

# UKERC Energy Strategy Under Uncertainties

## Financing the Power Sector: Is the Money Available?

### 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.

## Executive Summary

The electricity sector faces a level of investment in the coming two decades far higher than the past two decades. It needs to renew its ageing generation fleet, and shift towards capital-intensive low-carbon forms of generation. Over the past few years, various organisations and commentators have suggested that the sector may be unable to deliver, questioning whether there will be a sufficient flow of money into the sector to finance these investments. This report examines the evidence for these claims, looking at three key issues:

- The size of the gap between required and current levels of investment,
- The ability of energy companies to scale up their capital expenditures,
- The ability of financial institutions to provide the necessary funds, and the mechanisms by which they might do so.

### *Is there an investment ‘gap’?*

Estimates of the size of the investment challenge range from the often quoted DECC / OFGEM figure of £110bn by 2020 (including transmission & generation) to much higher figures ranging from £200bn to over £300bn by 2030 from organisations such as National Grid, the Committee on Climate Change and London School of Economics. Across all the scenarios assessed in this study, the average amount of new capacity needing to be added to the system was 3.4GW each year up to 2020. This increases to 5.7GW up to 2030, reflecting the greater levels of plant retirement post-2020. Within this average, individual scenarios differ considerably. For example, OFGEM estimates range from a capital expenditure (CAPEX) of £3.5bn to over £7bn per year for the more environmentally ambitious scenarios up to 2020.

These figures are considerably higher than the build rate during the 2000s which averaged 1.2 GW capacity added per year, with CAPEX of £1.1bn per year. This discrepancy led to concerns about the ability of the sector to deliver the required investment. However, in the 2000s finance for power generation was particularly sparse, with only about half the level of investment compared to the previous decade.

More recently since 2009, investment has been scaling up significantly. Over the period 2009–2012, average capacity additions were 4 GW per year<sup>1</sup>, with average annual CAPEX of £4.8bn. These are much closer to the estimates of investment needs. In 2012 in particular, wind investment reached 1.9 GW<sup>2</sup>, which compares favourably with an average requirement of 2GW per annum across all future scenarios for the studies reviewed in this report. However, to reach the most environmentally ambitious scenarios, wind investment would need to scale up to around 3GW per annum (e.g. National Grid ‘gone green’ scenario), requiring an extra £2bn per annum.

These recent figures therefore suggest that immediate concerns about a large ‘gap’ in investment may be overstated, partly because investment rates have recently increased substantially, and partly because electricity demand has decreased since the recession. The most recent estimates by National Grid of capacity requirements are considerably lower than previous estimates. Total investment rates currently being delivered by the market seem broadly adequate for all but the more ambitious scenarios up to 2020. However, this conclusion comes with a major caveat that current rates of investment can be sustained through the period to 2020. There are signs that the reduced demand and other market conditions is causing the major utilities to scale back planned capital expenditure by as much as 30% by 2015 relative to 2012 levels. The ability to reverse this and stimulate greater capital flows is largely dependent on the outcomes of market reform, a topic outside the scope of this report.

Moreover, significantly more will be required post–2020. The more ambitious scenarios would require scaling up by around £2.5 – 7.5bn compared to the average CAPEX over the past four years, and by £0 – 5bn compared to 2012 CAPEX levels.

### ***Can Energy Companies Scale up Investment?***

Traditional utility companies have recently faced difficult market conditions, with significant demand destruction across Europe as a result of the

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<sup>1</sup> 2.3 GW of gas, 1.3 GW of wind, and 0.5 GW of solar

<sup>2</sup> 0.7 GW onshore, 1.2 GW offshore

recession, leading to excess capacity and low margins. In the 2000s, utilities took on much higher debt levels to fund mergers and acquisitions across Europe. Energy companies are now attempting to de-leverage their balance sheets in order to maintain reasonable credit ratings and access to the low-cost bonds and shares on which their business model depends. This constrains their ability to raise debt to cover increased investment. Raising additional equity tends to be costly, and is viewed as dilutive by existing shareholders unless there is clearly a very strong economic growth story. These conditions have led to a wide degree of speculation about the future of these companies and whether they are up to the investment task ahead.

Their future role in the UK depends largely on market conditions. If energy companies do not find it attractive to invest in the UK due to weak market fundamentals or other sources of risk, then it is unlikely that other companies will find it attractive to invest either. Utilities are still dominating overall investment rates in the UK, although their role in different market segments is evolving.

In the offshore wind sector, consortia with multiple investors are usually put together to finance the much larger scale of investment required. Utilities usually own the majority of the equity, with consortia of banks holding the debt. The involvement of utilities with an established presence in European electricity markets provides an important anchor giving financial investors some reassurance that the utilities will not walk away from projects that run into difficulties. The ratings agencies take the same view that utilities will not abandon failing projects of strategic importance to their business. This means that utilities cannot scale up investment by simply shifting these projects off-balance sheet in order to avoid affecting their credit ratings. Scaling up through projects therefore implies greater diversification of partners, and taking a smaller share. In the onshore wind sector, utilities have played a significant role in creating a secondary market for projects by buying the assets which frees up pre-construction funds to be recycled into new projects.

Nuclear investments are huge, with unique risk profiles. Equity investors seem most likely to be utilities or equipment manufacturers, or more likely a combination of both, but with significant guarantees (implicit or explicit) from

national governments. The fossil fuel segment of the market could become more diversified depending on the degree to which capacity markets look attractive to independent power producers. Utilities seem likely to play a continued role here too, especially for the large investments required for carbon capture and storage if that technology takes off post-2020.

### *Can the Financial Sector Provide Enough Money?*

Finance sector participants tend to say there is not a lack of money, just a lack of good projects. However, the textbook assumption that in a perfect market, finance will be available as long as the reward is high enough to compensate the risk hits limits when it comes to demands for very large volumes of finance. The vast majority of money in financial markets is structurally required to be in low risk investments. 90% of funds held by the largest institutional investors are in bonds and shares of investment-grade companies. Whilst higher risk capital is no doubt available, the volumes by comparison are probably too small to address the scale of infrastructure investment required.

Project finance has been a dominant form of finance in the onshore wind sector, usually involving smaller project developers using high levels of debt to achieve low cost of capital. Up until the financial crisis, banks were lending at ever narrower spreads, seeing onshore wind as low risk, backed by secure subsidy regimes and long-term power purchase agreements. Since 2008, risk margins on loans have increased, but with a much lower base rate, the cost of capital for onshore wind projects has remained relatively unchanged. Volumes dropped as banks retrenched immediately after the crisis as they needed to reduce their own leverage. But volumes appear to be recovering, and unlikely to be a constraint. Recent business-wide surveys of CFO attitudes show emerging confidence in the availability of bank debt.

Some commentators have suggested that institutional investors could play an increasing role by taking a direct stake in investments rather than going through utilities. It has been argued that these investors, which includes pension funds and insurance companies with liabilities extending in some cases over several decades, would naturally like to hold long-lived assets to match these liabilities. Indeed, infrastructure projects such as roads and

public buildings have attracted increasing levels of financing from such institutional investors.

Some involvement has been seen in some of the offshore wind projects, but this is currently at a low level. Whilst the total assets managed by these investors is vast (~\$70 trillion), it is highly segmented, and the great majority of the money (90%) is dedicated to liquid low-risk assets, such as bonds and shares. Around \$2.5tn is available for long-term fixed illiquid assets, but only a small share of this goes to energy projects. Institutional investment in renewables across Europe was between €2 – 4bn per annum in 2011/2012, with perhaps 10% of this going to the UK. However, there does seem to be a growing appetite amongst institutional investors to put more money into infrastructure funds, and some estimates suggest that the amount of money available could increase by a factor of 2 or 3 (up to \$6.5tn). If this were to feed through proportionally, the UK energy sector could therefore see an increase from this source up to perhaps \$1bn per annum. However, this depends on achieving a suitable risk profile for the investments. Institutional investors have tended to prefer assets with guaranteed returns. In the energy sector, these have mostly been in regulated assets such as distribution networks for gas and electricity. It is yet to be seen whether the generation assets in a more de-regulated market could meet these requirements.

A final factor which may limit the role of institutional investors is their tendency to prefer low-profile investments with a low degree of adverse public exposure. They may prefer to remain junior partners in energy projects in order to avoid the risk that the current political and public focus on the high costs of new energy sources could turn into increased scrutiny of who is profiting from subsidies.

### ***Conclusions and Way Forward***

Very large volumes of finance are only available for relatively low-risk investments. The traditional utility model is designed to exploit this by providing an 'investment grade' vehicle that can be financed through low cost bonds and shares which are traded on a liquid market, thereby also meeting the needs of large institutional investors.

Questions have been raised about whether this model is still working, but recent evidence suggests that there is not a large gap in investment up to 2020 *if* investment rates of recent years can be maintained. This is a major caveat, considering that current CAPEX plans across Europe for the ‘big 6’ UK utilities are due to be cut by as much as 30% over the two years to 2015.

Moreover, investment post-2020 is likely to need to step up more significantly. If the utility model is to survive, they need to be able to make a profit in the market. This suggests therefore, that the primary focus of policy should be on getting the investment conditions right in the electricity sector, and keeping risks down. If the market remains unattractive to utilities, it is unlikely that any other major investors would find it attractive.

An alternative approach would be to completely re-regulate electricity generation on a fixed rate of return model which removes most of the risk for the investor. The regulated asset base model has proved attractive to institutional investors in the energy networks sector, and is likely to make finance readily available to the sector. The downside of this approach in terms of reducing competitive pressures and innovation should not however be underestimated.

The feed-in tariffs being introduced in the UK for low-carbon generation are a half-way house, providing fixed income, though not fixed returns because of uncertainty over construction and operating costs. It is yet to be seen whether these instruments will attract different business models that could structure new types of finance around these contracts.

There are ways to encourage this diversity of financing sources into the sector. In the short-term, there is a role for public financial institutions such as the Green Investment Bank and the European Investment Bank to take direct stakes in projects to leverage other investors in and to stimulate secondary markets for projects post-construction which can help accelerate the recycling of pre-construction capital into new projects. Project bonds may start to play a more significant role, but evidence is mixed about whether they will really take off to any significant extent.

In the longer term, ownership structures in the electricity sector are set to evolve. For example, whilst utilities own the majority of equity in offshore

wind projects, they generally involve quite wide consortia. Direct stakes in energy projects by institutional investors are currently low, but could grow to a sizable (though unlikely to be dominant) level. Equipment manufacturers often take a stake in offshore wind, and could do so also for nuclear. The capacity mechanism could also attract more diverse ownership, and could start to engage the demand side more actively. Combined with the growth of embedded generation, this may alter the characteristics of the market substantially over the next two decades, bringing with it a diversification of financing models for the sector.

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# 1. Introduction

The electricity sector faces a level of investment in the coming two decades that is far higher than that seen in the past two decades (Ofgem, 2010b). This is driven by two main factors. The first is the level of planned retirement of existing plant, creating a need for new capacity. This retirement profile is partly due to lower than average level of new investment during the course of the 2000s (Figure 2), which led to an ageing of the generation fleet. It has been significantly accelerated by the retirement of coal plant over the next few years as a result of the EU Large Combustion Plant Directive and Industrial Emissions Directive to control local pollutants (Environment Agency, 2013). Most of the UK's fleet of nuclear plant is also reaching the end of its life, and is due to close over the next decade.

The second factor driving up investment requirements is the transition to low-carbon forms of generation. This is being driven by the need to meet UK and EU targets for renewables (DECC, 2011b) and carbon constraints (CCC, 2010). Both nuclear and renewable energy are significantly more capital intensive than fossil fuel plant. This means that a transition from fossil-based generation to nuclear and renewable-based generation will tend to lead to an increased requirement for upfront capital. Capital intensive solutions are not inherently more expensive. Expenditure is focussed up-front in the plant construction, and offset by low running costs. Capital intensity in itself is only an issue if capital itself is constrained.

This report does not deal with the most important question driving these investments; namely, is there a business case for investing? The answer to this question depends on the fundamentals of the electricity market (i.e. its design, primary fuel prices etc.), and on the details of subsidy regimes in place to support the investments. These are all issues currently being finalised as part of the UK Electricity Market Reform (EMR) process, and are extensively discussed elsewhere. Instead, this report aims to focus on the narrower question of whether or not there may be constraints on the capital flows into the sector that could jeopardise the investments.

In practice it is difficult to separate these issues. Finance practitioners interviewed for this project noted that there is no shortage of money, just a

shortage of good projects. Since in practice the capital intensive options of nuclear and renewables also happen to be more expensive on a per kWh basis, the supply of ‘good’ projects is fundamentally tied up with the outcomes of electricity market reform (EMR) to set sufficient payments to generators through the feed-in tariffs and capacity markets.

Nevertheless, uncertainty remains over whether finance is available in sufficiently large volumes on sufficiently attractive terms to make the scale of investment required feasible. Given the economic upheavals of the past 5 years, and the impacts on the financial health both of the major energy players and the finance sector itself, the availability of finance is by no means a foregone conclusion. Section 1.1 provides an overview of the scale of the investment challenge, and in Section 1.2, this is compared with current recent trends to assess the size of the gap. Section 2 goes on to review the major routes by which investment is carried out in the energy sector. Section 3 then reviews the different sources of finance that are used to fund these investments. Section 4 identifies ways in which investment can be boosted before drawing conclusions in Section 5.

The analysis in this report is based on literature review combined with interviews with a range of different practitioners in the UK finance and electricity sectors. Many of the observations and conclusions drawn in this report therefore reflect a synthesis of contemporary views of various participants who are listed in the Appendix A.

## **1.1. Scale of the Investment Challenge**

Over the past several years, and particularly since 2009 when Ofgem carried out a major review, various organisations have published figures for the amount of capital required to finance future investments in the UK power sector (Table 1 and Appendix B). The studies show a wide range of capital requirements for the various scenarios, as shown in Table 1. Typically, most studies present their figures as cumulative total investment requirements up to the year in question. This makes cross-comparison between studies difficult when they are assessing different time horizons. For this reason, we convert the cumulative totals to an annual rate of capital expenditure (CAPEX), which has the benefit of aiding comparison with current industry investment trends in the following section.

Organisation	Study Year	Scenario	Investment (£bn)					
			2020		2025		2030	
			Annual	Total	Annual	Total	Annual	Total
OFGEM	2009	Green Transition	<b>7.8</b>	<b>78</b>	<b>8.1</b>	<b>117</b>		
		Green Stimulus	<b>7.3</b>	<b>73</b>	<b>7.7</b>	<b>111</b>		
		Dash for Energy	<b>4.3</b>	<b>43</b>	<b>5.1</b>	<b>74</b>		
		Slow Growth	<b>3.3</b>	<b>33</b>	<b>4.1</b>	<b>60</b>		
E&Y	2009	Central			<b>11.4</b>	<b>165</b>		
DECC	2012	Central	9.9	77	7.7	98	8.0	140
		Low Prices	9.9	77	8.0	102	8.1	142
		High Prices	10.0	78	7.9	100	8.0	141
		Low Growth	9.9	77	7.6	97	7.8	137
		High Growth	9.9	77	8.4	106	8.4	148
National Grid	2013	Gone Green	<b>7.0</b>	<b>49</b>	9.9	119	10.7	182
		Slow Progression	<b>3.4</b>	<b>24</b>	4.8	57	5.7	97
CCC	2013	Ambitious Nuclear					13.5	229
		Ambitious RE					17.2	292
		Ambitious CCS					13.2	224
		Ambitious EE					11.7	199
LSE	2012	Hitting the target					18.8	330
		Gas is key					10.3	180
		Austerity reigns					7.4	130
The Estate only, excludes transmission)	Crown (OSW excludes)	2012 Slow Progression	3.1	24				
		Tech. Acceleration	4.5	35				
		Supply Chain Eff.	4.5	35				
		Rapid Growth	6.2	48				

**Table 1 – Comparison of investment requirements between studies<sup>3</sup>**

Source: (Ofgem, 2010a, Ernst & Young, 2009, DECC, 2012b, National Grid, 2013, CCC, 2013, LSE, 2012a, PWC, 2012)

<sup>3</sup> Figures in bold in the table correspond to where the study explicitly states an investment figure. Non-bold figures have been calculated by taking capacity addition figures and multiplying by a common capital cost.

A key difference between scenarios is the level of ambition in terms of carbon emissions. Since low-carbon technologies are more capital intensive, the more ambitious scenarios have a higher CAPEX requirement. This is clearly shown in Figure 1 which demonstrates the inverse relationship between capital requirements and emissions intensity. Of particular note here are the scenarios from the Committee on Climate Change (CCC, 2013) which are broadly consistent with the assumptions used for the 4<sup>th</sup> carbon budget (CCC, 2010). These estimates are considerably higher than any other estimates in the other studies included in this assessment. A large share of the reason for this is that the scenarios are the most ambitious, aiming to achieve 50gCO<sub>2</sub>/kWh. This is significantly less than the 100gCO<sub>2</sub>/kWh assumed in the DECC projections. However, the CCC costs are still higher than the National Grid estimates under their 'Gone Green' scenario, which also reaches 50gCO<sub>2</sub>/kWh by 2030. Analysis of the variations between cost estimates between scenarios is provided in the Appendix.

