kind’ (NOAK) plants built after the first wave of new plants. However the historical evidence and analysis presented above suggests that the capital cost estimates for nuclear power that are being used to inform these projections rely on containing increases to a much greater extent than has previously been the case. In fact, the evidence suggests that construction costs in real terms have often increased well above expectations, and there is no evidence of a consistent declining cost trend during any period over the last four decades in the US, France and Europe.

The analysis presented in this case study suggests that there is the potential for a considerable degree of uncertainty over nuclear cost estimates. The strike price agreement for Hinkley Point C can perhaps be seen as a policy response to what the evidence suggests are well-founded concerns over the uncertainty of nuclear costs, and a desire by government to protect against the continuing risk of cost escalation, and an implicit willingness to accept the criticisms of ‘over-paying’ when the alternative is to be completely exposed to the uncertainty. Nevertheless, and despite the implications of the potential for higher costs explored in Section 6.4 above, it would appear that nuclear project developers currently take a more optimistic view on the potential for minimising (or eliminating completely) any cost escalations, construction delays and below-target plant load factors, especially given that they will bear these risks. An alternative perspective is that they believe that there may be a possibility in future to seek additional support if costs do rise, and if this is the case, then the contractual details around any escalation clauses and break points in the CfD become key – a point explicitly acknowledged by EdF Energy when they refer to the need for agreement on the ‘duration, indexation and the conditions for review’ of the CfD (EdF 2012).
With respect to cost forecasting, a number of key messages emerge from the case study in this chapter. Firstly, the assumption (based on technology learning rates) that costs can (and indeed, will) decline for reactors being constructed in the near future appears to be inconsistent with much of the historical evidence for the past cost trajectory of nuclear power. It seems difficult therefore to justify the application of the experience curve method of future cost projection for a technology where the evidence that costs are following a downward path is largely absent – at least in countries with similar levels of economic development to the UK.

A potential concern for policymakers (and also the industry) is that if policy support is predicated on the assumption that it is effectively ‘buying down’ costs (see Chapter 4), then that support may become more difficult to sustain politically if no evidence of cost reduction emerges – and this may be particularly the case if other technologies are able to demonstrate cost reductions.\(^{34}\) Related to this is a concern that estimates and forecasts have been subject to continued appraisal optimism and, whilst this is in no way unique to the nuclear industry, what does differentiate it is, once again, the relative absence of directly relevant evidence of data that would support such continued optimism. The very long build times of nuclear projects, together with the relatively limited number of individual projects likely to be taken forward within the UK also makes it considerably more challenging for the nuclear industry to demonstrate cost reductions over short timescales (even assuming that learning and cost reductions are happening) – creating the risk of additional political pressure on any support for the industry.

\(^{34}\) The reverse is also true – if nuclear projects are able to successfully contain costs and costs for other technologies do not fall as projected, then nuclear may be in a very competitive position.
There is also a parallel with offshore wind (see Chapter 5) in that the nuclear case study suggests that there can be occasions when ambitious deployment rates may compromise the ability to incorporate learning into successive units. In addition, growth in deployment typically leads to increased competition for raw materials, components and skills, and therefore potential commodity squeezes and supply chain bottlenecks, especially (as is the case for nuclear) where there are only a very small number of suppliers for critical major components.

A further key characteristic of nuclear energy is that it is typically very large-scale and site and regulatory environment-specific, and cannot easily benefit from mass production economies of scale in the way that, for example, PV (see Chapter 7) or indeed wind turbines can. Economies of unit scale may well be offset by growing complexity and/or increasingly stringent regulations, whilst opportunities to benefit from multiple unit construction at the same site or in the same country may be limited, adding to the policy risks described above. Taken together, these factors have the potential to undermine, or even reverse, the potential benefits of technology learning that are discussed in Chapter 4, and these issues are taken up in the discussion in Chapter 8.
7 PV case study: Falling costs and the policy response

7.1 Introduction

Since emerging from its early use in the space industry, the cost trajectory of photovoltaic (PV) technologies\(^\text{35}\) has largely been one of dramatic and sustained cost reductions (Nemet 2006), coupled with substantial market growth in recent years. As Figure 7.1 shows, cumulative PV deployment has grown very quickly from the mid-2000s onwards, with less than 3GW installed globally by the end of 2003, but only a decade later this figure had grown to a total of over 139GW, with approaching 60% of that in Europe, driven by a combination of cost reductions and strong policy support in many countries (EPIA 2014).

![Figure 7.1 Global PV cumulative installed capacity (EPIA 2014)](image)

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\(^\text{35}\) There are a wide range of PV technologies, although by far the most common to date is crystalline silicon (often abbreviated to c-Si and referred to as ‘1st generation’), followed by thin film technologies using cadmium telluride (CdTe), amorphous silicon (a-Si) or copper indium gallium di-selenide (CIGS) and often referred to generically as ‘2nd generation’. Other technologies known generically as ‘3rd generation’, such as organic PV, are under development but have yet to make a material impact in terms of deployment (Candelise 2012b, IEA 2014b).
Many analyses forecast that this recent strong growth is set to continue, with the IEA for example suggesting that globally 752GW of new PV capacity will be built in the period between 2013 and 2035, with more than 20% of this total growth being in EU countries (IEA 2013).

Turning specifically to the UK experience, PV makes an interesting example in comparison to the offshore wind and nuclear case studies because by 2011, the UK Government had concluded that the support mechanism which it had introduced only a year earlier to encourage PV deployment was too generous, given that costs were falling much more quickly than had been anticipated (DECC 2010b, DECC 2011b). The challenge facing policymakers was, therefore, very different to that of offshore wind and nuclear (where the concerns were over rising costs and costs uncertainty respectively). This chapter begins with a review of the evolution of PV costs, including forecasts, drawing upon the extensive literature on those costs, including the working paper produced by my colleague Chiara Candelise as part of the UKERC TPA ‘Cost Methodologies’ project (Candelise 2012b, Gross et al. 2013). The chapter then goes on to examine the UK policy response to the recent larger than expected cost reductions.

### 7.2 The history of PV costs and forecasts

The dramatic cost reductions which PV has enjoyed are demonstrated in Figures 7.2 and 7.3 below which show the long-term and more recent price\(^36\) trajectories. These figures represent the cost of PV modules (the PV panels alone) and therefore exclude the costs of the additional equipment required to complete a PV system such as the inverter (to convert the direct current

\(^36\) The extent to which market prices are a good indicator of true economic production costs is discussed later in this chapter. Market prices are typically used in PV cost analyses because the nature of the technology, its production processes and market composition mean that such data is readily available — in a way that it is not with other technologies, for example nuclear reactors. This means that the distinction between cost estimates and cost forecasts used elsewhere in this thesis (see Chapter 2) is adapted, since for PV, cost estimate data can largely be replaced with actual price data.
from the module into alternating current), wiring and mounting systems and installation costs (Junginger et al. 2008). Collectively these additional costs are known as Balance of System (BoS). The convention for presenting module costs in isolation in part reflects the very installation-specific nature of the BoS costs, but also that the focus of effort for PV cost reduction has historically been on the module since the BoS components are typically components or processes which are in a relatively mature state of development (Schaeffer et al. 2004). However, the substantially reduced costs of PV modules does now mean that the BoS costs are an increasing share of the total costs, which in turn has recently led to an increased focus on how the BoS costs may also be reduced (IEA 2014b).

![Figure 7.2 PV module price trend 1976 onwards (Candelise 2012b)](image)

According to (Nemet 2006), the three strongest drivers for the cost reductions reflected in Figure 7.2 in the period from 1980 to 2001 were (in descending order of importance): increases in the manufacturing plant size, increases in the conversion efficiency of the module, and reductions in the cost of the silicon feedstock. The results of Nemet’s analysis suggested that other factors, such as increasing silicon wafer size and the amount of silicon required per unit of rated output, made only a marginal contribution to observed cost
reductions. In addition to the increase in plant size, others also attribute the manufacturing cost reductions to the move from batch processes to continuous production lines and the increasing vertical integration of the companies involved in the production process (Candelise 2012b).

However, as Figure 7.3 shows, the clear downward trend was interrupted in the early 2000s, a reverse which (Junginger et al. 2008) attributed to a combination of silicon supply shortages (leading to rising costs of the feedstock), the rising costs of the energy used in the PV module production processes, and increased demand (which in turn allowed suppliers to increase prices and margins). Junginger et al. also observed that whilst, the silicon supply shortages forced up the cost of the feedstock, they also stimulated efforts to reduce the amount of silicon required per rated unit of output. This reaction is also identified in (Candelise 2012b) which added that rising silicon prices led to new investment in the production of the feedstock, and that it also encouraged an increasing speed of development in thin film technologies (requiring less silicon) and laid the foundations for further cost reductions since the thin film technology is particularly suitable for large-scale continuous production processes. These observations were largely borne out as the upward trend proved to be relatively short-lived as costs reverted to a downward trajectory from the late 2000s onwards with costs falling markedly in the early 2010s.

The lowest of the three data series in Figure 7.3 (denoted as ‘UK £ (€)’ because it represents the ‘Europe €/Wp’ data converted into GB Pounds), has been included to illustrate the potential for currency conversion processes (as described in Chapter 2) to introduce a potentially misleading step-change result which is not present in the underlying original currency data series. For example, the rises in module costs shown at the start of 2008 and
2009 for values in £ are attributable to the devaluation of Sterling against the Euro over these periods, as demonstrated by the absence of the step-change in the corresponding European data series (the line that starts as the highest). The effect is exacerbated in this case since annual historical currency conversion rates were used so a change in a currency’s value which may have occurred over the course of a year does not show up until the data series moves to the next year, and then the entire annual change is represented in a single step.

Figure 7.3 Average PV module prices 2003 onwards (Candelise 2012a, Candelise 2012b)

The most recent cost reductions shown in Figure 7.3 can, to an extent, be seen as a result of the market reaction to the previous period of higher prices and margins, and several studies e.g. (Candelise 2012b) correlate these reductions with the market over-supply (a factor which Junginger and his colleagues had speculated in their 2008 report could result from the increasing profit margins attracting new entrants). However, there is also speculation that not all of the most recent cost reductions are sustainable and there was evidence emerging by 2012 that prices were below production costs (ibid.), leading to the industry shakeout predicted in (Junginger et al. 2008). There is also evidence that the reductions in module
costs were accompanied by reduction in BoS costs, which (Candelise 2012b) ascribes to a combination of greater market competition driving down margins, increasing experience and greater purchasing power of suppliers and installers, and improved grid connection rules reducing transaction costs. (Marigo and Candelise 2013) focus on the dominant role of Chinese manufacturers in recent cost reductions, concluding that these were driven primarily by increased production capacity and improved production processes, aided by access to credit facilities and other government support, with lower Chinese labour costs making a relatively minor contribution.

In respect of cost forecasts, PV has been the subject of numerous experience curve analyses, and using cost and deployment data to identify the learning rate (or rates) has provided a number of insights into the evolution of PV costs (Junginger et al. 2008). In their 2011 paper, (Yu et al.) identify three distinct periods for PV experience curves, shown in Figure 7.4 below, concluding that learning rates vary markedly between the periods, reflecting discontinuities in the downward trajectory and the negative learning rate (i.e. the rising costs discussed above) in the early 2000s.
The learning rates shown in Figure 7.4 above can be compared to the results in (Junginger et al. 2008) who calculated a progress ratio of 0.79 (so a learning rate of 21%) for the entire period from 1976 to 2006. The Junginger et al. and Yu et al. findings were broadly consistent for the period covering the early 2000s, concluding that the learning rate during this time was essentially zero or negative. Junginger et al. also suggest that there is some evidence that the overall learning rate for the period 1991-2006 was slightly better than the 1976-2006 ratio at 23%.

Other analysts have also concluded that there is good evidence to support a learning ratio of approximately 20% for PV, albeit with the proviso that there are significant variations and that the drivers of cost reduction have been complex and difficult to isolate (Gambhir et al. 2014), a point reinforced by (Candelise et al. 2013) who caution that neither experience curves or engineering assessment analyses can fully explain the recent experience of PV costs. The Yu et al 2011 analysis also found that using a Multi-Factor Learning Curve
approach (see Chapter 4) to derive near-term cost trajectories yielded less optimistic forecasts than a One-Factor approach.

Notwithstanding these concerns, the remainder of this section examines the evolution of cost forecasts for PV. In this regard, (Nemet 2009b) provides a very useful analysis, summarised in Figure 7.5 below, which compares actual prices with the range of forecasts that were consistent with the cumulative deployment actually reached in each year.

