Europe Economics

Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies

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Europe Economics
Chancery House
53-64 Chancery Lane
London WC2A 1QU

Tel: (+44) (0) 20 7831 4717
Fax: (+44) (0) 20 7831 4515

www.europe-economics.com

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Summary

In this report we have updated the BEIS 2015 hurdle rates for solar, onshore wind, offshore wind, merchant CCGT, hydro, tidal stream, wave, geothermal, biomass, energy from waste, landfill gas, sewage gas, anaerobic digestion (AD), advanced conversion technology (ACT), CCS, gas reciprocating engine, and coal plants retrofits.

The figures produced are as follows.

Table 1: Hurdle rates and components for 2018

	Real cost of debt	Real cost of equity	Effective tax rate	Gearing	Pre-tax cost of capital (hurdle rate 2018)	Hurdle rates 2015
Solar PV	1.96%	15.1%	10.2%	80.0%	5.0%	6.5%
Onshore wind	2.30%	13.4%	9.4%	77.5%	5.2%	6.7%
Offshore wind	2.30%	17.7%	10.2%	77.5%	6.3%	8.9%
CCGT	1.70%	8.4%	17.0%	35.0%	7.5%	7.8%
Hydro	1.96%	10.8%	17.0%	70.0%	5.4%	6.9%
Hydro Large Store	1.96%	8.4%	17.0%	60.0%	5.4%	6.9%
Wave	2.30%	22.3%	10.2%	72.5%	8.6%	11.0%
Tidal stream	2.30%	21.2%	17.0%	70.0%	9.4%	12.9%
Geothermal CHP	3.66%	48.3%	17.0%	72.5%	18.8%	23.8%
Biomass Dedicated >100MW	2.45%	10.2%	17.0%	45.0%	8.1%	9.2%
Biomass Dedicated 5-100MW	2.45%	10.0%	17.0%	45.0%	7.9%	9.0%
Biomass CHP	2.45%	13.0%	17.0%	45.0%	9.9%	12.2%
Biomass Conversion	2.45%	11.8%	17.9%	45.0%	9.2%	10.1%
ACT standard	2.45%	11.7%	10.2%	56.0%	7.2%	9.2%
ACT advanced	2.45%	13.4%	10.2%	56.0%	8.1%	10.2%
ACT CHP	2.45%	15.2%	10.2%	56.0%	8.9%	11.2%
AD CHP	2.30%	26.8%	10.2%	72.5%	9.9%	12.2%
AD	2.30%	21.3%	10.2%	72.5%	8.3%	10.2%
EfW CHP	3.05%	12.2%	10.2%	57.5%	7.6%	9.4%
EfW	3.05%	9.9%	10.2%	57.5%	6.5%	7.4%
Landfill	1.96%	10.2%	10.2%	57.5%	6.1%	7.4%
Sewage Gas	1.96%	11.4%	17.0%	57.5%	7.1%	8.5%
CCS Gas FOAK	2.45%	17.2%	17.0%	65.0%	9.0%	11.3%
CCS Gas NOAK	2.45%	13.1%	17.0%	65.0%	7.3%	9.2%
CCS Coal FOAK	2.45%	17.4%	17.0%	65.0%	9.1%	11.4%
CCS Coal NOAK	2.45%	13.3%	17.0%	65.0%	7.3%	9.3%
CCS Biomass	2.45%	17.4%	17.0%	65.0%	9.1%	11.4%
Gas CCGT IED retrofit	1.70%	7.5%	17.0%	35.0%	7.0%	7.7%
Gas Reciprocating engine (inc. diesel)	2.30%	14.1%	17.0%	70.0%	7.1%	7.8%
Coal plants All retrofits	1.70%	8.3%	17.0%	35.0%	7.4%	8.2%
OCGT	2.30%	14.1%	17.0%	70.0%	7.1%	7.8%
CCGT CHP					9.0%	

Source: Europe Economics.

We have derived these values through analysis of developments in bond markets (estimating risk-free rates from UK government bonds and debt premiums for bonds of the relevant ratings from corporate sector data), developments in the energy market (based on share market data), in the electricity sector (based on a combination of share market data and data on electricity price volatility) and evolution of risk drivers for the technologies in question, including considerations of factors such as allocation risk, policy risk, development risk and construction risk.

We can see that hurdle rates have fallen for all our technologies. This is despite rises in systematic risk across energy markets in general and the electricity generation sector in particular. The hurdle rates here have fallen mainly through a combination of falls in market-wide parameters (the risk-free rate and the equity risk premium) and in debt premia, convergence in risks in this sector, and falls in effective tax rates.

In addition, using more limited data and noting the rapidly evolving nature of the business models involved, we propose a hurdle rate of 7.3 per cent for Lithium-ion battery storage and 7.5 per cent for demand side response (DSR).

1 Introduction

This is the final report from Europe Economics' project for BEIS entitled "Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies".

In BEIS modelling of the costs of electricity generation (including both renewables and non-renewables), storage and demand-side reduction technologies, financing costs are reflected through what are termed 'hurdle rates'. Hurdle rates are defined as the minimum project Internal Rate of Return (IRR) at which investments will proceed. This would typically reflect the weighted average cost of capital (WACC), which in turn reflects returns realisable from alternative investment opportunities available to the developer and the relative and absolute risks of particular technologies or projects. In this report hurdle rates are understood as capturing the whole life of a project from planning and development to being fully operational.

Prior to the current report, the most recent previous report on hurdle rates commissioned by BEIS was produced by NERA,[1] and the assumptions developed there were used in the 2016 BEIS Electricity Generation Costs report.[2] In this project Europe Economics is revising the evidence on financing costs of generation technologies, building on that NERA report and on recent updates by regulators, and taking into account changes in market-wide factors such as the risk-free rate and the equity risk premium, as well as technology-specific risks due to learning and technology maturity since the previous update.

The specific list of technologies covered in this study includes those set out in the following table.

Table 2.1: List of generation technology types

Solar PV >5MW	Hydro >5MW
Dedicated Biomass >100MW	Hydro large store
Dedicated Biomass 5-100MW	Wave
Biomass CHP	Tidal stream
Biomass Conversion	Geothermal CHP
Onshore Wind >5MW	CCGT
Offshore Wind	CCGT IED retrofit
ACT standard	CCGT CHP
ACT advanced	OCGT
ACT CHP	Reciprocating engine (gas and diesel)
AD >5MW	Coal IED retrofit
AD CHP	CCS Gas – CCGT
EfW CHP	CCS Coal
EfW	CCS Biomass
Landfill	Demand Side Response
Sewage Gas	Storage Technologies

1.1 Starting point

1.1.1 2015 hurdle rates

The starting point of our analysis are the hurdle rates used in 2016 by BEIS, and the evidence underlying those hurdle rates which can be found in NERA's 2015 report.

Unless stated otherwise, all hurdle rates in this report are expressed in real pre-tax terms. Table 1.1 summarises the 2015 hurdle rates for the technologies relevant for this report.

1 NERA (2015), "Electricity Generation Costs and Hurdle Rates"
2 BEIS (2016), "Electricity Generation Costs".

Table 1.1: 2015 hurdle rates

	Hurdle rate pre-tax real 2015
Solar	6.5%
Onshore wind	6.7%
Offshore wind	8.9%
CCGT	7.8%
Hydro	6.9%
Hydro Large Store	6.9%
Wave	11.0%
Tidal stream	12.9%
Geothermal CHP	23.8%
Biomass Dedicated >100MW	9.2%
Biomass Dedicated 5-100MW	9.0%
Biomass CHP	12.2%
Biomass Conversion	10.1%
ACT standard	9.2%
ACT advanced	10.2%
ACT CHP	11.2%
AD	10.2%
AD CHP	12.2%
EfW CHP	9.4%
EfW	7.4%
Landfill	7.4%
Sewage gas	8.5%
CCS Gas FOAK	11.3%
CCS Gas NOAK	9.2%
CCS Coal FOAK	11.4%
CCS Coal NOAK	9.3%
CCS Biomass	11.4%
Gas CCGT IED retrofit	7.7%
Gas Reciprocating engine (inc. diesel)	7.8%
OCGT	7.8%
Coal plants All retrofits	8.2%

Source: BEIS (2015), NERA (2015).

1.1.2 Approach to decomposing hurdle rates

NERA's estimates were largely based upon survey responses and were for hurdle rates or costs of equity and debt overall. As such they may have embodied all kinds of unstated assumptions and implicit models, including real options, liquidity premia, high book-to-market premia and others.[3] NERA's estimates were then, of course, revised by BEIS, as we have noted above.

For our purposes, the exact modelling assumptions upon which the BEIS hurdle rates were arrived at is of only restricted relevance. What we need is simply a WACC-CAPM equivalent of the BEIS hurdle rates, as a startpoint for our analysis. To spell this point out, suppose that a BEIS hurdle rate for technology X had been arrived at using a model that assume real options and liquidity adjustments should be added on top of a CAPM-type asset beta of Z for the cost of equity. In that case, for us, the relevant asset beta startpoint would

[3] We note that NERA's own approach did indeed notionally include assigning real option value and asymmetric risks over-and-above the CAPM result. Within a CAPM framework, however, any ultimate hurdle rate can be treated as derived from a risk-free rate, equity risk premium and asset beta. As we shall explain in more detail below, one way to interpret our "baseline" asset betas is therefore as the CAPM asset beta equivalent of whatever other factors underpin the BEIS hurdle rate conclusions.

not be Z. Instead, it would be something greater than Z that, if it had been applied in a CAPM model with no further adjustments, would have produced an overall cost of equity equivalent to that used by BEIS.

As such we, first, decompose the final hurdle rates into the relevant components (such as risk-free rate, equity risk premium, cost of debt, cost of equity and gearing) and then consider how those components have changed (if at all) since the last update.

To decompose the overall hurdle rates into WACC components we need to make certain assumptions. In particular, we assume that the difference between the final hurdle rates used by BEIS and the hurdle rates implied by the values for various WACC components reported by NERA is driven by the cost of equity, and specifically by the equity beta. This allows us to use the cost of debt figures reported by NERA along with the estimates of gearing, to derive the cost of equity that would be consistent with those figures given the final hurdle rate and the effective tax rate.

For technologies where NERA's report does not provide estimates for the cost of debt and/or gearing we aimed to obtain information from other projects implementing those technologies. Failing that, we assessed where on the spectrum of risk and state of development defined by the technologies for which we do have data the remaining technologies are. For example, in absence of evidence suggesting otherwise, we assumed that hydro large store had similar cost of debt in 2015 as hydro, or that wave and tidal technologies had cost of debt at the upper bound of the levels we observe for other technologies.

Given those inputs (as well as risk-free rate and ERP) we can derive the cost of equity, equity betas and asset betas for individual technologies. For further details regarding the decomposition of 2015 hurdle rates see Appendix: 2015 Starting Point.

1.1.3 Drivers of risk

NERA's framework summarising the key risk drivers is presented in the figure below.

Figure 1.1: NERA's hurdle rates risk classification

CAPM "beta" risk (systemic, market-correlated risk)	**Asymmetric risk** (downside > upside risk or vice versa)	**Real option value** (flexibility to "wait and see" uncertainty resolved)
• Volatility of revenues • Fuel price volatility & FX risk • Carbon price volatility • Basis risk	• Allocation risk • Construction risk • Policy risk • Technological maturity	• Novelty premium

Source: NERA (2015).

For each of the technologies under consideration, NERA also identified the key risk drivers perceived by investors. The results of that part of NERA's survey are presented in the table below.

Table 1.2: Key risk drivers based on NERA's survey results

	Allocation	Policy	Development	Technology	Construction	Fuel price	Carbon price	Fuel availability	Revenue
Solar	Yes	Yes	Yes		To an extent				
Onshore wind	Yes	Yes	Yes		To an extent				
Offshore wind	Yes	Yes	Yes	Yes	Yes				
CCGT	Yes	Yes				Yes	Yes		Yes

	Allocation	Policy	Development	Technology	Construction	Fuel price	Carbon price	Fuel availability	Revenue
Hydro	Yes	Yes			To an extent				
Tidal stream	Yes	Yes		Yes	Yes				
Wave	Yes	Yes		Yes	Yes				
Geothermal	Yes	Yes		Yes	To an extent				
EfW / landfill	Yes	Yes				Yes		Yes	
ACT / AD	Yes	Yes		Yes	To an extent	Yes			

Source: NERA (2015).