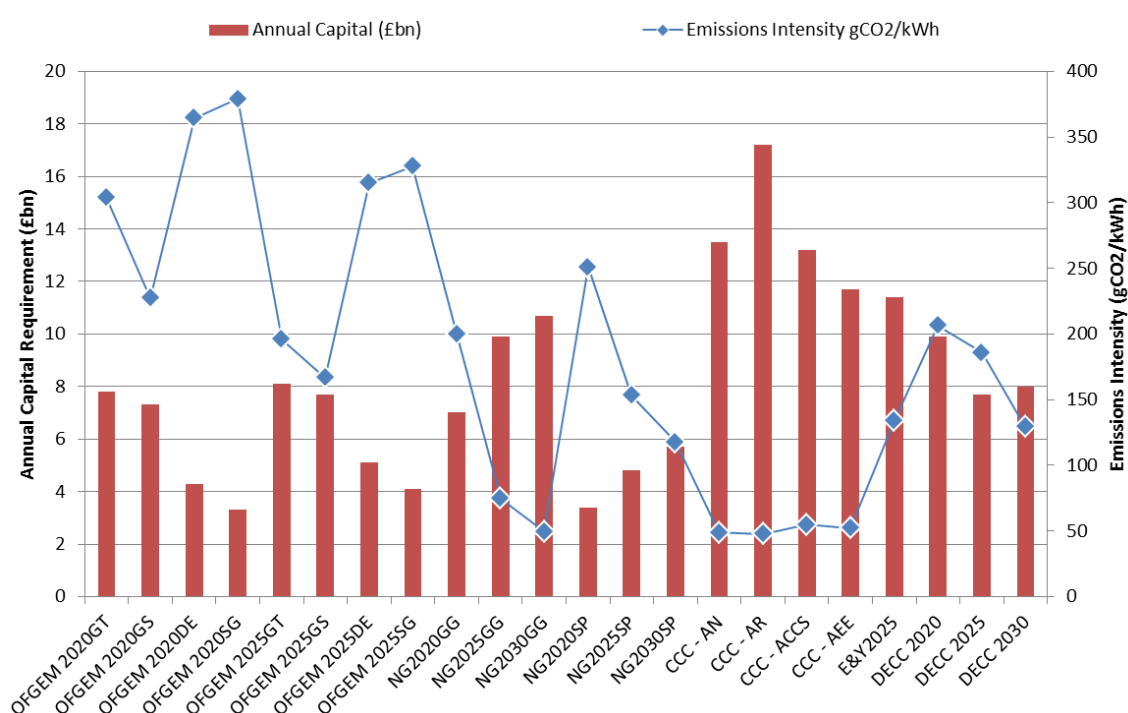


Figure 1 – CAPEX requirements and emissions intensities

Source: (Ofgem, 2010a, Ernst & Young, 2009, DECC, 2012b, National Grid, 2013, CCC, 2013, LSE, 2012a, PWC, 2012, Author calculations)

The profile of expenditure over time varies between the studies. Whereas the OFGEM scenarios have a broadly similar level of annual CAPEX requirement

for the 2020 and 2025 timeframes, the National Grid scenarios show significant increases in annual expenditure after 2020, particularly because of the addition of new nuclear plant over this timeframe. By contrast, the DECC scenarios show a higher rate of expenditure for the period up to 2020 than after 2020 because these scenarios are largely driven by 2020 targets for renewables. Meeting these targets implies a large ramp up in expenditure to 2020, with a drop-off after 2020. More detail on the breakdown of investment by technology is provided in the Appendix.

The investment implications of these new build scenarios shows that the CCGT build features less strongly in the CAPEX figures because it is less capital intensive than the other generation types. The increase in CAPEX required for wind after 2020 contrasts with the relatively flat capacity additions – this is because of a shift from onshore wind to offshore wind which is more costly per MW installed.

## 1.2. How Big is the Investment Gap?

One way to judge the feasibility of these future scenarios is to compare these investment rates with historical trends over the past 20 years, as shown in Figure 2. It appears from the chart, that investment in power generation over the past 20 years has been quite cyclical, depending on both capacity retirement and demand cycles in the economy. By contrast with much of the 2000s, the past few years have seen a significant increase in the rate of new additions, with on average of 4 GW added over the four years 2009–2012, comprising 2.3 GW of gas, 1.3 GW of wind (0.6 GW onshore, 0.8GW offshore), and 0.5 GW of solar.

The chart shows for comparison the implied new plant capacity additions for the future scenarios identified in the previous sections. At 4 GW per annum, the total build rate of the past four years is higher than the OFGEM 2020 scenarios, and is not far behind the National Grid ‘Gone Green’ scenario, albeit with a significantly smaller share of renewables (1.9GW vs. 3.7GW for the NG scenario).

Detailed figures on the total CAPEX associated with these capacity additions is difficult to obtain, but an estimate can be made by multiplying the capacity by the same unit costs that we assume in the future energy scenarios. These

estimates are similar to others in the literature, quoted at £5 billion (SSE, 2011) and £5.7 billion per annum (PWC, 2012). At £4.8bn, average CAPEX over the past four years is below OFGEM Green Transition and Green Stimulus investment requirements for 2020 (£7.6bn and £7.1bn respectively), but somewhat ahead of the more pessimistic Slow Growth and Dash for Energy scenarios (£4.1bn and £3.1bn respectively).

The latest full year 2012 was a particularly strong year. Wind investment in 2012 reached 1.9 GW (0.7 GW onshore, 1.2 GW offshore). This compares to around 2 GW of wind required annually, as an average across the different future scenarios. Detailed comparisons with individual scenarios can be made by reference to the figures in the Appendix. Total investment exceeded £7bn, with £5bn for renewables, close to the OFGEM 2020 scenarios. Therefore, over recent years, and for 2012 in particular, investment rates compare quite favourably with the expected investment requirements up to 2020.

The period post-2020 looks more challenging, largely because the problem of replacing retired plant becomes more acute over that time frame. For example, the National Grid ‘gone green’ scenario for 2030 would require £12bn per annum total, with £8bn pa for renewables, around 60–70% increase compared to investment levels in 2012.

In summary, the investment trends of recent years look more than sufficient to meet the less environmentally ambitious scenarios. The more ambitious scenarios, including those of the CCC for the 4<sup>th</sup> Carbon Budget would require scaling up by around £2.5 – 7.5bn compared to the average CAPEX over the past four years, and by £0 – 5bn compared to 2012 CAPEX levels.

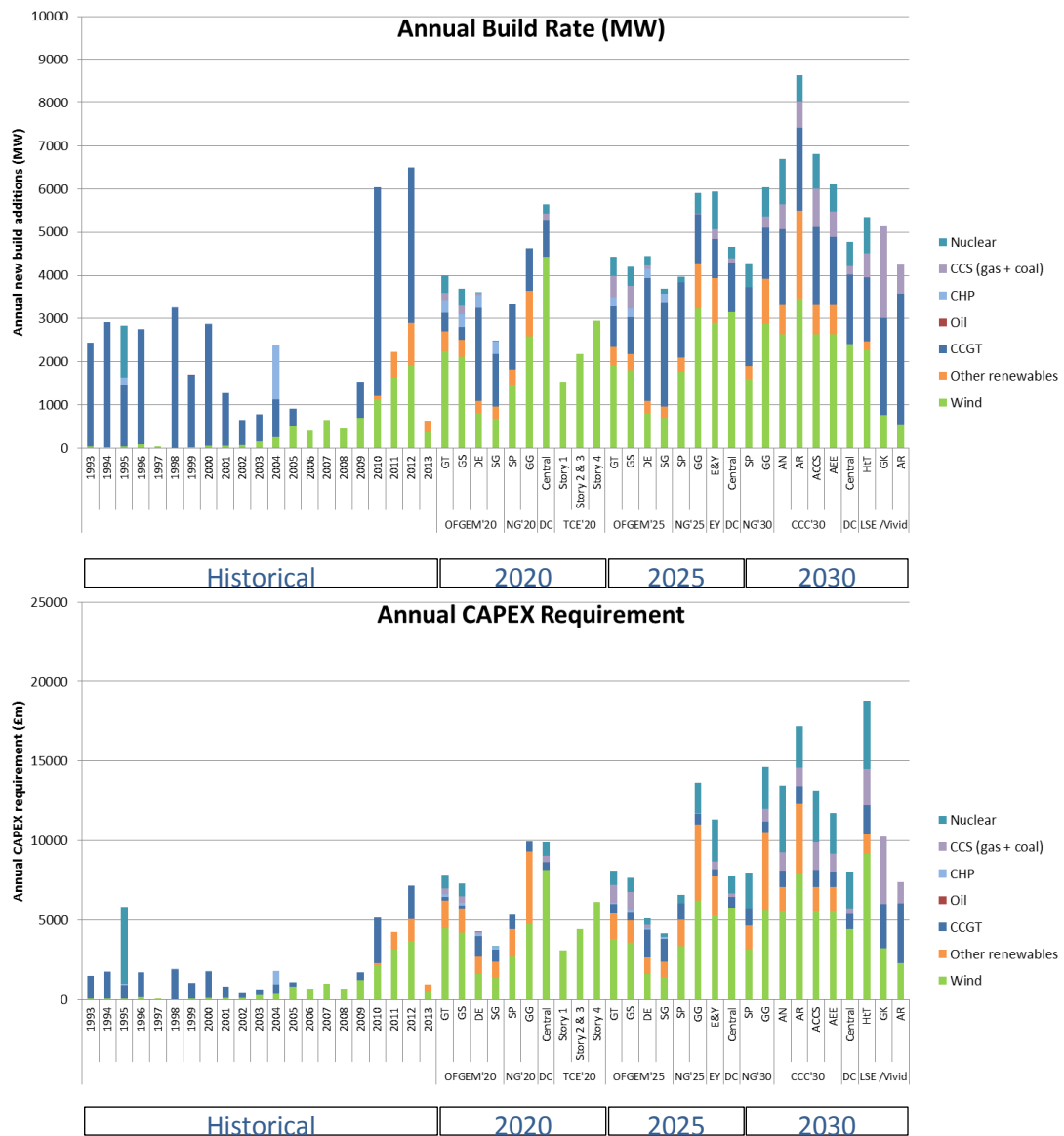


Figure 2 – Comparing historical and projected build rates (MW) and CAPEX (£m)

## 2. Investment Channels

A high level perspective on power generation investment will see two dominating paths for finance, on balance sheet (mostly applying to utilities, reviewed in Section 2.1) or project finance (off balance sheet, reviewed in Section 2.2). This is demonstrated in Figure 3, which represents global investment by security for renewable energy. A similar pattern is evident for wider energy generation investment. This section will analyse these key two sources of finance, looking at historical trends, impacts of the financial crisis, and more recent patterns. The objective is to reveal potential constraints and the feasibility of these sources ability to fill the financial gap alluded to in the previous section.

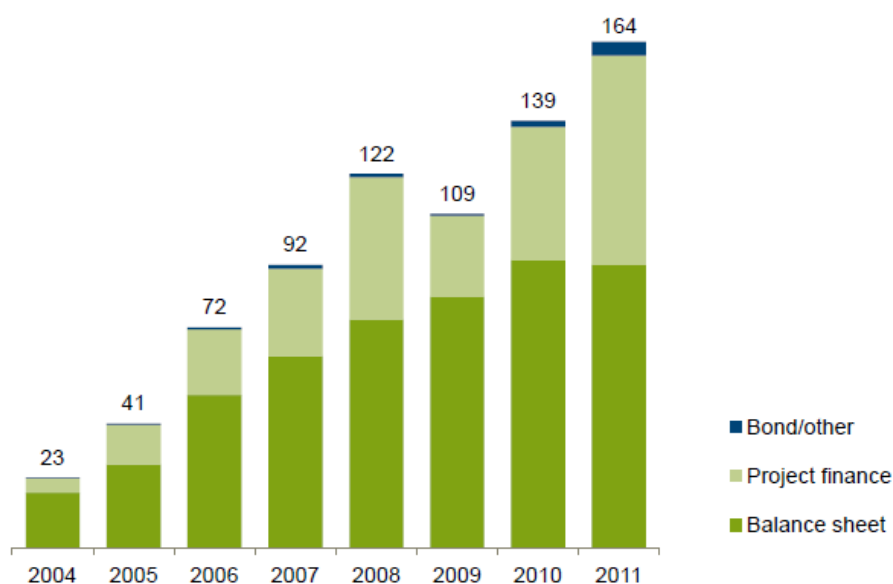


Figure 3 – Global renewable energy investment by type of security from 2004–2011 in \$ billion

Source: (UNEP, 2012) with data from BNEF

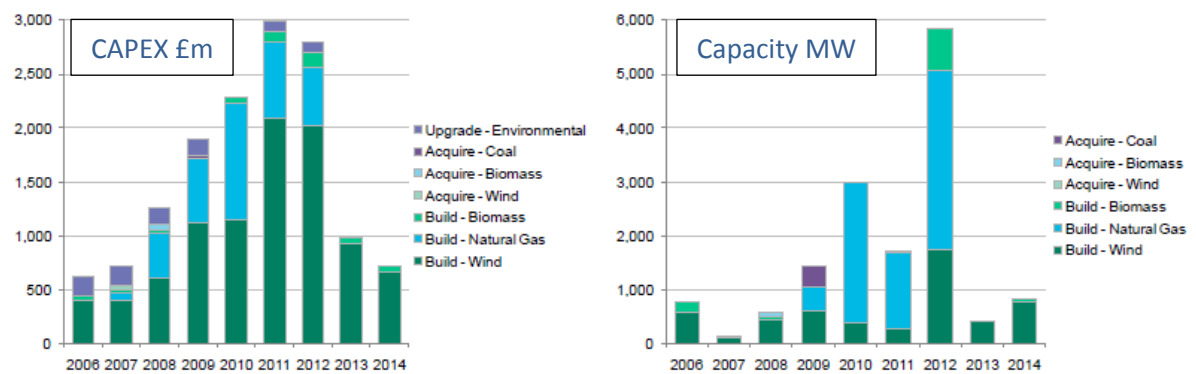
### 2.1. Utility investment

#### 2.1.1. CAPEX Trends

The ‘big 6’ energy utility companies own around 65% of UK’s generating capacity, supply 87% of total electricity (BNEF, 2012) and 4 of these own 9 of the 14 regional distribution companies in the UK (National Audit Office, 2010), evidencing their vertical integration and control of the UK energy

sector. The ‘big 6’ are dominated by some of Europe’s biggest energy companies; with only two companies being UK owned.

Of the 16.5 GW of new capacity added to the UK system between 2006–2012, approximately 85% (14 GW) has been built by the major power generating utility companies (BNEF, 2012). Figure 4 shows how this utility investment has been split over time and between different technologies. The time profile of expenditure here is different from that in Figure 2 because more detailed assumptions are made in the BNEF data regarding the timing of CAPEX expenditures for a given build profile. In addition to the new build, utilities also acquired around 500 MW of wind farms from project developers over this period (ibid). This data confirms the utilities role as major investors in UK power generation.



Source: Bloomberg New Energy Finance. Note: MW capacity excludes repowering and retrofits. Includes all projects under construction at start 2012.

Figure 4 – Investment rates by the major utilities

Source: (BNEF, 2012)

The ability of utilities to maintain or expand these investment rates depends almost entirely on the overall health of their balance sheets. Capital expenditure (CAPEX) under their current business model is usually financed from their balance sheet. In other words, CAPEX is financed directly from cash available to the business either from accumulated retained earnings or from access to sufficient credit. Although CAPEX does not directly affect the profit and loss account of the company (since a fair valued investment will add equally to both liabilities and assets side of the balance sheet), the amount of cash available for CAPEX does depend on the profitability of the businesses over time, and / or its ability to raise additional credit.

To some extent, CAPEX competes with dividend payments which are also discretionary payments from cash flow, and are desirable to maintain share value. CAPEX investment is essential to ensure company growth and reliable future revenue. However, it may take some time to see the benefits of these investments, particularly when they are for generation assets which can take years to construct and begin producing revenue. This is a key conflict, between the short term interest of shareholders and the long term benefits and requirements of power generation CAPEX investment. Companies have to manage these competing demands to ensure that sufficient cash can flow through the business to maintain liquidity.

Looking at the top 25 utilities across Europe as a whole, Figure 5 indicates that whilst the outlook for earnings is to return to growth over the next couple of years, the earnings margin is set to remain well below pre-recession levels, and for the two large German utilities with assets in the UK (RWE and E.ON), earnings are set to fall over the period to 2015 according to this analysis. The outlook for CAPEX is similarly constrained, with overall levels set to dip slightly from around €80bn to around €73bn between 2012 – 2014.

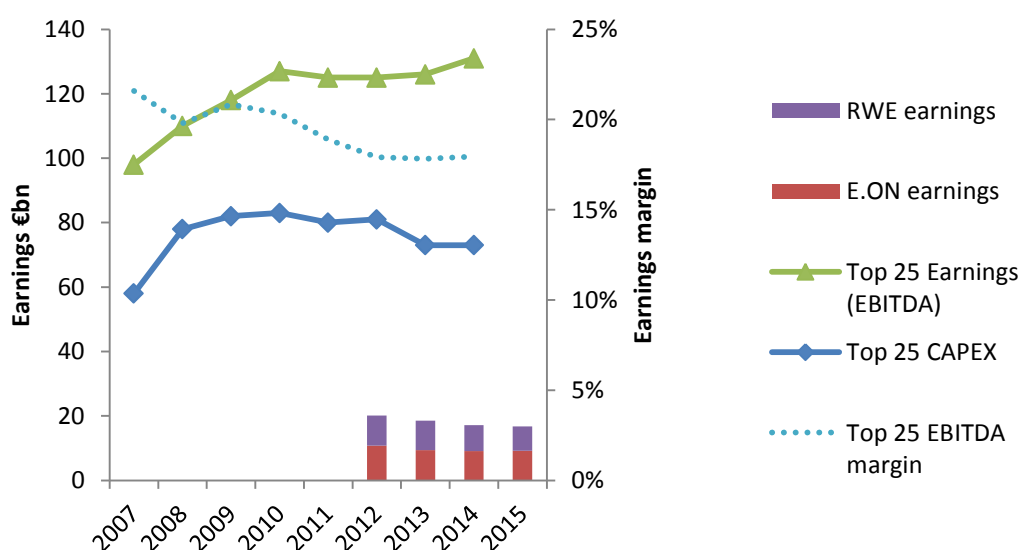


Figure 5 – Earnings and CAPEX outlook for Europe's top 25 utilities<sup>4</sup>

<sup>4</sup> EBITDA: earnings before interest, tax, depreciation and amortization

Source: (Standard & Poor's, 2013)

Estimated CAPEX plans for the 'big 6' companies operating in the UK are shown in Figure 6. These are the total CAPEX for the company as a whole, not just for the UK. These figures show that CAPEX plans are set to be reasonably steady on average over the next year, but this average is skewed by the large expected increase in CAPEX for EDF as a result of the additional safety-related expenditure to their fleet following Fukushima (EDF, 2012). Taking this out implies that for the other 5 companies, total planned CAPEX is set to drop relative to 2012 levels by 12% in 2013, 24% in 2014, and 30% in 2015.