![Figure 7.5 Actual PV module prices compared to forecast range (shaded grey) (Nemet 2009b)](image)

What Figure 7.5 shows is that PV prices have been largely consistent with forecasts. However, prices have usually turned out to be at the top of the forecast range, which supports the contention in (Candelise 2012b) that earlier cost forecasts tended to be over optimistic in terms of cost reductions. With the benefit of several more years of data beyond 2005, the same analysis also suggested that much more recent forecasts had tended to underestimate cost reductions, predicting that costs of around $1/Wp would be achieved in the 2020s when in fact this was close to being achieved by 2012 and, according to (Kost et al. 2013), had actually been achieved by Autumn 2013.
A study published by Fraunhofer (Kost et al. 2013) also used an experience curve approach to forecasting PV costs out to 2030, shown in the diagonally shaded range in Figure 7.6 below, and concluded that the LCOE of PV in southern Germany would be similar to CCGT and hard coal plants by 2020 and below the average LCOE of fossil-fired plant by 2030, although not below the LCOE of brown coal (lignite) plants. This expectation was echoed by (Morgan Stanley 2014) which forecast that PV would be economic in Europe without subsidy by 2020. The pace of PV cost reductions in the early 2010s is further illustrated by comparing the forecasts in Figure 7.6 to those by (Junginger et al. 2008) who estimated that a nominal ‘grid parity’ cost (i.e. comparable with the full delivered cost of electricity from conventional sources) of €0.20/kWh would be achieved by 2020 in northern European locations. The (Kost et al. 2013) work (i.e. only five years later) was forecasting PV costs per kWh between 40% and 65% lower than this figure for the same year. The authors of the Fraunhofer study did, however, sound a note of caution when they suggested that there was the potential for a near-term pause in cost reductions as market over-supply led to a period of consolidation – a point which some recent US evidence appears to support (Crooks 2014).
These experience curve-based forecasts are complemented by the analysis in (Bosetti et al. 2012) which used an expert elicitation process to gather and summarise views on the LCOE of PV in 2030, under a range of different EU Research, Development and Demonstration (RD&D) scenarios, see Figure 7.7 below. The left-hand area shaded in Figure 7.7 represents the range of 2020 forecasts which Bosetti et al. derived from the literature. Whilst the findings show that, almost without exception, the experts involved in the study expect that additional RD&D spending will result in lower costs in the future, perhaps a more interesting finding is that authors of the study calculated that the learning rate implied by the results lies between 7% and 9% – substantially below the expectations derived by the other work described above.
Recent UK-specific cost forecasts out to 2030 have also responded to the sharply declining costs in the early 2010s. Figure 7.8 below plots the evolution of costs forecasts made for PV systems (module plus BoS) between 2008 and 2012 with the later projections, shown with crosses, both starting substantially lower than those made in 2008 (reflecting actual cost reductions) and ending much lower (reflecting the view that these cost reductions were sustainable and that there was still significantly more opportunity for further reductions). In this respect, these forecasts make for interesting comparison with those in the offshore wind case study (Chapter 5) where forecasts responded to rising costs and then projected future reductions but only to a level similar to the pre-increase forecast (see Figure 5.1), suggesting that the long-term view of the ‘end-point’ for cost reductions in the offshore wind sector was largely unchanged. Nevertheless, it is still the case that analysts expect cost reductions to level off at some point in the future, with (Gambhir et al. 2015) for example predicting that module costs for established PV technologies may start to level off at around $0.5-$0.6/Wp.
Recent industry-sourced cost forecasts (CEBR 2014) are even more optimistic than the DECC figures shown above, predicting that the LCOE of large-scale PV will achieve parity with new CCGT plants by 2018 (compared to DECC’s view that parity will not be achieved until around 2023). These forecasts, shown in Figure 7.9 below, also highlight an interesting point with regard to wholesale electricity prices and the electricity generation costs of new plant. As of 2014, the cost of electricity generated from even the lowest cost new plant (CCGT) is well above the wholesale price of electricity, and is projected to remain so for the entire forecast period out to 2030, with the LCOE of large-scale PV also forecast to be above the wholesale price of electricity until around 2024 (the industry view) or 2027 (the DECC view). Current wholesale electricity prices would be expected to reflect the existing mix of plant and fuel costs for the reasons discussed in Chapter 3\(^{37}\), but the disparity between wholesale prices and the costs of electricity from new plants reinforces the need to consider the counterfactual in discussions over the costs of moving to a low-carbon generation fleet. The comparison of the LCOE of PV and CCGT also raises the question as to the extent to

\[^{37}\] Wholesale electricity prices would also be expected to reflect any system costs borne by the generators, but not the retailing costs.
which it is appropriate to compare the costs of dispatchable and non-dispatchable technologies in this way – see Chapter 3 and the discussion in Chapter 8.

Figure 7.9 Comparison of industry and DECC large-scale PV cost forecasts (CEBR 2014)

Figures 7.8 and 7.9 show how the rapidly evolving cost experience fed through into expectations of future costs, and it is this combination of experience and expectation that provides the context for the policy responses discussed in section 7.3 below.

7.3 Recent UK PV policy

In respect of overall deployment levels, the recent history of UK PV policy can be seen as a clear success with around 5,000MW of cumulative deployment by the autumn of 2014, starting from a negligible base in 2010. The relatively smooth upward trajectory of cumulative deployment shown in Figure 7.10 does however mask a more variable underlying
level of activity (Rowley et al. 2015) which resulted from a rapidly evolving policy environment, brought about as the UK Government responded to the substantial cost reductions described in the previous section.

Figure 7.10 UK PV cumulative deployment to date (Solarbuzz 2014)

To provide an overview of the policy developments that drove both the overall deployment and the underlying variability, Table 7.1 below collates the key UK Government policy activities that relate to incentives for PV deployment, starting in 2009 with the introduction of technology-specific banding of the Renewables Obligation (RO) scheme.

Banding of the RO scheme meant that higher cost technologies, such as offshore wind and PV, were able to receive additional support as they would qualify for more than one Renewable Obligation Certificate (ROC) per MWh generated (lower cost technologies remained at one ROC/MWh or even less for some technologies deemed to be particularly low
cost. Although the Renewables Obligation scheme was introduced in 2002 it had no practical impact on PV deployment until after 2009 because the support available up to that point through un-banded, technology-neutral ROCs was insufficient to bring forward any PV projects, given the relatively high costs of the technology at the time.

Even with the introduction of banding, the characteristics of the RO scheme meant that it was relatively inaccessible to smaller renewable energy projects, an issue that was recognised by policymakers (DECC 2009a), and which led to the introduction in April 2010 of a Feed-in Tariff (FiT) mechanism aimed at smaller projects, with support for PV limited to installations below 5MW in size. The Feed-in Tariff for PV ranged between £0.41 and £0.29 for each kWh generated (regardless of whether the electricity was used on-site or exported to the grid). Whilst the actual rate for a project was largely dependent on the size of the installation with small projects attracting the highest FiT and large systems the least, these values reflected the perceived high cost of PV at the time. By way of comparison, the support then available to offshore wind projects through the Renewables Obligation mechanism was equivalent to around £0.10/kWh, which was paid on top of whatever wholesale price of electricity project developers were able to secure (Greenacre et al. 2010). The FiT was complemented by an export tariff paid for the 50% of PV generation that was deemed (in the absence of export metering) to be exported to the grid, although this was set at a relatively low level (£0.03/kWh, well below the wholesale price of electricity). In practice, PV owners were encouraged to ‘self-consume’ as much of their PV output as possible, since doing so allowed them to avoid incurring the retail cost of that output.
<table>
<thead>
<tr>
<th>Date</th>
<th>Policy Mechanism</th>
</tr>
</thead>
<tbody>
<tr>
<td>April 2009</td>
<td>RO banding introduced (DECC 2009b)</td>
</tr>
<tr>
<td>July 2009</td>
<td>Consultation on Renewable Electricity Financial Incentives (DECC 2009a)</td>
</tr>
<tr>
<td>April 2010</td>
<td>Feed-in Tariff available for projects up to 5MW (DECC 2010b)</td>
</tr>
<tr>
<td>Mar 2011</td>
<td>Consultation on fast-track review of Feed-in Tariffs for small scale low carbon electricity (DECC 2011b)</td>
</tr>
<tr>
<td>June 2011</td>
<td>Feed-in Tariffs Scheme: Summary of Responses to the Fast-Track Consultation and Government Response (DECC 2011c)</td>
</tr>
<tr>
<td>Oct 2011</td>
<td>Consultation on Comprehensive Review Phase 1 – tariffs for solar PV (DECC 2011d)</td>
</tr>
<tr>
<td>Oct 2011</td>
<td>Consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 (DECC 2011c)</td>
</tr>
<tr>
<td>Feb 2012</td>
<td>Consultation on Comprehensive Review Phase 2A: Solar PV cost control (DECC 2012e)</td>
</tr>
<tr>
<td>May 2012</td>
<td>Feed-in Tariffs Scheme Government response to Consultation on Comprehensive Review Phase 2A: Solar PV cost control (DECC 2012f)</td>
</tr>
<tr>
<td>July 2012</td>
<td>Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012 (DECC 2012g)</td>
</tr>
<tr>
<td>Sep 2012</td>
<td>Further consultation on PV ROC banding (DECC 2012a)</td>
</tr>
<tr>
<td>April 2013</td>
<td>ROC banding for PV split between rooftop and ground-mount (DECC 2012g)</td>
</tr>
<tr>
<td>July 2013</td>
<td>Consultation on the draft Electricity Market Reform Delivery Plan (DECC 2013a)</td>
</tr>
<tr>
<td>Dec 2013</td>
<td>Electricity Market Reform: Consultation on Proposals for Implementation (DECC 2013f)</td>
</tr>
<tr>
<td></td>
<td>Investing in renewable technologies – CfD contract terms and strike prices (DECC 2013i)</td>
</tr>
</tbody>
</table>
As Table 7.1 shows, the FiT mechanism has since been revised several times, with the first revision (DECC 2011b) coming less than eighteen months after the policy was originally introduced, the second (DECC 2011d) following approximately six months later, and the third (DECC 2012d) another six months after that. These revisions were introduced in response to UK Government concerns that rapidly falling costs meant that the returns available from PV installations were running well above original expectations (and well above returns available from other prospective investments), which in turn meant that PV installation rates were above the level anticipated and that the burden imposed on all consumers through the socialising of the FiT mechanism costs were too high (Muhammad-Sukki et al. 2013). The overall purpose of these successive revisions was to reduce the level of support available through the FiT to more closely align the incentives with the (reduced) costs, but the opportunity was also taken to revise the details of the mechanism so that by mid-2012 support was more focussed on the size and type of PV installation which the UK
Government wished to encourage, the FiT contract period was reduced, and the degression\textsuperscript{38} of the FiT level was linked to deployment levels.

The period from mid-2012 onwards saw further reviews of the support for PV, although these were now either focussed on the incentives for larger schemes through the banded RO mechanism (amid UK Government concerns over the cost of those incentives relative to rapidly declining costs) or were increasingly becoming bound up in the wider review of policy under the Electricity Market Reform (EMR) process. In 2013 the ROC banding for PV was revised (following an additional review in late 2012) to introduce a split between ground-mounted and roof-top systems, with support now focussed on incentivising the latter at the expense of the former (DECC 2012g). By mid-2014, it was the UK Government’s view that cost for large-scale PV projects had reduced to the level where they were able to (and therefore should) compete with broadly similar-cost renewable technologies for support under the Contracts for Difference (CfD) mechanism introduced under the EMR (DECC 2014d). Support for small and mid-scale PV projects continued to come from the FiT scheme, with RO-based support for new projects scheduled to cease once the RO to CfD transition period comes to an end.

The multitude of policy reviews, differentiated support mechanisms and complexity of stratified support levels described above did not appear to stymie PV deployment in the period from 2010 onwards, although it is clear that some had considerably more impact than others. The relative contribution to total deployment of each variant of the policy mechanisms is summarised in Figure 7.11 below, showing that the largest contribution to cumulative UK PV deployment to date (at 42\% of the total) is from installations supported through Feed-in

\textsuperscript{38} ‘degression’ is the term used to describe how the FiT support level is reduced over time so that earlier projects receive a higher FiT than later projects. The degression mechanism is intended to reflect the reduced support required for later projects as costs fall.
Tariffs aimed at small-scale projects, followed by large-scale ground-mounted installations supported through the Renewables Obligation.

**Incentive Schemes for 5GW UK Solar PV**

![Incentive Schemes for 5GW UK Solar PV](image)

*Figure 7.11 UK PV deployment grouped by incentive scheme (Solarbuzz 2014)*

In practice, one of the principal concerns of the UK Government with regard to PV deployment appears to have been that it was *too* effective, with rapidly reducing costs outpacing downward revisions to support levels and leading to higher than anticipated project returns and deployment (and also costs to be borne by consumers). The considerable challenge for policymakers in discerning the level of support required to incentivise a desired level of deployment in the face of rapidly changing costs which may not be following the previously observed or forecast trajectory is recognised by several commentators, including (Nemet 2009b) and (Candelise *et al.* 2013).

