UKERC Energy Strategy Under Uncertainties

Supply Side Change: Technology Assessment – Methods and Uncertainty

Working Paper

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UKERC is undertaking two flagship projects to draw together research undertaken during Phase II of the programme. This working paper is an output of the Energy Strategy under Uncertainty flagship project which aims:

- To generate, synthesise and communicate evidence about the range and nature of the risks and uncertainties facing UK energy policy and the achievement of its goals relating to climate change, energy security and affordability.
- To identify, using rigorous methods, strategies for mitigating risks and managing uncertainties for both public policymakers and private sector strategists.

The project includes five work streams: i) Conceptual framing, modelling and communication, ii) Energy supply and network infrastructure, iii) Energy demand, iv) Environment and resources and v) Empirical synthesis. This working paper is part of the output from the Environment and resources work stream.

Contents

1. Introduction

Technological change is a complex process. It involves not only the development along specific technology pathways, but also interactions with systemic, behavioural and institutional changes across the economy as a whole (Weyant, 2011). Changes rarely follow a simple linear pathway; innovation involves feedback and iterations between different stages of development (UKERC, 2014). Predicting the future of technological change is therefore fraught with difficulty. For individual electricity generation technologies, there are many different aspects of performance that may be uncertain, including amongst others: capital and operating costs, operating efficiency, dispatch profile (e.g. intermittent, seasonal), build time, reliability and availability once built, carbon capture rates for CCS and safety and waste disposal issues in the case of nuclear. Systemic uncertainties include the degree of electrification of heat and transport, leading to uncertainty over growth rates of electricity demand as well as uncertainty over daily and seasonal variations. Increasing the ability of the electricity system to integrate intermittent generation sources also relies on systemic changes such as increasing interconnection, storage, and responsiveness of the demand-side.

Yet assessment of potential future performance is necessary in order for both policy-makers and companies to make decisions about which technologies to support and invest in. This paper aims to provide an overview of technology risk in the power generation sector, firstly by reviewing how technology assessment methods treat such risks, and secondly by reviewing some of the major risks facing the key low carbon generation technologies. The paper then aims to draw lessons about the extent to which our (in)ability to predict technological development outcomes has implications for energy policy.

This paper addresses three domains of risk:

Techno-economic risks relate to attributes of individual technologies that have an impact on their economic performance. These include for example capital and operating costs, environmental and other externalities, build time, availability and utilisation rates, reliability and intermittency of outputs. Uncertainty in all of these parameters affects the financial viability of projects.

Programmatic risks are sources of risk that are not techno-economic in nature, but nevertheless play an essential role in influencing the dynamics of individual technology development. These are wide-ranging in nature, and include the existence of appropriate innovation networks, political and regulatory support, social acceptability, as well as institutional, market and supply-chain structures to support scale-up and deployment.

System integration risks relate to the performance of groups of technologies when combined together. Ultimately the security of the electricity system as a whole will depend on the robustness with which supply and demand can be matched under conditions of stress or shock. Because different generation technologies have different strengths and weaknesses, the risk exposure of the system as a whole is different from that of its component parts.

Section 2 is concerned with a review of assessment methodologies used in each of these different domains, looking at how they deal with uncertainty, and their potential strengths and weaknesses. The section first reviews techno-economic evaluation methods. These include the types of analysis that commercial project developers go through for market-ready technologies in terms of technical and financial due diligence when assessing a potential investment prospect. Next, the section reviews methods used for assessing the dynamics of technology pathways. Cost and performance characteristics may be expected to improve over time for some technologies, but these developments are difficult to predict accurately. Such methods therefore need to help decision-makers deal with uncertainties in the development phase. Finally the section reviews the methods used to assess technology risk at the whole system level. Typically such assessments involve more elaborate models of the evolution of the energy system over time, and are concerned with the interaction between many different technologies for the supply of electricity and the balancing of this supply with an evolving demand profile.

Section 3 then provides an overview of the main sources of technology risk for four technologies that have been projected to be key in achieving the UK's 4th Carbon Budget: CCS, nuclear power, offshore wind and solar PV. The report aims to characterise these technology risks not only in terms of capital cost risks, but also on other sources of risk such as reliability, availability, build time, safety and other aspects of technology performance. These other risks are generally not as well characterised as capital cost risk, so quantification of these risks has not been possible, although some estimates of the scale of risks have been made in some cases.

Section 4 then draws out policy implications and conclusions. The paper suggests that whilst many of risks are 'specific', in the sense that they affect the performance and cost of a particular generation technology, in some cases the risks may be large enough to become 'systemic' risks that have the potential to substantially re-orient energy sector pathways. These include potential major disruptions which could be either positive (e.g. emergence of a new lower cost disruptive technology), or negative (roadblocks to development of one of the major sources of generation), requiring major changes to system planning. Potential examples of such risks are outlined. Whilst some potential sources of disruption can be identified in advance, others may arise from unknown or unexpected sources, making them even harder to characterise. Potential policy responses are explored, noting that these will depend on the domain in which the technology risk arises.

2. Technology Assessment Methodologies

This section provides an overview of technology assessment methodologies, focussing on the way in which these address risk in each of the three domains identified in the introduction.

2.1. Techno-Economic Risks

2.1.1. Technical / Engineering Assessments

From a commercial perspective, a technology assessment can be any tool used to reveal and understand uncertainties, typically from a specific project level. An example of the different stages of technology assessment is shown in Figure 1. This follows the project cycle for the case of offshore wind. Other technologies will have a different timescale, but would generally go through similar stages and types of assessment.

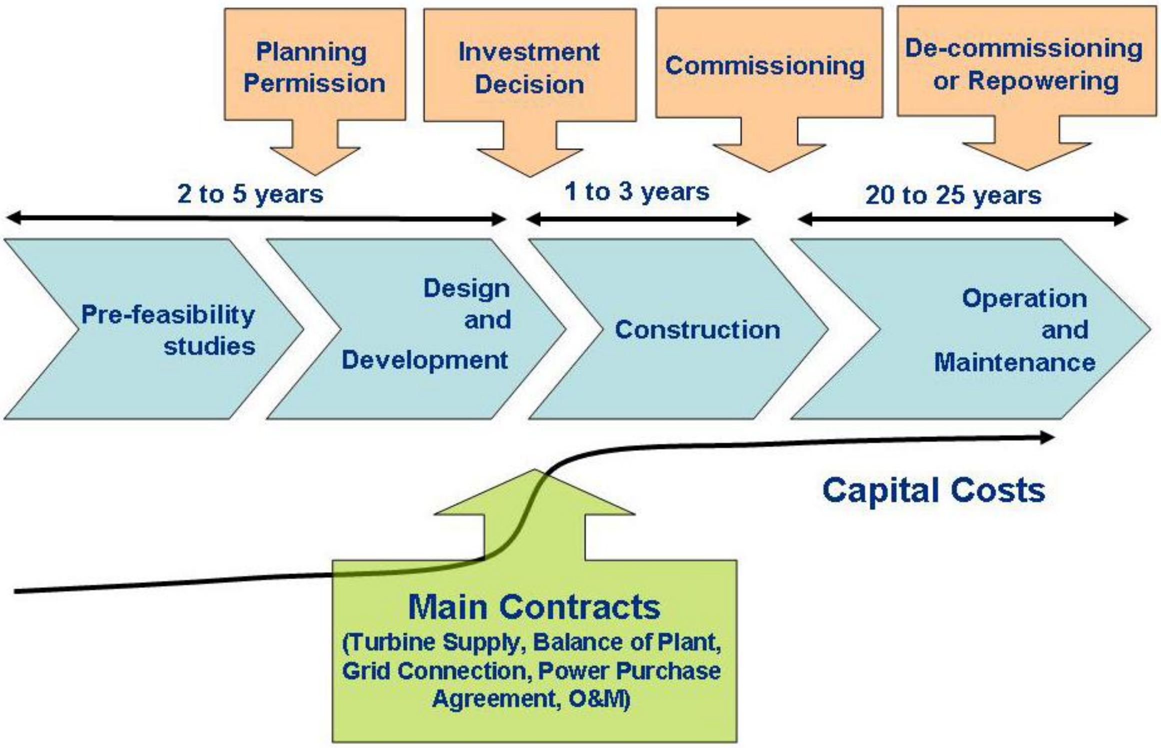

Figure 1 – Typical offshore wind project lifecycle

Source: (Kolliatsas, 2012)

Pre-feasibility study

These studies are performed at the first stage of projects development. According to (Kolliatsas, 2012) they include a wealth of assessments beginning at site-screening (pre-feasibility) where things like access and grid connection availability are assessed to get a short list of potential sites. Strategic Environmental Assessments

(SEAs) should be identified if available, along with any planning and legislation requirements (ibid). A basic cost analysis can be initiated in this phase. They also recommend an assessment of any health and safety hazard be added to a risk register at this stage, which can be used to track risks and act as a knowledge base for mitigation measures and potential issues throughout a projects lifetime.

Risk Register

According to (Willams, 1994) a risk register has two main purposes: to act as a knowledge repository which is particularly useful for a project consortia which may have multiple partners, and to initiate analysis and relevant plans. There are a number of analysis which can flow to and from a risk register, which in turn can be used to assess various aspects of a project throughout the development cycle. This assessment tool should be kept up to date throughout a project lifecycle. The types of uncertainty which can be covered in a risk register can include (Willams, 1994):

- Cost analysis: cost and revenue uncertainties
- Time analysis: built time uncertainty
- Technical specification: uncertainty to achieve desired design and standard
- Risk reduction: uncertainty of risks occurring and measures to mitigate
- Contractual: what risks can be managed in house and what risks can be contracted out, some actuarial risks may be high impact but will not be feasible to cover and therefore should have a very low probability of occurrence

Feasibility study

A feasibility study (Kolliatsas, 2012), will take place once one or more specific sites have been selected and covers all aspects of a projects development. Assessments are wide ranging and can include those of: regulatory environment, resource and site conditions, technical solutions, grid connections, environmental, social, health and safety, constructability, schedule, costs, revenues, financial and business modelling. For the sake of this discussion these will not be explored in detail. This extensive list of assessment areas represents the wide range of uncertainties which are common when developing a commercial project and this list may grow as more issues or concerns are uncovered. At this early stage there will also potentially be a wide knowledge gap for each of these areas.

Pre-construction, design, development and contracts

If no prohibitive issues have been identified from the previous feasibility studies, particularly environmental concerns, then a single project may be selected and progressed. If this project gets approved with planning and consent, then a detailed design can be undertaken. All the information from the previous stages will be used as useful inputs and as a specific design is selected and analysis becomes more refined and detailed, uncertainties should be reduced. For this paper it is assumed a detailed front end engineering design (FEED) study will be used for this stage of the project.

FEED is a standard engineering design process which typically happens after a feasibility or conceptual phase. It is still in the early stages of project development but enables project developers, sponsors and other relevant stakeholders to get an idea of early estimates on key attributes such as performance, cost and availability and enable a more detailed assessment.

The main objective of a FEED study is to lay down the basic plans and requirements so the Engineer Procure and Construct (EPC) contract can be written up for contractors (Tenaska Trailblazer Partners LLC, 2012). A FEED will also ensure that expectations on performance, availability and cost are set out appropriately. It is a crucial part of project planning and can require around 15 – 20% of the engineering and planning component of the project, helping to reduce risks and uncertainties before moving to the actual engineering and construction phases of a project (ibid).

When all cost estimations, technical expectations, and detailed designs have been set out, the process of EPC contracting may ensue. This process may involve a tender or bidding process whereby the contract is awarded to a particular or multiple contractors. The project may use an engineer procure construct (EPC) contractor, whereby based on the previous FEED, they have the responsibility to deliver the project under certain specifications, cost and time. EPC can also be used as a framework from which a project can be designed and planned around. Of course this is only one example of how this phase of a project can be undertaken. This is briefly being discussed as EPC could also be seen as a framework from which technologies, projects and uncertainties therein can be assessed and managed.

During the engineering phase a detailed design will be developed from the FEED and the process of quantifying, defining and communicating what is required from the contractors or builders is undertaken (Yeo and Ning, 2002). This is when a lot of funds, resources and schedules are committed to the project (ibid). Next is procurement, from the detailed design, specifications and other documents, for project equipment and materials, including activities such as sourcing, purchasing, contracting and onsite management (ibid). Finally is the construct phase, whereby the materials and equipment are used to follow the detailed design from the previous stages to ensure the project is delivered on time and on budget as agreed.

There are major uncertainties raised throughout an EPC, such as managing complex timetables of interlinking and dependant phases of work, bottlenecks along the supply chain and problems with sourcing and procurement (ibid). Such a framework or contract is in place to help manage and eradicate such uncertainties, ensuring a project is delivered on time, on budget, to the desired specifications.

Construction, operation & maintenance

As an EPC is delivered, uncertainties will be uncovered throughout the construction process, the level of which will depend on the maturity of the technology and the previous experience and knowledge base already available. From the recent nuclear builds in Europe, build time and cost overruns (Harris et al., 2012) have made it apparent that up to date construction experience in order to have better build plans and cost estimates can be crucial.

The same rules will apply for operation, maintenance and decommissioning. These activities for a particular technology and the uncertainties they uncover through 'learning by doing' for instance, can be related to how developed that technology is. For a less developed technology, these activities are more likely to uncover wide ranging uncertainties. Whereas for a more developed technology, it is more likely that the uncertainties are better understood and less uncertainty will be uncovered. From this idea comes the notion of first of a kind (FOAK) and Nth of a kind (NOAK) technology. NOAK plant, according to (NETL, 2013) is commonly known as the fifth plant or higher, but this figure appears rather arbitrary, so they also define it as when cost reductions due to experience become minor. Figure 2 gives a schematic representation of how costs evolve with the deployment of a technology.

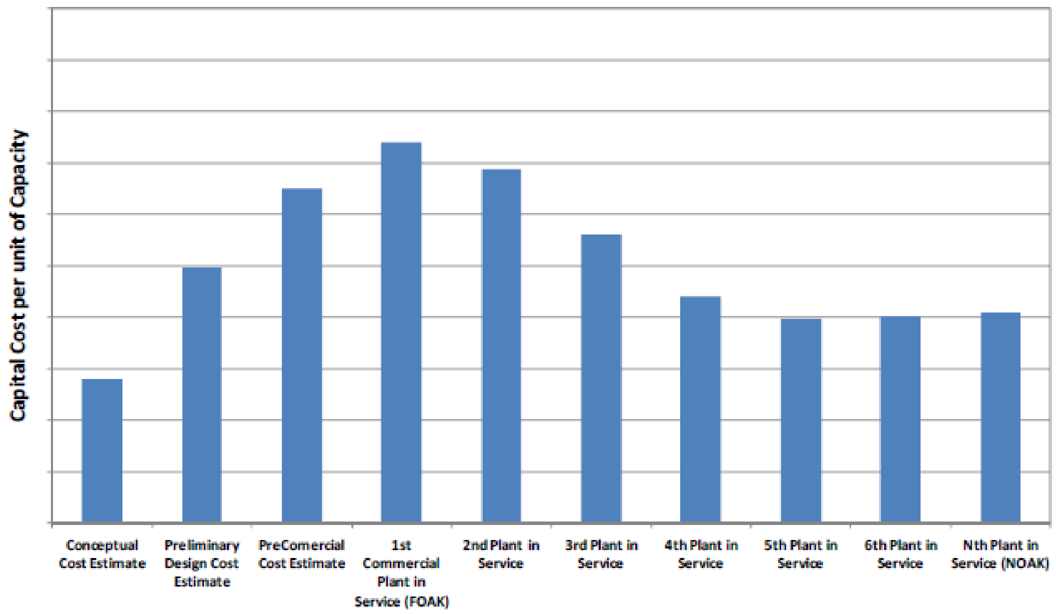

Figure 2 – Typical effect of experience on power plant costs

Source: (NETL, 2013)

This concept is relevant to all new technologies and there are fundamental differences between the construction of FOAK versus NOAK plant. Moving from FOAK manufacture of a single plant, to gaining experience to constructing an NOAK plant, should see the reduction of things like the FOAK premium which relates to supply and manufacturing costs of new technologies, reducing overall costs (Mott

MacDonald 2011). One caveat is that some manufacturers reduce FOAK charges to enable market entry (Kolliatsas 2012), which could distort estimations of cost reductions using this concept.

As experience is built up moving from FOAK to NOAK, cost reductions can also be attributed to the learning and understanding of various technology uncertainties. When build experience, installation and project management for a particular application are undergone, knowledge and skill base is fostered, enabling benefits from efficiency and productivity. These benefits from experience should also carry through to operation, maintenance and decommissioning. It would appear that the assessment methods for a FOAK and NOAK are likely to be similar (DECC, 2013a), but the understanding and knowledge would progress, uncertainties would reduce, and assessments should become more accurate.

Experience and knowledge gained from construction and operation of these projects would reduce uncertainty, and feed back into policy, informing policy makers how best to support technologies. Information on costs and performance can also be used to benchmark against which the efficacy of policy can be checked.

2.1.2. Financial Assessments

Discounted Cash Flow

Part of a feasibility study will feed any cost data from the pre-feasibility study phase and use it to assess the cost and revenue streams against potential profits for the project. At this stage alongside basic technology assessment to select the specific potential hardware, it will be important to assess the financial feasibility of the project. There are various techniques used throughout industry, and there is no standardised method, however there are 2 basic principle metrics used to assess the financial feasibility of a project which will be briefly introduced here, both from the discounted cash flow (DCF) family: net present value (NPV) and internal rate of return (IRR).