We also note that based on the in-depth interviews, NERA reported that solar investors estimated 200 bps as the premium for allocation and development risk, and 50-100bps for construction risk. Based on its illustrative model, NERA stated that "it is not unreasonable to estimate hurdle rate impacts of 100-200bps for allocation and development risk". In the context of onshore wind, in-depth interviews provided NERA with the same estimates.

We understand that, in 2015/16, for BEIS and the peer reviewer, an area of specific disagreement with NERA's report was the treatment of allocation risk, which BEIS regarded as having been exaggerated. Consequently, we reweight the assumed baseline relative treatments of allocation, development and construction risk. So instead of these carrying approximately equal weight, we assume that in 2015/16 there was a ratio between them of 20:40:40 — i.e. allocation risk was only half as significant as the other two risk drivers.

In our analysis in later sections we consider the extent to which those asymmetric types of risk are still relevant for the technologies under consideration (section 5.2.3).

1.2 General methodological points

1.2.1 The different revenue support assumptions for different technologies

We develop two sets of hurdle rates based on two different sets of assumption.

Revenue support assumption #1

Under the first revenue support assumption, the hurdle rates we are considering for technologies which were at some point considered eligible for contracts for difference (CFD) scheme[4] are to reflect the cost of capital the technology would have if the energy it produced were traded via contracts for difference.[5] The main intention of a CFD is to provide greater certainty and stability of revenues to electricity generators using higher-risk or less mature technologies, by reducing their exposure to volatile wholesale prices. On the other hand, the design of the contract is supposed to protect consumers from paying unnecessarily for higher subsidies when electricity prices are high (and hence subsidies not required and there may also be a difference payment due from the generator back to the contract counterparty). By its nature therefore, a CFD reduces (without eliminating entirely) the exposure of the generators using those technologies to price risk. That will be important in what follows later. Furthermore, we assume that for technologies which compete as part of the CfD allocation framework, the CfD (and hence the protection from merchant risk) is awarded only for a period (the period of the CfD) which may be shorter than the full economic life of the CFD-supported

4 These are: solar, wind (both onshore and offshore), EfW CHP, hydro, landfill gas, sewage gas, wave, tidal, ACT, AD, dedicated biomass with CHP, geothermal and biomass conversion. For more details on CFDs see section 5.2.1 of this report.

5 We note that in the revenue support assumption here the technologies are assumed *not* to attract Renewables Obligation support.

technology, meaning that a date may come in the future when even a CfD-supported technology becomes exposed to merchant risk.

By contrast, the revenue support assumption we are to use here for technologies such as CCGT is that CCGT generators do not have CFDs and thus are exposed to pricing risk. They have some support in the form of a stable revenue stream from Capacity Markets,[6] but the level of this is materially lower than that attained by generators with CFD support.

A list of technologies analysed under each of those two revenue support assumptions is presented below.

Table 1.3: Technologies by revenue support assumptions

Technologies analysed under the CFD revenue support assumption	Technologies assumed to be largely exposed to market risks
Solar PV >5MW	CCGT
Onshore Wind >5MW	CCGT IED retrofit
Offshore Wind	CCGT CHP
Biomass CHP	Dedicated Biomass >100MW
Biomass Conversion	Dedicated Biomass 5-100MW
ACT standard	EfW
ACT advanced	OCGT
ACT CHP	Reciprocating engine (gas and diesel)
AD >5MW	Coal IED retrofit
AD CHP	CCS Gas – CCGT
EfW CHP	CCS Coal
Landfill	CCS Biomass
Sewage Gas	
Hydro >5MW	
Hydro large store	
Wave	
Tidal stream	
Geothermal CHP	

Source: Europe Economics,

In addition to the above considerations, there is a case for certain technologies, e.g. CCGT, to be deployed as part of a portfolio of generation technologies as well as supply obligations (in case of vertically integrated utilities), with real option value from their dispatchable nature that would not be present in the same way if the CCGT were used on a purely standalone basis.[7] Hence here we consider the hurdle rate for CCGT generators within a portfolio (financed on balance sheet), rather than under the project finance-like structure.

Revenue support assumption #2

Under the second assumption, we consider all technologies to be employed on a merchant basis, i.e. without any protection from CFDs or other similar support schemes. Under this "merchant player" revenue assumption, all technologies would be equally exposed to market pricing risk. Because merchant player revenue streams are subject to greater volatility, we assume it is natural for their financing streams to reflect such volatility to some extent — i.e. that they have lower gearing levels, with dividend payments being more risk-reflective.

6 More on Capacity Markets in section 5.2.1.

7 Portfolio players have balancing market risk from their intermittent assets and supply obligations which is negatively correlated with the economics of dispatch of CCGTs. Thus, addition of CCGTs to such a portfolio can bring added benefits in terms of risk management and enable portfolio players to better extract the value of the real option.

1.2.2 The roles of qualitative and quantitative reasoning

Relevant data on the technologies considered in this project is sparse. Few firms have listed equity, and amongst those that do, even fewer focus on only one of the technologies. There have been even fewer bonds issued that we could use to estimate yields, and loans data is restricted and highly project-specific.

These factors have meant that, although we have sought to gather the maximum relevant data and make the most ambitious quantitative use of it that we could, it has been particularly important to also take account of qualitative reasoning. Qualitative reasoning is a routine part of regulatory cost of capital analysis. It is almost always important to take account of how the general business and risk environments have been changing and how they might differ in the future from those in the past. But in other costs of capital estimations, where data is more abundant, qualitative reasoning serves more as a cross-check or to help select a point estimate within the range or to resolve conflicting evidence. Qualitative reasoning evidence has also been used in the past when more precise data was not available, particularly when estimating beta differences. Examples include: Ofcom's 2005 and 2011 decisions.[8]

Qualitative reasoning has not, however, been our only evidence source. In forming a view as to how costs of capital have evolved since 2015, we have taken account of a range of drivers of change. We have sought to fine-grain the analysis to the point at which purely qualitative-to-quantitative analysis[9] applies to the smallest feasible portion, with as much as possible of the results defended more quantitatively. The cost of capital, for our analysis here, is defined as follows.

$$pre\text{-}tax\ WACC = cost\ of\ debt \cdot gearing + \frac{cost\ of\ equity \cdot (1 - gearing)}{1 - effective\ tax\ rate}$$

Our approach to estimating each of the components needed to determine the 2018 hurdle rates is illustrated in Figure 1.2 (more details can be found in the beginning of each chapter). As illustrated below, some of the parameters are estimated independently of the 2015 hurdle rates and NERA (2015) report — these are risk-free rate, equity risk premium (ERP), cost of debt and inflation. Other parameters are linked to the 2015 hurdle rates or their components (unless a more direct estimation approach has been possible) — these include effective tax rate (ETR), gearing and asset betas (which then feed into the calculations of cost of equity).

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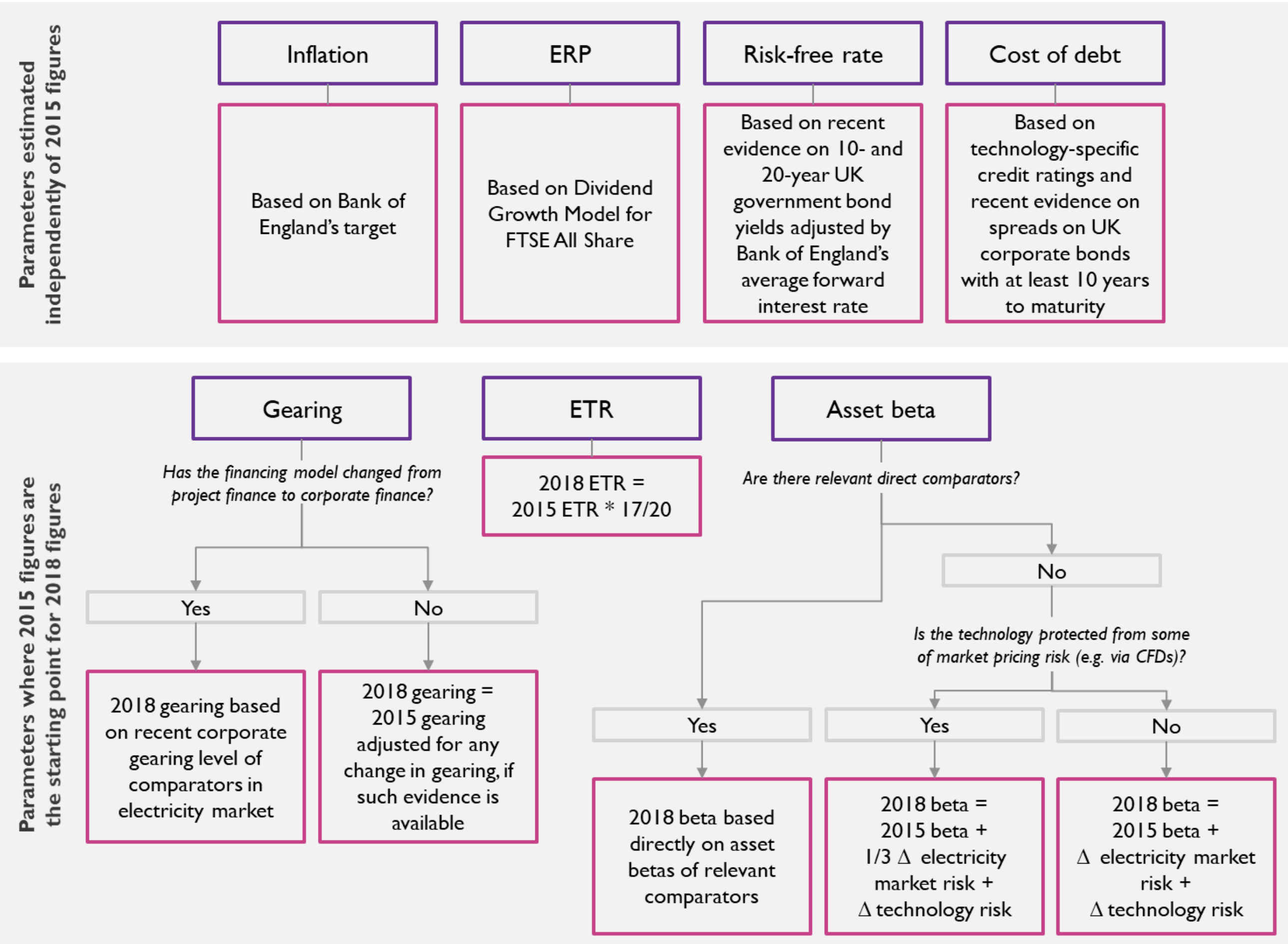
8 See p67ff of Ofcom (2005), "Ofcom's approach to risk in the assessment of the cost of capital", and paragraphs 6.136 to 6.142 of Ofcom (2011), "Proposals for WBA charge control".

9 That is, the drawing of a specific numerical conclusion from a broad-brush qualitative finding, such as "a bit", or "slightly", or "significantly".

Figure 1.2: Illustration of our approach to estimate 2018 hurdle rates



Source: Europe Economics.

1.2.3 Inflation

The analysis in this report is conducted in real terms, other than where specified as nominal. We take CPI as the best proxy for inflation. In line with the ling-term inflation target set by the Bank of England, we assume the inflation rate of two per cent.[10] In Appendix: Inflation we explain different measures of inflation and the interpretation of a real rate of return. We also note that it appears that NERA derived their real estimates using a two per cent inflation assumption, which means there is no mis-match in the treatment of inflation since the last update.[11]

1.2.4 Relevant horizon

The aim of this report is to provide forward-looking estimates of the hurdle rates rather than estimates capturing the current situation with no consideration for probable developments in the coming years. The two areas affected by this approach are:

- Risk-free rate — where we adjust the spot rates by forward rates expected in two to seven years; if we were to estimate the risk-free rate as of 2018, the forward-rate adjustment would need to be removed;

[10] http://obr.uk/faq/where-can-i-find-your-latest-forecasts/.