Despite the reductions in support described above, the perception that policy may still be over-rewarding PV installations persists, with some analysts suggesting that current levels of
support are ‘overly generous, and therefore at risk’ (Morgan Stanley 2014) pg. 26, and that the support available for PV through the FiT mechanism is likely to be reviewed again in the near future. The same analysts also highlight the potential need to revise the charging structure for grid electricity at some point, to reflect the concern that otherwise PV users will not pay their fair share of the grid costs but will still rely on the grid for those periods when their electricity consumption exceeds the output from their PV installation. In the UK for example, these grid costs, including transmission, distribution and other ancillary services required to ensure stable and reliable electricity supplies, are currently shared among users through charges imposed per unit of electricity supplied from the grid. The concern is that, if an individual user obtains a significant share of their own consumption from ‘self-generated’ sources, thereby reducing the units of grid-supplied electricity they consume, then this may mean that they are not paying their full share of the grid costs, despite remaining dependant on the grid to ensure reliable supplies regardless of the output from their PV installation – see Chapter 3 and the discussion in Chapter 8.

7.4 Conclusion

The history of PV costs is characterised by several decades of very substantial cost reductions (albeit with some relatively brief inversions to this downward trend, most notably in the early 2000s). These cost reductions have been achieved through a combination of a number of factors, including an increase in the number of PV module manufacturers leading to increased competitions amongst suppliers, the scaling up of the PV module production process, the development of dedicated supply chains for the inputs to those production processes, improved installation methods, and complementary reductions in the components of the PV installation that make up the Balance of System.
The last decade has also seen a remarkable growth in the level of global PV deployment with an increase of over 5,000% in the ten years from 2004, driven by very supportive policy environments in many countries, underpinned by taxpayers or consumers who are prepared to pay for the policy support (the cost of which were increasingly acceptable because of the substantial reductions in PV module costs). Since 2010, the UK has also had policy mechanisms in place that provided substantial incentives for UK PV deployment and these mechanisms have resulted in the rapid growth of the cumulative installed capacity in the UK, starting at close to zero less than five years ago and rising to around 5,000MW towards the end of 2014.

During this period, it is clear that UK policymakers have had concerns that the support available was at times rather too generous, as policy struggled to keep pace with the extraordinarily rapid price and cost reductions in the global PV module market – reductions which followed closely on from the period of PV module price rises in the early 2000s and which arguably made accurate predictions of costs more challenging. These concerns have led to a period of almost continuous policy revision with, in the space of the four years from 2010, around a dozen policy consultations, responses, reviews, roadmaps, strategies and delivery plans that relate to support for UK PV deployment. Whilst this complex and rapidly evolving policy environment does not appear to have hampered overall levels of PV deployment in the UK, concerns have been raised that it has resulted in a rather uncertain and erratic level of installations, which may have slowed the build-up of the industry in the UK.

Despite these concerns, both policymakers and the industry remain markedly optimistic over the future cost trajectory for PV in the UK, forecasting that large-scale PV will be cost-competitive with gas-fired generation by the mid-2020s. This optimism is shared by many
international analyses where there is a clear consensus that PV costs (for all scales of installation) will continue to fall for a considerable time. The almost unqualified success story of PV cost reductions to date and forecasts that suggest these reductions are likely to continue have driven, and seem likely to drive, continued and substantial increases in UK and global PV deployment. Whilst this is clearly good for the PV industry and for the achievement of low-carbon electricity generation targets, it may also bring into sharper focus concerns over the integration of variable-output renewable generation into electricity grids, and the extent to which traditional measures of electricity costs such as LCOE are appropriate for non-dispatchable technologies and/or those that rely on the stability of the electricity grid but may not be making their full contribution to the costs of providing that stability – issues which are discussed in the next chapter.
8 Discussion

8.1 Introduction

This thesis examines the history of electricity cost estimates and forecasts to address the central question: *How accurate are electricity cost estimates and forecasts, and are they fit for purpose in the context of policy analysis?* There are two strands to the analysis underpinning this thesis. The primary strand is concerned with the degree of accuracy of electricity cost estimates and forecasts and how that accuracy (or otherwise) may influence policy, and the secondary strand is focussed on the extent to which the limitations of commonly used cost metrics bear upon the usefulness of those metrics for policy. This chapter is structured around three of the subsidiary questions identified in Chapter 1, which flow from the central research question above, namely:

- To what extent have technology costs diverged from previous cost estimates and forecasts i.e. how accurate are cost estimates and forecasts? (covered in Section 8.2 below).
- Which are the most important aspects or issues of costs which are not typically included in those metrics commonly used in policy i.e. what is missing from cost estimates and forecasts? (covered in Section 8.3 below).
- How has policy responded to these multiple uncertainties over costs? (covered in Section 8.4 below).

To address these questions, this chapter draws upon the findings from the analysis in the case studies in Chapters 5, 6 and 7, and these are complemented by the evidence from the reviews of the use (and limitations) of cost estimates in policy, and methodologies for cost forecasting, in Chapters 3 and 4 respectively.
As Chapter 3 makes clear, electricity cost estimates have played a central role in policy, informing decisions as to what technologies are (1) deserving of support, (2) how much support is required, and (3) how long that support may be required for. The first two of these rely largely on cost estimates and the third relies largely on forecasts of the future trajectory of costs. The shortcomings of the cost estimates used in policy are categorised in Chapter 1 as limitations in extent (i.e. their ability to fully represent the complete economic cost of a technology or plant), limitations in applicability (i.e. whether or not they can answer all the questions which are asked of them), and limitations in methodology (i.e. whether a particular approach to estimation leads to uncertainties over the result of an analysis). Many of these shortcomings are well understood, so much of this discussion chapter is therefore concerned with the extent to which the evidence from the case studies magnifies (or not) those shortcomings and affects the usefulness of electricity cost estimates in policy.

8.1.1 Cost forecasting methodologies

Much of the very substantial body of literature reviewed in Chapter 4 on the methods and approaches to electricity cost forecasting focuses on the use of experience curve analyses, and these provide convincing evidence that the costs of a new or emerging technology can fall over time as cumulative deployment of that technology rises. What is less certain is whether cost will fall as deployment increases, regardless of the technology. The view that costs will almost inevitably fall may, in part, be linked to a possible degree of selection bias in experience curve analyses in that a technology which does not move beyond the invention or demonstration stages (because it shows none or very little prospect of ever being competitive with more established technologies) cannot become the subject of experience curves analyses based on empirical data – because there is no data on which to perform those analyses. The result is that technologies which have moved on from demonstration to significant
deployment over a sustained period may be over-represented in experience curve analyses, at least in respect of support for the argument that all technologies will follow a downward cost trajectory.

Chapter 4 divides the limitations of experience curve analysis into two broad groups, the first being those which are intrinsic to the approach and the second being those which relate to the data input and assumptions. The specific limitations discussed in Chapter 4 which resonate particularly with the evidence from the case studies are those associated with variable learning rates (e.g. PV), the disproportionate influence of early trends (e.g. offshore wind), the effect of modular versus large-unit technologies (e.g. PV versus nuclear), inadequate initial data and the use of proxies (e.g. offshore wind), and the extent to which costs are accurately reflected in prices (e.g. PV and to a lesser extent offshore wind and nuclear). The evidence from the case studies that is discussed below also suggests that costs may remain stubbornly high (such as in the case of nuclear), that costs may not start to fall, indeed they mean even rise, as early-stage deployment increases (such as in the case of offshore wind), or that where costs do fall there may well be unforecast interruptions to the downward trajectory (such as in the case of PV).

The alternative approaches to cost forecasting of engineering assessment and expert elicitation, also described in Chapter 4, have an advantage over experience curve analyses in that they do not explicitly rely on the historical evidence of a technology cost (or that of a proxy technology), and therefore can in theory take account of possible future changes in cost trajectories – for example the ‘non-reproducible events’ that (Bosetti et al. 2012), pg. 315, identify. However, the knowledge and understanding that these approaches rely on does not exist in a vacuum – engineering assessment of future costs will draw upon current costs and
the judgements of engineers with industry experience, so those judgements will almost inevitably be informed by the engineer’s view on the past history of the technology under consideration and the opportunities for cost reduction. Similarly, expert elicitation relies upon the judgement of experts who draw their expertise from their knowledge of the history and current status of a technology’s costs – with, as Chapter 4 suggests, the attendant risks of bias that they may introduce. These alternatives to experience curve analysis are often used where there is insufficient historical cost data to be confident about the actual cost trajectory, or where the data that is available is not thought to accurately reflect the direction of future costs. This does, however, raise the question that if there is insufficient data, then what are engineering and expert judgements based upon? Linking this specifically to the evidence from the case studies and earlier chapters, what is the source of the information which analyses such as (Mott MacDonald 2010) use to ‘make informed judgements’ (pg. 7) or (Parsons Brinckerhoff 2011) use to ‘take a view on the credibility’ of data sources (pg. 8), and is it accurate and sufficiently free from bias? These concerns, together with the other findings from the case studies that relate to the research questions, are discussed in the sections that follow.

8.2 The accuracy of cost estimates and forecasting

A key aspect of the context for a discussion of the accuracy of cost estimates is the extent to which estimates have changed for all technologies by a considerable degree during the last few years. To illustrate this, Figure 8.1 below uses largely the same UK-specific dataset as Figures 1.1 and 3.18, but the LCOE ranges are normalised to the midpoint value of the central range of estimates for each technology in 2006 so that the range blocks are centred around the index base value of 100 in the left-hand side of the chart. The central range blocks and the extended range lines are adjusted to be consistent with the normalised midpoint so
that the left-hand side of the chart shows the size of the range for each technology relative to the midpoint for that technology. The right-hand side of the chart shows the 2011 central and extended range values for each technology, based on values relative to the 2006 base index, to demonstrate the size of the relative ranges in each period and the relative changes in cost estimates between the two periods. Since all monetary values were in 2011 GBP before normalising to the index values, the effects of inflation are excluded. As well as demonstrating the relative size of the in-year ranges and 2006 to 2011 movements, the indexation process also allows values for PV to be included in Figure 8.1, which would not be practical if the underlying cost per MWh values were represented instead, because those values were very high (several hundred £/MWh) for PV in the UK in the mid-2000s.

![Figure 8.1 Normalised 2006 and 2011 cost estimates (including PV)](image)

39 Underlying LCOE values for PV (albeit 2007) are calculated from the system capex values in (Candelise et al 2013) with an assumed 10% load factor, 10% discount rate, 20 year operating life and O&M costs fixed at annual charge of 0.8% of capex. This results in a 2007 LCOE range centred around a midpoint of a little under £700/MWh. Underlying 2011 LCOE values for PV are from (Arup 2011), the same source as the onshore and offshore wind data.
Figure 8.1 reinforces the messages that the cost estimates for almost all electricity generation technologies increased substantially from 2006 onwards, that some technologies experienced cost (estimate) increases that were significantly greater than others, and that the range of estimates for some technologies is very wide. This latter observation relates particularly to fossil-fired generation technologies, whereas offshore wind and nuclear occupy something of a middle ground with still significant relative cost rises, with onshore wind showing the lowest relative cost rises (excepting PV).

Comparing the 2006 and 2011 ranges also reveals differences in assumptions over the nature of the underlying uncertainties, and in how different analyses adopted slightly divergent approaches. The 2011 ranges for onshore and offshore wind reflect the approach taken in (Arup 2011) which was to present only central, low and high LCOE values so the central ‘range’ is in fact a single point estimate, whilst the narrow central range for these costs in 2006 (based on DTI’s own analysis) largely reflected the degree of confidence at the time in capex estimates for these technologies. For nuclear power what is striking is that, whilst the total cost range spans roughly 50 index points for both 2006 and 2011 values, what changed by 2011 was the greater uncertainty in the central range, shown by the central range block for this year covering almost the full 50 index point range. For the fossil-fired technologies, the generally reduced size of the central range blocks for 2011 (relative to 2006) largely reflected increased confidence in the capex estimates, whilst the larger extended ranges largely reflected increased uncertainty over future fuel and emissions costs.

PV is the only technology that shows a relative cost reduction in Figure 8.1, albeit the underlying absolute MWh values were very high in the mid-2000s. By 2011 the underlying MWh values for PV were still high compared to other technologies with (Arup 2011)
suggesting a range of £201-£380/MWh with a midpoint of £282/MWh. However, by late 2013 those estimates had reduced substantially again, for the reasons described in the PV case study in Chapter 7, and by that point DECC’s estimated cost for large-scale PV was £158/MWh (DECC 2013b), well below even the lowest value in the Arup 2011 analysis. The implicit cost projections reflected in the CfD strike prices for large-scale PV were lower still, being set at £120/MWh for 2014/15, falling to £100 by 2018/19 (DECC 2013i). By comparison, between 2011 and late 2013 the range of cost estimates for the other generation technologies shown in Figure 8.1 had changed relatively little (ibid.).