The NPV of a project indicates the amount of profit or loss which can be expected by the stakeholders of an organisation if a project goes ahead, which is fundamental to financial management (Lumby, Jones 1999). The calculation includes all expected costs and revenues, but there can be inherent assumptions leading to some factors being excluded. The basic NPV calculation is the sum of a projects discounted cash flows, calculated for each year of the projects operation using the following equation (Lumby, Jones 1999).

$$\mathrm{NPV} = \sum_{t=0}^{n} \frac{A_t}{(1+r)^t}$$

Equation 1: Calculating a project's NPV[1]

The typical rules of decision making for investment using the NPV approach are:

NPV > 0 → Accept project

NPV ≤ 0 → Reject project

An alternative is to calculate the internal rate of return of a project, which allows comparison of the relative attractiveness or likely profitability of projects of different size. The IRR is equivalent to the discount rate which is applied to the discounted cash flow approach, to produce an NPV of 0 (Lumby, Jones 1999). This is the expected percentage rate of return a project will offer. 'Hurdle rates' are risk adjusted expected IRRs which can be set by an investor body. Depending on the perceived riskiness of a project, the investors will apply a suitable hurdle rate to it i.e. higher risk, higher hurdle rate applied. Typically when the projects cash flow and IRR are calculated the following rules can be applied (Lumby, Jones 1999).

IRR ≥ Hurdle rate → Accept project

IRR < Hurdle Rate → Reject project

Levelised Cost of Electricity (LCOE)

LCOE measures the cost of generating a unit of electricity, and allows a way of comparing cost-effectiveness across a range of different types of generation. Similar to the NPV and IRR methods, LCOE stems from DCF analysis. The LCOE is the discounted present value of the total cost per unit of electricity generation for the lifetime of the project, commonly represented in £/MWh. In other words, the LCOE is the price of electricity at which revenues would exactly balance the costs. This can be calculated by discounting the future costs and outputs, and dividing the present value future cost streams by the future outputs (Gross et al., 2007). The other method, the 'annuity method' involves calculating the total present value of the cost, converting to an Equivalent Annual Cost (EAC) and dividing this by the total annual average output (ibid).

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[1] A_t = projects cashflow
t = year (0 – year n, end of project life)
r = annual discount rate

The resulting LCOE gives investors or policy makers another benchmark from which they can estimate the relative cost-effectiveness of different generation options. It is an extremely popular metric for policy makers, used for directing policy measures and as a benchmark for judging the likely level of policy support required for different technologies. Uncertainties can be quantified using scenario or simulation based approaches, incorporating point estimates or distributions for the latter, for any of the technological uncertainties the analyst wishes to capture.

There are many limitations to LOCE analysis. Importantly, the approach only looks at *costs*, and ignores the *value* of power generated. In particular, the value of being able to dispatch electricity at times when prices are high because of a squeeze in the supply-demand balance is typically not captured in an LCOE analysis. Also, this is a predictive modelling technique so it is difficult to estimate future exogenous and endogenous changes. There are various factors which will typically not be captured, which include changes in power supply and demand, external costs and benefits (environmental), business impact (option value), system factors (costs of balancing, system services etc.) (Gross et al., 2007). However, some of these factors may be included in more detailed modelling techniques.

Dealing with uncertainty

From a methodological point of view, the most straight-forward way to incorporate uncertainty is through use of different discount rates in the DCF analysis (Brealey et al., 2006). A higher discount rate can be used to represent a higher level of risk associated with the reliability of future income streams. High discount rates tend to make capital intensive projects such as nuclear and renewable technologies less financially attractive compared to gas-fired CCGT plant which tend to be relatively cheap to build but more expensive to run. This reflects the higher risk faced by capital-intensive projects having all the costs incurred at the beginning of the project, so that if the revenues are put at risk later in the project's life, there is no way of curtailing costs later on. By contrast, projects with low capital cost but high operating cost are less exposed because they can curtail costs by stopping operation if revenues become unattractive.

Varying discount rates in DCF analysis is often used as a sensitivity analysis, but there is considerable limitations to this approach in understanding risk because there is no obvious way to calibrate the different discount rates used in such analysis (Trigeorgis, 1996). Moreover, such an approach is unlikely to adequately differentiate the particular sources of risk or uncertainty faced by the different technologies – in practice, the risk profiles of technologies will be very different, and should be discounted in different ways (Dixit and Pindyck, 1994).

Apart from varying the discount rate, there are two other main methods for modelling risk within a DCF framework as outlined by (Gross et al., 2007). The first is a scenario approach, whereby possible variables are modelled numerous times using different assumptions resulting in a range of output DCF metrics (ibid). The second method is to use a stochastic approach whereby a model simulation is run hundreds or thousands of times to give a probability distribution for the NPV (ibid). These DCF methods can both incorporate NPVs, IRRs and LCOEs to model the uncertainties and levels of risk involved in an energy project investment.

This ability to run stochastic financial analyses opens up a wide range of options for statistical financial analysis. Real options analysis (ROA) is a method for including the flexibility of managers to alter the timing of investment decisions in response uncertainties (Trigeorgis, 1996). ROA can be carried out through dynamic programming (Dixit and Pindyck, 1994), which is an extension of decision-tree analysis. This defines possible outcomes, and assigns probabilities to these. The decision-tree defines how a decision-maker responds to resolution of uncertainty at each branching point. Quantifying the value of these decision options then proceeds by assessing all the branches. ROA calculates option values based on the expected value over all branches contingent on making the optimal choice at each decision-point. The optimal decision in turn is evaluated based on all the possible outcomes downstream of that decision in the tree. This ROA value can be compared to a normal appraisal calculation (a probability-weighted average) of the outcomes along each possible branch.

The approach has started to be used quite widely in the analysis of energy sector investments, including investment in low-carbon options for climate mitigation. For a recent review of applications of ROA to renewable energy investments, see (Fernandes et al., 2011, Martínez Ceseña et al., 2013). Examples of applications to carbon capture and storage include (Zhu and Fan, 2011, Eckhause and Herold), for the case of nuclear, (Zhu, 2012, Kiriyama and Suzuki, 2004), for the case of wind power (Lee, 2011), decentralised renewables (Fleten et al., 2007). (Blyth et al., 2007),(Fuss et al., 2009, Reuter et al., 2012), analyse the impact of climate policy uncertainty together with market risk on investment decisions in the energy sector, identifying opportunities for improving mitigation policy design to reduce policy risk.

Many other statistical assessments of risk exposure can also be used. One common measure used in the financial services sector is value at risk (VaR) which measures the likelihood of an adverse event leading to downside risk (Linsmeier and Pearson, 2000). Value at risk is a statistical measure of the amount of money a portfolio, strategy, or firm might expect to lose over a specified time horizon with a given probability (usually 90%, 95%, or 99%). For example, a portfolio that is expected to lose no more than $1 million 95% of the time (or 19 of every 20 days) has a VaR of $1 million. On the downside, 5% of the time, or 1 day out of every 20, the portfolio is expected to lose at least $1 million. One of VaR's major criticisms is that it provides no information about how much the portfolio could lose (beyond the $1million) during this 5% of the time (Kidd, 2012). A closely related alternative is contingent value at risk (cVaR) which assesses the average size of losses should they actually occur, allowing for the possibility of fat-tail probability distributions (ibid) (Alexander and Baptista, 2004). Such methods are increasingly used to assess the income risk for energy technologies associated with market price variations (see e.g. (Fong Chan and Gray, 2006), (Deng, 2013), (Yau et al., 2011)).

As with all modelling techniques, the limitations of these methods lie with the accuracy of their inputs. This is of particular concern with newer technologies whereby the costs and other attributes which affect costs may not be very well understood. As pointed out by (Gross et al., 2013), this can lead to inaccurate costs in the early stages. Costs can also be biased, showing optimism towards increasing or decreasing costs of a particular type of technology from developers in order to get project approval or particular levels of support (Heptonstall et al., 2012, Gross et al., 2010).

2.2. Programmatic Risk: Understanding and Managing Technology Dynamics

Whilst the methods described in the previous section address a variety of different technical risks, another category of risk is involved when the technologies concerned have not reached full maturity and are still developing. In its widest sense, technology assessment has to deal with predicting a wide set of positive and negative societal impacts of major technological advances (Rodemeyer et al., 2005). The co-evolutionary nature of societal and technological developments makes this a complex task (Markusson et al., 2012, Geels, 2005), and requires technology assessment to engage with a wide group of stakeholders (Schot and Rip, 1997, Genus, 2006).

In this review, we focus for the most part on assessment of a narrower set of parameters such as expected costs and performance improvements. Even in this more bounded case, uncertainty in the dynamics of technology development mean that both the rate of such improvements as well as the final degree of improvement cannot be known with confidence. A taxonomy of different technology assessment approaches in this context is provided by (Tran and Daim, 2008).

Since the technology development process itself is uncertain, outcomes are subject to "programmatic risks" which comprise factors (other than techno-economic risks) which affect both the rate and the final extent of technology performance and cost improvements (see e.g. (Kindinger and Darby, 2000). These programmatic risks can be wide-ranging and comprise:

- Political and regulatory issues
- Adequacy of innovation networks
- Public acceptability (e.g. of safety, environmental or other externalities)
- Financial and market conditions
- Human-resources, skills and supply chains

Examples of procedures for identifying and managing such programmatic risks can be found for a range of technology development applications in the energy, defence, space and commercial sectors (DoE, 2011, DoD, 2006, Belingheri et al., 2000, Kindinger, 1999).

The way in which such risks are assessed depends in part on the stage of development of the technology, and the conceptualisation of the innovation and development process. We present three such conceptualisations in this section:

- Linear innovation pathways. This sees innovation as following a pathway from basic research through to commercialisation.
- Innovation ecosystem. This takes into account the more complex iterative nature of development relevant for most energy technologies in the near-market stages of development.
- Learning curves. This discusses a representation of technological improvement that result once technologies start to be rolled-out at scale.

2.2.1. Linear Technology Evolution Pathways

Figure 3 shows a typical linear representation of a technology development pathway. It begins with basic and applied research. These activities would involve activities in laboratories, universities, and private and public sector institutions like testing centres which have become more common in the UK. Assessments would focus on technical aspects of a technologies performance in order to prove the concept. However for this discussion, our attention is drawn to the latter stages, known as the valley of death. This is the most challenging time in the technology lifecycle, when it is required to move from a small scale to full scale demonstration to a full commercialisation.

The challenge highlighted by this model is to replace public support with private sector finance to enable commercialisation at a time when investment must be scaled up dramatically (Murphy and Edwards, 1993). The scale up of investment from the private sector would be attainable if risks were to fall. However, as summarised by (Trezona, 2009), the valley of death occurs when costs increase at a faster rate than risks decrease, leading to failure of that technology.

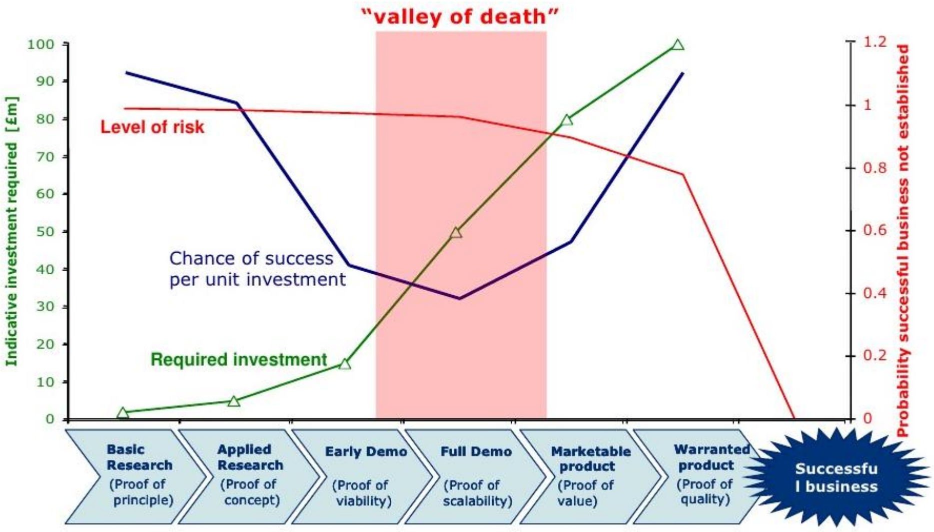

Figure 3 – Valley of death from cost increasing quicker than risks decreasing

Source: (Trezona, 2009) from Carbon Trust analysis; Mahler Ventures Ltd

Linked to this linear model is the concept of 'technology readiness levels' which are an indicator of the types of support required at different stages of technology development (see Figure 4). As described by (Mankins, 2009), "Technology Readiness Levels (TRLs) are: "…a systematic tool that enables assessments of the maturity of a particular technology and the consistent comparison of maturity between different types of technology." (Mankins, 2009), p. 6). TRLs were developed by NASA to quantify a technologies maturity and have been popular in the defence industry, but more recently they have been adopted for assessing energy technologies (Kolliatsas, 2012). TRLs have implications for the level of technology maturity a technology is at and therefore its riskiness. This technology maturity hierarchy view implies a reduction in uncertainties the higher up in the hierarchy a technology is.

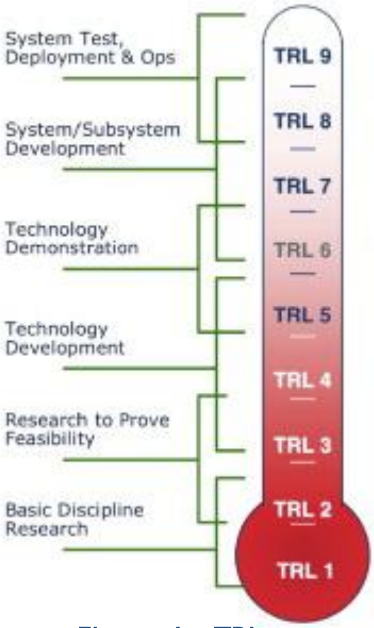

Figure 4 – TRLs

Source: (Mankins, 2009)

(Mankins, 2009) suggests the main limitations of the TRA are that it does not assess the level of difficulty getting a technology from one level to the next. It also does not provide any consideration into the importance of a particular technology development to the overall success of a whole system application.

Nevertheless, TRLs have been of use in a policy context. They can be used for setting benchmarks for a technologies expected future development. (RenewableUk, 2010) use TRLs to state what stage marine technologies should be at for 1st, 2nd etc. technology deployments, what TRLs should be for various deployment sizes and the potential costs therein. (DECC, 2012a) have also used TRLs to delineate the responsibility of various institutions regarding their supporting position in the UK innovation chain in their science and innovation report (Figure 5).

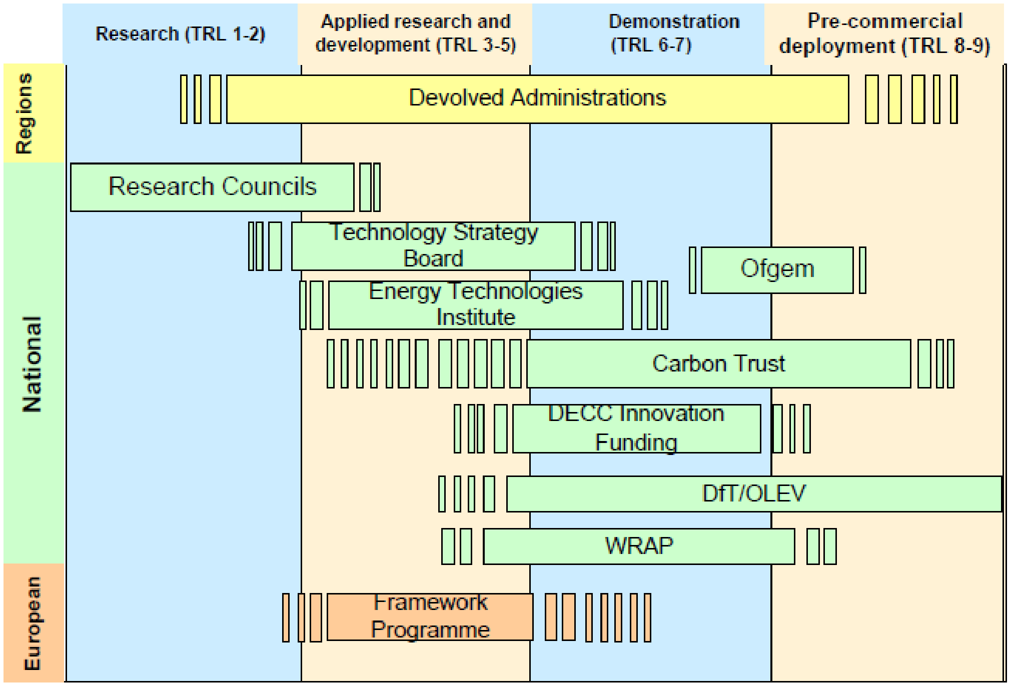

Figure 5 – UK technology funding landscape

Source: (DECC, 2012a)

However, a serious limitation of the linear representation of technology development for energy technologies is that it does not adequately represent the complex iterative nature of different stages in the innovation process, and the interactive ecosystem of organisations involved (UKERC, 2014). These issues are discussed in the next section.

2.2.2. The Innovation 'Ecosystem'

Whilst the linear process identified above is appealing in terms of its simplicity, in reality, innovation relies on a much richer set of relationships between research and commercialisation activities. This requires an exchange of ideas, information and skills across a wide range of organisations and institutions (Figure 6).