[11] Specifically, note 5 to Table 5.1 ("Hurdle rate estimates (2015, pre-tax real)") in NERA (2015) says: "5. Interpolation was carried out on nominal post-tax basis, as survey responses were predominantly provided on that basis. We convert the nominal post-tax figures to real pre-tax figures using the Effective Tax Rates published by KPMG[45] and an inflation assumption of 2%."

- Effective tax rate (ERP) — where we adjust the tax rate used by KPMG in 2013 by the corporate tax rate that would apply starting from 2020 (i.e. 17 per cent); if we were to estimate the ERP as of 2018, we would adjust the previous ETR by the rate applicable now (i.e. 19 per cent).

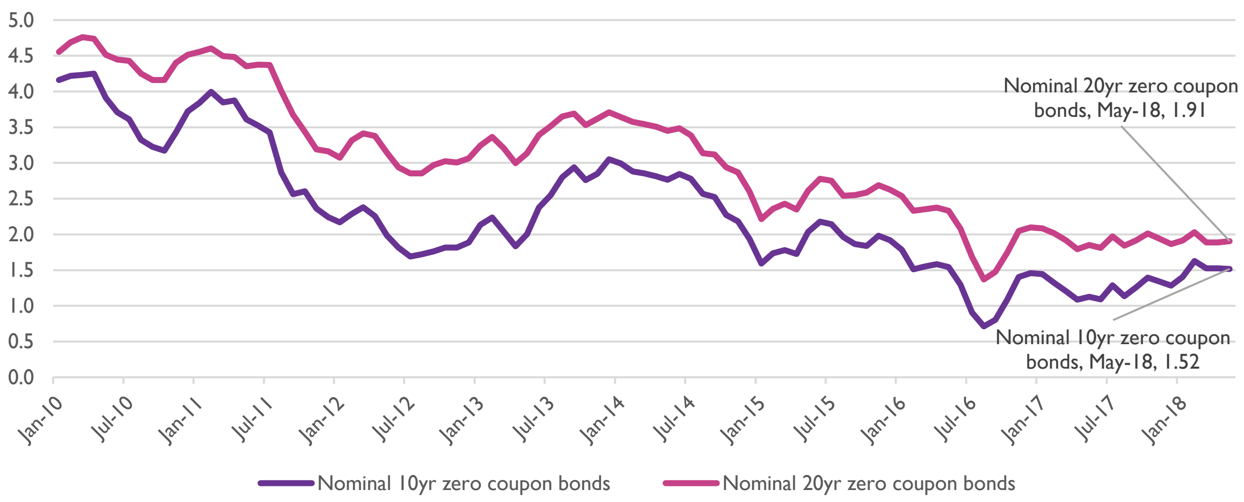
2 Financial Market Factors

In this chapter we present our analysis regarding the risk-free rate (section 2.1) and total market return (TMR) and equity risk premium (ERP) (section 2.2). The basis for the risk-free rate estimation are yields on UK government bonds, while the TMR is supported by a dividend growth model. For this report we update the risk-free rate with the latest evidence but maintain our recommendation regarding the total market return, which as a more stable market parameter is less like to have materially changed since last year.[12] The ERP is then calculated as the difference between the TMR and the risk-free rate.

2.1 Risk-free rate

The monthly average yields on zero coupon UK gilts have been declining in the past years, as illustrated below. As of May 2018, the average nominal yield on a 10-year bond was 1.52 per cent, and 1.91 per cent on a 20-year bond.

Figure 2.1: Nominal zero coupon UK gilt yields — monthly averages



Source: Bank of England (series codes: IUMAMNZC, IUMALNZC).

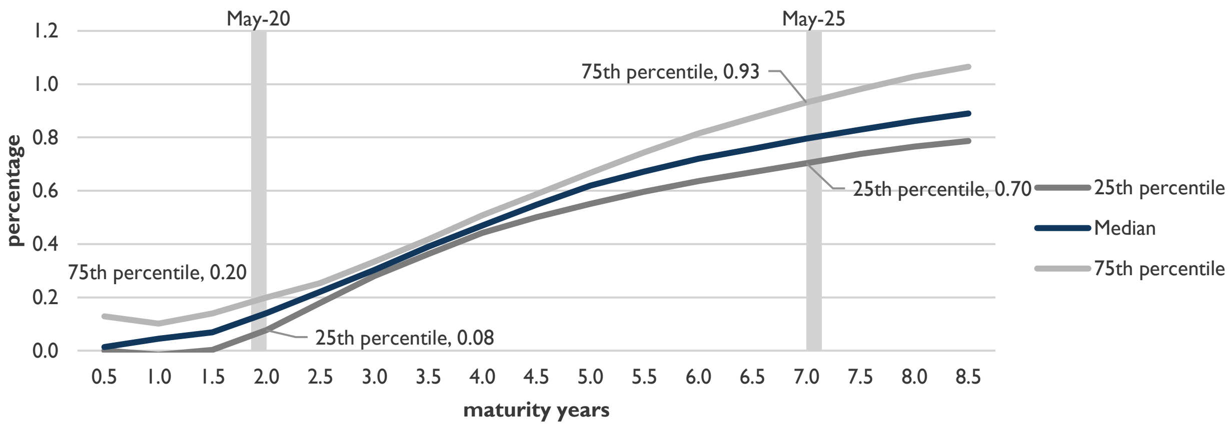
In order to estimate the risk-free on a forward-looking basis, we need to adjust the currently observed yields by the expected rise in interest rates in the coming years. The expected rise in interest rate can be estimated by subtracting nominal spot rates from nominal instantaneous forward rates for each maturity horizon respectively. To account for potential volatility in those predicted rates across time, we analysed daily data between July 2017 and May 2018, and calculated the 25th and 75th percentile of the distribution of the results. These are illustrated in Figure 2.2 below.

Based on the 25th percentile, the figure shows that — compared to the yields observed in May 2018 — interest rates are expected to rise by 8 bps before May 2020 and 70 bps by May 2025. Based on 75th percentile, interest rates are expected to rise by 20 bps by May 2020 and 93 bps by May 2025.[13] Therefore, the average expected rise during the 2020-25 period is between 39 bps (based on 25th percentile) and 57 bps (based on 75th percentile).

[12] See for example section 2.2 of Oxera (2018), "The cost of equity for RIIO-2. A review of the evidence", prepared for Energy Networks Association for a detailed discussion regarding the stability of TMR.

[13] We base our estimates on the 2020-25 period to reflect the short-to-medium term horizon which is likely to be relevant for this study.

Figure 2.2: Forward minus spot nominal rates based on the distribution of daily estimates between Jun 2017 and May 2018



Source: Bank of England, Europe Economics' calculations.

Forwards curves typically contain an underlying term premium, sometimes thought to reflect liquidity risk or changes in the extent to which investors bear inflation risk over different horizons. Since this premium would be captured by the forward curves even if no rise in interest rates is expected, it should be subtracted from the above estimates. Pflueger and Viceira (2015)[14] estimated that the average liquidity premium on UK government bonds over 1999-2014 was 50bps, but declined to around 10bps towards the end of the series. Golden et al. (2010)[15] decompose nominal and real rates, estimating the average inflation risk premium on UK gilts over 1985-2009 period to be 35bps. The increase in the inflation premium with term would therefore be less than this. Here we assume a total premium, combining liquidity and inflation risk term effects, of 20bps.

Therefore, the expected average rise in interest rates in 2020-25 period is between 19 bps and 37 bps. Combined with the yield on 10-year and 20-year government bonds of 1.52 per cent and 1.91 per cent respectively, we estimate the nominal risk-free rate to be between 1.71 per cent and 2.28 per cent. Our point estimate in nominal terms is 2.0 per cent, which is equivalent to zero per cent in real terms.

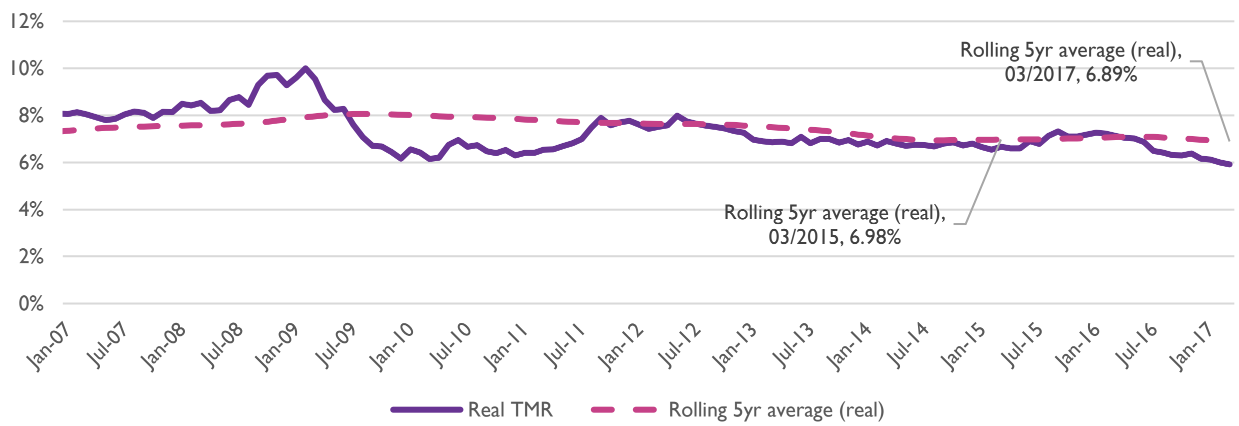
2.2 Total market return and equity risk premium

We recently conducted a comprehensive analysis of TMR and ERP for Ofwat. Below we present the main findings and conclusions from that analysis. Full details can be found in Europe Economics (2017).[16]

Below, we show the evolution of total market return based on our preferred model. We can see that TMR declined slightly in the two years between March 2015 and March 2017.

14 Pflueger and Viceira (2015), "Return predictability in the Treasury market: real rates, inflation, and liquidity".
15 Golden et al. (2010), "Forecasting UK inflation: an empirical analysis", Heriot-Watt University.
16 Europe Economics (2017), "PR19 — Initial Assessment of the Cost of Capital".

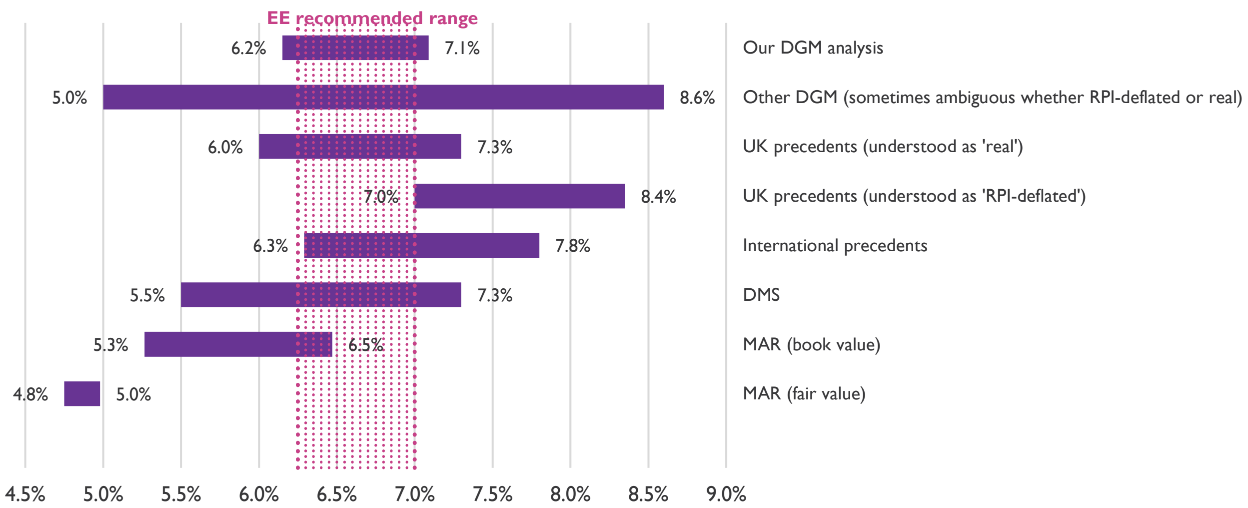
Figure 2.3: Multi-stage DGM based on GDP growth



Source: Europe Economics, Bloomberg's data.