Figure 8.2 below plots the in-year mean of European estimates of contemporary LCOE from 1995 through to 2011 and the range of UK-specific LCOE forecasts from 2013 through to 2030 for four major electricity generation technologies. This emphasises the considerable variation in LCOE estimates over time for all the analysed technologies, and contrasts the direction of past variation over time with future forecasts. Consistent with Figure 8.1, the clear trend for historic estimates for all of the technologies shown is one of rising costs from the early to mid-2000s onwards, with offshore wind and nuclear power apparently on significantly steeper upward trajectories than onshore wind and CCGT.
In respect of forecasts, the data in Figure 8.2 for offshore wind in particular suggests a relatively steep reduction in costs over the next 10-15 years, followed by a levelling off, albeit still at a point higher than the lowest of the historic estimates. Forecasts for onshore wind and nuclear suggest that relatively smaller cost reductions are anticipated for these technologies. Forecasts for CCGT costs do not follow the same trajectory, although this may in part be linked to assumptions over future fuel prices and CO₂ emissions costs rather than the underlying technology cost. In general, forecasts tend to show a much smoother and more consistent, often downward trajectory, although there is still a considerable range of estimates within specific future years. A clear message from the case studies is that the cost increases from the mid-2000s were largely unforecast and the remainder of this section discusses the
reasons for the cost increases (for offshore wind and nuclear) and cost reductions (for PV) to better understand what this means for the accuracy of cost estimates and forecasting.

8.2.1 Offshore wind

In the case of offshore wind in the UK, as the case study in Chapter 5 explains, the dramatic increases in cost estimates from the mid-2000s to the early 2010s were driven by a combination of: rising materials, commodities and labour costs; adverse currency movements; supply chain constraints (particularly in the turbine market but also in installation support services); increasing water depth and distance from shore of later offshore wind farm sites; and planning and consenting delays. Taken together, the cumulative effect of these drivers resulted in an approximate doubling of the estimated capex for UK offshore wind projects, which in turn resulted in a typical LCOE of around £140-150/MWh by 2010 – a value that is broadly consistent with the current strike price under the Contract for Difference mechanism, albeit with a limited reduction by 2018/19 (DECC 2013i).

These cost increases coincided with a significant increase in UK policy aspirations for offshore wind deployment and, whilst this does not necessarily imply causality, there is some evidence from the case study that it may well have been a factor for at least two reasons. Firstly, the costs of the first two offshore wind farms in the UK were significantly lower than subsequent projects and whilst their near-shore and relatively benign locations were almost certainly factors, it is also the case that there is some evidence that the published\(^\text{40}\) costs did not fully reflect the true cost and that suppliers bid very aggressively for work on the projects in the expectation of rapid industry growth driven by declared policy aspirations. The second reason for linking these cost increases to policy is that the rapid growth in the number of

\(^{40}\) The first two offshore wind farms in the UK received capital cost support in addition to support under the RO, and a condition of that support was that their costs were to be made publicly available (Greenacre et al. 2010).
projects in development (driven by a supportive policy regime) put pressure on the offshore wind supply chain which had yet to scale up for the increased deployment or had other lower risk/higher return markets for their products (for example in the case of turbine manufacturers) and services (for example in the case of installation and support vessels). This evidence from the case study highlights the risk of cost forecasts turning out to be wrong where the types of experience curve analyses described in Chapter 4 are applied at too early a stage in a technology’s deployment or where proxy experience curves from related technologies (in this case onshore wind) do not fully reflect the characteristics of the technology whose costs are being forecast. In the case of offshore wind, these issues were also compounded by external factors in the form of adverse currency and commodity price movements, which experience curve analyses cannot forecast, and which engineering assessment or expert elicitation approaches also find very challenging.

Despite this recent experience of increasing cost estimates, the offshore wind industry has remained optimistic over the possibility of future cost reductions, and whilst near-term cost forecasts have responded to actual cost experience, medium and longer term forecasts suggest that the industry believe that costs can fall very substantially (see Figures 5.1 and 5.5). The analysis in the case study in Chapter 5 suggests that for this to happen, most, if not all, of the major drivers of recent cost increases would have to move decisively in the right direction and furthermore, that direction would have to be sustained for several years. Clearly this is not impossible but it does raise the question as to how probable this is given the observed history.

The evidence from the case study on possible future cost trajectories for offshore wind provides some insight into this question, in that it suggests that the offshore wind industry
understands that cost reductions must be achieved if support is to be politically sustainable. This does, however, create the danger that cost forecasts may be overly optimistic about the opportunities for cost reductions since to do otherwise may jeopardise support (and therefore deployment and in turn remove the possibility of future cost reductions resulting from learning from experience). A comparison between CfD strike prices out to 2019 and industry cost projections (The Crown Estate 2012, DECC 2013i) suggests there is at least some degree of mismatch and whilst it may be possible to accept these in the short term, the question remains as to whether this will still be possible in the longer term, especially as the cost of policy support becomes increasingly manifested in higher consumer bills, and if the result is that offshore wind consumes a very large fraction of the total cap under the Levy Control Framework (LCF). This concern notwithstanding, the results of the CfD auction process announced in late February 2015 (DECC 2015) represent the most recent indicator of offshore wind costs, and if these turn out to be an accurate representation for the industry as a whole, then progress on cost reduction will have been substantial.

8.2.2 Nuclear
The recent trajectory of cost estimates and forecasts for nuclear power has some similarity with offshore wind in that increases in cost estimates in the mid-2000s fed through into higher forecasts, but whereas forecasts for offshore wind reflected expectations that costs would (eventually) fall back to pre-increase levels, the post-2005 forecasts for nuclear power shown in Figure 6.1 do not do this, and remain higher than previous forecasts, even for several decades out into the future. As Figure 6.3 in the nuclear case study shows, cost estimates have followed a trajectory of earlier cost increases up to around the 1990s, followed by an apparent decline during the 1990s, and then a reversion to cost increases from the mid-2000s onwards – although even with these relatively recent increases, current estimates for
nuclear power in the UK are towards the lower end of the range for low-carbon generation options.

The evidence reviewed in Chapter 6 suggests that the earlier phase of cost increases was driven by a combination of: an increasingly complex regulatory burden; frequent design changes (some as a result of the increased regulation and some as a result of attempts to improve designs); a lack of standardisation which meant that there were limited (or no) opportunities for learning and experience to feed through into proven improvements in later projects; and finally there is some evidence of appraisal optimism and some suggestions (albeit very difficult to prove) of cases where the industry was deliberately producing estimates below their real value in order to build support for the industry. The overall result was that cost estimates during this period largely failed to reflect or keep pace with real cost experience.

There was, however, encouraging evidence during the 1990s and early 2000s that nuclear costs were declining but this evidence was largely from countries with very different labour costs and regulatory environments. This did not, seemingly, prevent these estimates from feeding through into estimates for nuclear projects in OECD countries, including the UK, with very little or no adjustment for the differentiating factors, and at a time when there was very little evidence (either positive or negative) for OECD-specific cost because very few plants were being built in these countries. By the mid-2000s the experience from plants that were being built in non-OECD countries had fed through into UK estimates that suggested that nuclear power was close to cost parity with CCGT plant, the ‘default’ option for new electricity generation (see Figure 3.1).
As the nuclear case study in Chapter 6 explains, these apparently competitive costs led to the UK Government wholeheartedly embracing the prospect of new nuclear power but, in another parallel with the offshore wind case, this aspiration coincided with the start of the latest period of cost increases that were not forecast by the industry or by the engineering consultancies engaged by the UK government to provide analyses of nuclear costs. It should, however, be recognised that some commentators were at the time sceptical of these mid-2000s cost estimates for nuclear power e.g. (Thomas 2010), scepticism which is leant weight by the ‘cost realism’ issue discussed in Chapter 6 and in this section.

In part, the cost rises since the mid-2000s can be attributed to reasons similar to those for the offshore wind cost increases described previously, namely increases in global commodity prices and supply chain restrictions in specialist components and assemblies. These factors do not, however, explain the full increase in costs and the case study suggests that experience from ongoing nuclear projects in France and Finland (which are both very substantially behind schedule and over-budget) was influencing cost estimates in the late 2000s/early 2010s. There is also the issue of ‘cost realism’ which suggests that the impending likelihood of an actual project in the UK meant that the industry was forced to be more realistic in its estimates. If correct, this would imply that a proportion of the recent increases were not, in fact, increases in the genuine underlying costs and that the mid-2000 estimates (which had a clear impact on policy aspirations) were not a good reflection of true costs at the time. There may be a parallel here with carbon capture and storage (CCS) technologies, where cost estimates increased dramatically from the mid-2000s onwards (see Figure 8.3 below), during a period when no CCS power plants were being constructed but expectations that plants would start to be built in the relatively near future were increasing (Jones 2012).
Recent forecasts for the costs of new nuclear plants to be built in the UK over short and medium term time horizons do not appear to be constrained significantly by the dominance of evidence for cost increases from the case study in Chapter 6. Forecasts made in 2013 (DECC 2013c) for projects starting in 2019 (and so likely to be commissioned in the mid-2020s) ranged between £67/MWh and £94/MWh, with the range largely depending on capex and discount rate assumptions, with similar values forecast for projects commissioning in 2030. This draws attention to the general issue of applying experience curve analysis to forecasts of nuclear costs, in the absence of suitable data from which to build an experience curve, or where that data is not thought to be a useful guide to the future. The evidence from the case
study suggests that the application of the experience curve approach in this context is at best problematic and contested, and at worst seems to fly in the face of the available evidence.

Given these circumstances, some analyses appear to have made somewhat arbitrary judgements as to what values to use for learning rates. The analysis in (Parsons Brinckerhoff 2012) for example acknowledges that there is insufficient data to build a reliable experience curve for nuclear cost forecasting and so assumes a 5% learning rate. This may turn out to be accurate but it is difficult to see, a priori, how such an assumption will turn out to be any more accurate than, for example, 3%, 0% or -5%. A further challenge is that the very long build times of nuclear projects, together with the relatively limited number of individual projects likely to be taken forward within the UK, makes it considerably more challenging for the nuclear industry to demonstrate cost reductions over short timescales, even assuming that learning and cost reductions are happening.

The case study evidence also suggests that the very specialised nature of some of the major components of a nuclear power station, such as the reactor pressure vessel, may mean that the supply chain constraints and bottlenecks which led in part to the most recent wave of cost increases may sustain, therefore hampering any future cost reductions. In addition, the very large unit size of nuclear power station designs currently approved or likely to be approved in the near future for plants to be constructed in the UK restricts the options for the introduction of mass production techniques and reduces the opportunities for learning and subsequent cost reductions. This has led some commentators to suggest a move to small modular reactors (SMRs) which would both reduce the absolute capex requirement per plant and increase the opportunities for series production techniques (Ion 2014). This move would presumably not be expected to result in a lower LCOE (since the move to very large unit sizes was driven by
a desire to reduce LCOE through economies of scale) but the reduction in the absolute capex requirement per plant (and therefore reduction in the financial risk associated with a single plant) may increase the availability of finance for nuclear projects. If so, this would represent an interesting case of trading off minimising LCOE against the financeability of projects.

The evidence discussed above suggests that considerable uncertainties are likely to remain over the future trajectory of nuclear costs, which may undermine the political acceptability of support for nuclear if costs do not fall as the industry forecasts they will. Since, in common with other technologies, policy support is predicated on the assumption that costs will fall, then if they do not (or cost reductions do not become apparent until a considerable time has elapsed), then the support may become harder to sustain. This will, however, also depend on the degree to which other technologies are able to deliver on their cost reduction forecasts.

The question as to whether the UK Government’s package of policy support for nuclear power is a response to concerns over the accuracy (and therefore uncertainty) of nuclear cost estimates and forecasts is addressed in the policy response section below.

8.2.3 PV

As the case study in Chapter 7 shows, the history of cost estimates and forecasts for PV has been very different to offshore wind and nuclear power, but this does not necessarily mean that such estimates (and particularly forecasts) have always been accurate. Dealing first with cost estimates, the characteristics of PV technologies, their production processes and market composition has meant that estimates of current costs can largely be replaced with real market price data. On the face of it, this would appear to remove a source of uncertainty and potential inaccuracy in estimating costs, and the evidence from the case study largely supports this. However, there is also some evidence to suggest that there have been periods
when market prices may not have accurately reflected true underlying costs when excess capacity in PV module production industry led to very aggressive pricing from some suppliers.

These concerns notwithstanding, it is clear from the evidence in the case study that PV module technologies have enjoyed dramatic cost reductions which resulted from: an increase in the number of manufacturers and subsequent competition; scaling up of the production processes; and the creation of dedicated and larger scale supply chains for materials and components required by the production process. These have been coupled with improved installation processes and reductions in the cost of Balance of System components. What is also clear is that PV cost estimates/prices have in most cases accurately reflected these cost reductions (with the caveat described above).