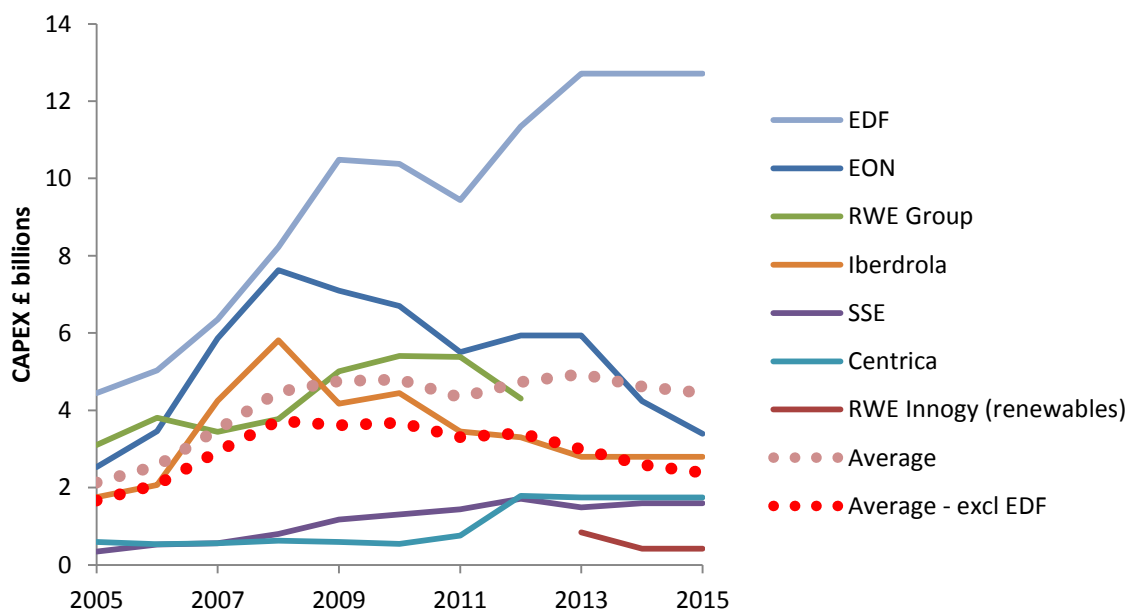
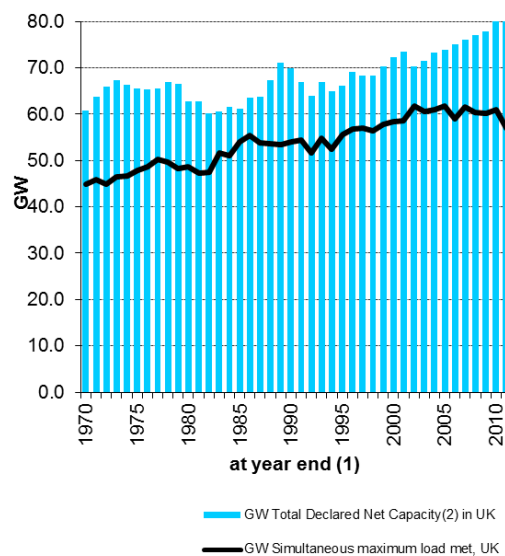


Figure 6 – Total CAPEX plans for the 'big 6'

Source: (Eon, 2013, Reuters, 2013a, RWE, 2013, SSE, 2013, Centrica, 2013, Iberdrola, 2013b, Iberdrola, 2013a, EDF, 2013, Boxell, 2012, Thomson Reuters Datastream, 2013a)

The drop in CAPEX plans and margins across European utilities is due to poor economic conditions. Chief amongst these is the considerable drop in demand for electricity that has resulted from the recession, leading to overcapacity of generation plant (IHS CERA, 2013). The picture of declining demand due to recession and excess generation capacity is repeated in the UK, as indicated in Figure 7. This is coupled in some countries, particularly Germany, with a drop in wholesale electricity prices caused by the greater levels of low-marginal cost wind and solar power entering the system (Ryser,

2013). This occurs because wind and solar are subsidised with payments outside of the wholesale market price. This means that they get dispatched irrespective of market prices, increasing volumes of supply during times of high availability, and thereby reducing both prices and demand for fossil generation.



**Figure 7 – UK capacity has risen despite flat demand**

Source: (DECC, 2011a, Investment Management Association, 2012)

Nuclear investment is an exception to the decline in CAPEX plans, but represents a rather special case because the scale of capital required to build a new nuclear power station creates particular issues with respect to financing options. For EdF's proposed plant at Hinkley Point C, CAPEX has been estimated at £16 billion (DECC, 2013). At the time of writing, negotiations are still on-going regarding the terms of UK government support for Hinkley Point, though headline figures have been announced including agreement of the strike price for the CfD at £92.50/MWh, indexed linked, for 35 years (ibid). These headline figures dominate the economic case for the project, although there are still important issues to resolve regarding exactly how risks and liabilities are to be assigned in practice.

Of concern to the financing case is the extent to which any debt raised to finance the project will be guaranteed. The UK Treasury has offered up to £10bn in loan guarantees, probably in the form of under-writing for bonds to be issued for the project. Such guarantees are required because of the scale

of the project relative to the size of the company's balance sheet. CAPEX for Hinkley Point represents over 40% of the market capitalisation value of EdF which is around €44 billion (£37 billion) (Bloomberg, 2013). To make this affordable, EdF needs to form a consortium of investors, which currently look set to include Areva the plant manufacturer, and China National Nuclear Corporation (CNNC) and China General Nuclear Corporation (CGN), leaving EdF with around 45–50% equity share of the project (WNN, 2013). Even at this level, this single project could create systemic corporate risks for the company if the project were to run into difficulties. Hence, bond guarantees help shift some of the liability off EdF's balance sheet.

### 2.1.2. Debt Levels

Poor profitability is exacerbated by the utilities' need to reduce debt levels. Debt for the big 6 companies increased dramatically over the 2000s following increasing levels of market liberalisation across Europe as the large companies embarked on an abundance of mergers and acquisitions to the extent that 40% of the European utility market changed hands from 2003–2008 (CCC, 2012, Ofgem, 2010b). This activity has seen debt levels increase 10 fold from 2000 to 2010 for the European utilities (CCC, 2012). The big 6 are imbedded in this trend and, on average have seen debt levels more than double in the last decade (see Figure 8.)

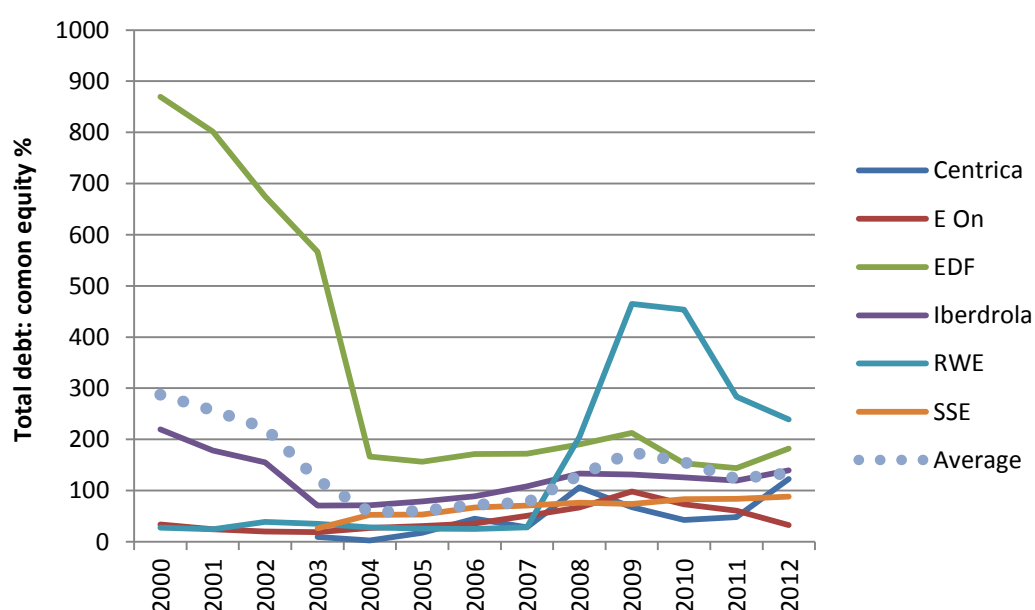


Figure 8 – Total debt: common equity %

Source: (Thomson Reuters Datastream, 2013a)

Debt reduction has stemmed mainly from sales of assets rather than by diverting internal cash flows from the balance sheet, but this nevertheless has an effect on corporate priorities with respect to new expenditure. They have embarked upon major cost reduction programmes and disposal of assets to reduce their debt levels (Ofgem, 2010b).

Although the cost of debt has decreased over the past 5 years since the height of the credit crunch, there has been an even greater decrease in Returns on Capital Employed (ROCE) due to downward price pressures (Figure 9).

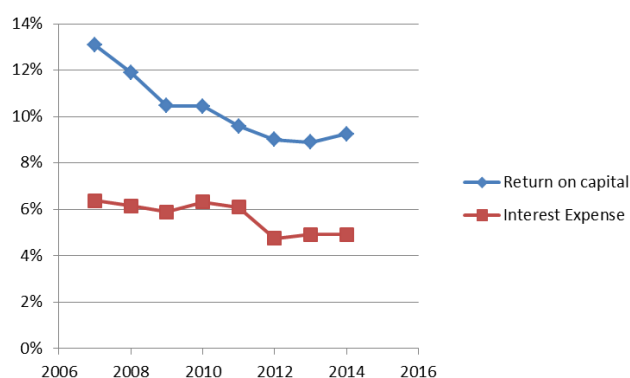


Figure 9 – Cost of debt and return on capital trends for top 25 European utilities

Source: (Standard & Poor's, 2013)

### 2.1.3. Credit Ratings

The companies' need to reduce debt levels is closely tied to their need to maintain their credit ratings. Assuming that other factors remain constant, the lower the level of a company's corporate debt, the greater the cushion provided by equity (since shareholders are the first to shoulder any loss in company value), and the less likely the company is to default on its loan repayments (Brealey et al., 2006). Credit ratings provide information to creditors about the health of companies' balance sheets, including the risk of default on corporate loans, and creditors will charge more for loans to companies with riskier credit ratings (ibid). Companies therefore need to maintain credit ratings to keep their cost of borrowing down. Most of the European utilities have lost their AAA ratings since the economic crisis, with A- ratings looking likely in the future (see Table 2). The pattern of decreasing

ratings is confirmed by the shifting of ratings distributions for the EMEA top 25 utilities, mostly energy (electricity and gas), shown in Figure 10.

Energy Company	Corporate credit rating
Centrica PLC	A-/Stable/A-2
E.ON AG	A/Negative/A-1
EDF S.A.	A+/Stable/A-1
Iberdrola S.A.	A-/Stable/A-2
RWE AG	A-/Negative/A-2
SSE PLC	A-/Stable/A-2

Table 2 – Standard & Poor's corporate credit ratings for the Big 6

Source: (Standard & Poor's, 2013)

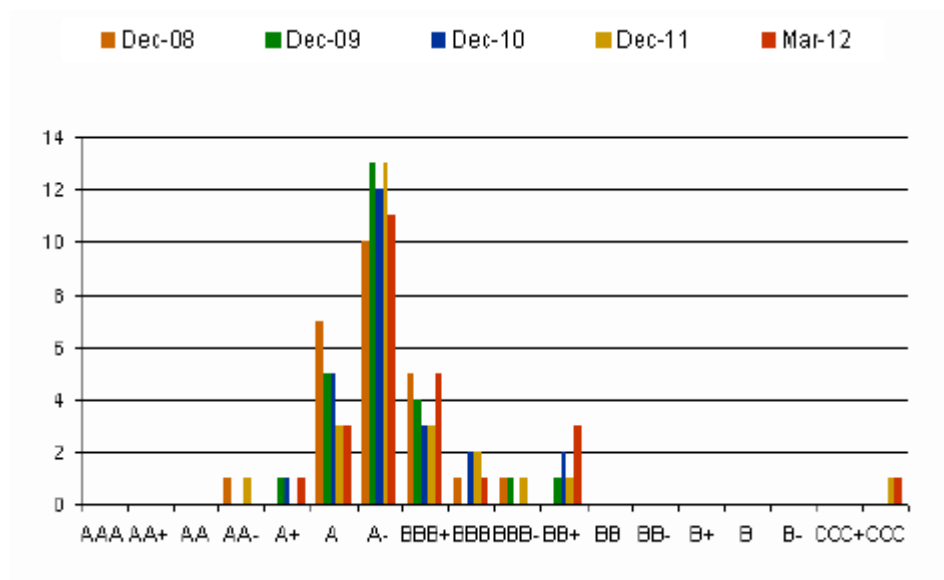


Figure 10 – EMEA Top 25 utilities long term ratings distributions

Source: (Standard & Poor's, 2013)

#### 2.1.4. Comparison Between Electricity and the Oil and Gas Sector

There are fundamental differences between the oil & gas (O&G) sector and power generation sector, notably that balance sheets are of a larger scale, and they are not leveraged to the extent of the utilities (Figure 11). However,

some parallels can be drawn from the UK oil and gas sector such as the scale of investments required to support the industry. It is also interesting to briefly explore this sector as they are currently small scale investors in the UK electricity sector with a potentially bigger role to play.

Investor confidence was hit in the last decade by the fiscal instability caused by numerous adverse tax changes in the mid-2000s along with the prospects of seeking more risky reserves, resulting in production numbers falling by up to 30% in the past two years (Oil & Gas UK, 2013). However, economic activity in the O&G has not been hit by the recession in the same way as it has for utilities. Renewed long term government commitment to the UKCS, with attractive policy such as field allowances and possible decommissioning allowances, has seen the biggest increase in assets and infrastructure in the last three decades and drilling number increase, with investment boosted from £8.5billion in 2011 to £11.4 billion in 2012, and expected to rise further to £13bn in 2013, with companies having just under £100bn of planned capital expenditure in total in their business plans (ibid).

One of the factors influencing the ability of oil and gas companies to make such investments is that their balance sheets do not have the same high levels of debt leverage as the utilities, so have more freedom to invest when conditions are desirable (Figure 11).

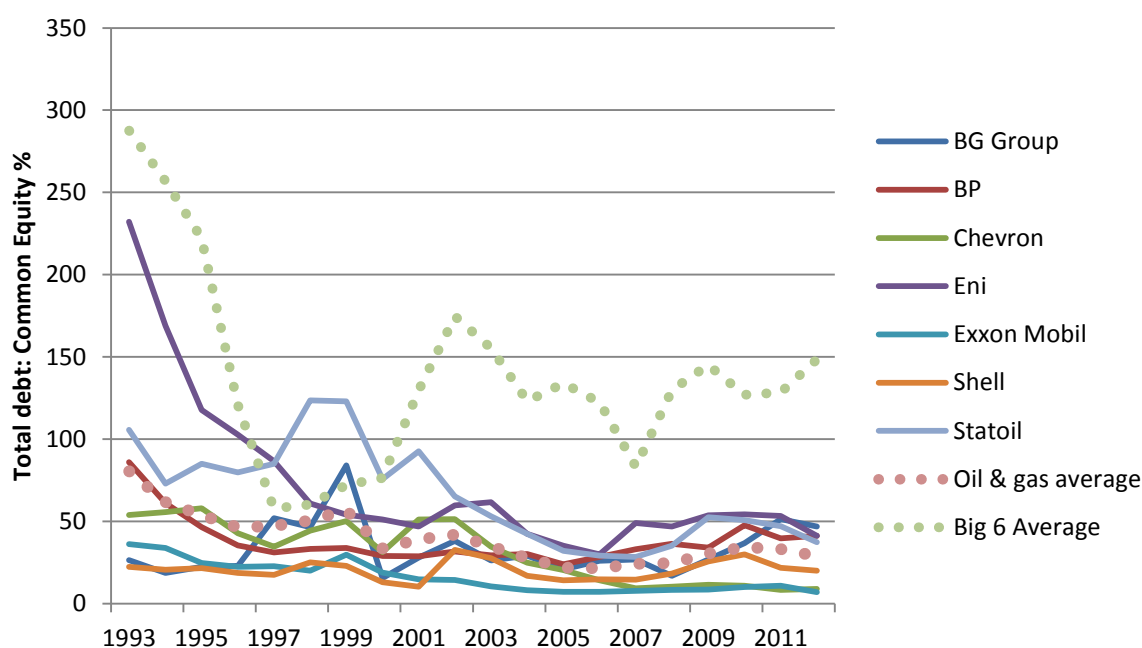


Figure 11 – Total debt: common equity % for oil and gas firms vs. the big 6 average

Source: (Thomson Reuters Datastream, 2013a)

## 2.2. Project-financed Investment

This section provides an overview of project financing and its role in channelling investment into energy generation projects in the UK. A dialogue is provided for the general historical project financing landscape followed by case examples where project finance has or potentially will be popular; onshore wind, offshore wind, and nuclear.

Project financing is distinct from the corporate on-balance sheet financing (as described in the previous section) in that finance is secured against the assets of a particular project rather than the asset base of a wider company. Project financing was popular for a while with utilities as a way of investing in assets without adding to debt on their balance sheet. It was seen as attractive, particularly for the riskier projects, as a specific project company is usually set up by the project sponsors, effectively moving the finances off their individual balance sheets.

However, since the Enron and other financial mismanagement scandals in the late 1990s and early 2000s, the ability of companies to ring-fence the liabilities associated with off-balance-sheet investments in this way has largely disappeared. Ratings agencies tend to ascribe responsibility for any debt associated with projects that could be deemed core to a companies' business, with the overall debt levels for that business (PWC, 2012). This removes incentives for utility-scale companies to use project finance as a way to invest in generation assets.

Nevertheless, project finance has been an important source of finance for smaller developers particularly in the onshore wind sector as discussed below, and indicated in Figure 3 at the start of this chapter. Project finance stagnated between 2008–2010 due to lack of project finance debt caused by the decline of the monoline guarantee businesses that had underwritten debt to these projects prior to 2008, but collapsed due to their overexposure to risks in the financial crisis (Standard & Poor's, 2013, Della Croce et al., 2011a). Lenders became less willing to offer finance without the security of these guarantees in place. This was partially fulfilled by multi-lateral lending institutions increasing their investment share in infrastructure (Della Croce et

al., 2011a). Late 2012 saw a re-emergence of capital issuances for recycling project finance debt, followed by a number of other sizable infrastructure projects early in 2013 (Standard & Poor's, 2013), suggesting that project finance may once again be re-emerging.