The above model was only one of the various approaches and data sources we examined. The figure below shows a summary of the results from those different strands of our analysis.

Figure 2.4: Summary of real TMR results



Source: Europe Economics.

Based on this analysis we our proposed real TMR range is 6.25-7.0 per cent, and our proposed point estimate is 6.75 per cent. Combined with our real risk-free rate estimate of zero per cent, this implies an ERP of 6.75 per cent.

3 Debt

Our approach to estimating the cost of debt is to first determine the appropriate credit rating for each of the technologies (section 3.1), and then to calculate the average spreads in May 2018 on UK corporate bonds with such a rating and at least 10 years to maturity (section 3.2).

The ratings assigned to the technologies under consideration are — to the extent possible — based on credit ratings assigned by one of the three main credit rating agencies to other projects applying the technologies in question. We prioritise evidence from projects in the UK or Europe, but in absence of that we use information from other regions in the world as an indication of the possible credit rating. Where no direct information was available, we assessed where on the spectrum of risk and state of development those technologies are relative to the technologies for which we have some information.

We also note that some of the technologies might be financed on-balance-sheet rather than via project finance. For CCGT specifically, since we are assuming that their assumed role has changed from being standalone merchant players into serving a role within a portfolio of generation technologies, we therefore assign them a rating more closely in line with those of standard comfortable investment grade electricity generators (i.e. BBB+),[17] consistent with the much lower corporate finance-style gearing we shall be concluding for in a later section.[18] We also assume BBB+ for several other coal and gas-based technologies.

Our assumed ratings are in certain cases adjusted by the insights from discussions with BEIS.

3.1 Bonds ratings

As indicated in Fitch (2017), the majority of renewable energy projects are rated BBB or BB.[19] In addition to this general benchmark, we examined ratings assigned by credit rating agencies to individual projects or companies using the technologies under consideration (see Appendix: Cost of Debt for details).

Drawing on these various sources, our conclusions on the ratings for each of the technologies under consideration are summarised below (and presented in Table 3.2 in the last section of this chapter).

- BBB+ for CCGT, gas CCGT IED retrofit, coal plants all retrofits;
- BBB for solar, hydro, hydro large store, landfill, sewage gas;
- BBB- for onshore wind, offshore wind, wave, tidal stream, AD, AD CHP, gas reciprocating engine (inc. diesel), OCGT;
- BB+ for biomass dedicated >100MW, biomass dedicated 5-100MW, biomass conversion, biomass CHP, ACT advanced, ACT standard, ACT CHP, CCS gas FOAK, CCS gas NOAK, CCS coal FOAK, CCS coal NOAK, CCS biomass;
- BB for EfW CHP, EfW;
- BB- for geothermal CHP.

3.2 Debt premium for bonds of the relevant ratings

To estimate the debt premium for bonds of different credit ratings, we obtained daily yields spreads data for a selection of bonds of appropriate maturity (10 years and above) available from Thomson Reuters and yields data from iBoxx (the iBoxx 10+ non-financials series) along with yields on 10-year government bonds. The results of our analysis are reported in the table below.

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[17] BBB/A-rated bonds have been often used by regulators as relevant benchmark. See for example Ofgem (2016), "Final Project Assessment of the NSL interconnector to Norway".

[18] See chapter 4.

[19] FitchRatings (2017) "EMEA Renewables Peer Review".

Table 3.1: Estimated May 2018 spread over benchmark government bond of corporate bonds by ratings

Rating	Spread (bps)
BBB+	170
BBB	196
BBB-	230
BB+	245
BB	305
BB-	366

Source: Europe Economics estimates based on Thomson Reuters and iBoxx data.

3.3 Proposed cost of debt

Table 3.2: Assumed bond ratings and proposed debt premium

	Debt premium (2015)	Assumed rating (2018)	Proposed debt premium (2018)
Solar	2.0%	BBB	1.96%
Onshore wind	2.4%	BBB-	2.30%
Offshore wind	2.7%	BBB-	2.30%
CCGT	2.7%	BBB+	1.70%
Hydro	2.7%	BBB	1.96%
Hydro Large Store	2.7%	BBB	1.96%
Wave	3.7%	BBB-	2.30%
Tidal stream	3.7%	BBB-	2.30%
Geothermal CHP	3.7%	BB-	3.66%
Biomass Dedicated >100MW	3.7%	BB+	2.45%
Biomass Dedicated 5-100MW	3.7%	BB+	2.45%
Biomass CHP	3.7%	BB+	2.45%
Biomass Conversion	3.7%	BB+	2.45%
ACT standard	3.7%	BB+	2.45%
ACT advanced	3.7%	BB+	2.45%
ACT CHP	3.7%	BB+	2.45%
AD CHP	3.7%	BBB-	2.30%
AD	3.7%	BBB-	2.30%
EfW CHP	3.7%	BB	3.05%
EfW	3.7%	BB	3.05%
Landfill	3.7%	BBB	1.96%
Sewage Gas	3.7%	BBB	1.96%
CCS Gas FOAK	3.2%	BB+	2.45%
CCS Gas NOAK	3.2%	BB+	2.45%
CCS Coal FOAK	3.2%	BB+	2.45%
CCS Coal NOAK	3.2%	BB+	2.45%
CCS Biomass	3.2%	BB+	2.45%
Gas CCGT IED retrofit	2.7%	BBB+	1.70%
Gas Reciprocating engine (inc. diesel)	2.7%	BBB-	2.30%
Coal plants All retrofits	2.7%	BBB+	1.70%
OCGT	2.7%	BBB-	2.30%

Source: Europe Economics' analysis, Thomson Reuters, Fitch, Moody's, private discussions.

We note that the debt premia we assign tend to be lower than those in 2015. In some cases that reflects changes in gearing (e.g. CCGT), in others increasing maturity of the technology meaning a lower credit rating, and to there are also broader market movements. We shall see in later sections that this drop in debt premia contrasts with a general tendency for asset betas to rise. There is no particular reason a debt premium must rise when an asset beta rises or vice versa. A firm might at the same time have a lower risk of default (implying a lower debt premium) and greater volatility in equity returns. That seems to be the case here.

4 Gearing

The approach used for determining gearing relevant for technologies financed via project finance relies on past evidence of similar projects and any evidence indicating changes in gearing since 2015. Where no information on changes in gearing are available we assume the same level of gearing as for 2015 (see section 9.1 in Appendix: 2015 Starting Point). For technologies financed on balance sheet (i.e. CCGT, CCGT IED retrofits, and coal retrofits) we use the average corporate gearing across the electricity sector.

4.1 Evolution of gearing since 2015

4.1.1 Project finance

Project finance gearing ratios across broader infrastructure have been fairly stable between 2015 and 2018.[20] That said, several sources suggest there will be a fall in the future[21], partly reflecting fundamental features of project finance, from around 80 per cent today to around 65-70 per cent in the future.[22] On the other hand, firms' increasing familiarity with CFDs means it becomes more feasible to assess bid win probabilities[23] and hence more feasible to finance projects with larger proportions of debt.

Specifically, gearing for offshore wind tended to exhibit a rise between 2012 and 2018, which is why we assume convergence on gearing for offshore to the level of onshore wind in 2015.[24] Wind in general is reported to have a gearing between 70 and 80 per cent.[25] Project finance gearing for solar appears to be currently around 80 per cent.

4.1.2 Corporate gearing

Since we assume CCGT to play a role for portfolio generators, it is now better understood as financed on a standard corporate finance basis, with a gearing reflecting that of other generators. As Figure 4.1 shows, in 2018 the average corporate gearing across UK and European electricity companies was 38 per cent, with the latest figure being 37 per cent (38 per cent being the median). Considering UK comparators in isolation, the latest SSE figure is slightly lower, at 35 per cent and for Centrica lower still. We therefore round to 35 per cent, which we take as our assumption for CCGT and coal retrofits.

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20 Moody's Investors Service (2017), "Thames Water Utilities Ltd." Credit Opinion See also CEPA (2017), "Background evidence: review of the UK infrastructure financing market", Financing Infrastructure for National Infrastructure Commission.

21 National Grid (2018), Hinkley-Seabank project: minded-to consultation on delivery model.

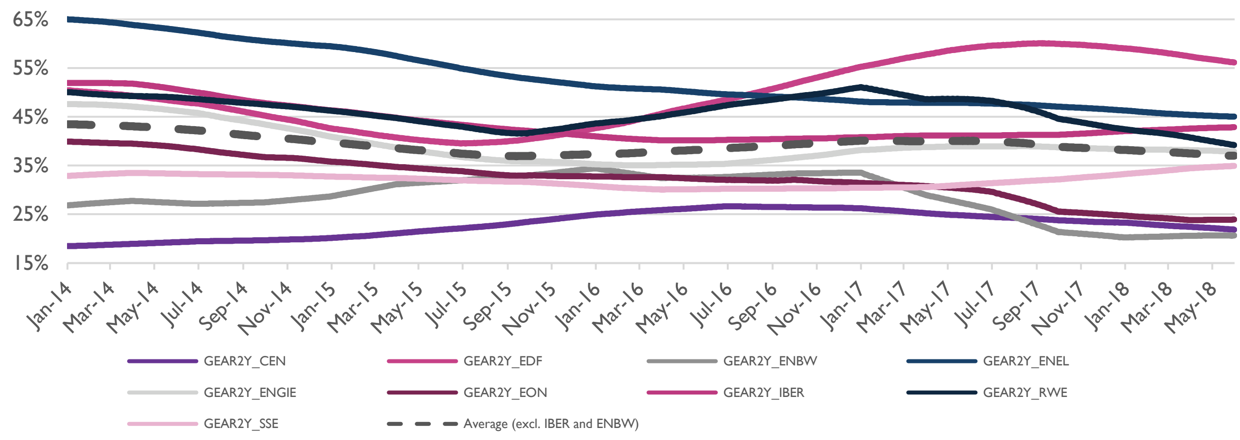
22 BNEF (2017), "Lower Debt Ratios Likely for Unsubsidized Green Energy".

23 Increasing familiarity in the CFD-allocation process is also important for the level of risk captured by asset betas. We estimate this impact in section 5.2.

24 We note, also, that the first subsidy-free offshore windfarm is under construction, with a 2022 delivery date. https://www.ipe.com/reports/special-reports/energy/offshore-wind-market-speeds-up/10013099.article.

25 https://windeurope.org/wp-content/uploads/files/about-wind/reports/Financing-and-Investment-Trends-2017.pdf.

Figure 4.1: Average 2-year rolling gearing for UK and European electricity companies



Note: For discussion of why Iberdrola and ENBW are excluded, see footnote 31. Including them would take the average to 35 per cent.
Source: Thomson Reuters, Europe Economics' analysis.

4.1.3 Gearing under our revenue support assumption #2 (merchant player)

Under revenue support assumption #2 a number of the technologies are subject to merchant risk instead of having CFD revenue protection. Because of that, revenue volatility can be expected to be higher under this revenue support assumption.

Corporate finance theory offers no straightforward prediction about the impact of revenue volatility upon gearing. However, a common view is that when revenue streams are more certain, there is what is sometimes referred to as a "quasi-securitisation" effect on gearing — i.e. that gearing can be much higher when revenue streams are more certain than when they are more volatile. The way this assumption is often put is that there can be a matching of costs and revenues — so if a high proportion of revenues are certain and steady then a high proportion of costs can, likewise, be certain and steady, in the form of debt servicing payments.

Conversely, as in the case of revenue support assumption #2, it is natural to suppose that when revenue volatility is greater, gearing will be lower. To repeat: there is no straightforward way to estimate by how much gearing will be lower in this case. However, we can use some indicative modelling to gain a sense of by what approximate order of magnitude gearing will be lower.