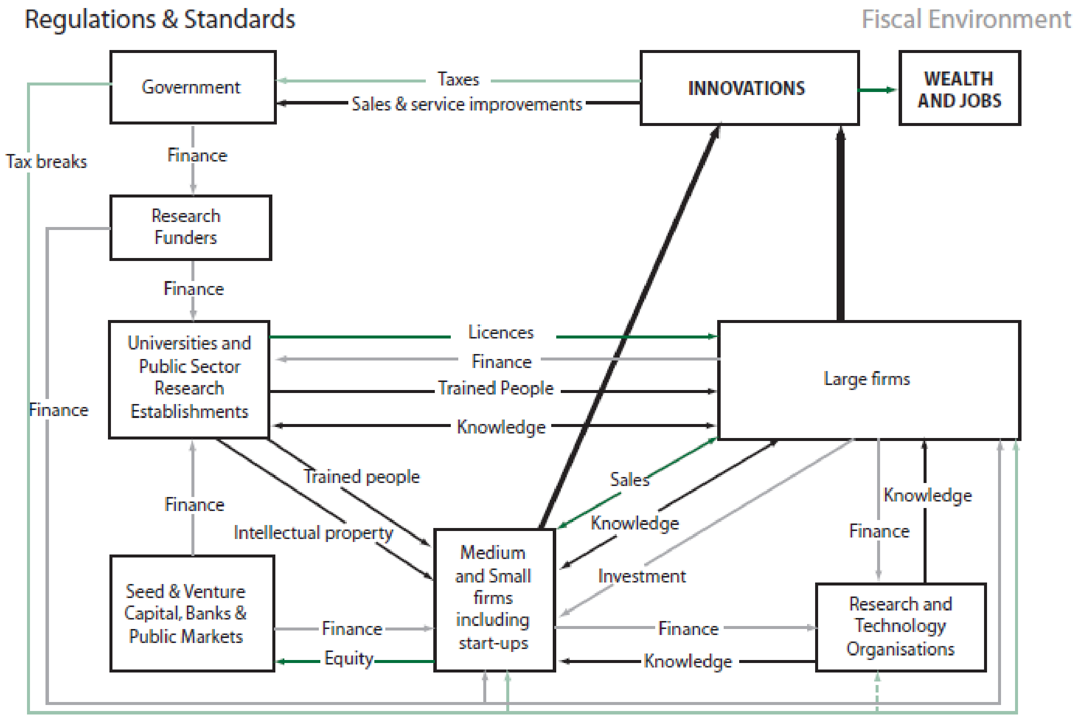

Figure 6 The Innovation Ecosystem

Source: (House of Commons, 2013) (attributed to Prof. Georghiou)

In practice therefore, the institutions identified in Figure 5 tend to be involved in promoting a wider range of activities than their immediate TRL banding would suggest. (Edler and Georghiou, 2007) provide a taxonomy, describing multi-stranded innovation policies that not only supports the 'supply' of innovation, but also measures to support the 'demand' for innovation, both private and public.

The distributed and networked nature of this technology development process makes it harder to pinpoint sources of programmatic risk. Coordination between research organisations and funders becomes crucial in this context. One example has been the Technology Innovation Needs Assessments (TINAs), a collaborative effort between DECC, BIS, the Engineering and Physical Sciences Research Council (EPSRC), the Energy Technologies Institute (ETI), the Technology Strategy Board and the Carbon Trust. These apply a common assessment methodology across a range of low-carbon technologies. For each low carbon technology, the TINA:

- Analyses the potential role of the technology in the UK's energy system
- Estimates the value to the UK economy from cutting the costs of the technology through innovation
- Estimates the value to the UK economy of the green growth opportunity through exports
- Assesses the case for UK public sector intervention in innovation
- Identifies the potential innovation priorities to deliver the greatest benefit to the UK

The process is coordinated by the Low Carbon Innovation Coordination Group (LCICG), and to date has produced TINAs for eleven main families of low carbon technologies.

The ETI is another institution involved in this development phase, a private public partnership who specialise in bringing together engineering companies and projects which help meet UKs low emission energy strategy. They make targeted investments across 9 key technology areas (ETI, 2013). ETI have a range of resources for assessing technologies, from in house technology specialists to the use of specialised in house software (Technology, 2013) such as the Energy System Modelling Environment (ESME) which helps them identify key areas for them to invest in and informs UK policy (Technology, 2013). Major uncertainties it aims to inform include targets and potential pathways, effects of technology acceleration on the solution, key constraints, system cost of meeting targets, and skills required to support the energy system (ETI, 2013).

Demonstration phases will be heavily engineering based assessments, as proof of viability for early demonstration and for a full scale demonstration, proof of scalability. At these stages, a technology will have to prove its technical functionality. It needs to prove its feasibility in its live environment, including performance, that it will produce viable amounts of electricity, buildability, durability, reliability, availability, maintainability etc.

All these factors will be assessed in some way, and there will typically be a wide range of uncertainty for all factors in these early stages. All of these factors will feed into what appears to be highlighted more than any other metric from the policy perspective, which is cost (Gross et al., 2010). In the policy world, most performance metrics and the uncertainties therein, can be quantified to some extent by costs, typically represented as the levelised cost of energy (LCOE). We will also see from the case studies in the following section that even at this early stage when uncertainties are high and costs usually not well understood, there are programmes pushed from the public arena to define and reduce LCOE.

Defining LCOE will also occur long before full scale demonstration phases (marine and CCS) to direct the levels of support required in these early stages to progress the technology. The stage of full scale demonstration and pre commercial is a somewhat grey area, because to even get a full scale demonstration, the project will have to prove its commercial feasibility, even though it will still be provided with generous public support. However, defining these potential costs at such an early stage appears necessary, particularly when offering large amounts of scarce public resources for expensive new technologies, which cannot expect permanence of this generous support.

There is a wealth of demonstration programmes for early technologies such as marine and CCS, from public bodies or public private bodies such as DECC, Carbon Trust and the TSB.

DECC have a recent range of innovation competitions for low carbon technology demonstration schemes, some carried out in collaboration with the other public bodies including a Bioenergy demonstrator funding opportunity, Energy Storage Technology Demonstration Competition, Offshore wind: Component Technologies Development and Demonstration scheme and Marine energy Array Demonstrator (MEAD) scheme (DECC, 2013d). These schemes are typical run in a competitive tendering process, enabling thorough assessment of technology capabilities, performance and costs, with a preferred bidder or bidders being selected to develop their demonstration fully.

The pre-commercial stage sees a shift from policy push programmes and assessments to a drive to the commercial spectrum, but there is still a lot of assessment work done in the policy arena before the private sector take over. There is a range of accelerator programmes and cost reduction programmes which are run at this stage of development. These include competitions for demonstrating innovation to reduce costs for a new technology or a technology which is being commercialised.

Examples are the CCS task reduction task force with the objective of reducing the cost of CCS to £100/MWh by the early 2020s (Crown Estate et al., 2013). With a similar objective is the offshore wind cost reduction task force with the objective of reducing offshore wind to £100/MWh by 2020 (Offshore Wind Cost Reduction Task Force, 2012). These initiatives have been set up to reduce costs of these technologies to a level where they can be cost competitive with other forms of low carbon electricity generation to enable the supporting hand from the public purse to be subsequently removed. Examples of this type of work will be revealed in the case studies.

2.2.3. Learning Curves and endogenous technical change

Learning rates were first theorised by (Wright, 1936) who in studying manufacturing processes of airplane parts, noted a constant decrease in production costs for every doubling of cumulative manufacturing volumes. This theory has since been applied to a wide range of applications in the manufacturing industries. More recently, it has been applied to the energy industry (Gross et al., 2013).

The theories for learning rates have been developed to a more sophisticated level, reflecting the complexity and multitude of actors involved in attempting to calculate technology cost reduction trends. The original learning curve is known as a single factor learning rate, whereby learning, or cost reduction is a function of cumulative capacity (Rout et al., 2009). Since then, two factor learning rates have appeared which emphasise learning and the impacts of R&D (Rout et al., 2009), in attempt to get a more accurate analysis of cost developments.

Theories have gotten more complex with time, with (Zangwill and Kantor, 2000) positing a difference equation to analyse individual points of learning, arguing current calculations are merely simple forecasts and do not delve into the uncertain nature of technology improvements. He also makes the point that it is more common for improvement measures to fail. (Li et al., 2012) uses an approach which effectively splits up the component parts to analyse their individual learning rates to get a more accurate representation for CCS plants. He also studies the effects of plant efficiencies on cost curves, stating this has been missed by previous studies (Li et al., 2012).

Learning curve calculations also rely on a time series against which the learning and cost developments can be calculated. This would infer that the technology would need to be at a developed stage and undergoing mass production to some extent to enable sufficient time series data to support the learning curve calculation. (Gross et al., 2013) state a 10 year period would be suitable to enable statistical analysis. As pointed out by (Gross et al., 2013), learning rates are well suited for helping the allocation of scarce resources for technology innovation and development. They are also good for evaluating the cost effectiveness of public policy and weighting public investment against potential environmental damage (ibid).

As stated previously, the requirement for accurate time series data means that this technology assessment method may not be effective for technologies in early stages of development. (NETL, 2013) however do attempt to use learning curves to estimate cost reductions from FOAK to NOAK technologies. This infers that cost curves can be applied earlier, but this does use an engineering heavy, bottom up approach, which relies less on historical data.

Calculating the cost reductions for technologies into the future is rife with uncertainty. Examples of uncertainties are outlined by (Rout et al., 2009) as the various types of learning which must be considered, cost increases, inaccurate estimates and expert opinion, changing uncertainties, funding in R&D impacts, unforeseen technological difficulties, forgetting by not doing, differing component learning rates and various exogenous price pressures. Most of these come from a lack or inaccuracies of information.

A major limitation pointed out by (Winskel et al.) is that it should not be assumed that market growth is correlated with cost reduction. There are many examples throughout history whereby exogenous factors have resulted in unpredicted ballooning of costs, such as the nuclear case (Harris et al., 2012) and more recently the offshore wind case in the UK (Heptonstall et al., 2012). (Winskel et al.) also points out that even when correlation is observed it is difficult to deduce causality. There is a long list of different types of learning pointed out by (Rout et al., 2009) such as learning by doing, learning by using, learning by searching (type of researching), learning by researching, learning by interacting, learning by expanding, learning by learning. To understand exactly where the cost improvements originated is near impossible but this would be most beneficial for developers to accelerate the technologies development and to understand really how costs could develop into the future.

Learning rates have been particularly popular for the wind and PV industries (Li et al., 2012). This reflects their reliance on subsidy support, and therefore need to estimate future costs and requirements for R&D and innovation spend. They have been less popular for hard to estimate learning rates for CCS (Ferioli et al., 2009) however (Li et al., 2012) uses an alternative method, analysing the various components and including effects of plant efficiency increases to provide learning curve calculations.

The approach to incorporating technological learning into modelling can have a very significant impact on results (Löschel, 2002), (Sue Wing, 2006). As described by (Löschel and Schymura, 2013), treatment of technological change in models is one of three dominant issues to resolve when deciding how to model climate change mitigation; the other two being the choice of discount rate and the treatment of uncertainties in climate impacts. Models tend either to assume exogenous or endogenous technological change (ibid). Exogenous change assumes that technologies tend to improve over time irrespective of what is happening within the model. Endogenous (or induced) technological change assumes that technology improvement is tied to uptake of technologies within the model (Popp, 2004) (Löschel and Schymura, 2013), (Bosetti et al., 2011). Typically, the assumption of induced or exogenous technological change makes climate mitigation policies appear less costly in these models (Kemfert and Truong, 2007) (Gerlagh, 2007) (Goulder and Schneider, 1999) (Rosendahl, 2004).

2.2.4. Technology Pathway Studies

Technology pathway and roadmap studies are a popular assessment methodology which can be used to probe the uncertainties associated with technology development. Prominent examples include:

- (UKERC, 2009) investigates the transition to a “secure and low-carbon energy system”. As well as assessing likely technology developments, the study includes scenarios for political ambition, needs for diversity of generation sources, uncertainties over levels of demand and other non-techno-economic variables.
- (European Commission, 2011) sets out a vision for how the EU commitment to 80% reduction in GHG emissions could be achieved. Scenarios focus on potential development pathways for each of the main sources of generation, as well as looking at demand-side potentials, assessing energy market conditions, mobilising investment and engaging the public.
- (IEA, 2009-2012) presents roadmaps for individual energy technologies. Each roadmap represents international consensus on milestones for technology development, legal/regulatory needs, investment requirements, public engagement/outreach and international collaboration.
- (IRENA, 2013) provide a review of the state-of-the-art of technology development, together with analyses the market potential and barriers for key types of renewable energy technology.

- (DECC, 2011a) sets out a UK renewable energy roadmap, identifying policy actions and targets that are needed to support innovation, supply chains and improve the ability to finance projects.
- (DECC, 2013c) provide a spreadsheet tool that allows users to experiment with different ways of meeting the UK's target to reduce emissions 80% by 2050 taking account of developments in technology cost and performance over this timeframe.
- (LCICG) coordinate technology innovation needs assessments (TINAs) as discussed in Section 2.2.2.

Whilst the specific approach taken to these pathway studies is different, they typically have a similar overall aim. They tend to identify the potential improvements that could be expected for particular technologies, map out key milestones in the development pathway, together with potential barriers to this progress and identify actions that need to be taken to advance or accelerate progress.

2.3. System Integration Risks

This section deals with the assessment of risks that arise when individual generation technologies are integrated together at the whole system level. Because individual generation technologies have different risk profiles which can to some extent offset each other, the vulnerability and risk exposure of the whole system is different from that of the component parts.

2.3.1. Technology representation in energy models

There are many different modelling frameworks used to try to assess electricity generation at the system-wide level. As described by (Scrieciu et al., 2013), these can broadly be divided along 2 axes, namely top-down vs. bottom-up, and optimisation vs. simulation (or other non-optimisation approach) (see Figure 7).

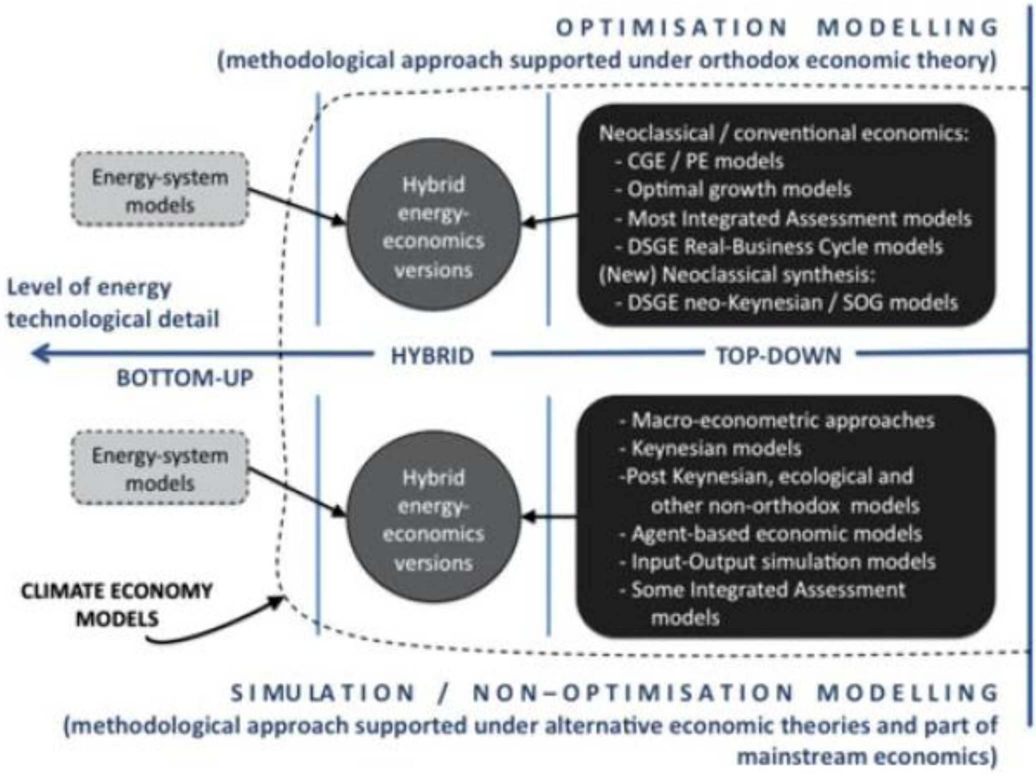

Figure 7 Typology of energy-economy modelling approaches

Source: (Scrieciu et al., 2013)

Top-down economic models tend to have very stylised representations of technology, often incorporating overall technology performance for whole sectors into the equation for the production function, with no specific representation of individual technologies (Weyant, 2004). Technological change is represented in these high-level models as part of the overall improvement in productivity (ibid), making it hard to identify specific causes and effects of technology risk and uncertainty.

Bottom-up energy system models tend to have the most detailed representation of individual technologies, and are therefore best suited to analysing the sources and impacts of technology risk. A review of energy system models is provided by (Connolly et al., 2010). Examples of optimisation models that have been widely used in the UK include the MARKAL / TIMES family of models (ETSAP, 2013), which have led on to other structurally similar models such as the ESME model (Day, 2012). These models have diversified as multiple users have adapted them to different applications, for example:

- The problems of over-optimised solutions associated with perfect foresight as described in (Keppo and Strubegger, 2010) are tackled by a version called SAGE which limits foresight by stepping through the modelling period in discrete steps to more realistically represent real decision-making (ETSAP, 2004b).