### **2.2.1. Role in UK Onshore Wind**

Project finance has been widely and successfully used by smaller project developers in the UK, particularly in the context of onshore wind development. A key factor in the development of onshore wind has been the way in which smaller companies seemed able to more efficiently develop projects than the larger utilities because of the smaller scale of individual projects, through independent developers, private equity firms and infrastructure funds (Mazars, 2012).

Bank loans were a key contributor to financing these projects and helping to grow the UK's cumulative onshore wind capacity. During the 2000s, pre-crisis, bank credit was cheap by historical standards because of low central bank base rates globally. Banks were keen to extend credit to projects that could earn a margin over low-yielding national gilts and treasuries. With a history of reasonably profitable projects, reliable income payment structures supported by national renewable energy support policies, and a good track record of low technical risk, debt levels of over 80% of total project financing was not uncommon (Mazars, 2012). Despite bank loans not being the cheapest source of debt, such high gearing made the projects financially attractive because it reduces the need for more costly equity financing. These attractive attributes led to 2012 being the most successful year for onshore wind debt financing in the UK to date.

Recently however, lower average leverage ratios have been noted. Historically, there was a wide range of ratios for projects ranging from below 60% to above 80%, reflecting site conditions, wind speeds and capacity factors but more recently lenders appear to be imposing a general cap. In 2012, maximum gearing ratios dropped from above 80% to below 75% (Mazars, 2012). This draws attention to lenders possible increasing risk aversion to these projects.

Project spreads (i.e. the risk premiums charged on loans) became very low in the run up to the financial crisis. Since then, despite a drop in base rates and inter-bank borrowing rates, the cost of debt for project financing wind projects has not dropped much, with lenders taking a wider spread, either another factor reflecting higher perceived risk, or simply reflecting their need to recoup greater levels of interest to help repair their own balance sheets (see Figure 12).

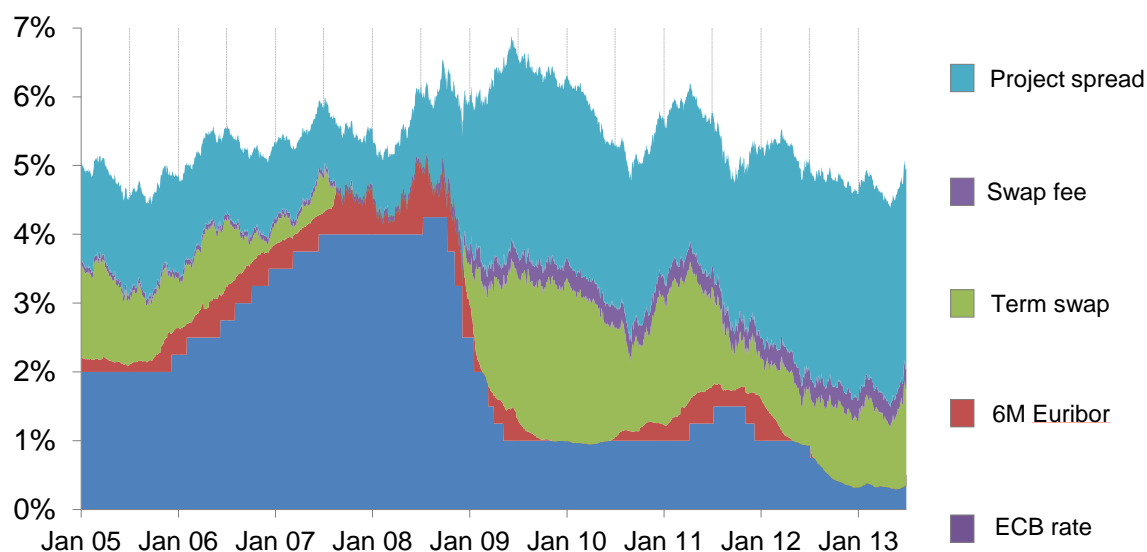


Figure 12 – Cost of debt for European onshore wind

Source: (BNEF, 2013)

There has also been evidence of a move to instruments which are designed to offer shorter debt repayment schedules. Traditionally refinancing schemes have been on a 15 year or longer basis, tied to a long term Power Purchase Agreement (PPA), but these have been reducing through various schemes, which can force refinancing after as less as 7 years (Mazars, 2012).

2012 being the best year for onshore wind debt project finance, must be viewed in context with the 10% ROC reduction in April 2013, which may have pushed the development pipeline forward, before this date (Mazars, 2012). Increasing project sweeps, reduced debt ratios and refinancing scheme lengths have occurred on a backdrop of increased pressures on capital requirements and long term lending discussed in Section 2.1. The accumulation of these factors, and a continuation of this trend would be expected to make it more difficult to acquire bank debt for onshore wind

project finance. Nevertheless, work by the (LCFG, 2012) suggests there is a strong pipeline of bankable yet challenging projects.

### 2.2.3. Financing UK Offshore Wind

In principle, what worked for onshore wind in the UK could also work for offshore wind. However, offshore wind is more complex and the technology is less mature. The challenging physical environment as well as the scaling up to larger turbine sizes significantly increases technical risks both during construction and operation phases. In addition, the sheer size of offshore wind farm developments requires the involvement of large companies. In practice this has meant that offshore wind consortia has included large utilities, energy companies and technology providers, who can cover the equity position and provide the technical expertise required. Figure 13 shows the current ownership breakdown for UK offshore wind. Much of this is owned by utility companies, and therefore would be considered part of their corporate balance sheet.

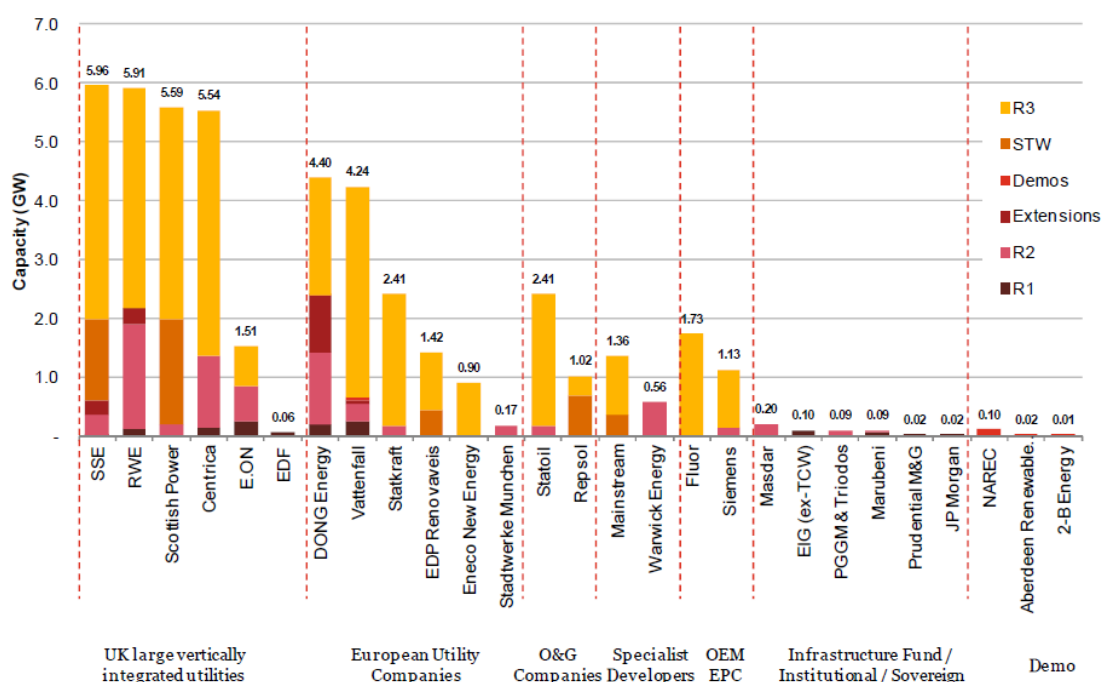


Figure 13– Equity ownership: shares of UK offshore wind by capacity

Source: (PWC, 2012)

However, because of the scale of the investments and their relatively high risks compared to on-shore wind, utilities often combine into consortia to develop these projects, using quite complex project-financing style deals, rather than simply using on-balance sheet utility financing. Due to the increased risk profile, the maximum debt leverage for these more risky projects has been limited to between 15 – 40% (PWC, 2012). The debt portions are typically provided by quite large consortia of banks, who are beginning to get comfortable with lending for offshore wind projects in the UK (Nelson and Pierpont, 2013), although these loans are often covered by bank guarantees provided by public institutions. The following table, shows the first examples of financing structures for UK offshore wind projects, illustrating the large number of organisations involved in the projects. This reflects the scale of the investments involved, and the need to distribute risk quite widely during the early development stages when they are not yet fully understood.

Project	Owners	Debt finance secured	Debt Providers	Date	Financing type	Debt: Equity Ratio	Tenor
Walney – 367MW	DONG Energy (50.1%), SSE (25.1%), PGGM (12.4%), Ampere Equity Fund (12.4%)	£224m	Lloyds Bank, the Royal Bank of Scotland, Santander, Siemens Bank, UK Green Investment Bank	01/12/ 2012	Refinancing of minority stake	N/A	N/A
Notes: The financing involves PGGM and Ampere Equity Fund refinancing on a non-recourse basis their 24.8% stake purchase of the Walney offshore wind farm completed in December 2010 – 70% of the purchase price was refinanced. This is the first minority refinancing without an ECA guarantee and the first time the GIB has invested in offshore wind. It was also the first project in the UK to get institutional investor backing before it was built. May not be viewed as true project finance as it was on balance sheet (Hervé-Mignucci, 2012).							
Lincs – 270MW	Centrica plc. (50%), DONG Energy (25%), Siemens Project Ventures	£425 m	Abbey Treasury Services, BNP Paribas, Nordea Bank, Skandinaviska Enskilda Banken, Unicredit Bank, DNB Bank, HSBC	01/06/ 12	Non-recourse project financing (construction stage)	43:57	Construction plus 15 years

	GmbH (25%)		Bank, KfW IPEX- Bank, Lloyds TSB, The Bank of Tokyo-Mitsubishi UFJ					
Notes: First offshore wind project to secure non-recourse project financing for construction phase								
Gunfleet Sands – 172.8M W	DONG Energy (50%), Marubeni Corp (50%)	£158 m	Mizuho Corporate Bank, Sumitomo Mitsui Banking Corporation	01/03/ 12	Refinancin g of minority stake	N/A	13 years and 8 months	
Notes: Project financing was insured at £158 million. Second ever UK offshore wind project finance deal, the first financed by a Japanese bank.								
Lynn and Inner Dowsin g wind farms – 194M W	Centrica plc	£340 m	BBVA, Bank of TokyoMitsubishi, BNP Paribas Fortis, Bayern LB, Bank of Ireland, Calyon, HSBC, KfW IPEX Bank London Branch, Lloyds TSB, NIBC, National Australia Bank, Rabobank and Santander	01/10/ 2009	Refinancin g of operationa l assets	N/A	N/A	
Notes: A consortium of 14 banks refinanced the operational Boreas wind farm portfolio. The financing sum also includes the 26MW Glens of Foudland on-shore wind farm.								

**Table 3 – UK Offshore Wind Project Debt Finance Deals**

Source: (Clean Energy Pipeline, 2013)

It is still early days with respect to development of large-scale offshore wind in the North Sea. Each new wind farm contributes to technological learning regarding the construction and operational risks involved. So far, each offshore wind project financed to date has had a bespoke financial solution, so it is hard to draw conclusions about emerging trends.

The question of whether or not project finance can be significantly scaled up in the future depends on the outcome of two issues. The first relates to operational risk. If experiences of the current round of early projects shows these risks to be low, this will encourage the emergence of a secondary market allowing project developers to refinance by selling-on the projects once construction is complete. This concept is discussed in more detail in section 4.2. This would enable construction capital to be recycled more quickly back into new projects, helping to accelerate overall investment rates.

The second issue to resolve is how to gear more debt into projects at the pre-construction stage. This looks difficult because constructing offshore wind plants is logistically challenging, involving extreme weather conditions, marine logistics, a fledgling supply chain which has been prone to delays (Greenacre et al., 2010) and typically involving complex multi-contracting structures, so they do not achieve investment grade status (Fitch Ratings, 2012), although some commentators have suggested that project bonds could however start to play a role by 2017 and beyond (PWC, 2012).

In the meantime, until experience builds up sufficiently to allow these issues to be resolved, the role of public institutions such as the European Investment bank (EIB) has become increasingly important as discussed in further detail in sections 3.1.2 and 4.3.

### 3. Sources of Finance

As described in the previous sections, the majority of the finance for energy generation projects flows through large organisation's balance sheets such as the utilities, or through project finance vehicles. This section explores in more detail where this finance comes from, focusing on the two key areas of bank finance and institutional investors.

The total size of the financial market is vast. Estimates by McKinsey ((Roxburgh et al., 2011), see Figure 14) indicate that the global value amounted to over \$200 trillion in 2010. The top three sections of Figure 14 relate to sources of finance that are not generally available for corporate finance, whereas the bottom three generally are. Collectively, these three sources amount to over \$100 trillion. The bottom (dark blue) section of the chart shows total stock market capitalisation, i.e. the total global value of company shares. The next (purple) section shows the value of bonds. The largest owners of bonds and shares are institutional investors, described in more detail in Section 3.2 and 3.3. The third (orange) section shows loans, mostly from commercial banks, described in Section 3.1.

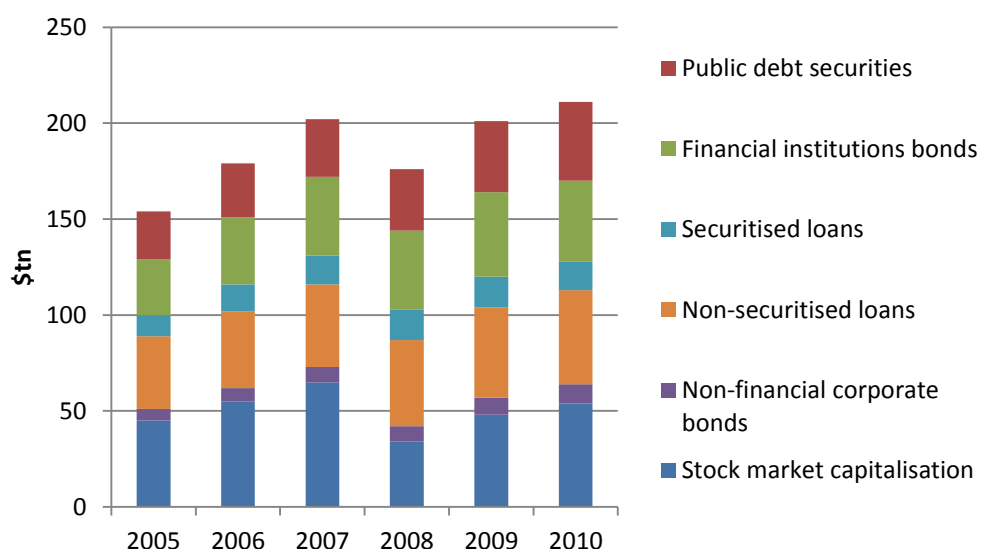


Figure 14 – Global stock of debt & equity

Source: (Roxburgh et al., 2011)

### 3.1. Bank finance

As seen in Figure 14, loans (mostly from commercial banks) make up almost half of the pool of finance available for corporate financing. This includes various lending instruments for mortgages, businesses and consumer credit (Bank of England, 2013). Global debt doubled in the past decade from €78 trillion in 2000 to \$158 trillion in 2010 mostly down to governments and financial institutions, and 31% of this is attributed to loans held by banks, credit agencies and other financial institutions (Roxburgh et al., 2011).

Section 2.2 discussed how banks are the principle sources of debt for onshore wind projects. Their importance is confirmed by (Ecofys, 2011) who state that the banking sector has been the principle debt financiers of European renewable energy, and the global scale of project finance for renewable energy is seen in Figure 3 to be around £65bn. Banks provide finance through bank loans and other financial instruments used to finance debt of energy projects directly through project finance or through company balance sheets, typically led by the integrated utilities.

#### 3.1.1. Trends in Bank Finance

Leading up to the financial crisis, according to figures from the Bank of England, a massive increase in debt lending from banks was noted in the UK (RBS Group, 2013). Bank lending grew from less than 10 billion in 2003 to over 80 billion in 2007 (ibid). This boom in bank lending was fuelled by an abundance of banking credit and inexpensive costs of finance due to desirable economic conditions, despite base interest rates increasing up to the crisis (see Figure 12). This led to bank loans taking an increasing share of net debt issuance as compared to corporate bonds in the UK over the 2000s, as illustrated in Figure 15.