In our gearing model, we make the following assumptions (a number of which are quite strong).

- We assume that, even for a firm with CFD protection, revenue volatility contributes twice as much to overall volatility as does cost volatility. This is a brute indicative assumption.
- We assume that cost volatility is unaffected by whether the firm does or does not have CFD protection.
- We assume that the extent to which revenue volatility is greater without CFD protection is given by the ratio of the average of intraday and day-ahead price volatility (in percentage terms) to just intraday volatility (in percentage terms). Interpreted in intuitive terms, this would be equivalent to saying that for a non-CFD-protected firm, revenue volatility comes equally from intraday and day-ahead price volatility, but for a CFD-protected firm only intraday volatility is relevant. We have estimated this ratio using Ofgem data, and find that in 2017 it was 1.46. Given that two thirds of risk comes from revenue volatility, that means that total volatility rises by 31 per cent.[26]

[26] 2 + 1 = 3
2.92 + 1 = 3.92
3.92/3 = 1.31

- We assume that gearing adjusts (from its CFD-protected level, i.e. the level we estimate under revenue support assumption #1) such that the ratio of equity payments to debt payments (i.e. the cost of equity times one minus gearing relative to the cost of debt times gearing) rises in line with the rise in volatility. The intuition here is that as volatility rises, volatile payments rise proportionately. This is a simplifying linearity assumption.
- We then estimate the new gearing at which the above condition is satisfied. This gives our estimate of the new gearing level.
- Because the intention of the above algorithm is to identify a new gearing level at which the risk associated with debt is the same, we therefore keep the same debt premium.

4.2 Proposed gearing under revenue support assumption #1

Table 4.1: Proposed gearing under revenue support assumption #1

	Assigned 2018 gearing
Solar PV	80.0%
Onshore wind	77.5%
Offshore wind	77.5%
CCGT	35.0%
Hydro	70.0%
Hydro Large Store	60.0%
Wave	72.5%
Tidal stream	70.0%
Geothermal CHP	72.5%
Biomass Dedicated >100MW	45.0%
Biomass Dedicated 5-100MW	45.0%
Biomass CHP	45.0%
Biomass Conversion	45.0%
ACT standard	56.0%
ACT advanced	56.0%
ACT CHP	56.0%
AD CHP	72.5%
AD	72.5%
EfW CHP	57.5%
EfW	57.5%
Landfill	57.5%
Sewage Gas	57.5%
CCS Gas FOAK	65.0%
CCS Gas NOAK	65.0%
CCS Coal FOAK	65.0%
CCS Coal NOAK	65.0%
CCS Biomass	65.0%
Gas CCGT IED retrofit	35.0%
Gas Reciprocating engine (inc. diesel)	70.0%
Coal plants All retrofits	35.0%
OCGT	70.0%

Source: Thomson Reuters; Europe Economics.

4.3 Proposed gearing under revenue support assumption #2 (merchant player)

Table 4.2: Proposed gearing under revenue support assumption #2

	Assigned 2018 gearing under assumption #1	Impact on gearing of increased asset beta risk	Assigned 2018 gearing under assumption #2
Solar PV	80.0%	-13.9%	66.1%
Onshore wind	77.5%	-12.9%	64.6%
Offshore wind	77.5%	-13.9%	63.6%
Hydro	70.0%	-13.0%	57.0%
Hydro Large Store	60.0%	-11.6%	48.4%
Wave	72.5%	-14.3%	58.2%
Tidal stream	70.0%	-14.2%	55.8%
Geothermal CHP	72.5%	-15.1%	57.4%
Biomass CHP	45.0%	-9.6%	35.4%
Biomass Conversion	45.0%	-9.6%	35.4%
ACT standard	56.0%	-11.7%	44.3%
ACT advanced	56.0%	-11.8%	44.2%
ACT CHP	56.0%	-11.9%	44.1%
AD CHP	72.5%	-14.7%	57.8%
AD	72.5%	-14.2%	58.3%
EfW CHP	57.5%	-11.0%	46.5%
Landfill	57.5%	-11.5%	46.0%
Sewage Gas	57.5%	-11.8%	45.7%

Source: Europe Economics.

5 Beta

In this chapter we present our analysis regarding asset beta and debt beta. Beta is a measure of the correlation between the returns of a project with the returns of the market as a whole.

There are various forms of evidence we examined to assess changes in asset betas since the last update:

- Direct evidence on betas for a few firms specialising in certain of the technologies studied.
- Changes in systematic risk of the energy and electricity market firms relative to the rest of the wider asset market. Changes in the energy markets would be applicable in their entirety only to electricity generators which are exposed to the same level of market risk exposure as the companies underlying our analysis. This means that, as discussed in section 1.2.1, only technologies which are not eligible for CFD scheme would experience a similar change. Technologies protected by CFDs would only bear those risks to a much more limited extent.[27]
- Impact of changes in wholesale energy market price volatility on project revenues.
- Factors affecting specific technologies under consideration such as maturity. In principle, these are included to the extent they are systematic in nature. What this means in practice is that we assume that the ratios of the systematic components of risk from different sources are the same as the ratios of the non-systematic components.[28] Idiosyncratic or project specific changes are excluded as they do not contribute towards project betas.

To estimate the changes in asset betas driven by technology-specific factors, we first identify the main risk drivers for each technology under consideration and the proportion of the overall risk (i.e. asset beta) those individual risk account for. Then, based on our research into regulatory and technological changes observed in the past three years, we estimate the impact those changes have on asset betas using a qualitative scoring system.

From the evidence presented in this chapter we derive the overall change in asset betas since 2015. Those changes are different for each technology and are applied to the 2015 asset beta derived from the hurdle rates used in BEIS (2016).

5.1 Electricity market

5.1.1 How asset betas changed in the electricity sector?

UK

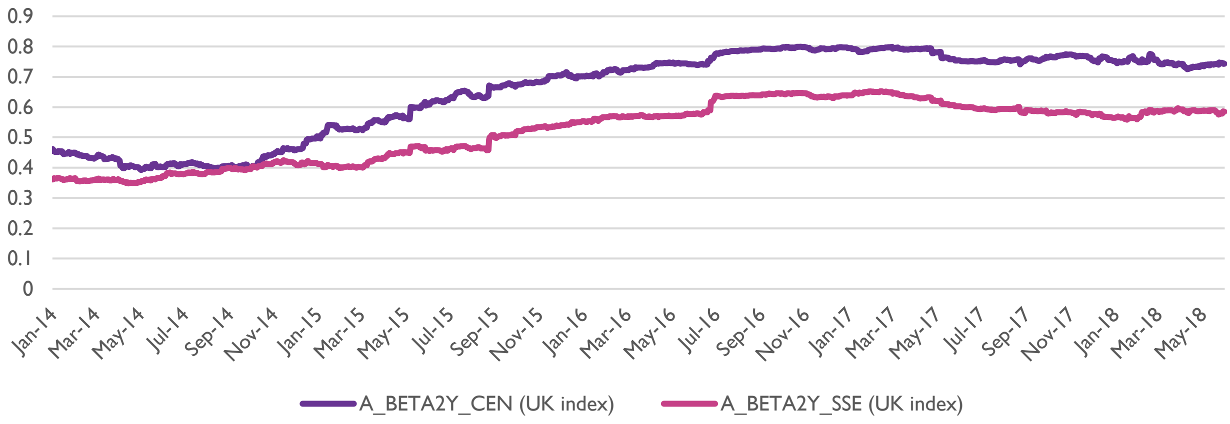
As illustrated in the figure below a rise in asset betas can be observed for SSE and Centrica. For both companies the 2018 (year to end-May average) betas increased by over 50 per cent compared to the average 2014 beta.[29]

[27] We note that even in cases where projects originally come forward under project finance structure i.e. off-balance sheet, the construction phase may be financed on sponsor's balance sheet, potentially affecting the gearing and hence hurdle rate via the corporation tax rate effect (see below).

[28] We note that this includes risks such as allocation or development risk.

[29] The betas increased form from 0.38 to 0.58 for SSE, and from 0.43 to 0.75 for Centrica.

Figure 5.1: Two-year asset betas for SSE and Centrica

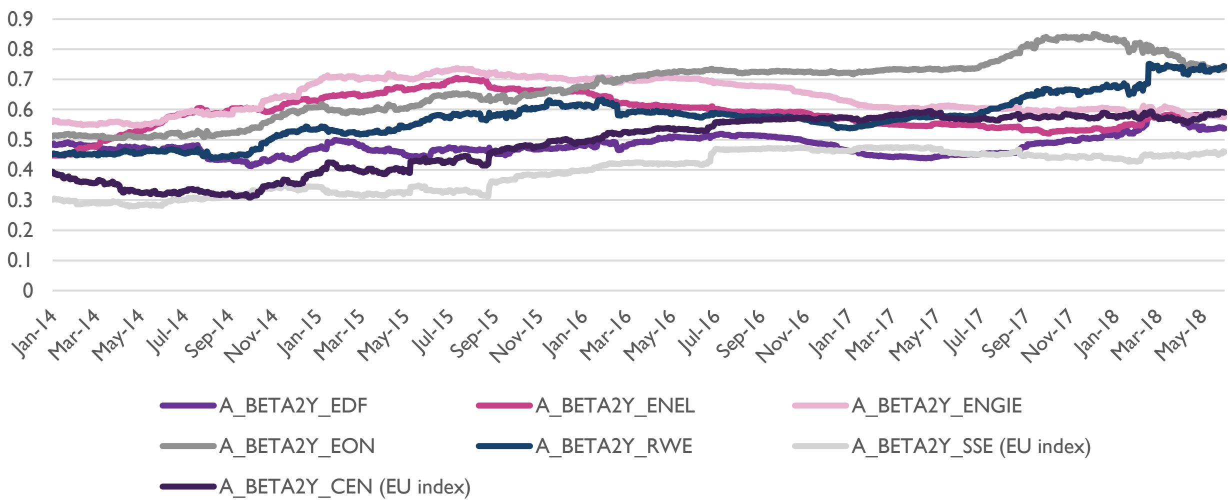


Source: Thomson Reuters, Europe Economics' analysis.

Europe

Given a limited sample of UK comparators as well as the recent CMA investigation in the energy market[30] which might have increased the perception of risk among investors (and thus potentially mean the rise in asset betas for the UK includes some rise that is firm-specific rather than indicative of general electricity sector trends), we also examine the asset betas of European electricity companies. For such comparators, a similar, albeit slightly lower rise is found. The following chart gives asset betas for a selection of European electricity generators from 2014 to 2018.[31]

Figure 5.2: Two-year asset betas for UK and European generators



Notes: Two-year asset betas calculated against European stock market index, rather than domestic indices, including SSE and Centrica.
Source: Thomson Reuters, Europe Economics' analysis.

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30 See https://www.gov.uk/cma-cases/energy-market-investigation.