- Analysis of uncertainty using sensitivity analysis or stochastic programming was incorporated into the TIMES model allowing multi-stage decisions to be represented (ETSAP, 2012).
- Hybrid approaches tend to combine multiple models, sometimes operating in an iterative way in order to combine the technology-rich insights of bottom-up models with the benefits of top-down models that can deal with the wider economic interactions between sectors. Sometimes these top-down and bottom-up approaches are integrated into a single platform, as is the case with MARKAL-MACRO (ETSAP, 2004a)

In each case, performance characteristics for individual technologies is estimated for future time periods. In the stochastic versions of the models, ranges are specified, with individual values chosen randomly from the range to give a spread of results which can be used to assess the impact of technological uncertainty on model outcomes.

Because of the problem that optimisation models can over-optimise solutions relative the real world they are aiming to represent (Keppo and Strubegger, 2010), some models take a simulation approach, aiming to represent technology uptake as a behavioural process relying on factors other than simple cost-effectiveness, so that technology pathways can develop despite on-going cost differentials. Examples of such models include POLES ((Enerdata) as used in the World and European Energy and Environment Transition Outlook (EC, 2011). Other examples of models that are not based on optimisation architectures include the International Energy Agency's World Energy Model (IEA, 2013b).

Because of the complexity of electricity systems (e.g. due to the need for real-time balancing of supply and demand), specialist models have tended to be developed for this sector, as reviewed by (Foley et al., 2010). These tend to include detailed technology specifications, similar to those included in the optimisation models, usually with assumptions built in regarding the extent to which technology performance is likely to improve over time, and usually specifying ranges in order to accommodate stochastic and scenario analysis (ibid).

Less formalised approaches to representing technology futures include pathway analysis which often relies on expert judgement using Delphi or other elicitation processes (Morgan, 1990), (Hoffman et al., 1995). For a review of recent applications of expert elicitation processes in relation to technology analysis, see (Bistline). Examples of international studies of technology pathways include the IEA's series of technology roadmaps (IEA, 2013a), and the EU 2050 Pathways project (Roadmap 2050).

The costs of mitigation action depend not just on technology assumptions however. A comparison across multiple modelling approaches discussed by (Paltsev and Capros, 2013), shows that the definition of costs and the way they are incorporated into the modelling framework can have a very substantial impact on estimates of the costs of achieving long-term abatement targets.

2.3.2. Adequacy and reliability assessments

From a future macro electricity system level assessment and planning perspective, technical assessments can be used to ensure system reliability, adequacy and security. System reliability can be summarised as:

"The function of an electric power system is to satisfy the system load requirement as economically as possible and with a reasonable assurance of continuity and quality….The concept of power-system reliability, however, is extremely broad and covers all aspects of the ability of the system to satisfy the consumer requirements." (Billinton and Allan, 1984).

(Billinton and Allan, 1984) describes adequacy as having enough facilities to meet the system requirements, i.e. generating enough energy to meet demand, and have transmission and distribution capabilities to deliver it to customer load points. Finally, security is defined as how the system responds to disturbances (ibid).

Three common metrics for assessing system adequacy and reliability are discussed in this paper: Loss of Load Expectation (LOLE); the average number hours or days where peak demand exceeds electricity supply, expected energy unserved EEU; the amount of electricity supply in kWh which may not be served in a year capacity margin; the excess of total installed generation capacity over peak demand (Billinton and Allan, 1984, Ofgem, 2013).

There are two basic methods for carrying out this type of uncertainty analysis, similar to the main types of uncertainty analysis discussed in the investment appraisal discussion; analytical methods using for instance a scenario based approach, or simulation methods such as Mote Carlo(Billinton and Allan, 1984). These can incorporate uncertainties on all aspects of the past, current or projected electricity system, such as generation intermittency or variability, expected capacity and proportions for each technology, build profiles, planned shutdown, demand profiles and planned shutdown. As there is no set methodology in how to obtain these metrics, this paper will look at a few significant studies in the UK to explore this area of assessment.

One example is the (Ofgem, 2013) Capacity Assessment Report. It uses a probability approach with sensitivity analysis. There is more likelihood that demand will exceed supply during winter, so it uses winter demand distributions. It then calculates the probability of demand exceeding supply in a randomly chosen half hour from this winter period. Other uncertainties captured as probability distributions are for investment and retirement decisions (new build, closures, mothballed), interconnector flows, and the impact of wind generation (see Figure 8).

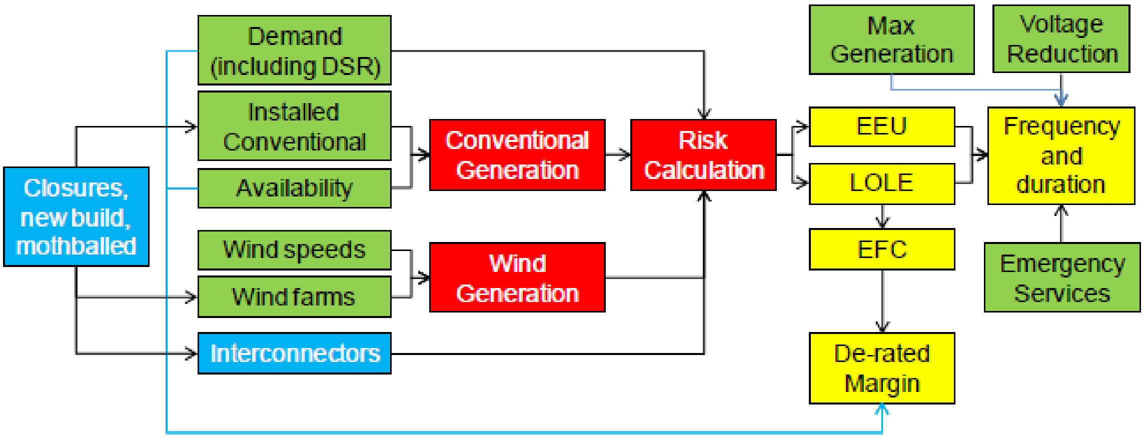

Figure 8 Schematic of the Ofgem capacity assessment model

Source: (Ofgem, 2013)

Other uncertainties listed as future economic growth, policy development and impact on demand, interconnector flows, investment and retirement decisions could not be assigned probabilities and for that reason a reference scenario and sensitivity approach was used. Their main probabilistic outputs were LOLE in hours per year (not outages, but loss resulting in SO mitigation measures) and Expected Energy Unserved (EEU) (Ofgem, 2013). Capacity margins were also calculated.

Another study was carried out by (National, 2012), and although the output was economic, looking at the cost of reinforcements and network upgrades, an interesting approach was adopted to incorporate the uncertainties involved in developing the future electricity system. A probabilistic technique was used investigate the effects of the new RIIO T1 price controls for network companies. Uncertainties were analysed and prioritised for the modelling, with subsequent probability distributions calculated for the selected uncertainties. The main risks were categorised into cost risks and volume risks (see below) (National, 2012). Also represented in the modelling were management responses to each of these uncertainties

Cost risks:

- Construction uncertainty
- Real price effects

Volume risks:

- Local generation connections
- Demand related infrastructure
- Wider reinforcement works
- Costs of meeting planning requirements
- Offshore network impacts

- Design standard changes
- Critical national infrastructure
- Climate change: flood and erosion protection
- GB and EU market facilitation

The main simulation outputs are distributions for load related CAPEX, non-load related CAPEX and OPEX. A graphical representation of an output for new generation is shown in Figure 9. The model was used to calculate the potential charging effects under various scenarios to test the efficiency of the new network charging mechanism.

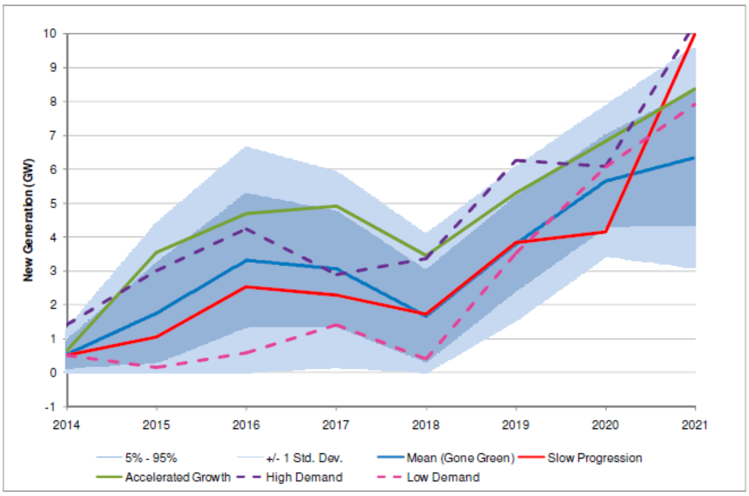

Figure 9 – New generation using a normal distribution around the mean gone green scenario (GW)

Source: (National Grid, 2012)

These studies, from regulator and system operator, attempt to incorporate uncertainties from all aspects of the generation fleet, but with the increased deployment of intermittent generation in the UK, there has been a wealth of research looking at the specific uncertainties and effects brought from this new fleet of capacity. Challenges which have never been experienced from previous traditional thermal plant are beginning to emerge, and as intermittent renewables increase in line with targets, these challenges will grow.

A UKERC study in 2006, reviewed 200 international studies and looked at the potential costs and merits of increased intermittent generation on the system, expressing reliability in terms of a capacity credit; how much traditional generation could be taken off the system (Gross et al., 2006). The study also expressed costs in terms of LCOE for the system supporting the integration of up to 20% intermittent capacity (ibid). The study showed that uncertainties will definitely increase due to this new generation fleet, but system reliability should not be compromised.

Another study focusing on this specific uncertainty was carried out by (Poyry, 2008). This specifically looked at how to keep capacity margins at 20% when 25% or 45% of intermittent renewables are on the system. A probabilistic in house model was developed which included major uncertainties by:

- Developing electricity demand scenarios with changes in annual demand and daily profiles
- Defining build profiles for renewable generation using Poyry renewable generation supply curve
- Defining generation capacity
- Identifying capacity requirements based on assumed renewable build profile

The model included patterns of deployment and different mixes of generation. Various scenarios were compared on generation capacity and mix, and other policy indicators such as gas use, import dependence and carbon emissions. The major outputs enabled a scenario comparison of the various effects on capacity margins. An example output was what additional firm capacity would be required to ensure a 20% capacity margin on the system shown in Figure 10**Error! Reference source not found.**.

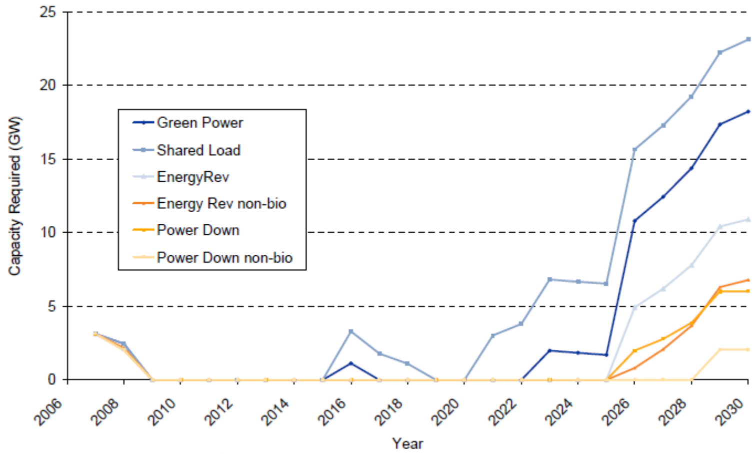

Figure 10 – Additional firm capacity to retain a 20% capacity margin (GW)

Source: (Poyry, 2010)

2.3.3. Economic Assessment

Electricity system economics can be used as a way of analysing the current and future state of the system. When used effectively, methods can provide insight into potential problems, such as shortfall of capacity and can offer meaningful insight into system and capacity requirements. A few basic methods are introduced to show how these can be sued in system assessment.

Load duration curves are effective at determining how much baseload capacity and peaking capacity is required. Along with demand shifts, they are important tools of analysis in system economics and in determining how much capacity of each technology should be built (Stoft, 2002). They can also be used to analyse the effect of prices on demand or load. In addition to this, screening curves can be used to find the optimal mix of different technologies on the system (ibid). Increasing integration and policy requiring low carbon technologies has somewhat complicated this type of analysis, but they are still useful fundamental techniques.

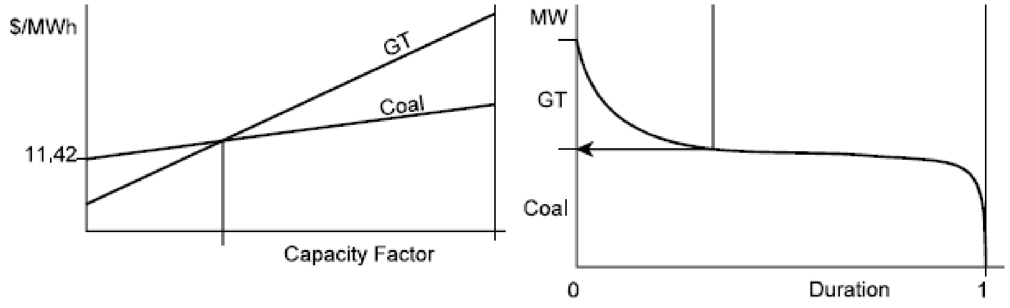

Figure 11 – Using screening curves to find optimal technology mix

Source: (Stoft, 2002)

Electricity prices are often calculated by constructing a merit-order stack. This materialised from the pooled electricity market, whereby the cheapest technology option would be deployed first, with the most expensive technology deployed for that given hour setting the marginal price. Moving to a bilateral market would suggest a very different market structure and analysis, but the same idea can be used to analyse wholesale price effects. Merit orders can be used to analyse the effects of new capacity on prices and margins, or help inform what new capacity to invest in (Staffell and Green, 2012). With the increased integration of intermittent generation, it has been used as a tool to analyse the possible price effects of high levels of intermittent penetration

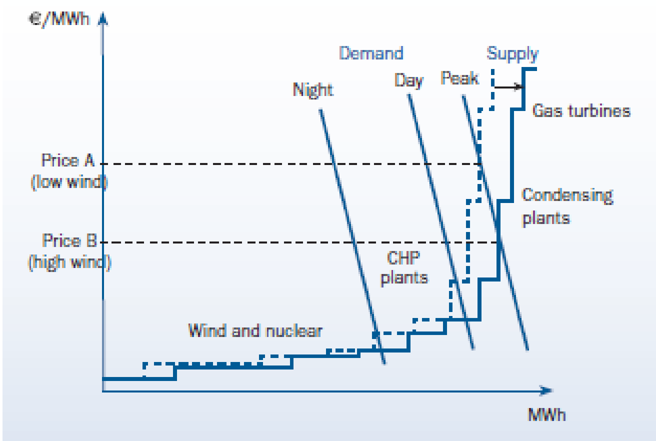

Figure 12 – Effect of wind at different times of the day

Source: (Poyry, 2010) from EWEA Economics of Wind

In Figure 12, with electricity supply and demand curves, the merit order is used to analyse the price effects of having a high penetration of wind on the system. Having a typically low marginal cost, it is deployed early when available, therefore shifting the supply curve and reducing power prices, being more prominent at peak times. The merit order effect does have limitations such as not usually accounting for dynamic system constraints for instance minimum stable loads, energy storage, reserve requirements and ramp up rates (Staffell and Green, 2012). Nevertheless, it is a proven effective assessment method for aiding capacity investment decision making, system planning and analysing price effects which can be used in conjunction with other tools for a more holistic system analysis.

2.3.4. Portfolios and Technology Diversity

In the assessment methods and techniques discussed above there appears to be a potential gap for analysing and understanding the probability of the outlier events, the back swans events (Aven, 2013) or unknown unknowns (McManus and Hastings, 2006) sometimes referred to as 'ontological' risks (Lane and Maxfield, 2005). These events may have a low probability of occurrence, but their impact can be hard felt. It is worth bearing the distinction in mind, as it is often easier to focus in and analyse the impacts of specific risk, and lose sight in the forecasting process both of the probability and the impacts of systemic risks. As noted in (Makridakis and Taleb, 2009):

"We can always make a prediction, either judgmentally or using a statistical/mathematical model. Once such a forecast exists, a more difficult task and bigger challenge is to assess its accuracy, or alternatively, the uncertainty involved, as the reality can sometimes be substantially different from the forecast. Unfortunately, however, most of the emphasis in predicting social science events has been on forecasting, rather than assessing uncertainty correctly and realistically. The biggest difficulty in such assessments comes from the fact that the greatest uncertainty is from rare "black swan" events whose probability of occurrence cannot be estimated, because, by definition, such events are infrequent, while also appearing at highly varying intervals."

As noted by (Stirling, 2010), under such intractable forms of uncertainty, ambiguity and ignorance, probabilistic approaches to managing risk may be inapplicable. In such circumstances, diversity may provide a more robust response. The risk exposure of a portfolio of multiple technologies may be lower than the risk profiles of the individual components of the portfolio (Bazilian and Roques, 2008). This is because they react differently to different external shocks, potentially making them more robust as a whole.

Portfolio theory is a way of assessing these risks across multiple assets, allowing investors to choose combinations of investments that are mutually beneficial in terms of their risk correlations, leading to better risk-return characteristics than for the individual components of the portfolio (Markowitz, 1952). Work from (Awerbuch and Berger, 2003) suggests these same methods can be adapted for deciding on the optimal mix of electricity generation from a societal point of view. In an energy context for example, a system which is overly reliant on fossil fuels will be open to fuel price risk, so investment in other forms of energy would be a sensible strategy to hedge against this. (Awerbuch and Berger, 2003) states that investing in technologies such as solar PV and wind may have comparatively high energy costs *vis-a-vis* conventional generation, but their inclusion will reduce the overall portfolio cost and risk.