In respect of forecasts for PV, the evidence reviewed in the case study suggests that much of the forecasting based on experience analyses has been broadly right, although there is a degree of divergence with earlier forecasts tending to be a little optimistic in terms of future cost reductions and later forecasts being too pessimistic. There have also been discontinuities in cost trajectory of PV (see Figure 7.4) which were not forecast (indeed could not have been forecast) by the experience curve analyses. Whilst some of the analyses reviewed in Chapter 7 did suggest that these interruptions in the downward trajectory may well occur, it is very difficult or impossible to accurately predict when such interruptions will occur (or their magnitude) so they have not generally been reflected in cost forecasts. The evidence also suggests that experience curve analyses (or engineering assessment and expert elicitation approaches) have not been able to fully explain the recent trajectory of PV module costs. The message, that it would be wrong to assume that any downward cost trajectory will be smooth
(even for those technologies such as PV where the overall direction has been one of dramatic reductions), creates a potential problem for policymakers. The case of PV provides a good example when in the late-2000s the UK Government needed to accurately estimate policy support requirements for PV in a period which was (with the benefit of hindsight) only a brief interruption to the downward cost trend – but that this was not necessarily apparent at the time.

The case study suggests that forecasts of future PV costs have generally responded to the experience of falling current costs by reducing all forecasts, even over the long term, which suggests that analysts believe that current costs are a relatively accurate reflection of true underlying costs and are not a temporary phenomenon. If an element of cost reductions was thought to be temporary then this would be expected to be reflected in forecasts of future costs either as a temporary reverse to the downward direction or as a shallower cost reduction trajectory. In this respect there are similarities with the cost forecasts for nuclear in Chapter 6, albeit with recent movements going in opposite directions, in that changes in cost estimates (downwards for PV, upwards for nuclear) are forecast to sustain over the medium term. By contrast, (upward) changes in cost estimates for offshore wind are forecast to be reversed over the long term.

One factor which may bear upon the accuracy of cost forecasts for any technology is the ability and willingness of market participants to respond to supply and production bottlenecks, and the PV case study suggests some interesting findings in this regard. Demand pressure in the early 2000s which the PV industry could not immediately satisfy led to a temporary period of higher market prices. The industry response to this was a significant increase in production capacity and the number of PV module manufacturers in a space of
just a few years, which created the opportunity for the economies of scale in the production process, increased competition and encouraged the supply chain developments described above and in Chapter 7. The overall result was that limited production capacity, coupled with increasing demand, created the conditions where the industry was incentivised to increase in scale and return to a downward cost trajectory.

Crucially, the characteristics of the PV module production process with attendant low barriers to entry made that relatively straightforward to achieve. By contrast, the nuclear industry is characterised by large-unit, high specialised components and a complex regulatory environment – all factors which create major barriers to the entry of new market participants – so the industry response to periods of higher prices in terms of capacity building is much more muted, which in turn means that the potential cost reduction benefits of increasing capacity and competition are not forthcoming. The offshore wind industry is not such an extreme example as nuclear but it does have significantly higher barriers to entry than the PV industry and, as the case study in Chapter 5 observes, the incumbent manufacturers often have had other, lower risk or higher return markets for their products which has acted as a disincentive to build additional capacity.

8.2.4 Cross-technology observations
The evidence from the three case studies suggests that the ability of an industry to react to an excess of demand over production capacity can have a bearing on the accuracy of cost forecasts insofar as where the characteristics of an industry are conducive to a positive reaction to this situation, then it will help to create the conditions where expectations of future cost reductions can be realised. The Offshore Wind Cost Reduction Taskforce, for example, emphasised the need for genuinely competitive component supply markets,
suggesting that this can facilitate ‘more competitive pricing, greater levels of innovation in product and service provision, rationalisation of procurement, and greater availability or reduced risk of bottlenecks’ (Offshore Wind Cost Reduction Task Force 2012) pg. 9. Where the characteristics of the industry are such that any reaction to periods of increased demand is sluggish, muted or even non-existent, then the conditions for future cost reductions will be delayed (or will not be created at all). This may mean that cost forecasts turn out to be wrong, because expectations of future cost reductions are largely predicated on assumptions that industries are able to react positively (and in a timely fashion) to increased demand. Where an industry is either unable or unwilling to respond to increased demand by increasing production capacity, the case studies suggest that the result may be that prices rise – in the absence of any increases in underlying costs. In cases where production capacity substantially exceeds current demand, the opposite reaction may result – price reductions in the absence of reductions in underlying costs. Both these situations increase the difficulty of accurately estimating and forecasting costs.

An enduring challenge for cost estimation is the lack of, or limited access to, real project data and true project costs. A partial solution to this, adopted by successive UK governments and other organisations, has been to use engineering consultancies to carry out cost estimation and forecasting. In principle, such organisations are in a position to draw upon their knowledge of real projects, but this approach does raise the question of whether they can be genuinely independent of the (implicit or explicit) aims of the commissioning body. Whilst it is almost impossible to determine whether this actually happens in practice, there is at least circumstantial evidence from the case studies to lend weight to this argument. The first example is the case of the estimates for nuclear power in the early 2010s – at a time when the UK Government was in the early stages of the process of negotiating potential support with
EdF Energy. The relatively low estimates produced on behalf of the UK Government had two useful consequences (for the Government), with the first being that they helped to justify their strongly supportive position on nuclear power (because it appeared to be very cost-competitive), and the second consequence was that it helped to provide a relatively low ‘anchor’\textsuperscript{41} cost for future negotiations over the level of support required. Around the same time, EdF Energy were also attempting to establish their own (substantially higher) ‘anchor’ cost (Marchant 2012). As the case study in Chapter 6 explains, during this period, EdF were engaged in a delicate balancing act concerning cost estimates, being on the one hand anxious to position nuclear power as a relatively low cost low carbon technology and on the other hand anxious to maximise the negotiated level of support (which required costs to be emphasised).

The offshore wind cost forecasts produced for the Crown Estate in 2012 (see Figure 5.5) present another interesting example where the outcome of the process was, to a degree, influenced by the interests of the commissioning body. In this case, the (acknowledged) objective was to explore the potential pathways to achieving cost reductions with a target of £100/MWh so it is not particularly surprising that one of the pathways did indeed forecast costs reducing to that figure by 2020. Arguably, it would have been more remarkable if this cost reduction had \textit{not} been forecast by the analysis, given that, as the case study explains, policy support was predicated on cost reductions, and a clear understanding by the industry that DECC’s desire was to see offshore wind costs reducing down to £100/MWh.

\textsuperscript{41} The process whereby each participant in a negotiation proposes an ‘anchor’ position, which then influences the subsequent negotiation, is a well understood principle (Galinsky and Mussweiler 2001), to the extent that participants often expect each other to provide such a position before negotiation can begin. Failure by one of the participants to provide an anchor position can be problematic – for a particularly vivid illustration of this, see the ‘this man won’t haggle’ scene from Monty Python’s Life of Brian (HandMade Films 1979).
It is also possible to speculate that the organisations conducting cost analyses will be anxious not to draw extreme conclusions which could potentially adversely impact their other clients (such as project developers, component and equipment manufacturers and utilities) but regardless of such speculation, what these two examples from the case studies do is to reinforce the message that the context of cost estimates and forecasts is key, together with an understanding of for whom and by whom those estimates are being made.

8.3 What is missing from cost estimates

The discussion in Section 8.2 above has focussed on the extent to which electricity cost estimates and forecasts have turned out to be a reliable guide to actual costs. This section expands that consideration of the accuracy of estimates to encompass a broad definition of what is ‘missing’ from the cost estimates used in policy analyses. A key issue is the extent to which estimates and forecasts capture the costs that a technology or individual power station will impose on the system to which it is connected. As Chapter 3 explained, the metrics most commonly used in policy analyses have not generally considered the system costs which are incurred outside of the power station boundary. However, this missing element from cost estimates has come under increasing scrutiny, driven by the increasing proportion of electricity generation from intermittent and location-specific renewables such as wind and PV (and the clear policy aspirations for considerably more deployment of these technologies), and given further impetus because the ‘capacity and balancing’ costs (which the majority of analyses assume will be at least partially provided by conventional generators) have risen as a result of the rising costs associated with new conventional plant (for example, see Figure 3.14).
Chapter 3 explains that some analysts in the debate as to how these missing costs are best represented take the view that it is simply not appropriate to compare for example the LCOE of a technology such as PV with the LCOE of a CCGT plant because their characteristics mean that they impose very different costs on electricity systems. The favoured approach of such analysts tends to focus on calculations of total system costs for a range of scenarios with different mixes of variable renewable and conventional plant, drawing conclusions as to the total costs that each mix is forecast to impose. This has the advantage that it does not require the potentially problematic allocation of additional system costs to a particular technology or plant. It may not, however, provide the information that is required by policymakers who have historically focused on LCOE as a guide to which technologies are deserving of support and how much that support should be. This is because these analyses must still make input assumptions before they can provide answers to questions such as, for example, how much CCS capacity and annual output may be required to deliver the lowest cost route to a certain level of decarbonisation – and one of those input assumptions is about technology costs.

The alternatives to this approach are the ‘enhanced LCOE’ and ‘market value’ approaches described in Chapter 3. The first of these attempts to calculate the additional system costs associated with a particular level of variable renewable generation, and then allocate those costs over the output of that renewable generation. The latter approach takes as its starting point the typical value of a unit of electricity generated and deducts the additional costs which variable renewable generation is calculated to impose, to arrive at a ‘true’ market value for the renewable output. Neither approach is without critics, not least because of the sometimes very pessimistic results for variable renewables in terms of the additional costs or reduced market value. Given that system integration costs generally rise as the proportion of electricity supplied from variable renewable sources rises (see Chapter 3), these attempts to
share those costs over renewable output leads to the problematical result that the ‘enhanced LCOE’ of such generators may rise (or the ‘market value’ of output fall), even if the underlying costs of the technology are on a downward trajectory. In this regard, (Schaeffer et al. 2004) raise a potential trade-off between the cumulative deployment of PV that would be required to deliver cost reductions down to ‘grid parity’ and the risk that the share of total generation from PV associated with such deployment may start to increase the system costs for balancing and reliability – making the achievement of true grid parity more difficult. Whilst an interesting point, this concern does perhaps ignore the fact that learning and cost reduction is the product of the global production system whereas integration costs are specific to countries, regions or system control areas.

The analyses reviewed in Chapter 3 also draw attention to two other potential cost-related impacts of integrating variable renewables. The first of these is the extent to which the theoretical fuel and CO$_2$ emissions savings from adding renewable generation to a system are offset by the reduced operational efficiency of conventional thermal plant resulting from running plant part-loaded and with more frequent (and steeper) changes in output. Whilst the evidence is by no means unequivocal, if the impacts are as predicted by some analyses, then these will manifest themselves in higher costs per unit of output for conventional generators – which in turn will be passed on to consumers – but will not generally feature in LCOE estimates. The second impact relates to the extent to which renewable generators will be forced to curtail their output at times, either because of grid constraints or that output exceeds demand$^{42}$. Whilst most analyses suggest that this is only likely to become significant at relatively high penetrations of variable renewables, it may become an issue in the calculation of costs since the reduced load factor of the plant that is forced to curtail its output would (as

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$^{42}$ ‘exceed demand’ in this context would mean demand net of the supply from conventional flexible plant required to maintain grid security.
Chapter 3 explains and the analysis in Chapters 5 and 6 shows) have an impact on plant LCOE.

These concerns over the extent to which current cost metrics substantially over-value variable renewable generation and/or under-value output from conventional generators represent a key issue in terms of policy, given the potential implications for projections on the overall costs of meeting policy aspirations. A related concern is how any additional costs should be recovered from consumers, assuming that they can be accurately calculated. In the case of large-scale, grid-connected variable renewable generation there is the option to pass these costs onto the operators of the plants, who would then be expected to pass them on to their customers, similar to how system and ancillary costs are currently treated. In the case of domestic-scale generation (from PV for example) where the generation is ‘behind’ the electricity meter (and so only manifests itself as reduced system demand) then a different problem is encountered. In these circumstances, the current mechanism for allocating system-wide costs falls down because these costs cannot be allocated to this ‘invisible’ generation and in addition the owners of that generation will be using less units of grid-supplied electricity (which has the system costs allocated to it) and may therefore not be paying their full share of those costs. From a policy perspective, this creates the risk that some generators and consumers may bear a disproportionately high share of the system costs – for services which all consumers are benefitting from.

There are a number of issues of a more tangential nature but that nonetheless are important components of a discussion of electricity generation technology cost estimates and forecasts and these are discussed below. The first is one of the counterfactual i.e. how are the cost implications of selecting a greater share of a particular technology relative to another,
alternative technology analysed and presented? The case studies focussed on individual technologies but they do not, of course, exist in isolation, and it is how the cost estimates and forecasts of different technologies compare to the alternatives that perhaps matters most, notwithstanding the case for policies to achieve overall reduction in electricity demand if all feasible technology options are considered to be high cost. Since it is the incumbent generation mix which drives the existing costs that consumers are exposed to, it also matters how the costs of technology options compare to those existing costs. Whist policymakers have attempted to analyse the potential impact on future electricity bills (DECC 2014c), what is often missing from the discourse is the fact that all electricity generation technologies are considerably more expensive than the current costs of generation from the existing UK power station fleet, largely because that fleet is relatively old, much of which has had its investment costs written off some time ago. The effect of this is to make any comparison of new plant LCOE with current wholesale electricity prices potentially misleading and unhelpful because it is a false counterfactual since the incumbent fleet cannot be replaced at the cost implicit in current electricity prices.