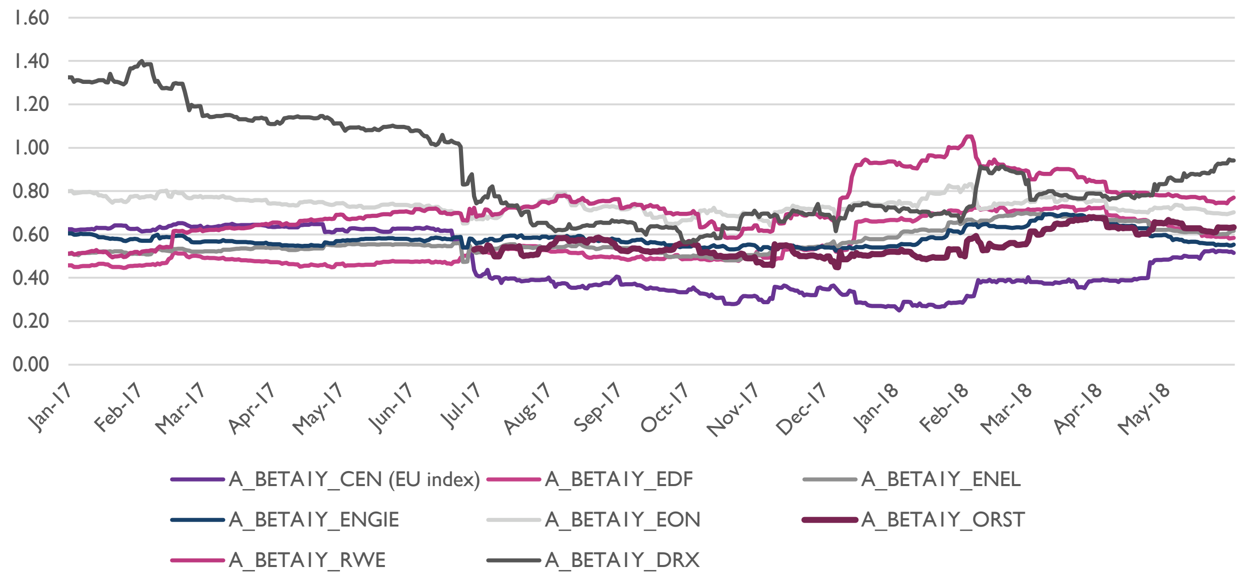
31 This is a fairly broad set of electricity sector firms of different kinds, including conventional portfolio generators and generators that use a mix of conventional and renewable energy. As we note in the main text, these are not direct comparators for the technologies we are investigating. Rather, the purpose of this part of the analysis is to consider how asset betas have changed across the electricity sector. The chart excludes Iberdrola, the two-year beta of which in 2014 was likely still to carry significant Spanish macroeconomic risk following the Eurozone crisis, and ENBW, which was an outlier with an anomalously low beta of only 0.03 in 2014. There were various other firms we considered for which asset beta data was not available.

Across the set, the average beta was 0.46 in 2014 and 0.60 in 2018, a rise of 0.14, rather lower than the average rise of 0.26 for SSE and Centrica on the UK index.

Offshore wind

It is usually best practice in the UK to place most weight upon two-year asset betas, but to consider one-year asset betas, also. If we consider one-year asset betas, we can also add in Ørsted, a Danish energy company that is particularly active in wind energy and has ten operation offshore wind farms in the UK (and many others internationally), whose stock listings are available only from 2015 (and hence one-year betas are available only from 2016).

Figure 5.3: One-year asset betas for European generators



Source: Thomson Reuters, Europe Economics' analysis.

The simple average one-year asset beta, across the set of comparators apart from Ørsted, was 0.46 in June 2016 rising to 0.55 at the end of May 2018. Over the same period the rise for Ørsted was 0.53 to 0.63, a rise broadly in line, proportionately, with other generators, but at a level of around 0.07 to 0.08 above that of more conventional electricity firms.

By the use of (highly volatile) six-monthly betas, we can consider how Ørsted's beta evolved for a slightly longer period. Using those results we can see that the average six-monthly beta for Ørsted was 0.68 in 2018 and 0.72 as of the end of May 2018.

- Uniper — In 2016 E.ON spun off its fossil fuel assets into Uniper and recently sold its stake in the company to Fortum. Uniper generates most of its energy from natural gas, coal, hydropower, oil and nuclear.
- Innogy — In 2016 RWE spun off Innogy — a European energy generator, distributor and supplier focusing on renewable technologies (wind farms specifically). In March 2018, it was announced than E.ON is going to acquire RWE's controlling stake of Innogy.
- Intergen — Intergen is a global power generation company with three operating power plants in England. While all three of them are based on the CCGT technology, Intergen is expanding of one of them (in Spalding) with part of the capacity coming from OCGT (the entire expansion is planned to add up to 945MW, of which less than 300MW would come from OCGT). The project is expected to be operational by 2020.

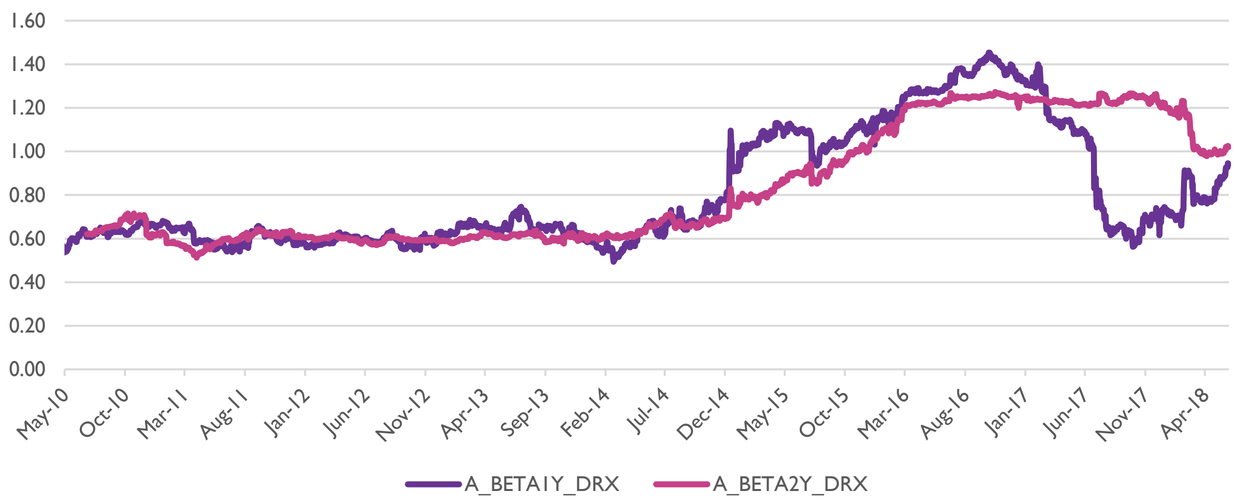
Figure 5.4: Six-monthly asset beta for Ørsted

Source: Thomson Reuters, Europe Economics' analysis.

Biomass conversion

Separately, we also analysed Drax — a UK energy company generating energy mainly from biomass. One-year and two-year asset betas are illustrated in the figure below. Two-year asset beta averaged 1.07 in 2018 and was 1.02 as of end of May 2018.

Figure 5.5: 1-year and 2-year asset beta for Drax

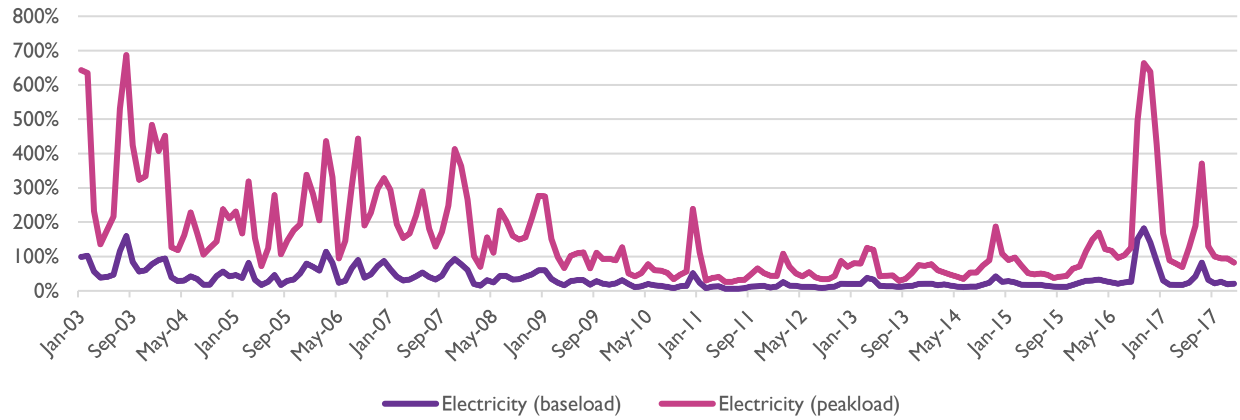


Source: Thomson Reuters, Europe Economics' analysis.

5.1.2 To what extent might price volatility be driving the rise in asset betas?

One key driver of risk is pricing volatility. The volatility of electricity prices increased from 2014 to 2017. As illustrated below (Figure 5.6) peakload electricity prices were visibly more volatile in 2016 and 2017 than in 2015. The same (though to a lesser extent) applies to baseload electricity prices.

Figure 5.6: Electricity day-ahead monthly price volatility



Source: Ofgem.

The table below shows the ratio of volatility in 2017 to volatility in 2014 (the last full year supporting the data underpinning the 2015 results). The volatility measure we are using is based on the standard deviation.

Table 5.1: Change in volatility of electricity and gas prices

	Average volatility for months in year	
	Electricity (baseload)	**Electricity (peakload)**
2014	19%	73%
2017	29%	133%
Ratio of 2017 volatility to 2014 volatility	**1.54**	**1.81**

Source: Ofgem, Europe Economics' calculations.

This rise in day-ahead pricing volatility of between 54 and 81 per cent, depending on whether peakload or baseload electricity prices are the key drivers of returns for a given technology or company, suggests a material rise in asset betas. Electricity prices will be a key driver of returns for non-CFD-protected electricity generators. Consistently with our findings in section 5.1.1, this rise in electricity price volatility suggests we should expect asset betas for electricity generation to have risen, insofar as it is exposed to price volatility.

5.1.3 To what extent might price volatility-related risks affect CFD-protected technologies?

CFD-protected technologies are shielded from day-ahead pricing risk. That will not eliminate all sources of risk, of course. Indeed, it will not even shield them from all pricing risk. CFD-protected technology firms might still choose to operate in forward markets and are still exposed to intraday risk. Furthermore, even though CFDs provide a hedge against wholesale market price volatility, the reference price that is used to calculate difference payments for intermittent generators is the day ahead price. Project operators are also still susceptible to balancing risk and changes in intra-day price volatility to the extent they have imbalanced hedge position while PPA counterparties take on such risks one could expect that this would be priced and passed through to projects. Moreover, there have also been changes such as movement towards more marginal imbalance price calculation by Ofgem under the Cash-Out Reform (BSC Mod-P323).[32] Thus, insofar as asset betas for energy generation can be shown to have risen (on which, see below), we should expect that to be reflected, to some extent, in CFD-protected technology firm asset betas, also.

How should we think about what proportion of general electricity generation asset beta rises, associated with increasing price volatility, might be reflected in CFD-protected technology asset betas? It can be proved

[32] https://www.ofgem.gov.uk/publications-and-updates/authority-decision-approve-bsc-modification-p323.

that, subject to certain assumptions, the ratio of the standard deviations of returns (above the risk-free rate) should be equal to the ratio of the asset betas.[33] Volatility of intra-day prices also increased. Based on Market Index Prices from Elexon[34], we can see that the ratio of standard deviations of prices in 2014 and in 2017 was 1.21, indicating a 21 per cent rise in volatility.[35]

This suggests that for CFD-protected technologies may experience only between around a quarter and around two fifths of the pricing volatility of non-CFD-protected generators. This indicates that, for any rise in asset betas in the wider electricity market, associated with increasing price volatility, we should expect the increasing-price-volatility-related rise in asset betas of CFD-protected technologies to be less.

5.1.4 Implications for our technologies

The implications of the above analysis differ by technology.

Drawing together the lessons of the section 5.1.1 above, we assume asset betas for electricity market have risen by around 0.15 since 2015. All of the evidence presented indicate an increase in asset beta in the electricity sector. We place most weight on the direct evidence for the rise in asset betas for UK and European electricity companies combined. Given that the rise for the (limited two-firm sample) of UK firms is higher than the average across the EU market, we round up the 0.14 figure for the whole EU to 0.15.

As illustrated in section 5.1.2, the increase in price volatility is likely to be a significant part of the overall drivers of this 0.15 asset beta rise. However, as discussed in section 5.1.3, since the price volatility rise for CFD-protected technologies is materially less than that for non-CFD-protected products, the asset beta rise for CFD-protected technologies should be expected to be materially less. Our price volatility analysis above suggests we should expect it to be only of order 25 to 40 per cent of the non-CFD-protected rise, insofar as the broader asset beta rise is attributable to increased price volatility. Based on this range, we assume that CFD-protected technologies participate in only one third of the general electricity sector asset beta rise (barring technology-specific factors) — i.e. 0.05 rise in asset betas. The remaining 0.1 would only affect those electricity generators which are not shielded from market risks by CFDs.