To some extent, this thinking is reflected in the government's Low Carbon plan:

"Rather than picking a single winner, this plan sets out how the UK will develop a portfolio of technologies for each sector. This has two virtues. It will reduce the risk of depending on a single technology. And it will generate competition that will drive innovation and cost reduction. In electricity, the three parts to our portfolio are renewable power, nuclear power, and coal- and gas-fired power stations fitted with carbon capture and storage."((Government, 2011) p5)

Also in 2011, the Government announced its specific commitments to key renewable energy sources of onshore wind, offshore wind and biomass in its Renewable Energy Roadmap in order to meet its renewable energy targets (DECC, 2011b). This was updated in 2012 to include PV due to its notable 50% reduction in cost from summer 2011 to March 2012, with a cumulative capacity increasing five and a half fold during this period (DECC, 2012c).

Whilst avoiding dependence on a single technology is sensible, a portfolio of four or five technologies is still not very large, especially since all of these technologies are relatively new and still have significant risks. This exposes the technological pathway to 2030 to significant risks. The UK's 4th carbon budget sets a restriction on total UK greenhouse gas emissions for the period 2023-2027. Although it does not prescribe particular technology breakdown for achieving the budget, the Committee on Climate Change has produced consistent scenarios for the 2030 timeframe which require electricity sector emissions to be reduced to $50gCO_2$/MWh by 2030. Total new build in the UK under these scenarios is shown in **Error! Reference source not ound.**. CCS, wind and nuclear combined make up over 60% of all new build. Including other renewables in this total takes it to over 70%. In all their scenarios, significant amounts of each technology are required, which raises questions about the extent to which other sources could be rolled out more quickly if there was a major problem with delivery of any one of these main technological pillars.

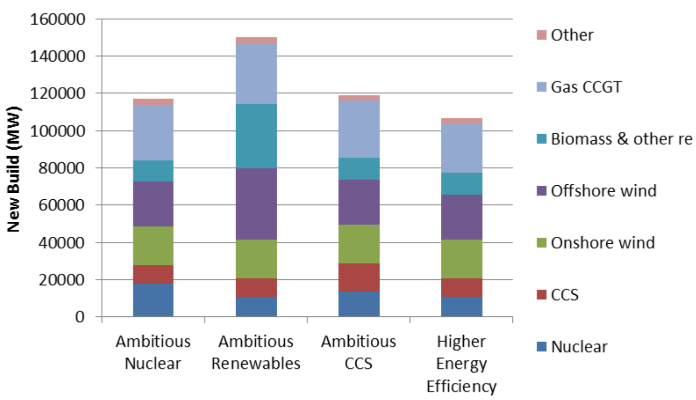

Figure 13 Scenarios for cumulative new power generation build to 2030

Source: (Committee on Climate Change, 2013)

3. Overview of Risks by Technology Type

There are many different technologies that will be important in the transition towards a low-carbon electricity system. We have picked on four here to provide an illustration of the importance of addressing technology uncertainty across a range of different performance characteristics: nuclear, CCS, offshore wind and solar PV. In each case, we briefly review the status of the technology, look at some of the key uncertainties, and the way in which these have been addressed in technology assessments to date.

As well as classifying the source of risk according to the three domains described in the previous section, these risks are also described in terms of the scale of their potential impacts. 'Specific' risks are those that affect the rate and degree of deployment along a particular technology pathway. Systemic risks are those risks that are significant enough to have the potential to substantially re-orient overall energy sector pathways, not just confined to that particular technology. These include potential major disruptions which could be either positive (e.g. emergence of a new lower cost disruptive technology), or negative (roadblocks to development of one of the major sources of generation), requiring major changes to system planning. The distinction between the two types is not watertight, and is more a difference of scale than a difference of type. Systemic risk in the financial sector is becoming a relatively well-developed field of analysis, linked to the concepts of 'too big to fail' and the development of stress-testing and associated regulatory structures. Literature on systemic risks regarding the emerging technologies in the electricity sector on the other hand is rather limited, though some speculative effort is made in this paper to identify potential sources of such risk.

There are many potential sources of systemic risk that are not covered in this report. Disruptions could occur on many fronts on the supply side, for example in fossil fuel supply (e.g. shale gas in Europe creating similar reductions in gas costs that have occurred in the US), or breakthroughs that could lead to much earlier than expected deployment of one of the myriad of different renewable energy options currently being developed and deployed. Perhaps more likely are disruptions on the demand-side, whereby much more efficient, integrated and responsive intelligent appliances could enable integration with distributed sources embedded into the built infrastructure, obviating the need for significant amounts of the current centralised infrastructure.

It is beyond the scope of this report to analyse or quantify these risks in detail. Instead we attempt to illustrate the potential disruptions and vulnerabilities, with a few brief examples, in order to assess the adequacy of the tools and methodologies used to assess technology development and ask whether systems are in place to adequately manage these risks.

These technologies have very different characteristics which greatly affect their risk profiles and their technology development pathways:

- Modularity and build time: Solar PV can be installed in small modules meaning it can benefit from mass installation and economies of scale rapidly, offshore wind is less modular but still entails multiple units per project whereas CCS and nuclear plants are much larger units which take much more time to build (up to 10 years for nuclear and CCS). This alters the rate at which learning can take place between successive rounds of investment

- Ability to innovate between investment cycles: this can be seen as more feasible with higher volume installations such as for solar PV and wind, whereas it may be difficult to innovate for slow build rates like nuclear and CCS and move to next generation technology in a timely manner.

- System integration: nuclear can provide reliable power with capacity factors of up to 90%, albeit with significant limits on its flexibility, and a strong economic and technical bias towards operating as baseload capacity., Solar PV and wind on the other hand are intermittent, raising challenges and costs for balancing the grid. CCS may be reasonably flexible, depending on the engineering constraints of dealing with variable flows of CO_2 in the transport and storage stages.

In addition, there are exogenous market factors such as gas price uncertainty which can have wide impacts across the technologies. As gas price sets the marginal price of electricity, fluctuations can have major implications on profitability of all types of plant. There have also been major price movements relating to commodity prices for technologies having positive effects for solar PV from cheaper sources of silicon (Candelise et al., 2013) but negatively on the cost of offshore wind from cost increases in prices of materials like concrete and steel (Heptonstall et al., 2012).

3.1. Nuclear

The nuclear power generation industry has a turbulent history in the UK. The UK's attempts to build a domestic nuclear industry have been compared unfavourably with French nuclear, giving some commentators an argument why 'picking winners' to some extent can be necessary for successful technology development because of the ability to focus design and learning efforts on fewer technology designs (Taylor, 2007). Whilst the choice of PWR faced considerable uncertainty, in hindsight it was a risk that largely paid off (Watson et al., 2012). The UK nuclear fleet currently consists of three different technologies, mostly a fleet of their own AGR design, most of which are designed differently, while the French fleet are all PWRs of three standard types. This has provided the French with the ability to build a successful domestic and export nuclear electricity and technology industry (World Nuclear Association, 2013), proving the benefits of decisive technology development and policy direction. However (Watson et al., 2012) argue that with such a politically influenced technology decision, it is difficult to tell whether they made the right technology choice.

18% of electricity supplied in the UK in 2011 and 2012 (DECC, 2013f) came from its fleet of nuclear reactors, but these are aging. All but one plant, (8 GW, comprising 87% of the nuclear fleet capacity) are due to shut down by 2023.

Given the lack of recent new build projects outside of Asia, there is relatively little market-based data on which to assess project risks for new nuclear build. Many aspects must therefore be considered at this stage to have a relatively high degree of risk. Many of these risks would be transferred to the private sector in the UK, at least in principle, since the agreed strike price for nuclear power in the contracts for difference should hold even if there are cost overruns, and companies are only paid for what they produce, so reliability risks remain with the companies. In practice however, there is quite a strong degree of interaction between these kinds of risk and the safety requirements that are imposed by nuclear regulators, dealt with under systemic risks. Here we focus on two particular aspects of new nuclear build, waste management, and build time uncertainty. These have the potential to create costs to the system which spill over into the public purse, and potentially have wider impacts on system costs.

3.1.1. Waste management

Whilst there are significant techno-economic issues to be addressed, risk around long-term waste management is largely a programmatic risk, involving the ability of policy-makers to work within the bounds of public acceptability to find suitable sites. If no strategy can be found, then nuclear power is not a viable long-term option. However, given that long-term waste disposal options are unlikely to become operational until after 2050, there is large scope for pushing decisions on this issue into the future. This means that substantial progress can be made in continuing with short-term decisions about new build, without resolving the long-term issue. We therefore consider it here in terms of a specific risk.

The lack of clarity over these waste disposal options means that costs remain largely speculative, so that waste liabilities for future plant are even more uncertain than historical liabilities. There has been a consistent lack of a long term solution for waste disposal in the UK, argued by the government back in 2003 as a reason not to proceed with any build (Greenhalgh and Azapagic, 2009).

However, the publication of the government's policy on radioactive waste in the Managing Radioactive Waste Safely (MRWS) white paper (Defra, 2008), and subsequent arrangements have helped materialise the governments new nuclear programme (Greenhalgh and Azapagic, 2009). Now, the government's position is that any new nuclear plant must cover the costs of future waste and decommissioning out of their current operating costs without any public subsidy. This requires companies to put aside funds each year which can accumulate over the operating lifetime of the plant to pay for these back-end costs.

The problem with costs being so uncertain is that it creates a barrier to investment because of the potential for liabilities to be higher than originally expected. In order to help companies manage this risk, the government therefore has proposed to introduce a fixed payment mechanism, the so-called 'waste transfer price' (DECC, 2011c):

"In order to provide Operators with certainty over the maximum amount they will be expected to pay for waste disposal the Government will, at the outset, set a Cap on the level of the Waste Transfer Price. The Cap will be set at a level where the Government has a very high level of confidence that the actual cost will not exceed the Cap. However the Government accepts that, in setting a Cap, the residual risk that the actual cost might exceed the Cap is being borne by the Government. Therefore the Government will charge an appropriate Risk Fee for this risk transfer. Hence for clarity, the Waste Transfer Price will include two separate risk allowances:

• The Risk Premium is the premium over and above expected costs that will be included in the Waste Transfer Price to reflect the risk being assumed by the Government, when the Waste Transfer Price is set at the end of the Deferral Period, that actual costs might be higher than the Waste Transfer Price.

• The Risk Fee is an additional element included in the Waste Transfer Price to reflect the small residual risk being assumed by the Government, when the Cap is set at the outset, that actual costs might be higher than the Cap."

The government is aiming to charge for this transfer of risk via the risk fee, but it is very hard to determine an appropriate 'market price' for this risk, since it would be almost impossible to obtain an insurance against such open-ended risks.

As an illustration of the potential scale of subsidy, DECC have published an indicative waste disposal liability based on cost estimates for the disposal of intermediate level waste of £14.5k/m^3. Based on this estimate, the illustrative cap would be £48.4k/m^3. However, estimates of the NDA's true marginal cost for waste disposal is put at £67k/m^3 which suggests a significant risk that future liabilities may end up being transferred to the public purse. Estimates of the potential total value (undiscounted) of this subsidy have been estimated at between £400m to £1500m depending on the lifetime of the nuclear plant between 40-60 years (Greenpeace, 2011). The Birmingham Policy Commission (Birmingham, 2012) puts the waste transfer fee price cap into context, estimating that it is worth at most 1.5-2% of the revenue from sales of electricity, and quotes DECC estimates that the likelihood of the cap being exceeded is less than 1%.

The true scale of these risks comes down to an assessment of how realistic these estimates of these liabilities are. In principle, the government could try to sell a portion of the ultimate liability on the secondary market to reality test pricing assumptions against market value, although the liquidity of such markets is likely to be questionable.

3.1.2. Build time uncertainty

Build time is a major techno-economic uncertainty with large implications for the financial viability of new projects. (Harris et al., 2012) found that the 6 year construction phase used to inform UK policy at that time was 2 years under the global average (Figure 14).

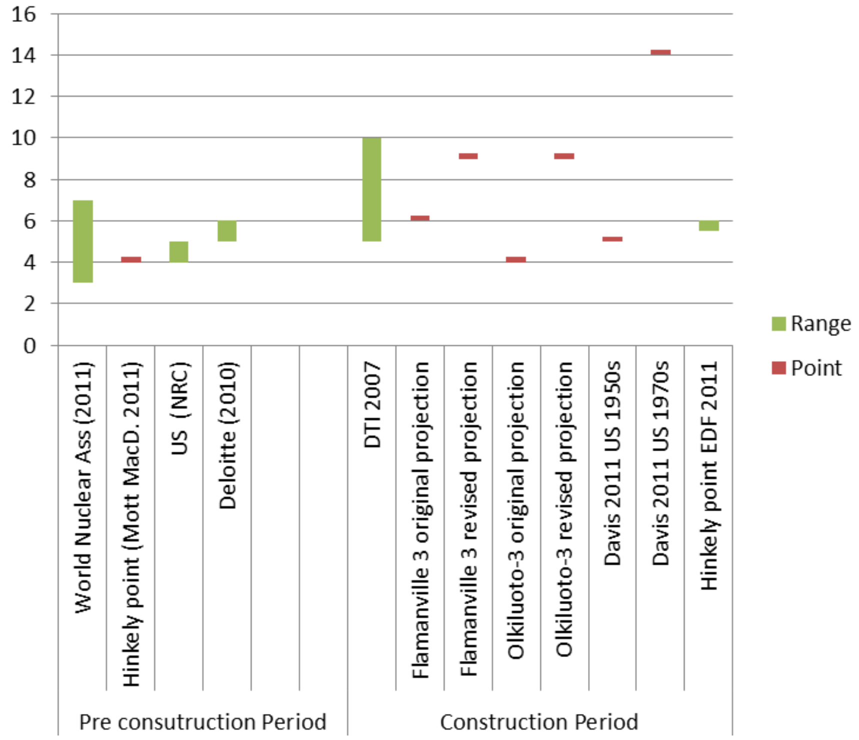

Figure 14 Build time estimates for new nuclear plant

Source: (Harris et al., 2012)

On the backdrop of the only two nuclear plants constructed in the EU, one in Finland and one in France, both overrunning with new projected construction times for Flamanville of 9 years (originally 6) and in the case of Olkiluoto-3 a still unknown build time, increased from originally 4 years, build times in Europe have been increasing (ibid). Globally, build times have reduced over the 2000s compared to earlier decades because of the high proportion of plant built in Asia. The industry is looking to learn from these experiences to improve build times for future rounds of investment in other parts of the world. However, doubts remain about the ability to translate the Asian experience very directly into a European context because of the very different commercial and regulatory environment in which projects operate(Nuclear, 2013). This lack of experience of projects outside of Asia, and the impacts on build time uncertainty is illustrated in Figure 15.

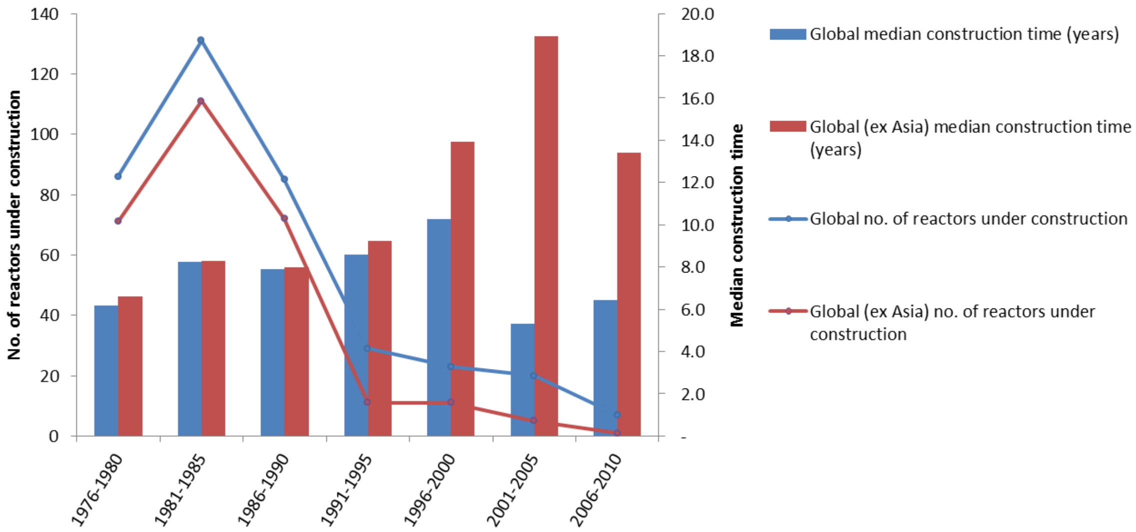

Figure 15 Number of nuclear reactors and global median construction times

Source: (Harris et al., 2012)

To a large extent, build overruns will impact commercially on the company developing the project. However, there may be wider implications for system security of supply because of the very large scale of the projects. In the UK, these plant are expected to come on line around the same time that existing nuclear and coal plant are due to shut down. Given the range of uncertainty in build time suggested by Figure 14, there must remain some doubt about whether this will in fact be achieved. If a delay to the new plant coming on line led to a reduction in reserve margin (i.e. was not replaced with other types of generation), the impact on energy security could be measured by metrics such as the loss of load expectation LOLE or expected energy unserved EEU (Billinton and Allan, 1984, Ofgem, 2013). Current proposals for the capacity market for example would be that a LOLE of 3 hours should be used as a reliability benchmark for assessing capacity needs (DECC, 2013b).