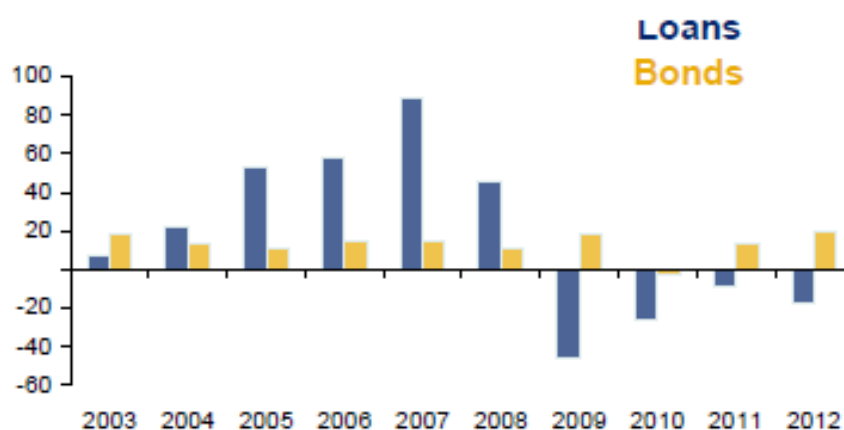
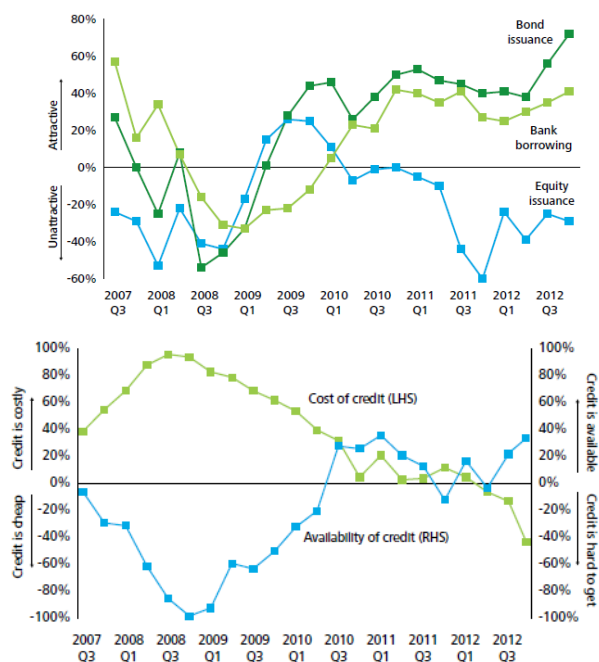


Figure 15 – UK net corporate loans and bond issuance £ billion (2003–2012)

Source: (RBS Group, 2013) with data from BOE & Group Economics

In the years immediately following the financial collapse, this trend reversed dramatically (Figure 15), and there was a relative lack of finance from banks for energy sector investment (PWC, 2012, IHS CERA, 2013), driven by increasing economic uncertainty hindering competitive rates between institutions and increases in the costs of finance (Bank of England, 2013). Banks' constrained balance sheets, together with increasing pressure to de-leverage made the provision of low cost long term finance more difficult (PWC, 2012, IHS CERA, 2013, Roxburgh et al., 2011). Work by the IMF confirms that a bank's ability to lend throughout a crisis largely depends on the strength of their balance sheets (Kapan and Minoiu, 2013). Research by (RBS Group, 2013) showed that bond issuance also stalled in 2010.

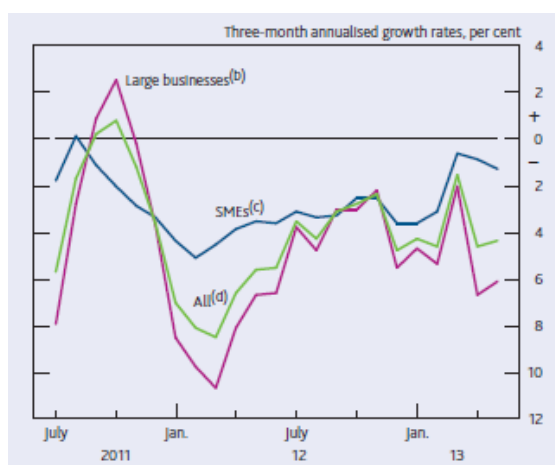
For the economy as a whole, there are signs that access to credit is easing again, with bank borrowing and bond issuance both being viewed more positively in a survey of CFOs (Deloitte, 2013) (see Figure 16).



**Figure 16 – CFO survey showing opinions on attractiveness, cost and availability of corporate credit facilities**

Source: (Deloitte, 2013)

This trend is supported by figures from the (Bank of England, 2013), who conclude that the most important factor for the improved availability of finance, was the recent positive economic outlook. Figure 17 shows a gradual increase in lending to non-financial businesses in the UK. A gradual improvement in competition between banks has also been noted, enabling lending beyond the large companies with the strongest credit (ibid).



**Figure 17 – Lending from UK financial monetary institutions to non-financial businesses by size**

Source: (Bank of England, 2013)

For energy sector in particular however, it is still proving difficult to obtain attractive bank loans with the long maturities required for low-carbon generation projects due to on-going liquidity and capital constraints, see (Kaminker and Stewart, 2012). This points to the need for relatively rapid refinancing to accelerate the turnover of capital, as discussed in Section 4.2.

#### **Box 1 Basel III regulations**

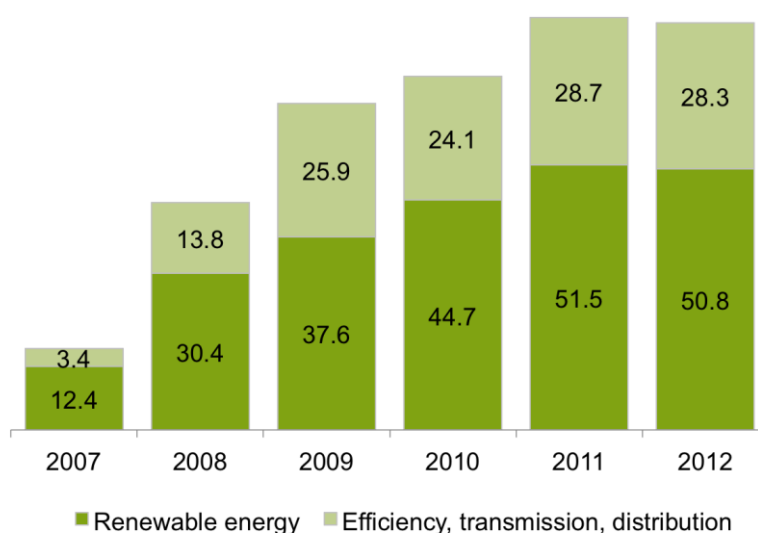
Basel III regulations are being introduced in light of the global recession to ensure more restrictive capital requirements and balance sheets are less leveraged. These regulations are summed up by (PWC, 2010) under three main areas of regulation. Firstly, under capital ratios and targets, standards will be set for capital definition, measures put in place to tackle the cyclical negative effects felt from the crisis, minimum leverage ratios and capital requirements (equity raised from 2% to 4.5%) shall be enforced, and policies will be introduced to tackle systemic risk in institutions (ibid). Secondly, Risk Weighted Asset (RWA) requirements will focus on strengthening capital requirements for counterparty risk and stipulate higher capitalisation to capture risks involved in complex trading activities (ibid). Finally liquidity standards will be set with a coverage ratio to set a minimum requirement for liquid assets and a net stable funding ratio to promote the use of stable funds (ibid).

These regulations in the near term could have a negative impact on banks profitability and thereby create limits to growth (Kapan and Minoiu, 2013). This could further reduce the feasibility of funds for energy investment, particularly due to their perceived riskiness and typically illiquid configuration. However it is argued that the new regulations will reduce inherent risk making the banking system safer with banks benefitting indirectly through lower costs of funding (Kapan and Minoiu, 2013).

#### **3.1.2. Development and multilateral banks**

At a global and European level, bank loan volumes for renewable energy projects have been dominated by multilateral and development banks, particularly after the financial crisis when regulations and limits have been stricter on commercial private banks (UNEP, 2012). Global lending from these institutions for broad clean energy projects was \$79 billion in 2012 (see

Figure 18). For renewable energy specifically, development bank finance in 2012 was \$51 billion out of a total of \$60 billion (UNEP, 2013). In Europe, \$20 billion was made available from Germany's KfW, and \$4.3 billion came from the European Investment Bank in 2012 (UNEP, 2013).



**Figure 18 – Global development bank finance for broad clean energy, transmission and distribution, \$billion (2007–2012)**

Source: (UNEP, 2013) with data from BNEF

In the UK by contrast, public bank involvement has been limited, with most bank debt for onshore wind being sourced from commercial banks. Offshore wind in the UK has attracted funds from KfW (see Table 3). The EIB have only two generation projects listed in the UK, both currently under appraisal (an offshore wind farm and the Drax coal to biomass conversion) (EIB, 2013). The potential to use greater involvement of public and development banks to leverage further investment into UK clean energy generation is discussed in Section 4.3.

### 3.2. Institutional investors

Institutional investors are defined as “specialised financial institutions that manage savings collectively on behalf of other investors based on specific objectives in terms of acceptable risk, return maximisation and maturity of claims” (Davis and Steil (2001), quoted in (BIS, 2007) p. 1). Some commentators state that institutional investors include pension funds, insurance companies, endowments, sovereign wealth funds and investment

managers (Nelson and Pierpont, 2013) which goes beyond this definition. Some analysis focus only on the larger categories of insurance funds, pension funds and mutual funds with a remainder designated as ‘other’ (Kaminker and Stewart, 2012). This analysis takes the term broadly and will look at the conventional and unconventional investment management assets and sources (see Figure 19), including private equity firms and hedge funds which can provide vehicles for institutional investment money to flow through to projects.

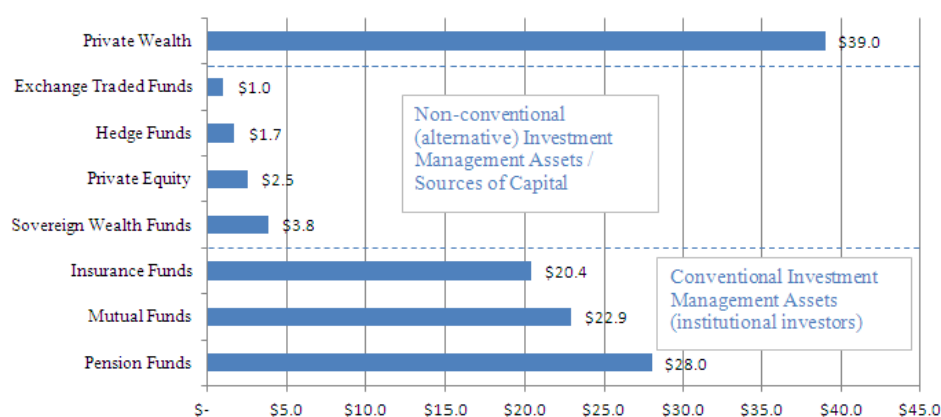


Figure 19 – Global fund management industry, assets under management, 2009 in USD \$ trillion

Source: (Della Croce et al., 2011a) adapted from Climate Change 2011, (Deutsche Bank 2011)

### 3.2.1. The Case for Institutional Investors engagement with Electricity Sector

The structure of institutional investors typically means that their liabilities range from short-term to very long-term. For example, pension funds receive income from contributors who may not expect a pay-out until up to 30–40 years later. Most financial institutions aim to hold a range of assets which broadly match their liabilities. Since there is a limited range of financial assets with such long lifetimes, it has been posited that institutional investor money could be well-matched to long-lived physical assets that typically apply in a range of infrastructure investments such as roads, public buildings (hospitals, schools etc.), as well as electricity sector infrastructure (Kaminker and Stewart, 2012).

Following the OFGEM 2009 Project Discovery report suggesting a gap in UKs future electricity generation investment requirements, commentators have

attempted to identify which part of the financial markets could supply capital to fill this gap. In particular, several studies have singled out institutional investors as the appropriate financiers (PWC, 2012, CEPA, 2011, Holmes et al., 2012). An attribute which attracts immediate attention to this source of finance is its sheer scale. This has been demonstrated in Figure 19 and is estimated at \$71 trillion in assets under management (\$80 trillion if both the conventional and unconventional sources are included from Figure 19), of which \$45 trillion are invested in service of long-term institutional obligations (Nelson and Pierpont, 2013). Due to their expertise and scale, it is suggested that they have the ability to potentially lower the costs of finance for risky low carbon energy projects.

(Nelson and Pierpont, 2013) point out that there are three main routes for institutional investors to finance energy projects. Firstly, the easiest route is to invest via bonds and shares of organisations involved in these projects such as the utilities, which has been an effective and popular route to date (ibid). Secondly is direct investment which is the most difficult and expensive route and due to the expertise required, is currently limited to the largest 150 institutions (ibid), which has been discussed in the project finance section. Finally is through pooled investment vehicles and infrastructure funds which can be effective ways for smaller institutions to pool their resources and increase the liquidity of the investment through a publicly traded pool (ibid). This section will explore these three finance routes.

### **3.2.2. Investing through bonds & shares**

It is important to note that institutional investors are already indirectly responsible for supplying the majority of finance into the electricity sector as a result of being such dominant players in traded equities and bond markets through which the major utilities derive their main source of funds. Figure 20 shows the allocation plans of UK managed assets which reflects the majority stake allocated to equities and bonds. Although the composition of allocation has changed, around 80% has being designated for equities and bonds (Investment Management Association, 2012). This is justified by institutional investor's expertise in and preference for tradable liquid assets.

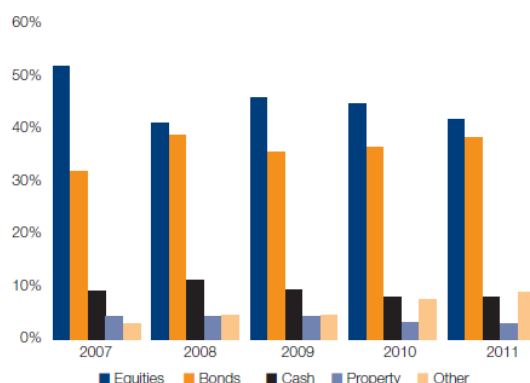


Figure 20 – Allocation of UK managed assets (2007 – 2011)

Source: (Investment Management Association, 2012)

### *Bonds*

The constraints that limit utilities from raising additional debt by issuing additional bonds arises because of the need to maintain credit ratings (as discussed in section 2.1). From the financial market perspective, credit ratings matter because institutional investors are required to limit exposure to risky investments. Financial regulations codify requirements on risk exposure, liquidity, transparency and diversification (Nelson and Pierpont, 2013). These regulations and limitations are being reinforced with the introduction of the Basel III and Solvency II regulations.

This leads to an extremely important dynamic in the relationship between energy markets and financial markets. Acceptable levels of risk in the energy market (at least under the corporate utility financing model) are effectively constrained by the level of acceptable risk in the regulated sectors of the financial market. If risks rise to the extent that utilities lose their A ratings, they may lose their investment-grade status. This not only puts them at a disadvantage in terms of having to borrow at higher interest rates, but the volumes of money available at these higher risk ratings may simply not be large enough to sustain the utility financing model. Simply in order to balance the needs of these two interdependent sectors, the scale of bond issuance therefore has to be carefully managed.

Nevertheless, economy wide, European corporates have started using the debt markets more intensely and bond issuances have recently increased on the back of decreased bank lending, and record low sovereign bond yields, as

investors seek more attractive alternatives (Deutsche Bank, 2013) and Figure 15.

This economy-wide trend is also repeated in the energy sector. Market data from (Thomson Reuters Datastream, 2013b), shows that bond issuances from four of the 'big 6' integrated energy utilities has been fairly active since the financial crisis (RWE, EDF, Centrica, SSE). Steady bond issuance activity from utilities since the crisis is also indicated in analysis from (Miller, 2011), fuelled by investor appetite for low coupons.

An increase in bond issuances to expand utility balance sheets would widen the viable channel for institutional finance to flow. However, if utilities are simply changing the composition of their debt by moving towards bonds instead of bank loans, overall potential investment for the energy sector will not expand. Bonds do, in principle, offer a viable route for institutional finance to flow, but the net increase of finance for this route relies on the ability of utilities to expand their balance sheets without increasing credit risks, which is determined as previously discussed by electricity market conditions.

There is also the potential of project bonds as a mechanism to channel institutional finance, which will be described in section 4.4.

### *Shares*

Companies are also limited in terms of their ability to issue new equity for example through new rights issuance. The theory of when and how companies can expand their equity-base by issuing shares is discussed in Section 4.1.1. Issuing new stock is widely seen in the financial markets as being dilutive of company value (Financier, 2013), even if they are linked to particular investment opportunities that should increase the value of the company, such as investment in additional physical assets. An exception can be in cases where share price has been increasing, but looking at the historical share prices of the UK utilities shown in Figure 21 however, demonstrates that the share prices have decreased dramatically since the financial crisis.

This theory has been reflected in the sector, where institutional investors who dominate utility ownership have been reluctant to issue equity, particularly

for the construction of new low carbon generation assets (SSE, 2011). So even if utility managers did wish to raise equity for new investments, the risk aversion being noticed from investors is being reinforced by company underperformance and a lack of trust. For this to change, investors will have to believe in feasible returns from the more challenging energy projects, and companies will need to perform better, which would be eased by an improved economic landscape.

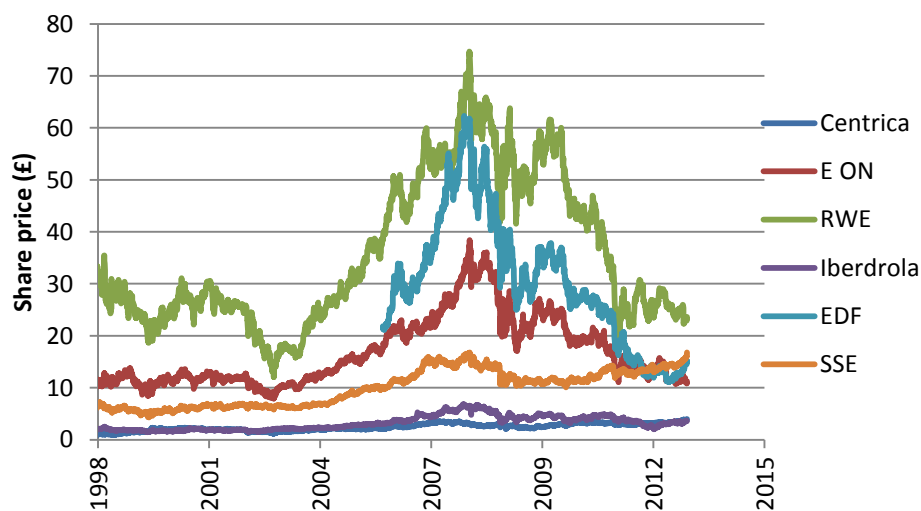


Figure 21 – UK integrated utility share prices from 1998 – 2013 (£)

Source: (Thomson Reuters Datastream, 2013a)

### 3.3. Direct investment, private equity & infrastructure funds

#### 3.3.1. Experience to date

Figure 22 illustrates that different types of institutional investment fund have different limitations on how the assets they can invest in in terms of liquidity and longevity (World Economic Forum, 2011). This limits the available capital that is suitable for energy sector investment to the small portion of funds in the top-right corner of the chart, and even this small share tends to be highly segmented by region and by sector.