Technologies exposed to market risk

Since non-CFD-protected technologies — i.e. OCGT, EfW, dedicated biomass without CHP, gas CCGT IED retrofits, and gas reciprocating engine — are broadly exposed to the same pricing risk as electricity generation as a whole, we attribute the whole 0.15 rise in energy sector asset beta to the respective asset betas of those technologies (before making adjustments for technology-specific factors, discussed below).

We also attribute the whole 0.15 rise to all technologies for which CFDs are available under our first revenue support assumption but which are assumed to be employed on a merchant basis under our second revenue support assumption (see section 1.2.1 for more details on the revenue support assumptions).

CCGT

In 2015 CCGT was treated as a standalone technology. Since that time, the standard practice for the use of CCGT has come to be as part of an overall portfolio of technologies, exploiting its relatively flexible output, allowing that electricity production portfolio to meet demand more precisely than individual technologies could if used alone.

Insofar as such a bundle of assets within such a production technologies portfolio (as opposed to investment portfolio) were completely interdependent(rather as the steering wheel of a car, its axle and its tie rod are not really independent assets, but instead work together to steer the car and thus contribute to its overall value), it could be argued that they really have one single asset beta, rather than being independent projects

33 See section 11.1 in Appendix: Asset Beta for details.
34 https://www.elexon.co.uk/operations-settlement/imbalance-pricing/.
35 The standard deviation was 11.6 in 2014 and 14.1 in 2017.

each with their own cost of capital. In that case CCGT would perhaps be argued to have the same asset beta as a portfolio generator overall. However, generation technologies in a production portfolio do not that complete a degree of complementarity and interdependence, and CCGT can at least to some degree still be treated as standalone, and as such continue to have a higher asset beta than those of portfolio generators.

The UK's portfolio generators have an average asset beta of 0.66, ranging from SSE's 0.58 to Centrica's 0.75. We might therefore expect that CCGT should have an asset beta of above 0.75, perhaps treating the UK portfolio generator average, 0.66, as a lower bound.

If it were fully standalone, CCGT might be exposed to a similar set of risks to those of a company such as Drax.[36] Drax has some revenue stabilisation from CFDs (for which its biomass part of the business is eligible) but also some exposure to pricing risks (through the coal-related part of its business) and to some supply contracts risk (through Haven Powers). The asset beta of Drax is 1.07. We might reasonably expect that CCGT, when used within a portfolio, should have a lower asset beta than Drax, and so use 1.07 as an upper bound.

If we consider CCGT as a weighted combination of a portfolio generator and Drax, the question then arises as to what weights to use. If we give the upper (1.07) and lower bound (0.66) equal weights, that implies an asset beta for CCGT of 0.87 (meeting the test of being above 0.75). That is the value we use hereafter.

CFD-protected technologies

By contrast, under the revenue support assumption we are using in this report, solar and wind technologies as well as hydro, hydro large store, wave, tidal stream, geothermal CHP, biomass CHP, biomass conversion, ACT, AD, AD CHP, EfW CHP, landfill and sewage gas are assumed to have CFDs.[37] These provide pricing protection up to day-ahead, and thus material though not perfect pricing insurance. It is also worth observing that even renewables technologies may find it attractive to trade in forwards markets if prices are sufficiently high. Thus we should expect that, even with CFDs, those technologies will exhibit some limited participation in general electricity generation and broader energy market asset beta trends.

For those technologies, we assume they participate in one third of the general electricity market 0.15 beta rise, i.e. rise by 0.05 before technology-specific adjustments.

Offshore wind and biomass conversion

Later, although we shall calculate the offshore wind asset beta on a basis consistent with that of other technologies, we shall consider a cross-check from direct asset beta estimates. We do not have a pure play comparator. The closest to a pure play firm is Ørsted[38], but the data available do appear to suggest that asset betas for offshore wind may now lie at of order 0.07 to 0.08 above those for more conventional technologies. The average asset beta (against the European index) for our conventional and portfolio generators comparator set was 0.6 as at end-May 2018, and 0.66 for Centrica and SSE. If we give each of these equal weights and add 0.07, that would imply an asset beta crosscheck value of 0.7 for offshore wind. That is consistent with Ørsted's six-monthly beta data, giving a 0.68 average for 2018 and a 0.72 asset beta for end-May 2018. Since Ørsted have a more diversified portfolio of assets than other generators and is regarded as one of the better-in-class providers, we can regard the Ørsted asset beta as likely to constitute a lower bound — i.e. we should expect that our calculation below should produce an asset beta of above 0.7 (though probably not greatly so).

36 Indeed, Drax has considered moving into CCGT.

37 See more on how regulation has changed in this area below.

38 Ørsted has assets in UK and Denmark as well as having won new contracts in Taiwan to build OSW. They also have a footprint in Energy from Waste. Hence Ørsted is not truly pure play. However, it is the closest to a pure play firm that we have available.

For biomass conversion, we use the estimate for Drax's as our direct datapoint for asset betas. We take the 2018 average (i.e. 1.07) as our proposed asset beta.

CCS

CCS is an eligible technology under the CFD scheme, but does not compete in the allocation framework set out for renewables, and hence under our revenue support assumptions would be exposed to energy market risks. However, as an eligible technology we treat them, for the purposes of this report, as if they were shielded from changes in elements of risk in the energy market. In practice, for asset beta estimation, this means attributing only 0.05 of the overall 0.15 rise in the energy market's asset beta to CCS's asset beta.

This assumption is not changed under our merchant-player revenue support assumption.

5.2 Technology specific

5.2.1 Summary of changes in energy market regulation

In the table below we summarise the main developments in the relevant regulatory support mechanisms (noting that RO is excluded). For a more detailed overview, see section 11.5 in Appendix: Asset Beta.

Table 5.2: Changes in regulation — overview

	CFD	CM
Solar	• As part of Pot 1, only eligible for the 1st allocation round • 5 projects awarded • Strike price: £50/MWh for projects to be delivered in 2015/156, £79.23/MWh for project to be delivered in 2016/17	n/a
Onshore wind	• As part of Pot 1, only eligible for the 1st allocation round • 15 projects awarded • Strike price: £79.23/MWh for projects to be delivered in 2016/17, £79.99/MWh for projects to be delivered in 2017/18	n/a
Offshore wind	• As part of Pot 2, eligible for both allocation rounds • 2 projects awarded in the 1st auction, 3 in the 2nd auction • Strike price in the 1st auction: £119.89/MWh for projects to be delivered in 2017/18, £114.39/MWh to be delivered in 2018/19; • Strike price in the 2nd auction: £74.75/MWh for projects to be delivered in 2021/22, £57.5/MWh for projects to be delivered in 2022/23	n/a

	CFD	CM
CCGT	n/a	• CCGT is the main provider of capacity • The clearing price and auctioned capacity increased since 2015 • CCGT's share of the awarded capacity declined from 47% in 2015 to 43% in 2016/17
Biomass conversion	• As part of Pot 3, no clear information about the allocated budget for this technology • No projects awarded • ASP:[39] £105/MWh for all delivery years	• Biomass as a fuel is the third main provider of capacity • Biomass' share of the awarded capacity declined from 16% in 2015 to 15% in 2016/17
Biomass CHP	• As part of Pot 2, eligible for both allocation rounds • 2 projects awarded • Strike price: £74.75/MWh for projects to be delivered in 2021/22	• See CHP below
ACT/ AD	• As part of Pot 2, eligible for both allocation rounds • 3 projects awarded in the 1st auction, 6 in the 2nd auction • Strike price in the 1st auction: £119.89/MWh for projects to be delivered in 2017/18, £114.39/MWh to be delivered in 2018/19 • Strike price in the 2nd auction: £74.75/MWh for projects to be delivered in 2021/22, £40/MWh for projects to be delivered in 2022/23	• See CHP below
Landfill/ EfW	• As part of Pot 1, only eligible for the 1st allocation round • 2 EfW projects awarded • Strike price: £80/MWh for projects to be delivered in 2018/19	• See CHP below
Sewage gas	• As part of Pot 1, only eligible for the 1st allocation round • No projects awarded	n/a
Hydro	• As part of Pot 1, only eligible for the 1st allocation round • Only projects with a bounded capacity (5-50 MW) were admitted • No projects awarded • ASP: £100/MWh	• Few GW awarded in the capacity market auction
Wave/Tidal	• As part of Pot 2, eligible for both allocation rounds • ASP higher than the others • No projects awarded • ASP in the 1st auction: £305/MWh for all delivery years for both technologies • ASP in the 2nd auction: ▪ Wave: £310/MWh for projects to be delivered in 2021/22, £300/MWh for 2022/23; ▪ Tidal: £300/MWh for projects to be delivered in 2021/22, £295/MW for 2022/23.	n/a

[39] ASP stands for Administrative Strike Price, i.e. the upper limit of the subsidy.

	CFD	CM
Geothermal	• As part of Pot 2, eligible for both allocation rounds • No projects awarded • ASP in the 1st allocation round: £145/MWh for 2014/15, 2015/16 and 2016/17; £140/MWh for projects to be delivered in 2017/18 and 2018/19 • ASP in the 2nd allocation round: £140/MWh	• See CHP below
CHP	n/a	• Capacity awarded slightly increased from 2015 to 2016/17 • Overall capacity awarded is below 10%
OCGT and Reciprocating Engine	n/a	• Around 6% of total awarded capacity in 2016/17

Source: Europe Economics.

5.2.2 Technology developments and maturing of the industry

There is likely to be a significant variability in the level of risk within the life of a project, as well as over longer periods of time as industries mature.

Regarding the evolution of risk within a project's life, the profile of an electricity generating company over time — from planning, to obtaining consents and subsidises, to construction, to becoming operational[40] — means that there are likely to be substantial and fairly predictable costs upfront, and less certain revenues later on. This profile implies that systematic risk associated with investing in such a company gradually declines as the company matures. This is because as more of the upfront investments are made the less uncertain and less remote future revenues become. As a result, one could expect hurdle rates (and cost of capital) to gradually decline as a renewable project progresses over this timeline.[41]

This implies that, the overall hurdle rate for a given technology is in fact an average of several gradually declining hurdle rates, each associated with a different stage of project development.

In terms of the evolution of risk as the relevant technologies and related industries mature, we can expect the risk of a new sector to decline over time and to ultimately converge to a level that is relatively stable over medium term. This is because new industries are often fairly dynamic due to technological and/or regulatory developments as well as accumulation of know-how allowing for cost savings and uncertainty reduction. There are three broad categories of innovation that could be expected to affect the risks associated with electricity generation:

- Technological innovation — e.g. improvements in technology efficiency or reliability, reductions in production costs etc.;
- Process innovation — e.g. improvements in the way electricity generators organise their businesses, taking advantage of the accumulation of know-how; process innovations also include improvements in the regulatory process accompanying the planning and development phases of a project — specifically the risk would decline as this process gets:
  - shorter — if the time between the initial planning phase and the operational phase shrinks, the present value of future revenue becomes higher as the revenues become less remote,

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40 UK Trade & Investment (2014), "UK Offshore Wind: Opportunities for trade and investment".

41 The argument is based on the risk-return "staircase" concept presented in Myers (1999), "Measuring pharmaceutical risk and the cost of capital", in: Office of Health Economics (1999), "Risk and return in the pharmaceutical industry".

  - less costly — this could happen if, for example, administrative costs decline, economies of scale are at play, or acquired know-how allows firms to develop projects and/or operate more efficiently,
  - less uncertain — with less uncertainty regarding the process and the likelihood of success, the hurdle rates in the initial phases should converge towards the rate in the final phase in which the project is operational;

- Commercial innovation — e.g. developing new business models or services which were not previously available such as smart metering.[42]

In the following sections, we discuss the developments relevant for each of the technologies that speak to such improvements in efficiency, learnings effects and mitigation of risk.