As an illustration of the sensitivity of energy security to a 4% decline in reserve margin, we can look at analysis of the UK system carried out for DECC as part of the electricity market reform consultation (Redpoint, 2010). Figure 16 **Error! Reference source not found.**shows that above around 10% reserve margin, there is very little sensitivity to change, because the probability of unserved load drops to low levels. However, if reserve margins drop below 10%, then a further 4% drop could have a very significant impact. The various scenarios in Figure 16 show the green, red and yellow scenarios dropping by this order of magnitude in reserve margin around year 2024. This leads to an increase of around 20GWh in expected load unserved for a year. Whilst this is a small amount in absolute terms (around 2% of a single day's demand), it nevertheless represents a deterioration. Ofgem's recent capacity assessment report (Ofgem, 2013) indicates that a level of 3GWh EEU would roughly correspond to 3 hours LOLE. This suggests that a 20GWh EEU would represent a significantly worse standard of reliability than is likely to be tolerated over any significant length of time.

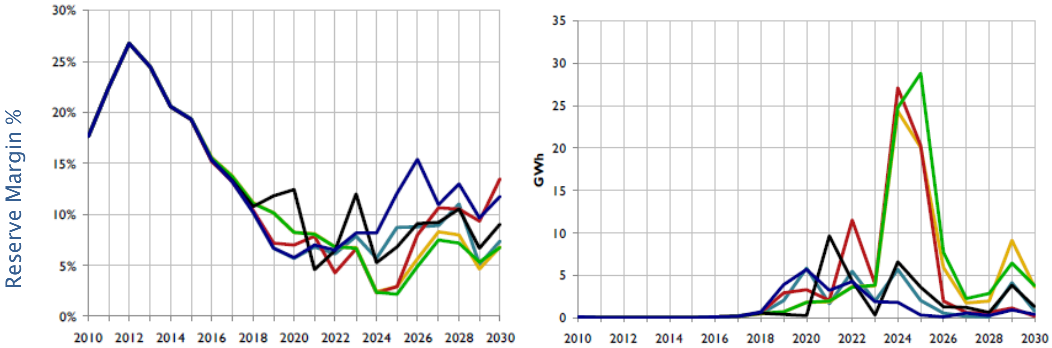

Figure 16 Impact of changes in reserve margin (left) on expected energy unserved (right)

Source: (Redpoint, 2010)

If other plant were to be brought online to cover the missing generation capacity, then the impacts would be financial rather than on security. To illustrate the potential scale of this effect, we can calculate the total system costs of replacing this either by extending the life of existing plant, or by building new gas plant. Hinckley Point C is planned to be 3200MW, which represents about 4% of UK electricity capacity, but a significantly higher proportion of baseload capacity. Based on calculations using the model presented in (Blyth et al., 2014),(see Appendix) the total system costs of supplying the additional electricity during the years in which the delayed nuclear plant was unavailable would be in the region of 8% of total system costs (including annualised capital, operating and carbon costs). If the gap were to be filled with new CCGT plant, the model suggests the total increase in system costs would also be of the same order.

Policy would have to adapt to such a situation, either by creating conditions for the additional plant to be built (e.g. through capacity payments), or perhaps even derogations to planned plant closures of existing thermal or plant extensions of existing nuclear plant.

Viewed over a longer time period however, these cost impacts would be substantially diluted, amounting to less than 1% of total discounted system cost over a 30 year period if the delay were to last up to 5 years. This is because any substitution of plant to make up for a delay would be temporary, and if new plant were built, this would effectively be bringing forward investment which would otherwise have been needed in later years anyway. The total inefficiency to the system as a whole might therefore be rather small, albeit rather disruptive during the actual period of any delay while it lasted.

3.1.3. Nuclear safety

Programmatic risks relating to the issue of nuclear safety pose a significant potential to alter nuclear power's contribution to UK energy mix, and therefore represent a systemic risk. The key issue is the role of safety requirements in the regulation of the nuclear industry, and the way these can have unpredictable impacts on costs. The need to address safety concerns, and changing requirements of protocols in response to safety incidents that arise in various parts of the world have historically been a major contributor to increasing licensing, construction times and cost escalation in the industry (Greenacre, 2012), and remain a key factor outside of the direct control of those building and regulating a particular new build programme. In the 70s in the US, Nuclear Regulatory Commission (NRC) regulation tightening led to large quantity increases of 41% for steel, 27% for concrete, 50% for piping footage and a 36% increase in electrical cabling ((Cohen, 1990) cited by (Greenacre, 2012)). Safety issues can potentially also represent a more direct and immediate roadblock to deployment of nuclear, as has been seen recently in Japan and Germany in response to the Fukushima disaster. Even if safety issues do not cause a road block, they can add significantly to the cost, as has been seen in France where EdF has had to increase capital expenditure by an additional €10bn over the period 2012-2015 to address safety concerns at their existing plant in response to Fukushima (FT, 2012).

Whilst the Fukushima disaster did not influence UK public opinion as significantly as in Germany, (Poortinga et al., 2013), the disaster is far from over (Shukman, 2013). Despite the low probabilities of high-impact incidents such as nuclear accidents, terrorist threats and so on occurring (at least on a plant-by-plant basis), the excessively high level of the maximum liability incurred means that companies are unable to obtain private insurance against such risks (Schultz, 2011). Valuing the risk is therefore very difficult. Estimates depend crucially on assessments of the likelihood of such events occurring. This tends to be a very subjective issue, and difficult to obtain impartial analysis.

The UK government intends to increase the cap on liabilities to €1.2 billion from its present level of £140 million as part of its implementation of an international treaty on nuclear third party liability – the Paris and Brussels Conventions, to which the UK and most of the other EU countries are signatories (DECC, 2012b). This increases substantially the range of low-level incidents that companies will have to cover themselves. It is however clearly well short of covering a full-scale disaster of the order of magnitude of Fukushima, for which the clean-up costs alone have been estimated at €175bn, not including the wider economic damages incurred (EnergyFair, 2012). Significantly higher liabilities in the private sector are not unprecedented (e.g. BP has allocated $41bn to settle claims resulting from the Gulf of Mexico disaster (Fontevecchia, 2013)), but such large sums are probably beyond the ability of relatively smaller utility companies to handle (e.g. market capitalisation of EDF is around €50bn (Bloomberg, 2013)).

The large size of each individual investment for nuclear also makes the technology relatively slow to change. Given that it takes a global average of around 8 years to build a single plant (Harris et al., 2012), and many more years than that to develop and commercialise next generation technologies, there is a risk that nuclear technology becomes stranded because of the relatively slow pace of technological progression compared to some of the systemic changes that are likely to happen around it. Some potential future pathways that involve much greater levels of dispersed generation capacity could alter the operating conditions for nuclear in unpredictable ways (Denholm et al., 2012).

3.1.4. Nuclear technology assessments

As stated by (Harris et al., 2012) the government have been relying on capital cost estimates to direct UK policy on nuclear. One issue with cost assessments is that it may be difficult to communicate the risks and uncertainties, which is required to fully understand a technology's development in order to drive it forward in the best fashion. (Greenacre, 2012) points out that these assessments have mainly been based on engineering, bottom up assessments. A reason behind this in the UK context would be that there are no recent estimates, or historical costs to make reliable statistical analysis such as cost curve analysis from. These engineering based assessments have also been proven inaccurate due to the major impact of exogenous and endogenous price pressures (Greenacre 2012).

A costs assessment, whether it is based on historical data or a more engineering assessment approach, is difficult to encapsulate the major uncertainties involved in nuclear based on build time, plant availability and performance. These assessments also will not incorporate any analysis of wider system effects of nuclear power. For instance, how contingency must be built into the system to deal with an unexpected nuclear reactor failure.

Looking at the history of nuclear development in the UK, it is clear to see that its support or the lack of has been down to how economically feasible it has been, tempered with security of supply and more recently, climate change drivers. What has become clear is that due to the complexity and length of these projects, these assessments have been prone to error (Harris et al., 2012), and therefore policy should go forward with the flexibility that these cost may be inaccurate, and may increase unexpectedly through time. (Nuclear, 2013) also pointed out that cost assessments have not been very transparent, and their accuracy has been hindered with political and industrial motivation to send an inaccurate message of lower costs as a project enabler.

3.2. Carbon Capture and Storage (CCS)

3.2.1. Overview of risks

Currently there is no full scale CCS plant in the power sector demonstrating a complete supply chain (Watson2012). However, there are currently 12 large-scale projects operational in markets around the world with two CCS projects nearing operation, located in North America, marking a particularly important development as they are the first CCS projects to be developed at large scale in the power sector (Global CCS Institute, 2014).

In the UK, the decision to support CCS was taken in 2007, with the opportunity to utilise its oil and gas skill set and potentially benefit from a first mover advantage. In 2010, the coalition government spending review, decided to support this competition with £1 billion for a successful demonstration project, two FEED studies were commissioned for Kingsnorth and Longannet, resulting on one project in the running, Longannet (ibid). This fell through with DECC blaming it on increasing costs and inability to reach a commercial agreement (ibid).

The competition was re-launched in April 2012, and in March 2013, DECC announced two preferred bidders, Peterhead CCGT and White Rose super-efficient coal fired station project (DECC, 2013e). The contracts for two Front End Engineering Design studies have now been signed amounting to £100m in total. These should take 18 months, with Final investment decision due to take place early in 2015 for construction phase (ibid).

Since only relatively small scale demonstration has been made available, costs are still well above the target of £10 – £15 per tonne CO2 (Low Carbon Innovation Coordination Group, 2012a). The cost reduction task force estimate first of a kind (FOAK) projects to cost in the range of £150 to £200 per MWh (cost reduction task force) making it one of the most expensive low carbon options. This group were tasked with reducing the cost of CCS to be competitive with other options, nearing the £100/MWh mark by the early 2020s, which they concluded was possible.

Of all the technologies being relied on to meet the 4th carbon budget, CCS is the least developed. Because of this, the sheer number of uncertainties is so large at this stage that combined they constitute a significant systemic risk that the technology will not be delivered in time to make a significant contribution to abatement in 2030.

(Watson et al., 2012) points to a wide range of uncertainties, though points out that many of these are not unique to CCS. Key techno-economic issues identified include:

- **Safe storage** of CO_2 in geological storage sites. A key uncertainty is whether storage will be secure over very long periods of time. Risks are both local (involving health and safety concerns) and global (regarding risk of CO_2 re-entering the atmosphere). There is uncertainty about probabilities and risks and a lack of experience with geological storage by developers, regulators and researchers.
- **Economic viability.** Uncertainty over the final costs and therefore commercial viability of the technology pose significant barriers to firms and policy-makers wholeheartedly embracing the research and development challenges that lie ahead for the technology.
- **Integration of CCS systems.** CCS exists today as sets of components, integrating these into working CCS systems requires many technical issues to

be resolved, which require large demonstration projects to be undertaken as the next step in developing the technology.

Key programmatic risks include:

- The **variety of technologies** available for CCS (e.g. pre- or post-combustion, oxy-fuel etc.). Because there is not yet clarity over the best route to take, research is divided between multiple tracks. This raises the dilemma over whether to close down options to focus efforts on fewer technology routes, or whether to keep the door open for longer on a wider range of options.
- **Scaling up** and the speed of development required to deploy at a significant scale over the next decade is a major uncertainty given the requirements for knowledge, technology, skills, supply-chain industries and institutions.
- **Policy, politics and regulation**. The political processes of getting acceptance, legitimacy and continued support for CCS are all important for its future. Key to this will be the regulatory framework, establishing verification methods for storage, and assigning and managing liabilities for storage risks. Putting a sufficient price on carbon is likely to be essential in order for the technology to compete with non-abated fossil plant.
- **Public acceptance** is an essential factor influencing the successful development and diffusion of new technologies. Given the range of issues still to be resolved with CCS technologies, there remains significant uncertainty whether CCS will be seen as a legitimate technology for climate change mitigation.

The problem of resolving many technical issues over multiple potential pathways is exacerbated by the size of demonstration plant required as the next major step in developing the technology. Because of the scale of each individual installed CCS plant, this can slow the pace of innovation and development.

3.2.2. CCS technology assessments

The case for policy support for CCS has primarily been built on the basis of bottom up engineering assessments, and these have fed from large consultancies such as (Parsons Brinckerhoff, 2011). Now the plan for the UK is to carry out a detailed FEED, to lay out the contractual terms and get the final investment decision for the first two UK demonstration projects.

A detailed cost analysis carried out by (Rubin, 2012) confirms the use of these assessments and also mentions the application of expert elicitation and deriving result from models. Although the focus of this study is on cost assessments, he highlights the lack of standardisation in assessments, how some assessments completely miss key components of the technology, providing misleading calculations.

In the UK there have been a range of studies focussing on the potential for CCS and how to accelerate it towards commercialisation in the most cost effective manner (Watson et al., 2012, Gough and Shackley, 2005, Crown Estate et al., 2013, APGTF, 2011, Low Carbon Innovation Coordination Group, 2012a). In a policy context in the UK it is clear from these studies that the UK has CCS in its sights to contribute significantly to its energy and economic future, and to do so it has focused strategic research on how best to drive the technology forward and make it cost competitive in the early 2020s with other low carbon options.

These studies are effective at giving a high level perspective of what should or could be done from developing CCS, and the underlying uncertainties and risks but it is difficult to really assess a technology and its development when a full scale plant has still not been built. Nevertheless, attempts have been made to address options for cost reduction even at this early stage (Crown Estate et al., 2013).

It is hoped that the detailed FEED will be completed by early 2015 (DECC, 2013e) and there will be no more delays preventing the development of CCS. However, there are already delays in agreeing the FEED contract delivery. When this FEED is produced it should present the most detailed engineering assessment ever performed for UK CCS, which cannot be compared to other demonstration projects like those in US, Norway and Canada as the UK context is very different ((Low Carbon Innovation Coordination Group, 2012a)). This will only be the beginning as the technology can only be truly assessed after FOAK projects, when a pipeline of projects are developed, operation can be evaluated and optimised and cost and development patterns can be analysed. Only after numerous deployments, will it become clear whether fossil fuel combustion plants can continue to be as flexible and reliable with the addition of CCS technology.

Assessments will be vital throughout the development process to ensure policy is pushing the technology in a pragmatic direction for all UK energy objectives. However, interpretation of such assessments is an important step that is sometimes missing. An interviewed stakeholder (Academic, 2013) pointed to a lack of engineering in-house skill from public institutions which they believed is required to assess a complex new technology such as CCS and direct the development of push and pull policy effectively. They pointed out that for developing effective policy, the types of studies being carried out are vital for understanding the technology and directing policy for the best way forward. These rely on literature reviews, workshops and engineering based studies, but to optimise these studies, an engineer or expert who fully understands the technology, its limitations and potential may be best to oversee such projects. They also pointed to the danger of outsourcing a lot of this type of work to consultancies, who may have certain client bias, where some of the major studies appear to stem from (Academic, 2013).

3.3. Offshore wind

The UK has the largest offshore wind resource in Europe and the first commercial UK offshore wind farm was developed in North Hoyle, North Wales in 2003, consisting of

30 2MW turbines with monopole support structures (BVG Associates, 2012). Since then, the UK has substantially increased capacity, now outnumbering the cumulative total of the rest of Europe (Figure 17).

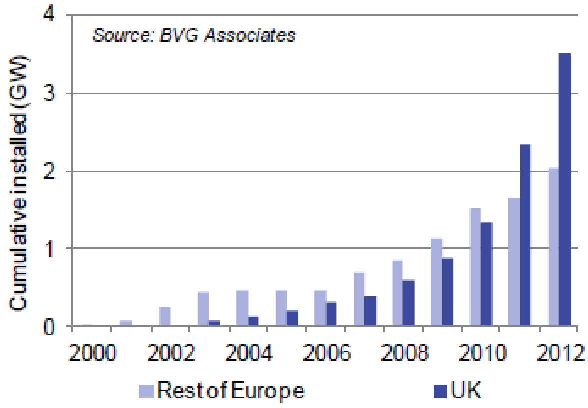

Figure 17 – Cumulative installed offshore wind capacity in UK and Europe 2012 estimate

Source: (BVG Associates, 2012)

3.3.1. Cost risks

The increasing experience of offshore wind installations is contributing to a certain degree of technology maturity, although unexpected cost increases occurred in the early stages of deployment as a result of underestimating the technical difficulties of translating onshore wind technology to a harsher marine environment (Gross et al., 2013). A primary focus for the offshore wind industry now is how to bring down costs to make it more affordable. Uncertainty over whether or not such cost reductions can be achieved represents a key risk factor for offshore wind. Because the application of the technology to the deepwater environment around the UK is relatively new, there are uncertainties around how maintenance costs will develop over the lifetime of the plant, and how long turbines will last for before needing to be replaced.

In 2011 in the UK Renewable Energy Roadmap, the government stated that the costs need to drop significantly, but that the ambitious 18GW would be achievable by the 2020s (DECC, 2011a). The UK Renewable Energy Roadmap also announced the establishment of a cost reduction task force in order identify options to reduce the costs of offshore wind to £100/MWh by 2020, as discussed further below.

The (Offshore Wind Cost Reduction Task Force, 2012) had input from the (Crown Estate, 2012) which commissioned a family of studies and concluded that the target could be achieved. One of the studies focused on technology innovations and had input from 56 different organisations, with 120 individuals contributing directly. A study performed by (BVG Associates, 2012) for the Crown Estate cost reduction project, found that out of a total potential cost reduction of 39% over the period

2011 to 2020, technology innovations could contribute a 25% reduction, with the remainder from supply chain improvements (see Figure 18).