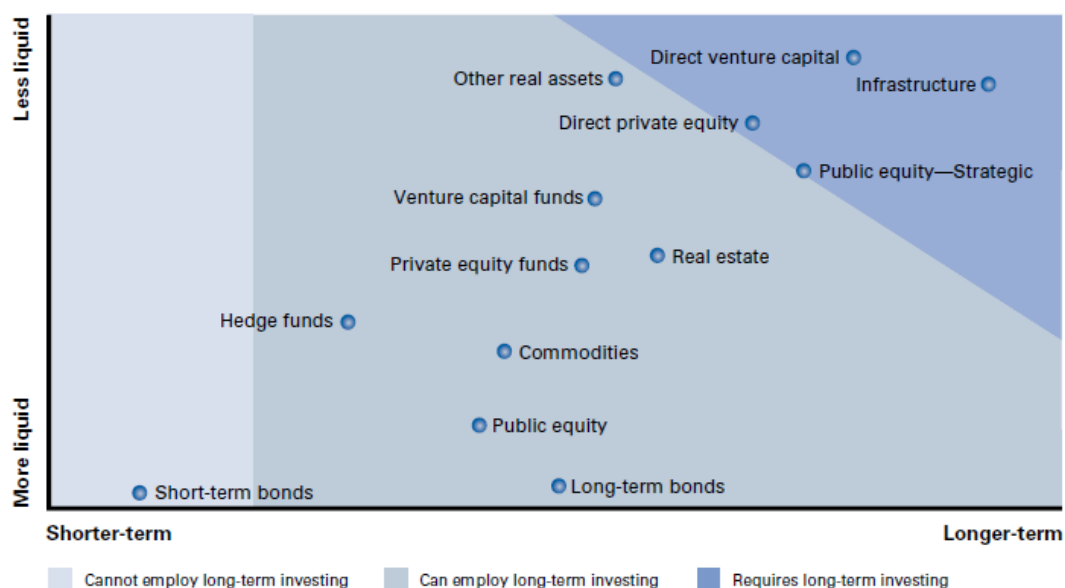


Figure 22 – Asset class liquidity vs. longevity

Source: (World Economic Forum, 2011)

Historically, the great majority of institutional investment has been allocated to liquid (tradable) assets such as bonds & shares as discussed in the previous section. However, a growing fraction of allocation is being made in alternative (illiquid) investment vehicles (Capgemini and RBC Wealth Management, 2013, Mercer, 2013) as illustrated in Figure 23 below.

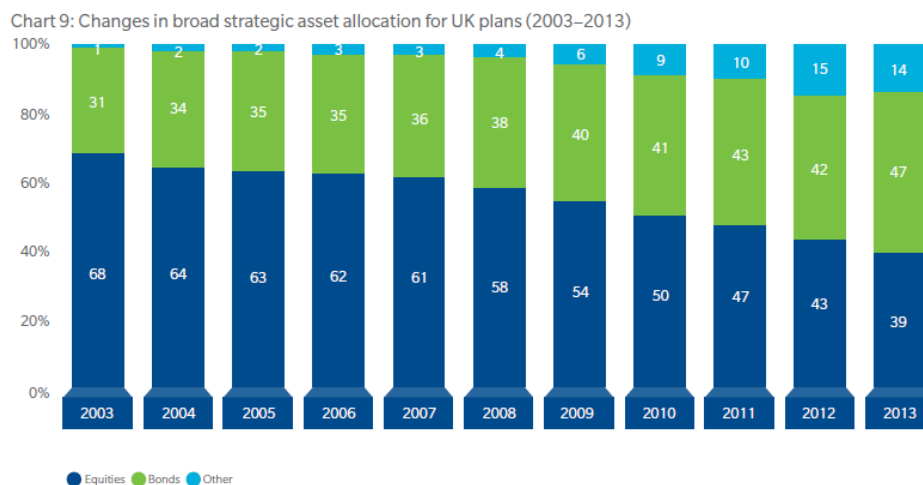


Figure 23 – Changes in asset allocation for UK pension plans (2003 – 2010)

Source: (Mercer, 2013)

These investments have been increasing over recent years as investors seek to gain value in a context of low returns on traditional investments

(Capgemini and RBC Wealth Management, 2013), though market practitioners typically expect that funds allocated to these routes would not exceed 10–15% of assets under management (Mercer, 2013). Recent examples in the UK energy sector include the purchase by Macquarie of the 800MW Severn gas-fired power station from DONG Energy (Reuters, 2013b), and the purchase by Munich Re of the 50% share of the 800MW Marchwood power station from Irish energy company ESB (DowJones, 2013). The three main routes alternative investments can go through are described in the table below. To date, the majority of infrastructure investment from institutional investors has been through unlisted equity of infrastructure funds and direct investment (Della Croce, 2012).

Direct investment	<p>Some allocation is made by institutional investors for direct investment in long-term infrastructure projects. Pension funds for example have experience in direct investment from property (Inderst, 2009), and sovereign wealth funds have stakes in some offshore wind projects as discussed in section 2.2 (Figure 13).</p> <p>One of the major benefits of direct investment is cutting out the use of a fund manager which is required in the other vehicles. This means that intermediate fees can be overlooked which are inherent for indirect investment, resulting in higher returns for the investors bringing with it more control over the asset (Inderst, 2009). Therefore building direct investment teams would not only change organisation culture, but also the risk and return profiles of projects (Nelson and Pierpont, 2013).</p> <p>The drawback to having a dedicated team are the high expenses involved, which would be required for infrastructure, and specific energy investment teams would likely be required due to the unique and complex attributes of these assets. For energy projects the direct investment option would be difficult for organisations with finance of less than £50billion, so it is likely to be only accessible to the largest 150 institutions (Nelson and Pierpont, 2013). Building of dedicated teams has been seen for large pension funds, such as Borealis building a team of 25 and CPPIB a team of 26 professionals dedicated to infrastructure investment (Della Croce et al., 2011b). Sovereign wealth funds may have different risk appetite and regulatory structures from other institutional investors which could in principle</p>
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	<p>mean that they have more freedom to invest directly, but nevertheless they tend to allocate 85% or more of funds to liquid assets and/or fixed-income instruments (IMF, 2013).</p>																		
Infrastructure funds	<p>Infrastructure funds enable institutional investors to pool finance into a fund whereby a manager with expertise in a particular investment area such as energy generation can use their skill set to lower risk and ensure sufficient returns. They are traditionally used to fund large infrastructure projects such as roads, hospitals and housing, but have gained some ground in funding low carbon renewable projects (Mazars, 2012, PWC, 2012).</p> <p>In 2007 before the crisis \$35.9 billion was raised globally with a small fraction for European energy projects, contrasted with £73 billion issued in bonds by European energy utilities alone in the same year (Caldecott, 2010). However Asian markets seem to be growing rapidly, with shares to energy and to Europe taking a significant share of global totals (Prequin, 2013b, Prequin, 2013a) (see Figure 24).</p> <table border="1"> <caption>Figure 24 – Breakdown of infrastructure deals by region and industry Q1 2013 (%)</caption> <thead> <tr> <th>Region/Industry</th> <th>Percentage (%)</th> </tr> </thead> <tbody> <tr> <td>Europe</td> <td>69%</td> </tr> <tr> <td>North America</td> <td>13%</td> </tr> <tr> <td>Asia</td> <td>8%</td> </tr> <tr> <td>Rest of World</td> <td>10%</td> </tr> <tr> <td>Social</td> <td>38%</td> </tr> <tr> <td>Energy</td> <td>31%</td> </tr> <tr> <td>Transport</td> <td>20%</td> </tr> <tr> <td>Utilities</td> <td>5%</td> </tr> </tbody> </table> <p>Figure 24 – Breakdown of infrastructure deals by region and industry Q1 2013 (%) Source: (Prequin, 2013a)</p> <p>IRRs for infrastructure funds are typically in the high teens, as opposed to lower requirements for pension funds. This could be another restriction as the challenging energy projects such as offshore wind have current IRRs of around 12%. If finance is to be channelled through infrastructure funds, it would be targeted for equity, as it is usually the focus for preconstruction and construction equity finance due to the higher returns involved (Caldecott, 2010). However, since the crisis there has been evidence of infrastructure funds targeting lower returns. (Taylor–DeJongh, 2009) note a target return from private infrastructure fund from 18–20% reducing after the crisis to 13–15% as they can't rely on financial engineering to generate higher returns. A continuation of this trend will see growing feasibility of infrastructure funds.</p>	Region/Industry	Percentage (%)	Europe	69%	North America	13%	Asia	8%	Rest of World	10%	Social	38%	Energy	31%	Transport	20%	Utilities	5%
Region/Industry	Percentage (%)																		
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Social	38%																		
Energy	31%																		
Transport	20%																		
Utilities	5%																		

	<p>A limitation on the regulation front are potential consequences from the Volker Rule and the Alternative Investment Fund Manager Directive (AIFM) Directive (Della Croce et al., 2011b). The AIFM aims to improve transparency from hedge fund and private equity fund managers through reporting systemic data, which commentators feel may create barriers and limit investment in these funds. The Volker rule prevents banks from trading in their own account or private equity or hedge funds, with a 3% ownership limit for a fund, representing another barrier to infrastructure funds (Della Croce et al., 2011b).</p>
Private equity and hedge funds	<p>These are investment vehicles used to pool investor capital. They have evolved to enable people with insufficient expertise or finance to make investments into projects which would be otherwise restrictive (Forbes, 2013). Some investors lack the scale of finance required to invest in a particular asset such as energy generation, so the pooling mechanism can be effective here, whereby a fund manager with expertise in the industry can be responsible for ensuring effective and efficient investment. They would be well suited to funding equity of energy generation investments due to the unique nature and knowledge required of the complex energy markets required to sensibly undergo investments in the sector.</p> <p>Private equity funds alone make up an estimated \$3 trillion (Forbes, 2013), so they are a potentially well fitted and sizable resource for channelling investment into UK energy generation assets. However, as pointed out by (IHS CERA, 2013) like other parts of the financial industry, funds such as private equity have been squeezed due to the closure of the initial public offering (IPO) markets and downward pressures on debt availability.</p>

Global investment through these routes into long-term fixed assets is estimated at \$2.4 trillion (World Economic Forum 2011). This large total is however greatly fragmented into many much smaller sectoral and geographical allocations. Investment into European clean energy infrastructure is a small share of this total, as shown in Figure 25. The chart shows that the average annual amounts invested over the four years 2009–2012 from these sources was almost €2bn (€0.5bn for direct investment,

€1.1bn for infrastructure funds and €0.3bn for hedge funds and private equity). Figures are not available for the UK, but could represent perhaps 10% or more of these European totals given the relative size of UK and European renewable markets.

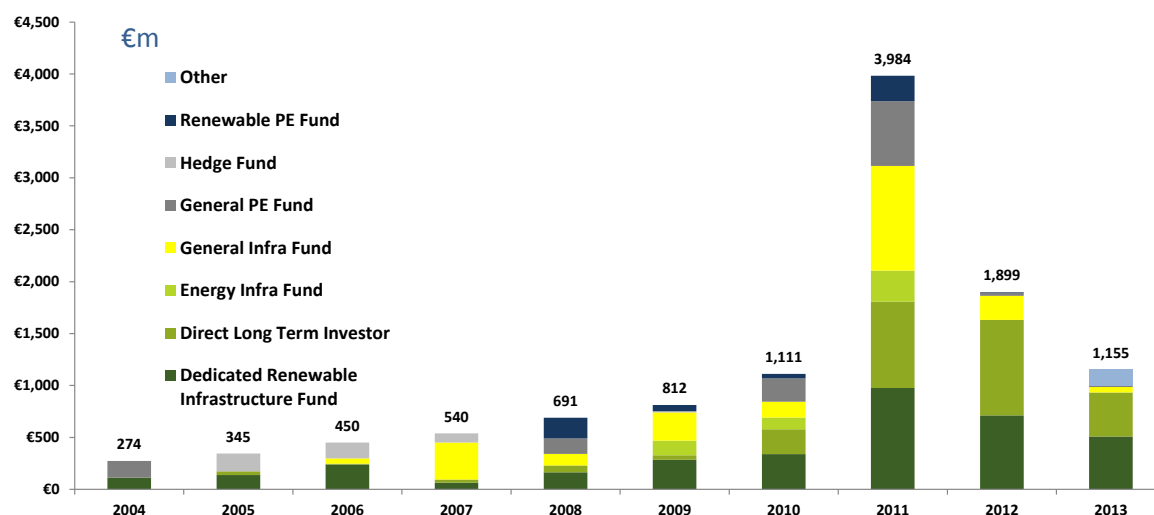
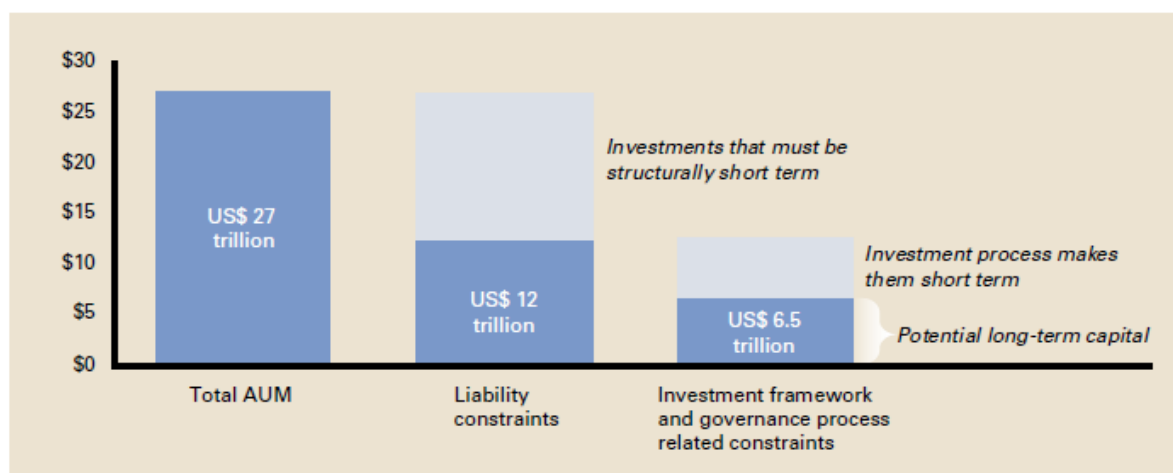


Figure 25 – Direct Institutional Investment in EU low-carbon infrastructure €m.

Source: (Hg Capital)

### 3.3.2. Potential Increases in the Future

The OECD (Kaminker and Stewart, 2012) has estimated the institutional investor's global capital value of \$71 trillion. (World Economic Forum, 2011) identifies a subset of these investors who could potentially invest in long-term assets, and arrive at an estimate of around \$27tn assets held by these groups. Of this, they estimate that \$15tn is required to be invested in structurally short-term assets, and a further \$5.5tn tends to be in short term assets because of investment processes. This leaves around \$6tn that could be available for investment in long-term assets (Figure 26).



Note: Numbers are estimates.

Source: Celent, NACUBO, The Foundation Center, SWF Institute, OECD, US Federal Reserve Flow of Funds, CEA, Oliver Wyman analysis

Figure 26 – World Energy Forum estimates of availability of capital for long-term assets

Source: (World Energy Forum 2011)

This figure of \$6tn is approximately 2.5 times larger than the estimated \$2.4tn total allocations currently made to investing in all categories of long-term assets globally (WEF 2011). If the share of finance to European energy infrastructure were to scale up by the same amount, then the volumes could increase from the level of around €2bn to perhaps €5bn for Europe as a whole. Perhaps 10% or more of this might be available for the UK, but it seems unlikely that investment volumes for the UK electricity sector would exceed £1bn per annum at the most. This makes a significant contribution, closing perhaps up to a quarter of the investment gap identified in Section 1.1

These figures are backed up by other estimates in the literature. (Ernst & Young, 2010) estimate a contribution of £8 to £15 billion for UK low carbon energy investment in total over this decade, based on an allocation of 5% of UK and European infrastructure funds, which again points to a contribution of around £1bn per year. (Nelson and Pierpont, 2013) are somewhat more optimistic, suggesting that across N. America, Europe and Australia, such funds could provide up to a maximum of a quarter of required project equity, and up to a maximum of half of debt requirements. However, they point out that significantly more attractive risk return profiles would be needed to achieve these levels of investment (ibid). Interestingly, CPI note that institutional investors are unlikely to be providing capital at sufficient scale to

set the prevailing cost of capital in the sector, suggesting that their influence is unlikely to bring down financing costs to any significant degree (ibid).

Infrastructure assets are complex by nature, and power generation assets could be considered some of the most difficult to understand and manage, more so for renewable and nuclear assets, with their reliance on policy mechanisms. This is compounded with their highly capital intensive nature. As such, for direct investment, they require specialist in-house expertise. Currently, there is a gap between the institutional community's interest and their actual investment due to this lack of capability (LCFG, 2012).

To build up in house expertise in a particular infrastructure asset class requires investment in a dedicated team. This can be expensive, and requires a certain amount of company strategy involvement as discussed previously. Hence the demand for investment pools and funds mentioned previously, or effective project consortia where various parties could share their expertise, and make these investments more accessible. A major consideration is the possibility of capital costs increasing from institutions being less directly involved in projects (Nelson and Pierpont, 2013).

## 4. Ways to boost investment

In this section, the report will discuss how investment could be boosted. Four key areas are explored; an overhaul of the utility model, boosting project finance through refinancing, an increased role for public institutions, and green bonds.

### 4.1. Overhaul Utility Model

#### 4.1.1. Review of literature on corporate capital structure and raising finance

Theories of how and when organisations raise finance include the trade-off theory and the pecking order theory (Gaud et al., 2007). Trade-off theory suggests that companies use a target ratio for deciding on debt and equity levels, which aim to balance the tax benefits with the actual financial costs of the debt (ibid). Pecking order theory sees the information asymmetry, costs and risks of raising finance as major deciders resulting in firms firstly choosing their own cash flows, then low risk debt, then high risk debt, and only under duress, issuing equity (Myers and Majluf, 1984). This appears to match behaviour under the current utility model. (Graham and Harvey, 2001) find some evidence in support of pecking order and trade-off theory, but highlight the importance that firms hold for credit ratings and financial flexibility when issuing debt and concerns on share dilution and appreciation when issuing equity.