An issue of increasing concern to policymakers is the proportion of a power plant’s costs which benefit indigenous suppliers. Whilst not strictly an issue of cost per se, if deployment of a technology is being supported through (for example) UK policy and the cost of that support is borne by UK consumers (and voters) then the extent to which UK companies and workers are able to benefit becomes more important. Whilst this may be seen as more of an industrial policy issue than one of energy policy, it is clear that project developers and some sections of the power generation industry are anxious to highlight the UK benefits of a particular technology – see for example (de Rivaz 2011, CEBR 2014). Sourcing an increased proportion of a technology or project from within the UK may also offer benefits by reducing
exposure to exchange rate fluctuations, of the type which affected offshore wind in the late 2000s (see Chapter 5). In addition, the experience from PV suggests that there may also be cost reduction benefits from developing indigenous markets and supply chains (Candelise 2012b).

Dealing specifically with the use of the LCOE metric in policy, there does appear to be a degree of disconnect between the well understood limitation that businesses don’t base their investment decisions on comparative LCOE analyses (see Chapter 3) and the fact that it seems the general direction and focus of policy relies to a large extent on this metric. This means that policymakers then have to reconcile these two positions by constructing policy mechanisms to make actors act in the desired way – which is problematical where the metric used for analysis and the factors that influence actors’ decisions are not well aligned. The evidence that an increasing contribution of variable renewable generation to total electricity supply may make wholesale electricity prices considerably more volatile than they are currently (see Chapter 3 and (Poyry 2009, Poyry 2011a, Poyry 2011b)) reinforces this concern because such volatility can make the investment proposition for new generation plant considerably more challenging – regardless of LCOE estimates. Another factor in the general category of what is missing from LCOE estimates is whether the scale of capex required for very large unit technologies, such as nuclear power, is becoming a more significant determinant of whether a project can proceed or not (see Section 8.2 above). If this is the case, then it raises the question as to whether this factor will reduce the value of LCOE analyses because there may be situations where a higher LCOE project is preferred over a lower LCOE project because of the lower total capex required (Ion 2014).
In defence of the LCOE approach, such analyses do arguably allow the focus to be retained on some of those quantities and relationships that matter most to policymakers and society – i.e. what costs will be incurred, when will those costs be incurred, and what output will be produced, from a prospective new plant or technology – rather than being overshadowed or obscured by the complexity of ‘full system cost’ models. Whilst recognising that traditional LCOE calculations ignore the wider system costs such as connection, balancing and reliability, the transparency of the calculation means that they can be very useful in challenging industry and project developers over projections of costs per unit of electricity (on which policy support is based) because the major inputs and assumptions such as capex, opex, load factor and discount rate/cost of capital must be unambiguously stated and leave less room for obfuscation (see for example the exchange between Carbon Connect and EdF Energy described in the nuclear case study in Chapter 6). Challenging the outputs from a system cost model is, by contrast, almost impossible without a detailed knowledge of the internal logic, functional forms and assumptions made within the model – knowledge which is unlikely to exist outside the owners of such models.

8.4 Policy responses to uncertainties over costs

The case studies in Chapters 5 to 7 and the material reviewed in Chapter 3 also provide insights into how UK policy has responded to uncertainties over costs – uncertainties which are inherent in the estimation process and uncertainties which spring from the fact that cost estimates and forecasts have frequently turned out to be wrong, sometimes by considerable margins.

Dealing with the latter issue first, the offshore wind case study shows that policy responded quite decisively to the cost increases experienced from the mid-2000s onwards. In the first
instance, the response was to increase the support available under the Renewables Obligation by 50% through the introduction of the ‘ROC multiple’ mechanism whereby offshore wind projects were offered 1.5 ROCs/MWh. When it became clear that this increase in support would not be sufficient to bring forward as many projects (or any) as the UK Government hoped, it was swiftly increased again to 2 ROCs/MWh, representing a 100% increase in the support available, and in the process of these two steps discarding the previously held policy position that support should be technology neutral. This was despite the principle of technology-neutral support being something of an article of faith amongst UK policymakers (Gross and Heptonstall 2010), inextricably linked to the mantra of ‘not picking winners’ and ‘it is for the market to decide’ (Gross et al. 2012).

However, the evidence suggests that once politically committed to a technology, then policymakers were prepared to go to very considerable lengths to support that technology, even when the cost estimates and forecasts for that technology had turned out to be inaccurate. In addition, policymakers appeared to have been prepared for the substantially increased support to be sustained for close to a decade since the RO banding was introduced in 2009 and support through the CfD strike price, albeit with some limited degression, was (at the time it was announced) expected to continue until at least 2018/2019. This commitment to increased levels of support over several years does, perhaps, reflect the limited room available to the UK Government for revisions to deployment aspirations in the face of firm commitments to achieving renewable energy generation targets and political constraints on deployment of (lower cost) onshore wind. It also suggests a considerable degree of flexibility in the implicit bargain between policymakers and industry that policy support is predicated on the timely achievement of cost reductions. That notwithstanding, the latest indications from the results of the CfD auctions announced in early 2015 provide evidence to suggest
that the UK Government was perhaps right to stay the course with offshore wind because costs do now appear to be falling significantly.

Although there are similarities between the offshore wind and nuclear cases, the sense in which cost estimates for nuclear power turned out to be wrong are slightly different. For offshore wind, cost estimates were being adjusted as data based on actual experience became available from the first UK projects, coupled with very detailed, site-specific, analyses for later projects under development. By contrast, the cost increases from the mid-2000s for nuclear power could not be informed by real UK projects (because there were none either in operation or in development), although the experience from the Finnish and French plants under construction was starting to become available by the late 2000s/early 2010s. What is left to explain the increases is a combination of the commodity and labour cost rises, supply chain bottlenecks and the increasing ‘cost realism’ described in Section 8.2 above (and what may also be described as increasing risk premium in cost estimates as the prospect of real projects with attendant huge financial risks became more likely).

It is clear from the case study evidence that the competitive cost estimates for nuclear power in the mid-2000s had an impact on policy, and helped to create the conditions where the technology was ‘back on the agenda with a vengeance’ (Blair 2006). That policy support was then sustained in the face of cost increases, culminating in the current package of policy measures of a Contract for Difference strike price, the Carbon Price Support mechanism, and a range of ‘facilitative actions’ such as the Generic Design Assessment process. Whilst the UK Government’s position on ‘no public subsidy’ is still formally held, it has become increasingly difficult not to see this as a purely semantic device to satisfy the terms of the
coalition agreement (Cabinet Office 2010) rather than an intellectually coherent position\textsuperscript{43}. That notwithstanding, the UK Government has found itself in a position where it is faced with considerable uncertainties over nuclear costs, created by the increases of recent years and the paucity of reliable data. When seen in this context, and coupled with the very clear political commitment to new nuclear (Rigby et al. 2013), the willingness of the UK Government to commit to a strike price of £92.50/MWh, indexed over 35 years, for the first new plant (DECC 2013\textit{j}) can be seen as a response to continuing concerns over the accuracy of cost estimates, and a strong desire to ensure that the risk of cost estimates turning out to be wrong is borne by the project developer\textsuperscript{44} – even if it may expose the UK Government to accusations that it risks over-rewarding.

A message which emerges from both the offshore wind and nuclear case studies is that when cost estimates have turned out to be wrong, the UK Government sustained its commitment to these technologies in the face of rising costs. This support has sustained even where the original political commitment to the technology was in large part based on those (inaccurately low) earlier cost estimates. The evidence from the case studies suggests that this may have been a combined result of firstly, a recognition that there was a limited set of practical and politically acceptable low-carbon generation options creating limited room for policy manoeuvre and secondly, a recognition that almost all electricity generation technology costs had increased.

On first examination, the case of policy support for PV in the UK is very different to those of nuclear and offshore wind, representing a clear success story in terms of cumulative deployment and falling costs. However, the evidence presented in the case study in Chapter 7

\textsuperscript{43} The ‘no public subsidy rule’ was subsequently caveated with ‘unless other technologies also receive a subsidy’.

\textsuperscript{44} At the time of writing it is not absolutely clear that the strike price agreement will provide complete assurance that no cost increases will be passed on, since the details of the contract are not yet in the public domain.
also makes it clear that policy support struggled to keep pace with rapid changes in technology costs which is perhaps not surprising since the size of the cost reductions had been substantially underestimated. The plethora of policy reviews and revisions which resulted from this almost continuous ‘catch-up’ process (see Table 7.1) in turn led to a rather erratic deployment trajectory, albeit one that was masked to an extent by the apparently continuous upward trend (see Figure 7.10). As the case study evidence shows, the policy response to these larger than expected cost reductions was driven by a desire to not over-reward PV project developers, and dampen down the somewhat feverish speed of take-up of the policy support, which the UK Government was concerned would place too high a burden on consumers (given the relatively small contribution to total electricity production that even substantial deployment of PV was likely to deliver in UK solar conditions).

PV does, however, appear to be a very good example of the efficacy of policy support, with incentives delivering (sometimes over-delivering) sustained, almost dramatic, rises in cumulative deployment, benefiting from cost reductions which in turn led to greater deployment and reduced costs of policy support per MWh. Recent cost forecasts make clear the strong expectation that costs will continue to fall and suggest that no policy support will be required for large-scale PV in the medium term. However, the case does highlight the uncertainty over cost forecasts and the difficulty in setting the correct support levels, in situations where falling costs are largely a result of global deployment and learning – over which individual country policies can have a limited impact.

In the case of PV, therefore, the result of incorrect cost forecasts was that the industry in the UK had to deal with something of a boom and bust cycle, linked to frequent and rapidly introduced (downward) revisions to policy support. This was coupled with concerns that the
returns available to project developers were at times very generous, exacerbated by the fact that they coincided with a sustained period of record low interest rates which increased the relative attractiveness of potential projects considerably, particularly at the domestic scale. This in turn was undermining the political sustainability of policy support for PV – a concern that the case study suggests still exists in some quarters.

As the case studies and supporting material show, the considerable uncertainties over electricity cost estimates are increasingly, and much more explicitly, recognised in many policy analyses. Cost analyses can in principle explore the potential effects of uncertainties, provided that the area of uncertainty is recognised and quantifiable, but this still leaves the genuinely unpredictable and unknowable – meaning that some sources of error in forecasts are all but impossible to anticipate. Even where policy analyses explore the sensitivity of costs to a range of different input assumptions, they generally must also settle on a single point or a narrow range of estimates for the details of policy implementation (for example the cost estimates implied by the ROC multiples, Feed-in Tariffs and CfD strike prices).

The evidence from the case studies suggests that such estimates may well turn out to be wrong, either because the wrong judgement was made over the most plausible values for known uncertainties or because of some genuinely unforeseeable factor. This presents a particularly difficult problem for policymakers because even if it is fully acknowledged in advance that estimates may be wrong, a figure must be decided upon because until that is done, policy aims cannot be translated into policy implementation. Policy support can of course be adjusted to reflect real cost data as that becomes available, but the evidence suggests that there is a danger that policy will struggle to respond quickly enough – and
therefore run the risk of either over-rewarding or failing to bring forward the desired level of deployment.

In the concluding chapter that follows, this thesis returns to these themes of the policy response to uncertainty over costs, the accuracy or otherwise of cost estimates and forecasts, and the degree to which commonly used cost metrics capture the full costs of particular technologies.
9 Conclusions

9.1 Introduction
The evidence presented in the preceding chapters draws a complex picture of rising and falling cost trajectories spanning a range of technology scales and characteristics, and raises questions over the ‘correct’ measurement of costs. One of the key challenges for this thesis has been to marshal this evidence so that useful conclusions can be drawn. It is perhaps tempting, when faced with such complex and sometimes apparently contradictory evidence, to take the view that the explanatory power of any conclusions will be very limited, since it is possible to selectively identify evidence that appears to support a range of perspectives. However, a careful analysis of the evidence from the case studies does allow for a number of key points to emerge. Since these continue from the discussion in Chapter 8, they are loosely grouped below in the same structure as that chapter with Sections 9.2 to 9.4 dealing with the accuracy of cost estimates and forecasts, Sections 9.5 to 9.7 covering what is ‘missing’ from the cost metrics used in policy analysis, and Section 9.8 and 9.9 addressing the policy response to uncertainties over costs. Section 9.10 recommends areas for further research and Section 9.11 concludes with final reflections on the wider implications of the evidence discussed in the thesis.

9.2 Sources of error in cost estimates and forecasts
The evidence from the case studies suggests that the accuracy of cost forecasts (and to a lesser extent cost estimates) can sometimes be poor, for the following reasons:

- The premature application of experience curve-based projections to emerging technologies, or the persistent application of experience-based projections when there is little or no evidence to support their use for the technology in question.
• The use of experience curves from proxy technologies which may have a large degree of similarity (providing the apparent grounds for confidence in the use of such proxies), but which may differ in some crucial aspects which bear upon costs.