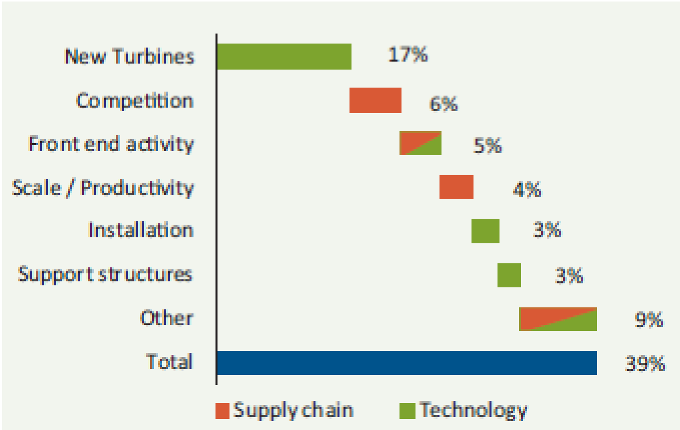

Figure 18 Sources of cost reduction

Source: (BVG Associates 2012)

The largest single source of innovation leading to cost reduction by 2020 is the development of new turbines. Development is undergoing a major transition with 4MW turbines for projects with Final Investment Decision (FID) in 2011, with up to 6MW turbines for FID in 2020 (BVG Associates, 2012). These turbines are being developed specifically for the offshore environment, with larger rotors, deeper waters, further from shore, in rougher conditions. Larger turbines are expected to lead to reduced costs of electricity because of a relatively smaller contribution from fixed operation and maintenance costs. New turbines would also aim to benefit from improved reliability. Bringing new turbines to market takes around 6-10 years, covering different stages of technology maturity, as illustrated in Figure 19.

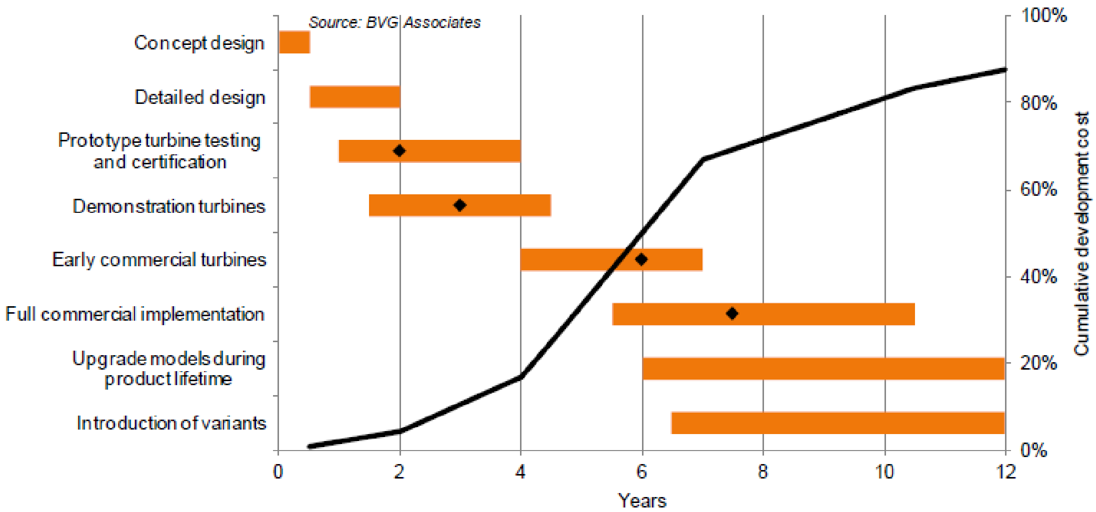

Figure 19 – Summary of typical timescales and spend and on new offshore wind turbine development

Source: (BVG Associates, 2012)

According to the (Low Carbon Innovation Coordination Group, 2012b), further cost reductions beyond 2020 are possible. Innovation has the potential of bringing costs down by 25% by 2020, 60% by 2050, with supply chain and financing improvements could reduce costs to £100/MWh by 2020 and to £60/MWh by 2050.

Supposing for costs in 2030 were along a roughly linear path between these two dates, this would put expectations for costs at around £85/MWh in 2030. If however such improvements failed to materialise, leaving costs at £100/MWh, then cost of delivering the 85 TWh/yr of offshore wind included in the CCC scenarios would be around £1.2bn higher than if the cost reductions were achieved. This is equivalent to about 3.5% of annual electricity generation system costs. This cost uncertainty links to a more generalised political risk for wind power, in that a persistence of high costs will tend to undermine the legitimacy of the technology, and lead to a lower appetite for public funding.

3.3.2. System integration risks

The key systemic risk facing wind power is the question of system integration. High penetration of intermittent renewables needs significant adaptations to the wider electricity system. Early discussions of wind integration tended to focus on the need for dispatchable, typically gas-fired, plant to be used as back-up for when the wind doesn't blow. More recent work has expanded the range of options for system response to include:

- Greater levels of **interconnection** between dispersed geographical regions will allow the system to average out wind speeds, making the supply of electricity from wind less variable (Gross et al., 2006). However, there are a number of uncertainties to resolve regarding the degree of interconnection required, the public acceptability of building overland transmission lines, the cost of building underground transmission, and the practical and institutional arrangements involved when these interconnectors cross national boundaries (Poyry, 2008, Gross et al., 2006).
- Research into **electricity storage** technologies have recently attracted considerable interest as a result of the prospect of greater intermittent generation. Historically, storage technologies have been prohibitively expensive, and the system has run largely on a real time matching of generation and demand (apart from a relatively small amount of pumped storage). With a more peaky supply profile, and options to bring costs down, storage technologies could become cost-effective. Research ranges across many different options, including various types of battery, fly wheels, compressed air storage and cryogenic storage (production of liquid air) (Koohi-Kamali et al., 2013) (Li et al., 2010). Key uncertainties remain about the ability to bring down the costs of these technologies sufficiently to make them viable for deployment at scale, but system savings could increase

notably when the system approaches decarbonisation in the 2050s (Strbac et al., 2012).

- **Demand-side** measures could help system integration by increasing the responsiveness of demand to variations in supply. This would require communication between the system and devices and appliances operated by end-users to turn down demand when supply is low, and turn up when demand is high. There is still considerable uncertainty over the realistic capacity for demand response. This will depend in part on some the outcome of some pathway developments for example electric vehicles and electric heat pumps for heating, both of which could expand the scope for flexibility in demand.

Each of these options is to some extent still uncertain, raising risks at this stage about the ability to cost-effectively integrate very large share of intermittent renewables.

3.3.1. Offshore wind technology assessments

In a detailed report on costs, (Greenacre et al., 2010) finds that the majority of cost forecasts were based on the learning curve methodology, with only some evidence of bottom up engineering assessment. Originally turbines developed for onshore application were utilised so assessment could have been inherited from the onshore application. This suggests a possible lack of offshore wind specific bottom up engineering assessment. One of the major cost reduction opportunities listed by the Crown Estate is greater activity on the front end including more potential for FEED studies with increasing deployment numbers, with early involvement of suppliers (Crown Estate, 2012). This shows how important FEED studies are in for the development of a technology and increasing its commercial viability. As pointed out by (Greenacre et al., 2010) there may have been too much assumed from the onshore wind sector. In hindsight it appears that costs curves, assumed from onshore wind were applied too early for offshore wind. So as far as the cost uncertainty is concerned, this method has not been successful in understanding uncertainties and risks. Offshore wind is in a strange position in that the it is intuitive to use assessments from onshore, yet they are completely different contexts, so these assumptions and using similar technology assessments should be approached with caution.

As experience is built up, learning ensues and the knowledge base grows, there will more opportunities to carry out more detailed bottom up technology assessments to inform costs and technology development. As cumulative capacity build, there will be more data from which statistical methods such as learning curves can prove more informative. From this example it appears that the less experience, the more difficult it is to accurately assess a technology, even though it is at this stage where detailed assessment may be most valued.

As pointed out by an interviewee, it appears that from a strategic level, institutions, namely the Crown Estate who are driving the cost reduction task force, appear to be doing more for developing the technology than top level government policy (Offshore Wind, 2013). In their well thought out approach to building up a knowledge base and industry contacts they are driving 'technology assessment' from all angles. This is informing and benefitting government and stakeholders from all sections of the supply chain. It could be argued that these projects have been driven by government. However, top level government policy, advised from DECC appears to be concerned with subsidy support, and not driving innovation at a strategic level, such as incentivising SME to enter the market who provide real opportunities for innovation and competition to enter the sector (Offshore Wind, 2013). This would potentially bring fresh innovation to the industry and help drive down costs.

An example of how assessment has influenced development in this work has been from the Carbon Trust Offshore Wind accelerator project, which aimed to reduce the cost of wind by 10% for Round 3 projects (de Villiers, 2012). This project ran a competition for optimising foundations in which had 104 entrants with a twisted jacket design winning overall. Fabricators found that this design would be 20% less to manufacture than the current optimised jacket foundations, with further design improvements possible.

3.4. Solar PV

Solar PV was listed in the (DECC, 2012c) Renewable Energy Roadmap Update as one of the eight key renewable technologies. This was down to major cost reductions and unexpected ramp up in deployment rates. Costs have fallen by about 50% between 2010 and 2012 (DECC, 2013g) when all other low carbon options experienced cost increases. Historically, prices have been extremely volatile, correlating somewhat to volatility and supply of silicon feedstock (Candelise et al., 2013). These recent extreme cost reductions can partly be attributed to Chinese manufacturer's supply of cheap modules, which some experts believe have been sold at reduced margins or even below production cost (ibid). This has had significant effects on the industry with a number of firms filing for bankruptcy at the end of 2011, with anti-dumping policies being formed in the US and Europe for future protection (ibid).

At the end of Q3 2013, there was 2.5GW of solar installed, representing 13% of renewable generation capacity and 6% of renewable generation(DECC, 2014).. The (DECC, 2012c) provides a deployment range of 7-20 GW, 20GW being the technical maximum deployable by 2020. Whereas the potential of solar PV to provide a considerable portion of the renewable energy for the UK has not received much attention in the past, against all odds its contribution is beginning to look promising.

Solar PV is now recognised as a mature, proven and reliable technology (DECC, 2013g). It is intermittent in nature and in the UK it has relatively low capacity factors with a central range being provided at 11% by Parsons Brinkerhoff analysis for the (DECC, 2013a) Electricity Generation Costs update, contributing to high energy costs. It is given a 25 year life span in this cost analysis (ibid).

Solar PV can be installed on roof tops of domestic and commercial properties and larger arrays can be deployed on brownfield and greenfield sites, and as it is less visually imposing than other forms of renewable energy it can be seen as a more feasible option for certain sites. In a recent survey, PV came up as the most publicly accepted source of renewable energy with an 85% approval rating (DECC, 2013g). As with other growing renewable technology industries, there are also macro-economic incentives if the UK can build a domestic supply chain and industry.

Like other sources of intermittent generation capacity, increasing deployment capacity creates challenges for balancing the grid. Costs for balancing are a factor which must be considered, i.e. backup generation for times of low supply or frequency balancing services. As high integration of solar PV is a more recent development, stakeholders are continuing to undertake research and development to understand and learn how to anticipate and control rapid changes in supply.

Another major challenge is the distributed nature. Although other forms of renewable energy are also distributed, solar PV can be distributed in smaller modules like those on domestic rooftops. Additional solar which cannot be controlled, such as the smaller scale domestic modules, could raise challenges in times when demand is at its lowest level (DECC, 2013g), particularly if there is an increase in inflexible capacity such as nuclear on the system.

3.4.1. Cost risks

The major uncertainty for solar PV relates to the extent to which costs for the technology could come down. Whilst this is a specific risk factor the technology, it also represents a potential systemic risk. If costs come down dramatically, the technology could prove disruptive across other generation technology pathways, as well as for the evolution of the system as a whole in terms of the balance between centralised and de-centralised generation.

35-55% of total PV cost is down to the actual module with the remaining components known as Balance of System (BOS). Cost reductions can be attributed to design improvements, standardisation, and as efficiency of modules increases, size decreases and therefore all system costs can reduce (Candelise et al., 2013). These developments all relate to learning, and the outcomes will directly affect the overall cost of solar PV. This type of cost reduction is not evident in other renewables technology such as wind whose efficiencies rely on an opposing power to size function.

Cost in turn will directly affect the deployment rates in the UK. Current policy has made unexpected cuts to subsidy provided for PV, small and large scale, in attempt to catch up in line with cost reductions. This illustrates the uncertainties involved in predictions of uptake and cost. Deployment rates will affect the balancing of grid, with a direct correlation between the amount deployed and the balancing challenges it brings. Technologies such as storage and smart distribution network innovations are being developed to manage such an increase in deployment.

In addition to the question of technology costs, the issues raised regarding system integration impacts raised above in the case of offshore wind also apply here, but are perhaps even more significant because of the distributed nature of solar PV generation. Large-scale PV penetration will require significant levels of grid reinforcement and investment to allow 2-way interaction with the grid, and integration, storage and demand-side response are likely to be essential components of a wider system development response to be able to deal cost-effectively with the intermittency of supply.

3.4.2. System integration risks

Solar PV faces many of the same system integration risks as described above for the case of wind, but because of the distributed nature of some PV applications (e.g. rooftop solar which is embedded within local distribution networks), the solutions are rather different, including for example the need for reinforcement of distribution grids to allow two-way flow of electricity between grid and end-users and different applications of storage technologies, and different levels of back-up generation because of the different correlation factors between load and supply for solar as compared to wind. Figure 20 shows recent estimates of the total cost of system integration for solar PV in the UK, showing how these costs can be reduced significantly if storage and demand response (DR) are increased appropriately to allow peak loads to be shifted to times of the day when higher levels of solar are available.

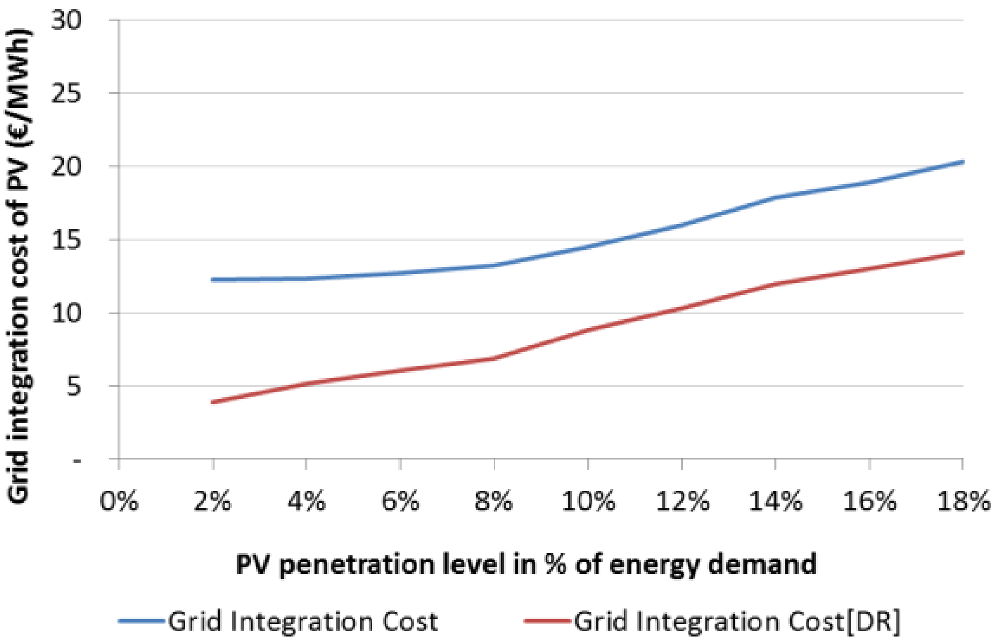

Figure 20 Additional capacity cost and distribution network cost of PV (€/MWh) in the UK

Source: (Pudjianto et al., 2013)

3.4.1. Solar PV technology assessments

Like all other Low Carbon technologies, LCOE have been a major area of assessment and quantifier for solar PV. As this study is looking away from this we will concentrate on other technology uncertainties. National Grid have been working with DECC, the solar industry and distribution network operators in order to find out how to maximise the rollout of solar PV while minimising grid balancing costs (National Grid, 2013). This analysis has shown that up to 10GW of capacity can be deployed without any additional balancing measures. This means beyond this level, solutions are required to support an efficient system. Assessments include analysing how to shift energy demand to times where supply is high from PV i.e. during the day, potential additional storage, domestic and more large scale, potential to export via interconnectors and working with the met office to analyse solar radiation patterns (ibid).

Although there is some interesting work going on in the field of solar PV, it is another technology which from a political perspective, mainly appears to receive attention around its LCOE. As highlighted by (Candelise et al., 2013), prices have been very volatile in the short term, therefore the use of learning curves which relies on long term trends to predict these have and will be problematic. (Candelise et al., 2013) also points out the problems of using a mix of data and expert opinion for forming engineering assessments, particularly when there is such evidence of market factors bearing down on costs, which may not be fully encapsulated in these methods.

The major risk and uncertainty in the current work being by the likes of (National Grid, 2013) on capacity, availability and demand is that the effects are not known until a high level of penetration is achieved. Assumptions can be made from experiences of other countries such as Germany and Italy, but the context will always be different than that of the UKs. The progress of wind has been rather gradual, but if deployment rates continue on the path they are on, grid challenges may appear closer on the horizon than first expected.