However, (Dittmar and Thakor, 2007) propose an alternative theory, stating that firms are more likely to issue equity when they are raising finance for new projects which are aligned with the investors views on the project returns, thereby enabling successful issuance. This may be correlated with times when share prices are high (Dittmar and Thakor, 2007), (Jung et al., 1996) and (Asquith and Mullins Jr, 1986). Evidence that equity raising can be a normal part of business comes from (Fama and French, 2005) who study a large selection of firms from 1973 to 2002 and find that firms regularly issue stock when they are not under duress and that 50% of firms sampled violated the pecking order theory. The authors also highlight the importance of investors agreeing with management objectives and target projects to support the issuance.

(Gaud et al., 2007) in a sample of 5000 European firms conclude that their policies on capital structure cannot be naively reduced to a simple trade-off or a pecking order theory. They state that firms prefer internal financing as opposed to external financing, but undergo scrutiny if there is a substantial build-up of slack, and that European firms usually impose upper limits of leverage. (Jung et al., 1996) provide additional evidence that many cases deviate from the pecking order theory, but confirm the expense involved in raising equity because new shares are often issued at a premium to current share prices. This can lead to a reduction of share prices when new stock issues are announced (Asquith and Mullins Jr, 1986). Different finance raising activities can portray different messages to investors and affect share prices: raising debt may send signals regarding managements positive expectations for future revenue streams, whereas issuing equity may be perceived negatively (ibid).

Reflecting on this literature in the context of the utilities suggests that as previously noted, the main route over the past decade to raising finance has been to increase debt (in line with pecking order theory), but that this has now reached unsustainable levels, and needs to be reduced (in line with trade-off theory). The alternative, whereby companies could expand their balance sheets through equity issuance as suggested by (Dittmar and Thakor, 2007) would require shareholders to perceive any new capital investments as having a secure and positive economic basis. In practice, this would require significant improvement in the underlying electricity market conditions, which currently do not support such an approach. Nevertheless, it is an option that policy-makers need to consider with regard to attracting additional capital to the sector in the future.

#### **4.1.2. Building a dedicated utility scale low carbon energy company**

One option is to set up a dedicated utility which specialises in low carbon projects. This would combine the advantages of the utility model (large companies with balance sheet scale matched to the scale of the investment required, and with access to low-cost capital through bond and share markets) with the advantages of specialisation, whereby the company can maximise learning and technology cost reduction through accumulation of project experience (Hagel and Brown, 2005).

So far in the UK, utility companies have tended to invest in a portfolio of technologies. While this can reduce overall risk for the companies themselves, it does not reduce risk for the investors, who are in any case able to pool risk across technologies by choosing a portfolio of shares across different companies (Brealey et al., 2006). For both the utilities and the oil and gas sectors, low carbon investment will always be just a part of their portfolio, at best included to aid diversification, so their dedication and expertise may arguably be somewhat limited.

However, if a number of investors grouped together to form a large investment arm, with the expertise and finance required to undertake the risks involved to specialise in low carbon energy investment, this could offer a viable channel, an approach championed by James Cameron, founder of specialist low carbon investor and advisory firm Climate Change Capital (Murray, 2013).

#### **4.1.3. Re-regulating the sector**

(Helm, 2009) argues that during the two decades after privatisation when there was considerable excess generation capacity, the liberalised market was well suited to driving efficiency into the generation business to reduce costs, but that now the sector faces a need to renew its capital stock, it may be time to return to a regulated asset base (RAB) model in order to allow access to low-cost capital sources that would come with the increased certainty of returns this would bring.

Under RAB regulation, returns to investments in energy infrastructure would effectively be a contractual arrangement with the regulator, providing a much greater degree of security regarding future repayments through bills (ibid). Energy infrastructure requirements could be set out in National Policy Statements, which are already published by DECC (e.g. (Decc, 2011)). Tradable RABs with competitive auctioning processes for separate OPEX and CAPEX functions would bring transparency (ibid). By removing the balance sheet from the model entirely, all the limitations discussed in relation to utilities and investors finances would be eradicated (ibid). A major issue would remain, in that it would still be necessary to convince consumers of the need to pay potentially higher prices for government decisions on UKs energy future, so that regulatory risk would not be entirely removed. However,

experience in other areas of the energy sector, such as the gas network industry in Europe indicates that institutional investors are more prepared to enter these kinds of RAB assets.

## **4.2. Ramp up Project Finance through refinancing**

Once the construction phase is complete and a generation plant has operated for a period of time to show it is functioning as expected, the technical risks for the project are significantly reduced, and projects are often refinanced to get better terms for the debt at this stage. Early stage refinancing has been an important feature for onshore wind. It allows project developers to recycle their capital into new projects.

A similar model is beginning to appear for offshore wind projects. For the Walney projects, the OPW joint venture who own 24.8% of the project, secured financing from DONG, and are looking to refinance their position under a 15 year PPA, after a number of successful years of operation (Hervé-Mignucci, 2012). However, the model requires a good understanding of the remaining technical risks that are being transferred to the new owners, and offshore wind is still at an early stage in the development of this experience.

The use of bridge financing is a method of securing finance for the risky construction phases. The idea here would be for utilities and OEMs project developers (those with the skills, experience and finance) to undertake the initial construction phase using equity financing. Consortia are arranged with these experienced parties, who would be comfortable managing the risks involved. After a short term of 12 months operation, sponsor equity investment can be refinanced under more agreeable terms such as subordinated debt with long term arrangements on the financial markets, freeing up funds for further construction projects for the investors (PWC, 2012). This model of bridge financing could lead the way until enough experience has been built to get the less traditional investors comfortable with construction risk. This could be an effective method of building a reliable pipeline for high risk low carbon energy projects. It would also be an efficient method of dealing with the shortage of finance from utilities and other organisations with over leverage balance sheets.

This process suggests a potential new business model for utilities (Financier, 2013). With their skills and experience of project development and operation, there is a viable place for utilities to act as engineering houses, getting their revenues from project development, and selling them on, rather than acting as long-term owners of generation assets. This would allow their balance sheet capital to be spread over a larger number of projects. Such a model would require support from shareholders, since it is quite a strong departure from the traditional utilities model. It would also require a sufficiently large pool of investors prepared to act as long-term owners of generation assets for the utilities to sell to. As discussed previously in this report, this would require significant improvement in the risk-return profile of the electricity markets (ibid).

### **4.3. Increased Role of Public Institutions**

#### **4.3.1. UK Guarantees and the Public Finance 2 (PF2) initiative**

The UK has introduced the Government Guarantee Scheme and the treasury have proposed the Private Finance 2 (PF2) initiative, both with various financing structures aimed to boost project finance (Standard & Poor's, 2013). These schemes could potentially fill the gap created by the collapse of the monoline insurance business model mentioned previously.

##### ***UK Guarantees***

The UK Guarantee scheme has been set up by the treasury to provide up to £40 billion of government guarantees for projects deemed nationally significant in the government's National Infrastructure Plan (HM Treasury, 2012). Guarantees will be provided based on the individual project requirements, such as fully guaranteeing debt, guaranteeing public sectors unitary charge obligations, construction phase guarantee or any combination or various other mechanisms (Standard & Poor's, 2013). Guarantees are more complex than debt, with the government effectively acting as an underwriter to the project. Due to the complexity, banks may consider it more difficult to refinance projects with guarantees than straightforward debt (PWC, 2009).

Table 4 shows the energy projects listed with the top 40 nationally significant projects according to Infrastructure UK (IUK). The government have recently announced a £10 billion UK Guarantee to advance the Hinkley point nuclear

project (One News Page, 2013, Alexander, 2013), although the amount is still rather speculative as negotiations are on-going.

Type	Details	Cost
New nuclear investment	EDF's application for development consent approved in March 2013 for Hinckley Point C	~£10bn TBC
Carbon Capture and Storage Investment	DECC announced in March 2013, that it would bring 2 preferred bidders to planning and design stage, in the CCS Commercialisation Programme	£1 billion
Gas investment (CCGT)	2 CCGT S36 (2.15GW) under consideration.	TBC
Biomass investment	Drax offered guarantee for coal to biomass conversion, also plans for Ironbridge conversion, and support from GIB for Selby conversion	£75 million drax
Wind energy investment	East Heckington (66MW) given planning permission in February 2013. Development consent approved for Pen y Cymoedd (299 MW – gained in May 2012), and offshore wind proposals approved in July 2012 for Race Bank (580MW) and Dudgeon East (560 MW). • One Planning Act application (Kentish Flats extension (51MW) has recently been awarded development consent, with a further three	TBC

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applications due for  
ministerial determination  
during 2013 (1.8 GW).

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**Table 4 – Energy plants in the top 40 IUK nationally significant infrastructure plans**

Source: (HM Treasury, 2012)

### ***Project Finance 2 Initiative***

The Project Finance 2 initiative, replaces the Project Finance Initiative which, since the early 1990s was the governments favoured method of procurement for infrastructure projects (S&Ps 2013 potential credit effects). Although this is an approach that has been used mainly for hospitals, schools, roads and accommodation projects rather than energy, it demonstrates another mechanism the government is using to engage with the private sector to ensure vital projects go ahead (ibid). Whilst the government will help manage the long term risks of projects, improving the rating and attracting the necessary investment, the key is to share risk management with the private sector providing credit quality throughout the project cycle (ibid).

However, some commentators argue that the scheme would lead to a high cost of capital, and would be expensive and unrealistic to scale up (Leach, 2010). Others argue that this scheme has been successful in the past for important infrastructure and is being used now for large infrastructure projects such as train stock worth £1 billion for London's Crossrail (Pickard et al., 2012), and that lessons could be taken from this effective tool for other public project interventions such as the UK Guarantees scheme described above.

### **4.3.2. The Role of the GIB and the EIB**

The Green Investment Bank (GIB) was set up by the UK Government in October 2012, with £3.8 billion in capital and borrowing power (Smith and Williamson slides 2013). This capital could grow to £18 billion within three years if co-financing support from the private sector, including institutional investors, can be secured. They are a for-profit bank with the aim of accelerating UK towards a green economy. In their first 5 months of operation they have invested £635 million to mobilise £2.3 billion in total in offshore wind,

energy efficiency, waste to energy and waste recycling projects, achieving a 1:3 leverage ratio (ibid).

Although some commentators point out the small scale of the bank compared to the size of the total investment required, they are an institution set up for green investments only, meaning all their attention can go into gaining knowledge and educating the investment community on how to make these projects a success. The hope is that the institution can also grow in order to leverage larger amounts of finance. They could also play a role in funding construction phases of projects before refinancing as suggested by (SSE, 2011), although at present as a fledgling institution, they do not appear to have the appetite for such risks, and are focussing attention on boosting secondary markets for refinancing of existing projects (Financier, 2013).

The European Investment Bank (EIB) is one of the largest investors in clean energy projects in Europe, providing €47 billion of funds during the period from 2007 to 2012 (IHS CERA, 2013), with €4.5 billion in 2012 alone for energy projects in the EU (EIB, 2012). Their strong AAA rating means that in 2012 they were able to borrow €71 billion on the international capital markets, a show of their financial capacity (ibid). To date, the role of the EIB in UK has been limited, as mentioned in section 3.1.2 they only have direct involvement in two projects, both currently under appraisal, for a coal to biomass conversion and an offshore wind project. Nevertheless, the quantity of finance committed from the EIB and quality of overall projects thus far shows from an EU level the important role public bodies provide in strategically managing risk and securing finance from the wider investment community for low carbon energy projects.

#### **4.4. Green bonds**

In 2012 the EIB set up the Project Bond Initiative (PBI) to attract institutional investors to important infrastructure investments. The initiative will enable project companies to issue investment grade bonds through an EIB risk sharing mechanism, and as part of the 2012–2013 pilot, up to €230 million in guarantees will be provided (EIB, 2012). As part of this initiative they have set up the European Public Private Partnership (PPP) Expertise Centre (EPEC) to enable PPP knowledge and experience sharing between the EIB, 35 EU Member States and candidate countries. This initiative shows how a large

public institution can lead the way for such as scheme, and if successful, could pave the way for private banks to take on the role giving access to long term bonds for large, high risk projects.

(Caldecott, 2010) poses a similar idea for green infrastructure bonds as a method of refinancing project operational cash flows providing easily tradable long term liquid assets with a lower cost of capital. Overcoming liquidity and capital barriers would open the door to institutional investors and increase the share of available investment they have for these types of project. There are a wide range of names for this class of instrument such as GIB bonds, green retail bonds, corporate green bonds, climate bonds, green bonds, but they all have similar attributes and would help in raising finance for low carbon energy investments (Caldecott, 2010). The real prize would be for green bonds to be issued to fund the risky construction phases, where acquiring low cost debt finance is a struggle, but if they are still seen as high risk they are unlikely to obtain investment grade ratings, and therefore would not attract sufficient investment.

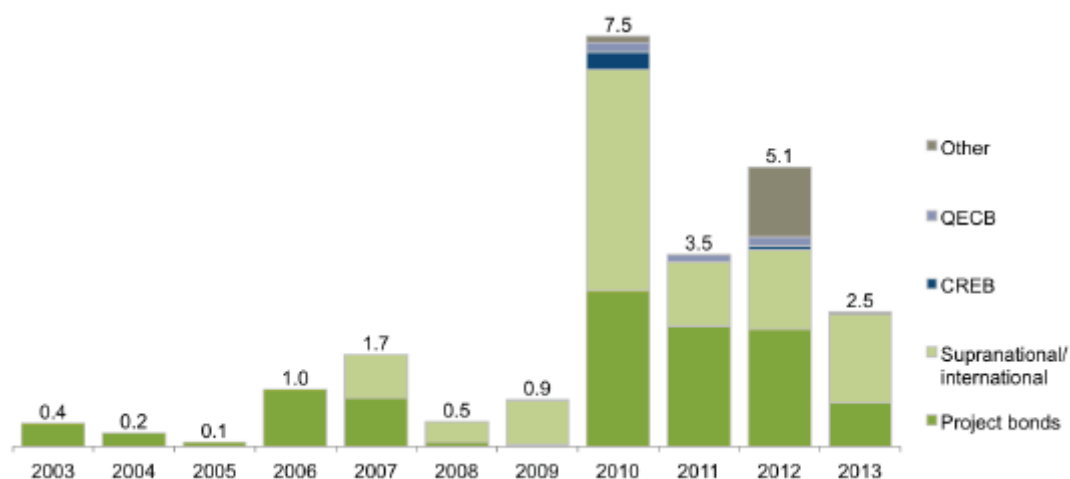


Figure 27 – Tier 1 Green bond issuance (\$ billion)

Source: (UNEP, 2013) with data from BNEF

There is a growing number of green bond issuances as seen in Figure 27, although this has slowed noticeably since the recession as investors seek less risky investments. The total number of general bond issuances which can be linked to low carbon energy projects has a figure estimated at \$11.6 billion in issuance globally in 2012 alone (only including investment grade ratings of

issuances over \$100 million) (Padraig and Boule, 2013) which shows the potential of this instrument. However, the UK market for green bonds for energy projects is still emerging, with only two issues in 2012 for small solar and wind energy projects.

A barrier highlighted by (Kaminker and Stewart, 2012) is that these long maturity bonds will be at the lower end of the investment grade ratings, which means they will require higher capital charges, which may be inflated further by regulations such as Solvency II. These ratings limitations would also only attract a limited span of investor interest, therefore limiting the market potential for such project bonds schemes (ibid). (PWC, 2012) comment on the complexity of green project bonds, and due to their immaturity, ratings agencies have yet to clarify their position on them. Also (Veys, 2011) warns that a typical minimum issuance size for a standard institutional investment grade bond is around £300 million, which means that only large projects, or pools of smaller projects would be able to access these sources of finance.

Recent green bond issuances by the private sector have recently overtaken those of public institutions, but so far have been made by large companies: EdF (€1.4bn), Toyota (\$1.75bn) and Unilever (£250m) (Economist, 2014). The EdF example is interesting as it shows the ability of the power company to raise debt for new investments in the current market conditions. However, these examples do not show that green bonds can yet stand separate from large corporate backing, so do not yet on their own represent a sea-change in financing models.

Nevertheless, green bond proponents suggest that through time and experience, bonds linked to projects without utility-scale would achieve better credit ratings, participants would get comfortable with issuance sizes to accommodate smaller projects, the market would grow, and they would offer another channel for sizable amounts of institutional investor finance to flow (personal communication – financier). An emerging global market is provided as evidence for this view, and along with schemes and institutions such as the PBI and GIB, suggests that UK could follow this path (ibid).

# Appendix

## A. Organisations Consulted During Research

The original intention of this research was to be based on a literature review. However, considerable knowledge of financing behaviour, trends and potentials is held by practitioners, rather than necessarily published. This research therefore benefited considerably from interviews with a range of practitioners in the finance sector. Since the individuals generally wished to remain anonymous, only organisation names are listed. In some places in the text, individual views have been referenced to personal communication. However, more generally throughout this text, these interviews have been synthesised to provide the basis for the views expressed in the report. The authors wish to express their gratitude to all those who gave their time to be involved in this study.

- Bank of America Merrill Lynch
- Barclays Bank
- Climate Change Capital
- Climate Policy Institute
- Ethix SRI Advisors
- Foresight Group
- Green Investment Bank
- Hg Capital
- IHS CERA
- Low Carbon Finance Group
- National Grid
- New Energy Finance
- Ofgem
- Pöyry
- Renewable Energy Generation
- Standard & Poor's
- University of Leeds
- Z/Yen

## B. Overview of Published Estimates

### Ofgem Project Discovery (Ofgem, 2010a)

This was a major review of the investments across the whole of the UK gas and electricity sectors<sup>5</sup> that are required in order to maintain energy security and meeting environmental targets. Similar projects had been undertaken at the international level by the (IEA, 2009), (Roadmap 2050, 2010) etc.