• Where there is insufficient data to use the experience curve approach for cost forecasts then the alternative approaches of engineering assessment and expert elicitation are frequently used, but these may rely on subjective interpretation of the opportunities for cost reduction, and are therefore open to errors in that interpretation. Where these approaches are adopted because the cost experience data is thought to be a poor guide to the future trajectory of costs, then the resulting forecasts are exposed to the risk that the experience data is a good indicator of future costs – and it is not always clear why such evidence should be ignored simply because it does not show falling costs.

• There is evidence that suggests continued appraisal optimism, even in circumstances where costs are not falling, sometimes coupled with aggressive pricing by suppliers who are anxious to secure policy support, win contracts or build experience in a new market. The evidence also suggests that such appraisal optimism can reduce substantially as the prospect of real projects increases, in turn leading to increased cost estimates.

• A constantly increasing regulatory burden may hamper, delay, or remove entirely the opportunities for an industry to learn from previous projects since designs will need to change to comply with changing regulations. This is particularly likely to be the case where the regulations governing a technology vary considerably between countries or regions and where the number of individual projects in a particular country is likely to be small (for example, as a result of the large unit size of a technology). The overall effect will be to reduce the opportunity for standardisation and the learning benefits that are associated with producing multiple units of the same, or very similar, designs over time.
• The ability of an industry to respond to increased demand is a key factor in whether or not cost reductions associated with production economies of scale and competition can be realised. Assumptions that all industries can respond in a timely fashion to increased demand by increasing supply are not always supported by the evidence, and industries that are either unable or unwilling to respond will not be in a position to benefit from the cost reductions typically associated with increasing market size.

• Linked to a number of the factors described above, the degree to which prices are an accurate guide to true underlying costs can create additional challenges for estimating and forecasting. For example, in those circumstances where production capacity substantially exceeds current demand, manufacturers may be prepared to sell their products at below the full economic cost, at least over the short-term. There may also be circumstances where reliable price data for particular technologies is not publicly available.

• Finally, the accuracy of cost forecasts can be severely affected by exogenous shocks such as rising raw material costs, driven either by demand variations for those materials over economic cycles, or by more fundamental constraints on the availability of a particular resource.

These factors do not, however, necessarily mean that achieving an acceptable degree of accuracy in estimation or forecasting is impossible. The evidence suggests that, given the right conditions and technology characteristics, estimates can be reasonable indicators of true costs, and expectations of falling future costs can be justified as the benefits of learning, economies of scale and series production techniques are realised.
9.3 Precision in the face of uncertainties

The evidence presented in the case studies and discussed in Chapter 8 also suggests that very precise cost estimates (or similar forecasts of future costs) for technologies that are so far unproven may well turn out to be wrong. Presenting the results of such analyses in very precise terms may therefore infer a degree of certainty which is not supported by the underlying conditions\(^{45}\), which resonates with the well known phrase ‘it is better to be roughly right than precisely wrong’, frequently attributed to the economist John Maynard Keynes but in its original form first coined by the philosopher Carveth Read. Whilst this may appear to be something of a truism when dealing with quantities that are known to be uncertain, this is not always reflected in the discourse around electricity cost estimates.

The learning that is required to deliver cost reduction is, as much of the literature confirms, an inherently stochastic process which makes forming predictions at any given point in time problematic because it may not be apparent until later on whether that point in time represented, for example, a temporary pause on a downward cost trend or was an indication that cost reduction opportunities for a particular technology were becoming limited. This uncertainty can create particular challenges if policy implementation requires (as it generally does) an accurate understanding of both current costs and the likely trajectory of future costs.

9.4 Assumptions that costs will always fall

The discussion chapter raised a concern that generalised assumptions that technology costs will necessarily fall may suffer from a degree of selection bias in the analyses that support those assumptions, because the only technologies for which experience curve analyses are

\(^{45}\) It is perhaps also worth reflecting on how accurate forecasts can be given that many commercial organisations find it very difficult to make accurate medium and long term predictions. As Jon Moulton of the UK Financial Reporting Council observed ‘Virtually no company can produce five year financial projections of even moderate accuracy. Over five years, the economic and technical background to a business is immensely variable’ (Hilton 2014).
possible are those which have such experience – and by definition have therefore progressed through the development stage into deployment at scale. It is not clear that this can necessarily be translated into an assumption that, simply because the end product (MWh) is the same, all the technologies and fuels which can be combined to produce that output will have broadly similar costs once technologies have reached an established stage – and yet such an assumption is sometimes implied by the prevailing discourse, to the extent that it is applied to technologies which are yet to be demonstrated at scale, and to technologies which have hitherto demonstrated very little capability for cost reduction. To echo the point made above, this does not mean that costs for these technologies cannot fall, but it does suggest that a significant degree of caution with regard to expectations is justified.

9.5 The inclusion of system costs

The extent to which LCOE captures the true costs of technologies which impose additional system costs is described in detail in Chapter 3, and it is clear that the limitations are the subject of a considerable body of analysis. However, the conclusions as to what this means for the usefulness or otherwise of LCOE are less clear since there is still a considerable range of views on the size of any additional system costs and how they are best represented. What is striking is that these limitations do not feature more strongly in the cost analyses that underpin policy support for such technologies. The evidence suggests that this may become increasingly problematic as the penetration of variable renewable generation increases, as is expected. It also draws attention to the concern that some of the energy system models often used for UK policy analysis may not represent very well the true additional costs which intermittent generators impose upon an electricity system.
9.6 The continued usefulness of LCOE

One factor which may bear upon the continued usefulness of LCOE is that even if the ‘full system cost’ analyses described in Chapter 3 are considered to be the most accurate approach, and such analyses can indicate the optimal mix of plant, policymakers must still ensure that something approximating to that optimal mix is built and operated. Even if the view is taken that such decisions are entirely left to the market (and the history of UK policy would suggest that that is relatively unlikely), then policymakers must still structure the market and provide incentives to ensure that the market will deliver the required outcomes – and to do that requires comparative assessment of technologies and projects, which in turn requires a cost metric that facilitates such comparisons. This may therefore lend weight to the ‘enhanced LCOE’ approaches described in Chapter 3. However, this ‘enhanced LCOE’ may still not provide a useful guide as to what types of generation plant companies may actually choose to build and operate – unless the market can be structured in such a way as to more closely align full system, lifetime costs with revenues.

For some technologies, particularly where very large generating unit sizes mean that the total capital costs of a project represent a significant fraction of a generating company’s total value, then the LCOE metric may give a poor indication of the financeability of the project (and by implication, a poor indication of whether a project is likely to be taken forward). In such cases, a project may have apparently competitive lifetime costs but the sheer size of the financial risk is a major factor in a company’s decision as to whether to take a project forward.

The increasing impact that the additional costs of low carbon generation will have on UK consumer bills over the next decade also draws attention to the degree to which those
additional costs provide a corresponding benefit for UK industry, jobs and associated tax revenues. Whilst these benefits are clearly not captured by traditional cost metrics such as LCOE, they may become increasingly important as the impact on bills becomes more pronounced.

Nevertheless, LCOE may still be a useful starting point for policy analysis, particularly if it is combined with a further step – which is to ask how much the values would need to diverge from current estimates and forecasts for key decisions to be different, and how plausible are such variances? The issue of whether past policy decisions would have been different, if what is now known about costs was known at an earlier stage, is addressed in Section 9.8 below. The relative simplicity and transparency of the LCOE calculation also provides a useful tool for policymakers who may need to challenge industry assumptions over estimated costs, particularly if such estimates form the basis of negotiations over the level of policy support required to bring forward deployment of a technology.

9.7 The importance of context, policy goals and instruments

Although not strictly an issue of what is ‘missing’ from cost estimates and forecasts, the evidence suggests that an understanding of the context in which such analyses are made is an important, but sometimes overlooked, factor. Estimates and forecasts may be developed for a range of reasons including: to understand the viable range of technology options for a given set of policy objectives such as reducing CO\(_2\) emissions or ensuring security of supply; to determine which technology options are deserving of policy support, how much that support should be for (and how long it may be required for); to provide the basis for negotiation between industry and policymakers over both the level of support and the design of support
mechanisms; or to set, explore or test both industry and policymaker aspirations for future cost reductions.

The nature of estimates (and the degree of accuracy required) may differ according to their intended use. Those analyses, for example, which are used to inform broad policy direction may have a very different nature to those used in the formulation of policy details and implementation. The key point here is that the context in which estimates and forecasts are made, who they are commissioned by, and who they are undertaken by, may have either a direct or indirect influence on the results, or the interpretation and presentation of those results.

9.8 The impact of better foresight on policy aims

The evidence from the case studies that is discussed in Chapter 8 makes it clear that the electricity cost estimates and forecasts which have guided policy decisions in the UK have often turned out to be wrong, or have changed considerably over relatively short periods of time. With the notable exception of PV, the result of these errors in estimation and forecasting have typically meant that costs have been higher than expected and/or have not reduced at the rate anticipated. Whilst it is impossible to be sure as to the answer, this does at the very least beg the question as to whether policymakers would have taken a different course of action, had they known then what they know now about the relative (and absolute) costs of technologies. Would they have, for instance, chosen to favour different low carbon technologies, or would they have taken a different view on the affordability or otherwise of decarbonisation objectives? The relatively limited suite of available low carbon technologies might suggest that the options were constrained to the extent that even if the higher costs were known at the time, policy decisions may not have been markedly different, but it is
possible to envisage differences in emphasis where cost considerations may have over-ridden other concerns – for example in the relative balance of onshore and offshore wind.

Given the issue of increasing absolute costs of decarbonisation (because almost all technologies have become more expensive), it is only possible to speculate how such costs (if known at the time) would have translated into perceptions of the affordability of substantially lowering CO$_2$ emissions, and whether those perceptions may have affected the broad political consensus that was achieved in the mid-2000s. Linked to this is that, whilst there is considerable evidence of the explanatory power of experience curve analyses, the evidence from the nuclear and offshore wind case studies does call into question the predictive power of experience curves, especially when combined with the concerns raised by several analysts that predictions of the total cost of deployment required to achieve desired cost reductions is very sensitive to assumptions over learning rates and experience curve starting points (see Chapter 4). These are key concerns since they challenge the widely held view that technology learning would lower the cost of moving to a low carbon economy (‘drastically reduce’ as (IEA 2000) describes it, pg. 98).

A more recent concern that the stubbornly high costs for some technologies raises is that it reduces the total annual deployment that can be achieved within the UK Government’s Levy Control Framework mechanism, which in turn reduces the opportunities for technology learning, market growth and supply chain development – and subsequent cost reduction opportunities. A counterpoint to this, however, is that a considerable degree of learning is a global process so UK policy is unlikely to be able to drive down costs on its own unless UK deployment of the technology represents a significant proportion of the global market. This may lend weight to the arguments discussed above that policy should have a much more
explicit focus on building UK industry (as well as driving down costs), given that it is UK consumers and taxpayers who are footing the bill.

9.9 The meaning of regulatory certainty

The need for ‘regulatory certainty’ is often described as a key requirement in the development and deployment of low carbon generation technologies (IEA 2014a) but the evidence from the case studies suggests that certainty in the form of minimising changes in support is not what is typically delivered. In the case of offshore wind, policymakers reacted to evidence of higher than anticipated costs by both revising the support mechanism, in the process moving away from the previously held tenet of technological neutrality, and twice increasing the actual level of support available. In the case of nuclear power, the CfD mechanism was developed as part of the Electricity Market Reform process (involving a comprehensive restructuring of the UK electricity market) once it became clear that a carbon price and a range of ‘facilitative actions’ would not be enough to bring forward new nuclear projects in the face of rising costs and formidable financial risks. In the case of PV, policy support was the subject of a series of reviews, (downward) adjustment to support levels, and changes in respect of which project types were favoured, in response to rapidly falling costs.

Given that the substantial changes in policy support for offshore wind and nuclear were driven by the evidence from the respective industries that more support was required, and policy revisions for PV were all but inevitable once the scale of cost reductions became apparent, the message seems clear that policy is unlikely ever to be static, and will always need to react to changing circumstances. Support is a balancing act between economic and political acceptability, achievement of deployment targets, aspirations to build national industries, and falling costs – and the experience from the case studies suggests that
expectations of certainty are unrealistic. Furthermore, since support is based on the understanding that costs will fall, support also has to fall – or the industry is not delivering on its side of the implicit bargain. The frequency of errors in cost estimation and forecasting described above, combined with the fact that policy must respond when costs change (or estimates become more accurate) would appear to make it very likely that there will be periods when technologies are over or under-rewarded because the evidence suggests there will almost inevitably be lags in the policy response.