There are a number of programmes which are currently shaping the development of solar PV technology and its supporting technologies, such as Ofgem's Low Carbon Network Fund which is being run to trial innovative approached and new technologies for distribution network operators (DECC, 2013d). Ofgem is also reviewing system planning, delivery and interconnection arrangements which could affect PV development through its Integrated Transmission Planning and Regulation (ITPR) project (ibid). Although this type of work is for the wider benefit of the electricity system and developing a low carbon future, they can be considered as methods to assess technologies and options which will directly impact the deployment of solar PV in the UK.

4. Policy implications and Conclusions

This paper identifies sources of technology risk as arising from three main domains: **techno-economic** risks associated with particular technologies, **programmatic** risks associated with managing the development pathways for these technologies, and **system integration** risks arising from combining multiple technologies into a robust electricity system as a whole. Some of these risks will be **specific** to the technologies concerned, whilst others will be sufficiently substantial to alter the development pathway of the overall electricity system, and are therefore **systemic** in nature.

The paper briefly reviews some key examples for those technologies that feature heavily in the CCC scenarios that underpin the 4th carbon budget. It does not attempt to fully survey all types of risk in the power generation sector, but rather aims to identify the scope and potential size of risks by illustrating with a few high profile examples (notably excluded are potentially disruptive demand-side technology developments). Examples discussed in the paper are highlighted in the table below.

Table 1 Technology risks overview

	Techno-Economic Risks	Programmatic Risks	System Integration Risks
Generic	• Economic & financial viability of technology • Uncertainty over future capital & operational costs • Market conditions – (e.g. future electricity demand, fuel prices etc.)	• Policy commitment, regulatory support environment • Public acceptance • Supply-chain adequacy for scale-up • Skills & knowledge requirements • Innovation coordination	• Achieving robust system through diversity of supply • Adapting supply-side options to changing characteristics of demand-side (e.g. greater demand responsiveness)
Nuclear	• Long-term waste management • Build time risk	• Delivering long-term waste management options • Regulatory risks associated with safety requirements	• Adapting to changing base-load profile of supply
CCS	• Safe storage • Integration of CCS component systems into operational whole	• Variety of technology pathways potentially fragments development efforts • Scaling-up technology	• Operating CO_2 transport & storage under variable generation profile
Offshore Wind	• Realising cost reductions (capital & operating costs)	• Uncertainty over domestic supply chain	• Integration issues of intermittency – need for storage, demand-side response, interconnection, back-up etc.
Solar PV	• Potential volatility of international supply chain costs	• Creating stable price support expectations	

The impact of failure of any individual technology to reach maturity is heightened by the fact that there are relatively few technologies involved in the electricity sector transition envisaged to 2030 under the 4th Carbon Budget. Given the relatively immature state of most of the technologies being relied on in the 4th Carbon Budget, the list of systemic risks is in reality longer than this. In particular, the potential for 'programmatic' risks (see Section 2.2) of failure to bring one or more of these technologies to maturity over necessary timescales seems high given the scale of deployment required to bring performance risks down to manageable proportions, and the complex interactions and system integration issues to be addressed for each of these technologies. These programmatic risks are poorly characterised, and little information is available from the literature review undertaken for this study. Moreover, the list of risks is further under-represented because of 'unknown unknowns', which by definition are poorly understood, and underrepresented in the literature.

Many of the most important risks relate directly to capital or operating costs, and these are amongst the more well-characterised risks in the literature. Even for technology risks that are not directly cost-related, impacts such as availability and reliability can often still be represented in terms of the economic or cost impacts. However, in some instances, other classes of impact are important to consider, in particular environmental or security impacts. Environmental risks are important over long timescales in cases where failure of a technology to reach maturity and fulfil its expected role could undermine the ability to achieve a low carbon trajectory. Security risks may play out over a shorter timescale, for example if plant availability is lower than expected, or if plant takes longer to build than expected, leading to a shortfall in generation capacity.

This paper also reviews the various technology assessment methodologies used to assess technical risk. For firms embarking on an investment decision, such analysis will be a standard part of their due diligence. In addition to financial appraisal using discounted cash flow simulations, and more complex energy system modelling, firms will undertake detailed engineering-based studies at the pre-feasibility stage, pre-construction and design stage, and then further analysis to support letting of contracts for construction, operation and maintenance phases.

Policy assessments will also span financial appraisal and energy system modelling, though with a greater emphasis on costs of generation, and less emphasis on revenue risk than firms would undertake. Policy-makers also tend to need to make judgements about prospects for long-term costs in order to decide whether or not to support early stage technology development. Methods used for this include learning curves, and separate assessments for the R&D, demonstration and pre-commercialisation stages of technology development. Technology readiness assessments are used to judge the stage of development of different technologies, and the type of policy support they are likely to need.

In practice, technology innovation rarely follows a simple linear pathway. Instead, it involves complex interactions and iterations between multiple organisations in an innovation 'ecosystem'. The UK funding model is similarly decentralised, with funding powers distributed across many different public and private bodies. This presents strengths and weaknesses in tackling technical risk.

On the positive side, decentralised funding provides a variety of institutional approaches each with a more tightly focussed remit, which may be more able to adapt support to the needs of the web of energy innovation activities. On the negative side, it makes oversight of the innovation process more complex. Despite efforts at coordination between the various innovation support bodies, decentralisation makes it harder to identify key areas of programmatic risk. This is exacerbated by the difficulties that all institutions face of identifying risk and failure as a learning opportunity. Most institutions have a budget for supporting particular aspects of technology development, and success of these institutions is measured according to the specific outcomes that arise from this expenditure. Competition between institutions means that they therefore tend to focus on opportunities and success, rather than the potential for failure and need for contingency planning.

The difficulty of openly identifying and discussing failure is compounded by the political need to show that all options are open. Building up the necessary supply-chains and attracting investment to each of the main energy options requires everyone involved to believe that the technology development pathways are possible and credible, and that real and substantial project pipelines will be developed in order to keep firms and investors engaged. A related problem is that political debate of technology pathways tends to be led by advocates who favour particular technologies, and are often opposed to other technologies, creating distortions in their analysis (Academic, 2013; Nuclear, 2013; Offshore Wind, 2013; Technology; 2013).

Technology risk and failure may also be underrepresented in energy system models. Many models use variations of optimisation routines which are built on an assumption of perfect foresight. Whilst the perfect foresight assumption is altered or diluted in some models, such structures potential lack the ability to explore adequately the kinds of systemic risk (or black swan events) that could cause sudden disruptive events or technology paradigm shifts. Models tend to be goal oriented, so they get to the answer specified by the modeller, with system cost as the output. They generally do not deal with failure. Although sensitivity and pathway analyses go some way towards this, they still tend to assume that everyone involved in a particular pathway or realisation of the world knows where they are going and no major mistakes or disruptions occur. The level of contingency planning is probably therefore currently underestimated, and it may be necessary to build more slack into the system. To allow for failure or underperformance in any one or more of the currently planned technology pathways, it would be necessary for the others to expand to compensate.

This paper has just scratched the surface of this issue, and it may be premature to make policy recommendations on this basis. However, it seems that technology risks may be deeper than most organisations involved in technology development would like to admit. Oversight of technical risk may therefore need to be strengthened, and credible contingency plans developed for meeting carbon reduction objectives in the event of one or more such systemic risks being realised. This requires appropriate ways of measuring and targeting progress, and analytical tools that can support adaptive decision-making and a more open discussion of the potential sources and responses to failure.

Appendix – Description of model used to calculate impacts

The discussion of impacts of technology uncertainty used the model developed in (Blyth et al., 2014) to monetise some of the impacts. This appendix describes the formulation of this long-term least-cost expansion planning model for the electricity sector.

In the model, there is a set of possible generation technologies i ∈ (CCGT, coal, nuclear, biomass, OCGT, onshore wind, offshore wind, CCS gas, CCS coal, CCS biomass). Key operating characteristics for these technologies include capital cost Γ_i , fixed operating and maintenance costs FOM_i , non-energy variable operating costs VOM_i , and heat rate HR_i. Capital costs are calculated as annuitized values, taking into account the overnight costs, the financial lifetime of the plant and a cost of capital discount rate ρ_{cap}. These parameters may vary over time. The model operates over a 30 year time horizon, with 7 time periods y ∈ (0,5,10,15,20,25,30). Any plant built in year y is deemed to have the characteristics associated with that vintage v. For example capital costs $\Gamma_{i,v}$ for later vintages v will be lower than for earlier vintages if that technology is expected to benefit from (exogenous) learning effects. Fuel inputs are defined for four main fuel types f ∈ (gas, coal, nuclear, biomass). Each fuel type is assigned a price in each modelling period, which is an exogenously defined variable $PF_{f,y}$. Each fuel type is assumed to have a carbon emission factor EF_f which defines the carbon emissions per unit of fuel used. Demand for electricity is modelled as an inverse load duration curve, which specifies the number of hours for which demand exceeds a certain level. The curve is divided into 11 tranches, t ∈ (1,…11); D_t is the total demand in each tranche, h_t is the number of hours at which demand is at that level. For each vintage of technology in each year carbon emissions are calculated as: $CO2_{i,v,y} = EF_f \; HR_{i,v,y} \sum_t h_t \, C_{i,v,y,t}$.

The key decision variables for the optimisation are the capacities of each technology i of each vintage v deployed in each year y and in each demand tranche t, denoted as $C_{i,v,,y,t}$. The total generation capacity in each tranche has to at least meet demand, $\sum_t C_{i,v,y,t} \geq D_t$. The model can only add capacity of vintage v = y, since vintages v> y are not yet available. For earlier vintages v<y, the model is obliged to maintain availability of these for the duration of the financial lifetime of the plant so that the full capital cost of the plant is recovered. However, the total number of hours over which the plants are dispatched is not fixed, so the deployment across the different demand tranches can vary by year. Existing plant are assumed to already be in the system, and the optimiser selects their appropriate deployment tranches. The capital costs of these plants are assumed to be fully sunk, so their costs only include operating and maintenance, energy and carbon costs. Deployment of plant is constrained to particular maximum and minimum level, with the minimum level used to ensure that the optimiser does not dramatically retire existing plant in an unrealistic manner and the maximum level forces the retirement of existing plant

(e.g. in line either with published retirement plans environmental performance directives).

Technologies are subject to different constraints on the maximum amount of capacity that can be deployed. For example, thermal plant such as nuclear, coal and gas do not have any overall resource constraint imposed on them, but they are subject to a maximum build rate $B_{i,v}$, so that the amount of any new vintage that can be added in a given year is constrained $C_{i,v,y} < B_{i,v}$ in order to represent supply-chain constraints on the rate of new build.

Wind on the other hand is subject to a total available resource R_i which constrains the total installed capacity: $\sum_v C_{wind,v} \leq R_i$, and the same holds for biomass. Wind power is non-dispatchable, so the optimisation cannot choose the level of deployment in each tranche separately. Instead, deployment in the baseload (tranche 1) is first chosen by the optimiser, and then relationship between deployment levels in the baseload tranche and the peak tranche reflects the relationship between the average capacity factor for wind over the year and the capacity credit for wind (defined as the amount of thermal plant that can be displaced whilst retaining the same level of system reliability at the peak). The contributions of wind to the intermediate tranches of the load curve are scaled between these two end points. Thus, wind is assumed to contribute much less during peak hours than during baseload hours. For example, if the load factor during the baseload was 33%, the load factor during peak would be 5%. This is also the capacity credit for wind, since it represents the level of dispatchable capacity on the system that could be displaced by the introduction of new wind capacity to serve load during peak hours.

Carbon capture and storage is set up in the model as a retrofit technology that can be applied to gas, coal or biomass base plants. Capital costs are the marginal costs of the additional plant, marginal emissions are assumed to be negative (so that the combined base plant + CCS have a reduced total emission compared to the base plant on its own).

To model the EU-ETS cap-and-trade scheme, the total carbon emissions from the system as a whole, $CO2_y$ in year y = $\sum_{i,v} CO2_{i,v,y}$, is constrained to meet a cap, CAP_y, the level of which is assumed to be an exogenous variable. The price of carbon, PC_y ,in this case is an output from the model, and is calculated as the dual cost of the carbon constraint. Banking of allowances between periods is enabled by allowing the model to choose emissions $CO2_y < CAP_y$, so that the difference is carried forward. This raises the cap, CAP_{y+1} , in the following year. The optimisation will choose to do this if abatement costs are higher in future years. Borrowing of allowances is not allowed. At the EU level, it is important to recognise that the electricity system does not constitute the entire emissions trading scheme. In this model, an estimate of the contribution of the other sectors within the EU-ETS to meeting the target is based on a simple cost curve approach. Baseline emissions for the non-electricity sector are taken from official EU-level forecasts made using the PRIMES model[2]. The contribution of other sectors to the emissions reduction effort is modelled by allowing the model to offset emissions according to a pre-defined marginal abatement cost curve. These emission reductions are optimised, reducing the degree of emissions reductions required from the electricity sector without affecting the balance of the electricity supply and demand.

The total long-run marginal cost of electricity generated by a particular technology i is

$$\mathrm{LRMC}_{i,v,y} = \sum_{t} C_{i,v,y,t}\ \left(\Gamma_{i,v} + FOM_{i,v} + \ h_t SRMC_{i,v,y}\right)$$

where the short-run marginal cost, SRMC, in the case of the EU-ETS, is the energy and other variable costs given by:

$$\mathrm{SRMC}_{i,v,y} = \ \mathrm{VOM}_{i,v,y} + \ \mathrm{HR}_{i,v,y} PF_{f,y}$$

Carbon prices calculated from the EU-level model are passed through to the GB market model. The structure of the electricity investment optimisation is essentially identical, except that the carbon price now feeds directly into the calculation of the plant operating costs. Thus, for the UK investment model

$$\mathrm{SRMC}_{i,v,y} = \ \mathrm{VOM}_{i,v,y} + \ \mathrm{HR}_{i,v,y} PF_{f,y} + \ \mathrm{HR}_{i,v,y} EF_f PC_y$$

The total system cost for a given year is simply the sum of all LRMC for all plant in the system, plus the cost of offsets. Total system costs over the whole modelling period sum the costs in each year, applying a discount rate ρ_{sys} to costs for future years. The model is solved as an optimisation whose objective is to minimise total system costs over the entire 30 year modelling horizon

The model was used to assess the economic impacts of a potential delay to new nuclear build. Assuming the lost capacity needed to be filled by additional alternative capacity, two options were explored;

- Replacement with existing plant facilitated by a delay in the retirement schedule. Given the model assumptions, this leads to the delayed nuclear baseload being replaced by additional generation from existing coal plant. This leads to substantial increases in system costs during the period of the delay because the capital costs of the nuclear plant are still being incurred, whilst also

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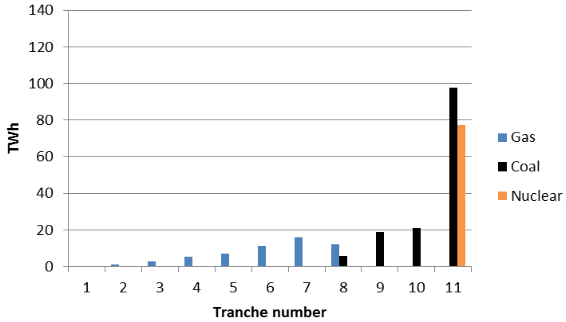
2 http://ec.europa.eu/clima/policies/package/docs/trends_to_2030_update_2009_en.pdf

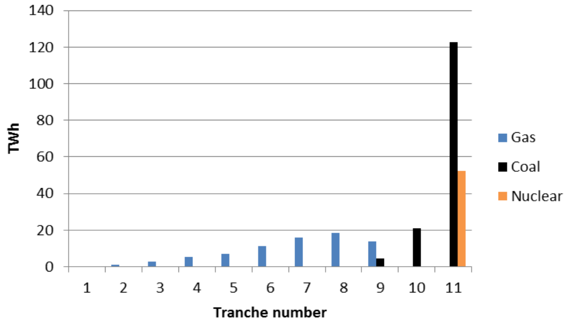
incurring the operating costs of the coal plant replacement. Long-run cost implications are much smaller, once nuclear returns to operation, the system returns to its planned level of capacity. The increased use of coal in the baseload leads to a change in the dispatch profile of both coal and gas in the shoulder of the load-duration curve.

- Replacement with new CCGT plant. In this scenario, new plant is built to cover the delayed nuclear plant. This leads to higher costs for the duration of the nuclear delay due to duplication of build capacity. However, the cost effects are relatively short-lived, since the CCGT plant built during the nuclear delay effectively represent an acceleration of build which would have occurred at a later date anyway. Long-term cost impacts are significantly lower than the short-run impacts.

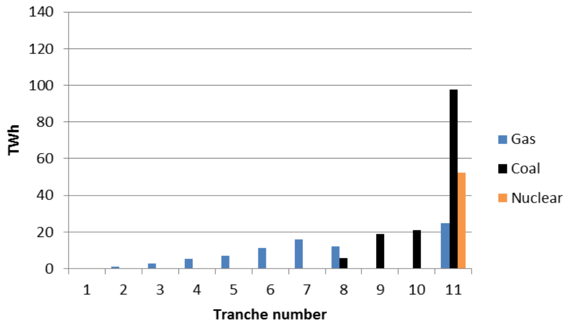
The generation mix for these two scenarios is shown in the figure below. The generation in the model is divided into 11 tranches, with tranche 1 representing peaking capacity, and tranche 11 representing baseload, with the rest of the load-duration curve spread evenly in capacity terms between the two.



a) Baseline scenario



b) Delayed nuclear replaced by a re-deployment of existing plant



c) Delayed nuclear replaced by purpose-built baseload CCGT plant

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