Nevertheless, the study was something of a landmark for the UK, resulting in spectacular headline figures for the amount of money required which triggered a number of other similar studies, started a public policy debate about the availability of finance for this kind of infrastructure development, and acted as a spur for the energy market reform which followed. The study was based on four representative scenarios.

**Green Transition.** This scenario is characterised by rapid economic recovery and a significant expansion in investment in green measures. The EU 2020 renewables target is met and deployment reaches 30% in the electricity sector. Energy efficiency measures are also effective, and carbon dioxide emissions reduce rapidly.

**Green Stimulus.** In this scenario recovery from the recession is slow and there is a higher cost and restricted availability of credit. Governments across the world implement ‘green stimulus’ packages in order to achieve environmental goals and support economic recovery.

**Dash for Energy.** Under this scenario, the recession proves short-lived. Demand bounces back strongly and then increases over time, although investment levels take some time to become re-established following the hiatus caused by the credit crisis. Security of supply concerns prevail over environmental concerns, and the proportion of energy delivered through renewables is less than half of the 15% target albeit against a high demand backdrop.

**Slow Growth.** Under this scenario, the recession and the ensuing effects of the credit crisis continue to drag on for a long time. Global and GB demand

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<sup>5</sup> Includes generation, transmission & distribution and storage

remain depressed, and as a consequence of this and financing constraints, and electricity infrastructure investment reduce considerably from pre-credit crunch levels.

	Green Transition (GT)		Green Stimulus (GS)		Dash Energy (DE)	for (SG)	Slow Growth
Economic recovery	Rapid		Slow		Rapid		Slow
Environmental actions	Rapid Renewables targets met, investment in CCS	–	Rapid Renewables targets met, investment in CCS	–	Slow Renewables targets not met, limited CCS	–	Slow Renewables targets not met, limited CCS
Electricity demand	Falls until 2015: energy efficiency Increases longer term: electrification of heat, transport		Falls until 2015: energy efficiency Increases longer term: electrification of heat, transport		Increases		Falls until 2012 – recession, then increases
Nuclear	Further extensions, strong new nuclear		Further extensions, strong new nuclear		No further extensions, new nuclear delayed		No further extensions, no new nuclear
Commodity prices	Medium gas, high carbon, low coal		Low prices, carbon	fuel high	High fuel prices, moderate carbon prices		Low fuel and carbon price

Table 5 – Summary of key assumptions in OFGEM 2009 Scenarios

Source: (Ofgem, 2010a)

### Ernst & Young Securing the UK's Energy Future (Ernst & Young, 2009)

Commissioned by Centrica in 2009 to update E&Y's previous estimates (Ernst & Young, 2008), this study reviewed investment needs across the electricity and gas sectors. The study considers a timescale out to 2025 under a single scenario, making the following key assumptions:

- 26% cut in carbon emissions by 2020 from a 1990 base level and measures to meet this target
- Over 40% of electricity to be generated from renewable sources from 2020, driven by the requirements of the EU Renewable Energy Directive
- Excludes ‘business as usual’ spend on networks, focusing instead on the incremental spend that will be necessary to safeguard supply security and meet the government’s low carbon agenda
- Closure of all the UK’s existing nuclear plant, except for Sizewell B, by 2023
- Retirement of 8GW of coal-fired capacity, which has complied with the Large Combustion Plant Directive but is likely to reach the end of its working life in the period 2021–2025.

### **DECC Energy Projections (DECC, 2012b)**

DECC has responsibility for producing official government projections of energy demand and supply and greenhouse gas emissions out to 2030 (DECC, 2012b). The main purpose of the analysis is to assess the adequacy of policy measures for meeting energy and environmental targets. For the electricity sector, these projections are made using the department’s own in-house model (DECC, 2012a).

The projections take account of climate change policies where funding has been agreed and where decisions on policy design are sufficiently advanced to allow robust estimates of policy impacts to be made. The projections for 2012 to 2022 indicate how DECC expects to perform against the first three carbon budgets.

The projections for the period 2023 onwards represent what DECC expects to happen in the absence of any additional policy effort. They show a reduction in emissions over the fourth carbon budget period, but not by enough to meet the fourth carbon budget level. The difference between the projections for 2023 – 2027 and the fourth carbon budget level therefore indicates the amount of additional policy effort that would be required to meet the budget. Sensitivity analysis covers impact of high / low energy prices and high/low economic growth rates.

The projections do not include explicit estimates of investment requirements, but they do provide estimates of new build requirements for each type of generation technology. Since DECC has commissioned and published various studies of the capital costs for these technologies, we have therefore used these studies to calculate the implied capital cost requirements of DECC's scenarios.

### National Grid Future Energy Scenarios (National Grid, 2013)

Starting in 2011, National Grid replaced its process of a central view forecast with annual scenario assessments of UK electricity and gas supply and demand. The purpose of the assessments is on the one hand to inform NG planning for infrastructure investments to support possible energy sector developments, and on the other hand to engage in consultation with stakeholders with an interest in NG's investment needs (including the regulator). The analysis considers two scenarios:

Slow Progression, where developments in renewable and low carbon energy are comparatively slow, and the renewable energy target for 2020 is not met. The carbon reduction target for 2020 is achieved but not the indicative target for 2030. Gone Green has been designed to meet the environmental targets; 15% of all energy from renewable sources by 2020, greenhouse gas emissions meeting the carbon budgets out to 2027, and an 80% reduction in greenhouse gas emissions by 2050.

Electricity	2012	2020	2030	2020	2030
Peak Demand/GW	61.1	57.5	56.7	59.7	62.7
Annual Demand/TWh	328	303	297	317	323
Total Capacity/GW	92.3	96.2	115.8	111.6	153.6
Low carbon capacity/GW	24.9	37.0	56.6	50.9	95.2
Residential Heat Pump (HP)/Millions	0.1	0.3	0.6	1.2	5.7
EVs Number/Millions	0.005	0.2	0.9	0.6	3.2
Residential gas	337	317	324	298	254

demand/TWh						
Annual	Gas	866	875	838	795	647
demand/TWh						
Renewable		4	13	23	15	34
Energy %						
Greenhouse Gas	Gas	26	>34	<60	>34	~60
(GHG) reduction						
%						

Figure 28 – National Grid energy scenarios

Source: (National Grid, 2013)

### Committee on Climate Change Next Steps on EMR (CCC, 2013)

In May 2013, the CCC published scenarios for ways in which the electricity sector could reduce CO<sub>2</sub> emissions levels to 50g/kWh, a level identified by the Committee that would be in line with the fourth carbon budget. The main purpose of the scenarios is to show that there are various technological options available to achieve such a reduction in emissions.

The CCC considers four scenarios, which all reach 50g CO<sub>2</sub>/kWh through a portfolio of low-carbon technologies, with differing emphasis on the four key options for decarbonisation (i.e. nuclear, renewables, CCS and energy efficiency). All scenarios include a minimum roll-out of the less-mature technologies, with around 25 GW of offshore wind and 10 GW of CCS installed by 2030. This is intended to develop a portfolio of options for on-going provision of low-carbon electricity after 2030 and creates flexibility to respond to changing relative costs. All scenarios include some continued roll-out of onshore wind, albeit at a slower rate than in the 2010s, and a significant new nuclear programme (i.e. 10–18 GW). The individual scenarios then differ in terms of how far each major technology can deliver.

All scenarios also involve a significant increase in deployment of flexibility options – demand-side response, interconnection, storage and back-up gas capacity in order to accommodate the additional renewable energy.

Specifically, the scenarios involve 25–40 GW of new unabated gas capacity, which by 2030 acts largely as a back-up for when wind output is low and demand is high (e.g. by 2030 the average load factor for new unabated gas capacity is less than 20% in these scenarios). We reflect this in our Section 3 analysis of the EMR Delivery Plan.

In order to assess cost implications, the CCC commissioned Pöyry to assess the latest information on costs and deployability of low-carbon technologies (Pöyry, 2013). Although the CCC report does not feature explicit calculations of the total capital requirements for their scenarios, this combination of commissioned data on unit costs together with estimates of new build requirements in the report allows these to be easily calculated.

#### **London School of Economics (LSE, 2012b)**

In 2012, LSE published a report 'Energy and the Economy: The 2030 Outlook for UK Businesses' commissioned by RWE to look at generation capacity and investment needs to 2030 in the UK under three different scenarios (LSE, 2012b). The first, 'Hitting the Target', involves political cohesion in a recovered Eurozone, high levels of investment in the power sector and reduced carbon emissions. The second, 'Gas is Key', assumes that economic momentum will lie with Asia. It explores how short-term price gains from switching to gas power are followed by environmental problems from missed carbon targets. Scenario three, 'Austerity Reigns', looks at how economic stagnation in the UK and Europe would result in less technological investment, with options such as carbon capture and storage, or shale gas, not being implemented.

#### **The Crown Estate (Offshore wind only) (Crown Estate, 2012)**

In 2012, The Crown Estate launched a project to identify cost pathways for offshore wind to 2020, and to identify potential cost reduction opportunities in the areas of technological improvements, supply-chain efficiencies, health and safety and operational procedures, financing options to reduce the cost of capital, and options for transmission cost reductions. The study identified total capital cost implications under four different scenarios, each of which identifies a different capacity of offshore wind installed, taking account of differences in market conditions (Figure 29) and differences in site type (Figure 30):

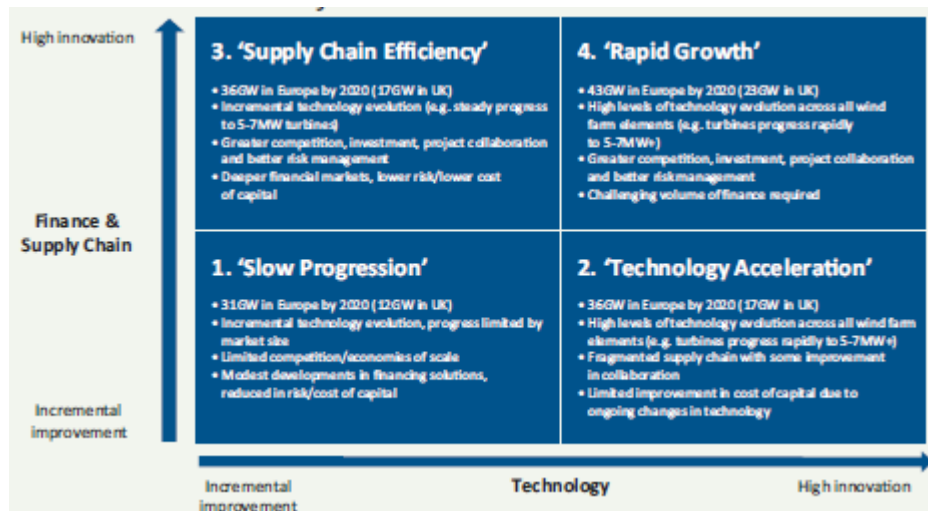


Figure 29 Four industry storylines

Site Type	Average Water Depth (MSL) (m)	Distance to nearest construction and operations port (km)	Average wind speed at 100m above MSL (m/s)
A	25	40	9
B	35	40	9.4
C	45	40	9.7
D	35	125	10

Source: The Crown Estate

Figure 30 Four types of offshore wind site

Source: (Crown Estate, 2012)

### C. Explanatory Variable Analysis

As described above, a key factor affecting the CAPEX estimates is the ambition level of the different scenarios. However, this is not the only difference. In order to identify which assumptions are driving the CAPEX estimates, a simple spreadsheet analysis was developed which could approximately re-construct the CAPEX figures provided in the studies based on the data provided. The form of the spreadsheet was based on the following logic. Total capital costs are the sum of investments in new build capacity  $N_i$  for technology type  $i$ , each with capital cost  $K_i$ . Total demand  $D$  is made up of a share of demand  $s_i$  for each technology. This demand is matched by supply from a mix of new plant ( $N_i$ ) and existing plant that is already on the system ( $X_i$ ). Both new and existing plant are assumed to be subject to the same utilisation factor  $u_i$ .

$$\text{Total Capital } C = \sum_i K_i N_i$$

$$\text{Total supply} = \sum_i (N_i u_i + X_i u_i) = \sum_i s_i D$$

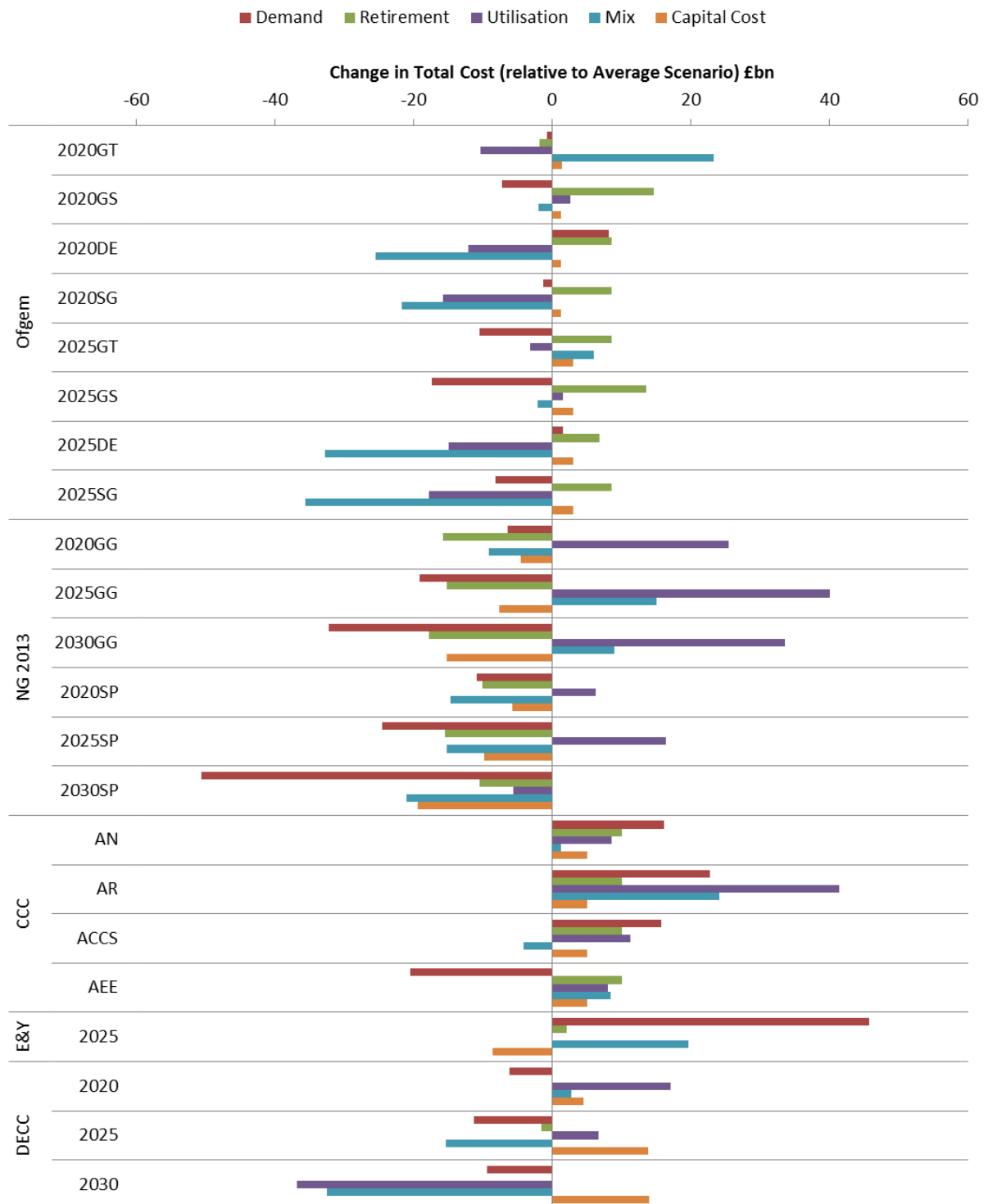
Re-arranging, we can calculate the capital cost  $C_i$  for technology  $i$  in terms of the other variables as:

$$C_i = K_i \cdot \left( \frac{s_i D - X_i u_i}{u_i} \right)$$

This equation gives us the 5 explanatory variables that we can use to explore differences between the scenarios, namely:

1. Total demand for electricity ( $D$ ), driven through differences in economic conditions and level of electrification for example in heating and transport
2. Amount of existing capacity on the system ( $X_i$ ), mainly reflecting different assumptions about retirement rates, particularly coal and gas driven by the industrial emissions directive, and also retirement rates for existing nuclear plant
3. Utilisation rates ( $u_i$ ) which vary considerably between studies depending on assumptions about the impact of variable renewables on the system
4. Share of this demand supplied through different technologies ( $s_i$ ), largely reflecting different levels of decarbonisation ambition.
5. Capital cost per unit installed ( $K_i$ ).

By changing each variable in turn to its average value across all scenarios, the impact of each factor in shifting the scenario away from the average can be calculated. These differences are shown in Figure 31. It should be noted that these deviations do not add up exactly to the total investment figures presented in each study, since the above calculation methodology is only an approximate representation of the methodologies used in studies. Nevertheless, they are close enough to provide a useful comparison.



**Figure 31 – Explanatory variable analysis – deviations of each scenario from the average**

The first point to note is the overall scale of impact of each of the five variables across all scenarios. It is clear visually from the figure that the most significant factors are 1, 3 and 4 (total electricity demand, utilisation rates, and technology mix). The rate of retirement is the next-most significant factor, with unit capital costs being the least significant differentiating

variable. However, it is unclear the degree to which the capital cost assumptions across the different scenarios are truly independent of each other, since there seems to be a degree of information sharing across the different studies. Also, the analysis here did not look at the full range of capital cost estimates identified. For example, in the Parsons Brinkerhoff study for DECC, high and low figures were also provided, but only central estimates have been included here. For these reasons, the potential for capital cost variation is understated by these figures. Nevertheless, where studies quote investment figures, they seem usually to be based on central estimates of unit capital cost, so this seems a reasonable basis for comparison across studies.

This analysis highlights that there are multiple reasons beyond simple environmental ambition as to why studies differ in their CAPEX estimates. These differences are likely to arise from the different models used to inform the analysis, for example the degree to which electricity sector scenarios are integrated into wider economic models which could show up a shift in electrification rates, and the degree of detail with which the impact of wind variability on utilisation rates is modelled.

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