An alternative interpretation of ‘regulatory certainty’ is the degree to which policymakers are prepared to continue support when faced with evidence that costs are not falling as hoped, or are even rising. In this respect it is clear that UK governments have been prepared to continue, and increase where necessary, policy support in cases where their preferred technologies have risen in cost. The recent cost reductions apparently achieved by the offshore wind industry will, if proven, provide considerable justification for policy decisions to persevere in the face of early-stage deployment cost increases. The out-turn costs for new UK nuclear plants will take considerably longer to become apparent, so it remains to be seen whether the continued strong policy support for this technology is justified on the grounds of eventual cost competitiveness, or more simply a desire to lock-in projects at current estimates given the history of uncertainty over nuclear costs.

The recent move in the UK to technology-grouped auctions for support for most low carbon generation technologies can also be seen as a response to the policy challenge created by uncertainty over cost forecasts, since (in theory at least) it largely removes from the policymakers the burden of such forecasts. The process also provides a mechanism for the
diagnosis of true costs – provided that the projects that are successful in auction bids are able to secure finance, and be built and operated, at the costs implicit in those bids.

9.10 Recommendations for future research

This section identifies potentially interesting and useful areas in which the research undertaken for this thesis might be expanded, and where additional work may provide further insights into the wider implications for policy. There are four clear opportunities which relate specifically to the methodological approach, and the first of these would be to supplement the empirical analysis of costs and historical narratives with interviews with key protagonists and representatives from the policymaking organisations, industry and the research community who were involved in either the production of cost estimates and forecasts or were developing policy to influence such costs (or to respond to changes in costs). This would provide additional sources of evidence which could then be compared to that which has already been presented here, to establish the degree to which it reinforces or contradicts the key findings of the thesis.

The second area for further work which relates to the thesis methodology is concerned with exploring the effects of taking a different approach to the data normalisation. Examples include using an alternative index to inflate values to a consistent year, or applying a rolling average to exchange rate valuations to reduce any potentially misleading effects of short-term variation in those rates. Partly linked to this is the question of whether it may be useful to selectively apply commodity or industry-specific inflation indices to establish, for example, whether there was underlying technology learning happening even when overall costs were on an upward trend.
Thirdly, the technology datasets used in this thesis could be analysed to determine the extent to which there is any systematic bias in cost estimates and forecasts that is, for example, related to the source of data. This builds on the observation made in Section 9.7 above concerning the importance of understanding why estimates are produced, who by, and for whom, and also links to the fourth methodological area in which the research could be expanded. This relates to an exploration of the opportunities for addressing any such systematic, institutional or expert bias in cost estimates and forecasts, perhaps by building on the recommendations in (Candelise et al. 2013) to widen the breadth of expertise and knowledge which is typically drawn upon when conducting cost analyses so as to benefit from, as Candelise et al. suggest, experience in the international markets and financial arenas. It may also be useful to conduct a rigorous examination of the degree of influence which more sceptical commentators have had on cost estimates – because the evidence suggests that, for some technologies at least, such voices appear to have been largely drowned out by more optimistic analyses, even when the pessimists have turned out to be right (or at least less wrong than the optimists).

In addition to these methodologically-focussed areas, there are a number of questions that relate to the issues raised in Section 9.8 above that may warrant further research. These include economic, social and political analysis of the potential implications if the costs of most low carbon electricity generation technologies were to remain stubbornly high. Would this for example lend weight to the argument advanced in (Helm 2012), and to a lesser extent in (Frontier Economics 2009), that the focus of policy should be on the research and development activities to discover and develop new technologies, rather than the current focus on ‘market-pull’ deployment to deliver incremental cost reductions of existing technologies (DECC 2011a)? Taking a much broader perspective, would it lend more weight
to arguments for a focus on adaptation rather than mitigation in respect of the effects of anthropogenic carbon dioxide emissions?

Linked to this is the question of whether past decisions by UK policymakers would have been different if the future trajectory of electricity generation costs had been known at the time that those decisions were made. Building upon the methodological suggestions made above, this is an area where interviews with key actors (assuming that this was possible) may yield potentially interesting results, particularly if combined with an analysis of the sensitivity of those decisions to different projections of costs – in other words, how much would past cost estimates need to have differed by to produce a substantially different policy or industry response? This may also be a useful point of engagement with current policymakers to explore how uncertainties of future costs might be more fully represented in policy analyses, perhaps through an examination of how robust policy decisions are in the face of potentially substantial errors in cost forecasting.

The possibility of an increased focus on UK industrial policy was also raised in Section 9.8, and there is the potential for further work here to, for example, assess the degree to which UK consumers and taxpayers may be more willing to pay for the higher costs of low carbon generation technologies if they are perceived to provide employment and wider economic benefits within the UK. The tension between political realities and the classical economic principles of comparative advantage and freedom of international trade may be an interesting starting point for such an analysis, since it may be that, at least initially, efforts to retain economic benefits within the UK may result in relatively higher costs for UK consumers and/or taxpayers – on the assumption that the UK is not necessarily the current lowest cost source of low carbon technologies.
The potential role for variations on existing technologies, such as smaller scale combined cycle gas turbine plants or small modular nuclear reactors in response to the respective challenges of system flexibility and very large project financing, may warrant further analysis since they both represent cases where the focus could shift from reducing the headline LCOE (which may only be achievable under a very constrained set of operating or financing characteristics) to technologies which may be more economically robust in the face of a wider range of practical circumstances. The evidence discussed in this thesis also suggests that reducing generating unit size may increase the opportunities for series production techniques and learning by doing, which may in turn deliver cost reductions. If this is indeed the case, then exploring how such technology variants may be represented in energy system models (and how the results from those models might be affected) may provide interesting and useful insights. This would be particularly useful if it could provide guidance on the likely nature of an electricity generation system that is sufficiently economically flexible to provide cost-effective solutions across a wide range of future scenarios – rather than an optimised solution that may be achievable only if a very particular set of circumstances are met.

The implications of the concern discussed in Section 9.4 above that costs may not fall as deployment rises echo arguments made in (Watson et al. 2012) and (Winskel et al. 2014) that policymakers should be prepared for periods when technology costs do not fall as anticipated, and that this should be better represented in analyses, in particular in energy system modelling. Another aspect of this challenge to the assumption that costs will always fall relates to the concern raised in Chapter 8 that there may be a degree of selection bias in those analyses that support the premise of cost reductions. Further research of the history of those technology paths which have not been successful may help to address this concern, and
improve the understanding of those technology characteristics which make the achievement of cost reductions more likely.

The issues discussed in Section 9.5 above that relate to the inclusion of wider system costs also represent a possible area for further research, perhaps for example by developing an ‘enhanced LCOE’ analysis for the GB electricity system so that the effects on total costs of different assumptions over base technology costs and the provision of balancing and reliability services may be explored. Such an analysis may then provide insights into comparisons between technology options that are not fully possible with traditional ‘power station boundary’ LCOE analyses.

9.11 Reflections and final thoughts

The central questions posed by this thesis are: How accurate are electricity cost estimates and forecasts, and are they fit for purpose in the context of policy analysis? The rather glib, but nevertheless tempting, answers to those questions are, respectively, ‘not very’ and ‘maybe’. Such answers would, however, ignore the complexity of the evidence presented and discussed in the chapters above. Addressing first the question of the accuracy of estimates (i.e. those made for notional plants to be built around the time that the estimates are made), these can be known with some confidence for that category of technologies which are well developed, have achieved large-scale, preferably global, deployment and where there are a sufficient number of competing suppliers to ensure that information on costs is widely available. In these circumstances the uncertainties that remain, leaving aside those resulting from variations caused by normal economic or business cycles, tend to be associated with the required fuel/energy inputs (and emissions costs in those jurisdictions where these are levied as an explicit cost). Estimates for the category of technologies which are less well developed,
have achieved none or very little in terms of current deployment, or where there is no recent history of deployment in the country or region for which the estimates are made, are likely to be subject to considerably greater error. Crucially, the (frequent) co-presentation and use of estimates for technologies which fall into both these categories implies significantly more comparability between them than the evidence suggests is wise. This is further compounded, since although estimates for both categories of technology are often presented with sensitivity ranges, this can convey the message that the underlying uncertainties are similar – when in fact the reasons are fundamentally different in character.

Similarly, the accuracy of forecasts (i.e. those made for notional plants to be built at some point in the future, relative to the time that the forecasts are made) is influenced to a considerable degree by the characteristics of the technology in question. The evidence suggests that for forecasts to have the best chance of achieving a reasonable degree of accuracy there must be sufficient reliable data on the past cost trajectory of the technology (which implies a substantial degree of deployment or the identification of a reliable proxy technology that has achieved such deployment), that the industry is able to respond to increasing demand in a timely fashion, and that the technology characteristics and regulatory environment lend themselves to serial production techniques.

Regardless of concerns over the accuracy of cost estimates and forecasts, these clearly still have, and will continue to have, a key role in policy formulation and the methods of implementation. It is also clear that, given the right set of conditions, costs can be expected to fall as deployment of a particular technology increases, hence supporting the validity of cost forecasts. However, what the case studies and the discussion highlights is how important an understanding of technology characteristics is when deriving both estimates and forecasts.
This is not simply because those characteristics bear upon the numerical values of the results (although of course they do), but because of the influence they have on the nature of the uncertainty of those results – and that does not appear to be as widely recognised in policy analyses as it should be.

The fact that a set of conditions must be met to have some confidence in cost estimates, and particularly forecasts, is well understood by many of the analysts undertaking those forecasts, and they are sometimes explicitly characterised as ‘conditional predictions’. However, the ‘conditional’ part of the prediction may be lost or misunderstood when such forecasts are adopted or used by others – or it is simply assumed that the headline condition that underpins the prediction (that of increasing deployment) will be delivered through policy and that the other conditions will then also materialise. The evidence suggests that, even if it is achieved, deployment on its own may be insufficient to bring about forecast cost reductions, because the other conditions may not be satisfied. The implication is that policy may need to address a much wider range of issues than an overwhelming focus on deployment, particularly if policy aspirations are technology-specific (as opposed to being focussed on achieving a desired outcome such as lower CO₂ emissions or maintaining security of supply).

There is a wide spectrum of views on the most appropriate approach to delivering on the overarching policy aim of decarbonising the electricity generation system, from those grounded in pure classical economic theory which largely focus on correcting negative externalities (and then leaving the market to deliver), to those which advocate a much stronger focus on encouraging deployment of preferred technologies. Overlaying this is the debate around whether the ‘demand-pull’ approach should dominate or whether the greater focus should be on research and development to (hopefully) deliver new and/or substantially
improved technologies to augment and/or replace the current suite of options. Critics of too rigid an interpretation of the classical economics approach point to the urgency of action required, questioning whether such an approach will deliver sufficient deployment within the required timescales, and also highlight the formidable practical challenges facing deployment of some technologies, and argue that a more pragmatic approach is needed where policy support is targeted at those technologies which are considered to be capable of making a substantive contribution. This aligns with evidence discussed in this thesis which suggests that since the opportunities for innovation and cost reductions are so dependent on technology characteristics then it may be most effective to focus support on those technologies which have the characteristics that lend themselves to the achievement of cost reductions over timescales commensurate with policy aspirations. In respect of the debate over ‘demand-pull’ versus research and development, the evidence suggests that technologies can take many years to move from the invention stage through to initial development and then on to cost-competitive commercial deployment, and that some technologies have struggled to achieve this even after decades of research and development effort. There is also evidence that dramatic cost reductions can be achieved for some technologies through improvements in the manufacturing process and supply chain, rather than fundamental changes in the underlying core technology. Taken together, this suggests that those commentators who advocate a focus on research and development aimed at creating new technologies, over deployment and incremental improvements to existing technologies may be running the risk of placing too much faith in the ability of research activities to deliver new, cost effective technologies in the time available.

Taking a broader view, the UK has very ambitious plans to reconfigure its entire energy system over the coming decades and to date much of the focus of effort has been on the
electricity system, but to achieve the wider energy system targets policy will need to have a
dramatic impact on other areas of the economy including the transport, industry and domestic
sectors (including energy efficiency). The evidence presented in this thesis suggests that the
accuracy of the information relied upon when assessing the costs of different policy options
can sometimes be very poor, and this has potentially serious implications for policy
formulation. In particular, it suggests that policy should be more open to the possibility that
the assumptions which underpin it turn out to be wrong. The issues discussed above also
suggest that policymakers should look for evidence from the broadest possible range of
expertise, avoiding the temptation to reject evidence which does not fit the desired narrative
and ensuring that the risks of bias in cost analyses are accounted for.

As has been discussed, a favoured UK policy response to this uncertainty, at least in recent
decades, has been the principle of ‘not picking winners’ and letting (by implication)
‘winners’ emerge from the market. The phraseology is important, because it runs the risk of
implying that there is some optimal future configuration of the energy system – when the
evidence suggests that what may really be needed is a system which is both technically and
economically robust under a wide range of possible futures, even if such a system may not
‘win’ in a least cost optimisation analysis. Addressing some of the recommendations for
future research made above may provide useful insights into the nature of such a system.
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