Solar

During the last three years, solar technology continued to gain importance in the UK energy market, with a constant increment in the total installed capacity.[43] The total amount of installed capacity increased from 9,535 MW in 2015 to 12,791 MW in 2017. At the same time, the module costs have been decreasing — in the UK, the price decreased by 18 per cent from 2015 to 2016 (although the rate of this cost reduction seems to have been gradually slowing down).[44] . The same trends were observed in terms of total installed costs, which decreased by 10 per cent between 2016 and 2017.[45]

Looking at the recent technological innovations, in the last 10 years the efficiency of silicon modules increased from 12 to 17 per cent, with room for further improvements. Experimental modules which are tested but not yet available on the market can reach levels of efficiency around 24 per cent.[46]

Onshore wind

The installed capacity from onshore wind followed the same path of solar PV during the last three years. Indeed, the *cumulative* capacity increased from 9,222 MW in 2015 to 12,973 MW in 2017.[47] However, the cost of wind turbines presented a more variable trend and fluctuated with demand and supply. There was a peak in turbine prices between 2007 and 2010, which was due to an increase in construction costs, higher demand level and technologies improvement. Turbine manufacturers introduced larger and more expensive turbines, which increase capital expenditure but delivered higher energy output, improving the reduction of LCOE. By the end of 2017, the average wind turbine price was around $1000/kW across the market.[48]

The total installation costs in Europe decreased by 19 per cent between 2010 and 2016, falling on average below $2000/kW. This implied that wind turbines accounted for a large share of the total installation costs — more than 60 per cent as reported by IRENA.[49]

Offshore wind

Offshore wind showed a growth in the total installed capacity, although in absolute terms the values are smaller than for solar or onshore wind. The capacity increased from 5,093 MW in 2015 to 7,514 MW in 2017, with the most relevant increment between 2016 and 2017.[50] For offshore wind projects, wind turbines account for a smaller share of the overall cost than for onshore wind projects, accounting for around 30-50 per cent of total installed cost. Moreover, the offshore location increases significantly not only the costs of

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42 Oxford Institute for Energy Studies (2017), "Electricity Networks: Technology, Future Role and Economic Incentives for Innovation".
43 http://www.irena.org/solar.
44 IRENA (2018), "Renewable Power Generation Costs in 2017", International Renewable Energy Agency, Abu Dhabi.
45 IRENA (2018), "Renewable Power Generation Costs in 2017", International Renewable Energy Agency, Abu Dhabi.
46 Fraunhofer ISE: Photovoltaics Report, updated: 26 February 2018.
47 http://www.irena.org/wind
48 IRENA (2018), "Renewable Power Generation Costs in 2017", International Renewable Energy Agency, Abu Dhabi
49 http://www.irena.org/wind.
50 http://www.irena.org/wind.

these projects in themselves, but also the cost of connecting to the grid network. Furthermore, the O&M costs are higher for offshore projects than onshore projects, due to the more challenging environment and their complexity. On the other hand, offshore wind projects can produce more energy than onshore projects, due to the presence of stronger and more constant winds.[51]

CCGT

The utilisation of CCGT has been weak in recent years. Although the total installed capacity for the CCGT is larger than for solar or wind, it slowly reduced during the period 2010-2016 (decreasing from 34 GW to around 32 GW in 2015 and 2016).[52,53]

In terms of changes, the last 10 years have seen an increasing role of the renewable technology in the energy market. For this reason, CCGT plants moved from being the baseload to the backup power generator, with a more flexible and cyclic use. These changes required improvements from the turbine suppliers, in order to create CCGT plants able to operate during the gaps of solar and wind load curve.[54]

Hydro

Hydropower is one of the most mature renewable sources for electricity. In 2016, it provided 71 per cent of the total electricity produced by renewable sources globally.[55] From 2015 to 2017, the installed capacity for hydropower in the UK steadily increased from 2059 MW in 2015 to 2167 MW in 2017.[56] During the last year the LCOE for hydropower did not change significantly. Indeed, as reported by IRENA,[57] its range in 2010 was $0.015-$0.322/kWh, and $0.018-$0.246/kWh in 2016. Due to its maturity, in the last three years there have been no relevant technological improvements.

Wave and tidal

As reported in the REN21 (2018) global status report on renewable technologies, among ocean energy technologies tidal technology seems to be close to technological maturity. During the last years, tidal technology has converged around the use of horizontal-axis turbines. Moreover, in 2017 the installation of the first arrays of tidal turbines began.[58] Looking at the total installed capacity in the UK, IRENA[59] shows that it doubled from 2015 to 2017, increasing from 8.94 MW to 18 MW. However, IRENA does not specify how much of this overall capacity can be attributed specifically to tidal and how much to wave.[60]

Innovation implemented in the tidal technology included:

- Development and implementation of tidal energy converters (TEC) progressed during the last years.[61] The MeyGen project is one of the most important operational plant, which signed a mile stone for this technology. It is active since 2016 and it has a capacity of 398 MW.[62]
- Looking at the different sub-technologies involved with tidal energy, in the 2016 report[63], JRC highlighted that the Horizontal-axis turbines technology had reached a technology readiness level (TRL) of eight, while tidal kite had reached level five, with possible improvement towards level seven during the 2017.

51 IRENA (2018), "Renewable Power Generation Costs in 2017", International Renewable Energy Agency, Abu Dhabi
52 BEIS (2017) “UK Energy in brief 2017”
53 BEIS (2017), “DUKES : electricity” , Chapter 5.
54 https://www.ge.com/power/transform/article.transform.articles.2018.jan.evolution-of-combined-cycle-pe
55 World Energy Council (2016) World Energy Resources Hydropower.
56 http://www.irena.org/hydropower.
57 http://resourceirena.irena.org/gateway/dashboard/?topic=3&subTopic=1057.
58 REN21 (2018), Renewable global status report.
59 http://www.irena.org/ocean.
60 http://www.irena.org/ocean.
61 JRC (2016), “JRC Ocean Energy Status Report: 2016 Edition”.
62 https://simecatlantis.com/projects/meygen/.
63 JRC (2016), “JRC Ocean Energy Status Report: 2016 Edition”.

Wave energy generation does not present the same maturity as tidal stream. There have been few convergences, partly due to the difficulties in harnessing wave energy for electricity generation. As argued by REN21 (2018), "[w]ave energy converter demonstration projects are mostly in the pre-commercial stage" and the market still depends on the government subsidies. Magagna et al. (2016) also indicate that "[a]t the end of 2016, the picture is not very different from 2014, with only a handful of devices successfully tested at TRL 8".[64]

That said, REN21 (2018) also recognises that "Europe saw significant deployment activity for ocean energy devices in 2017, and notable developments were found around the world".[65] For example, in 2017 "[a] new air turbine by Kymaner (Portugal) underwent tests at the Mutriku wave power plant in the Bay of Biscay, Spain. The device harnesses wave-driven compressed air, a technology known as an oscillating water column".[66] In the UK specifically, there seems to be a number of wave and tidal projects in the development, planning or construction phase.[67]

Geothermal

In 2015 geothermal technology provided only 0.3 per cent of the capacity installed globally. The total capacity installed globally increased from 11,787 MW in 2015 to 12,894 MW in 2017. The LCOE from 2010 to 2016 presented an increasing path, moving from $0.035-$0.076/kWh to $0.043-$0.113/kWh.[68] At the same time, IRENA (2017) indicates that "[t]he costs for electricity generation from geothermal technologies are becoming increasingly competitive, and they are expected to continue to drop through 2050".[69]

OCGT and reciprocating engine

The report prepared for DECC by LeighFisher found that, in 2016 the technology related to OCGT was mature, with no relevant changes in the construction period during the previous years. Moreover, since OCGT is an established technology, there have been no relevant technological developments.[70]

Reciprocating engine is a mature technology, used not only in the CCGT and OCGT plants, but also for CHP installation.[71]

CCS

The South Australian Fuel and Technology report, published in March 2017, pointed out that "[m]ost CCS systems for power generation around the world are classed as demonstration, prototype, or research and development. As at 28 February 2017, the Global CCS Institute database shows two operational large-scale CCS project in the power sector worldwide:

- Boundary Dam Unit 3 plant in Saskatchewan, Canada (Carbon Dioxide (CO_2) capture capacity of approximately 1 million tonnes per annum (Mtpa)).
- Petra Nova Carbon Capture Project (CO_2 capture capacity of approximately 1.4 Mtpa)."[72]

In 2016, the MIT published an article about the biggest energy advances of the year, reporting that "[t]his year saw advances for several emerging approaches to capturing carbon in power plants, including carbonate fuel cells, as well as at least some promising implementations of existing technology in the real world."[73]

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64 JRC (2016), "JRC Ocean Energy Status Report: 2016 Edition".
65 REN21 (2018), Renewable global status report.
66 REN21 (2018), Renewable global status report.
67 http://www.emec.org.uk/marine-energy/wave-and-tidal-projects/.
68 http://resourceirena.irena.org/gateway/dashboard/?topic=3&subTopic=1057.
69 IRENA (2017), Geothermal Power: Technology Brief, International Renewable Energy Agency, Abu Dhabi.
70 LeighFisher (2016) Electricity Generation Costs and Hurdle Rates. Lot 3: Non-Renewable Technologies.
71 U.S. Department of Energy (2015) Combined Heat and Power Technology Fact Sheet Series.
72 AEMO (2017) South Australian Fuel and Technology report.
73 MIT Technology Review (2016), "The Biggest Clear Energy Advances in 2016".

In March 2018 the first demonstrator CCS plant, which uses first-of-a-kind technology, was opened in the UK.[74]

Biomass CHP, ACT, AD, landfill, sewage gas and EfW

Looking at the bio-energy in general, during 2017 some initiatives begun in order to sustain and expand the development of this technology[75]. For example, the 20-country BioFuture Platform was established and, among other goals, its aim is to contribute in the creation of sustainable energy.[76]

Looking at the UK market for bio-energy (which includes landfill, sewage gas, AD, ACT and EfW), REN21 indicated that bioelectricity capacity increased by 241 megawatts (MW) in 2017 to 6.0 GW. This growth was driven predominantly by biomass, AD and EfW. In that year, bioelectricity generation increased by six per cent to 31.8 TWh — the growth was again driven by solid biomass fuels, AD and MSW, but was partly offset by reductions in landfill gas and biomass co-firing.[77] REN21 also noted that progress in the UK market has slowed down, due to changes in the regulatory environment.[78]

For other technologies such as ACT, landfill and EfW there have been few improvements in the past decade.

Focusing on biomass technology, the total installed capacity in the UK increased during the last years from 3,200 MW in 2015 to 3,537 MW in 2017.[79] The LCOE for biomass on a global basis was broadly stable from 2010 to 2016, only the minimum value increased: the ranges moved from \$0.032-\$0.170/kWh to \$0.061-\$0.170/kWh.[80]

In the UK, biomass and CHP are listed among the bulk and dispatchable generation technologies.

5.2.3 Summary of regulatory and technological developments with CFDs available for selected technologies

Based on the analysis presented in section 5.2.1 and section 5.2.2, we can assess the strength and the direction of various factors affecting risks associated with investing in the technologies under consideration. In particular, we focus on how the key risk drivers identified by NERA (see section 1.1.3) have changed since 2015.

In this section we present the asset beta changes that are consistent with our revenue support assumption that a number of technologies are eligible for CFDs (see section 1.2.1 for details). In the following section (5.2.4) we consider what changes in asset betas would be appropriate under the second revenue support assumption, i.e. where none of the technologies under consideration use CFDs.

Solar and onshore wind

The changes in the regulatory framework have affected solar and onshore wind in a similar way — they were not included in the second round of CFDs allocation. Although neither of these technologies have participated in CFD allocation schemes in the past few years (and hence allocation risk is currently non-existent), under our revenue support assumption we are to assume a scenario in which they were in a CFD allocation round, and hence there would be some allocation risk remaining. Nonetheless, we assume that the learning process from previous rounds should have eliminated a material portion of this risk — say, half. As those two technologies mature — accumulate know-how, achieve economies of scale and drive the costs down — we expect the development and construction risk to decline, however, given their relatively well-established nature the scope for reduction in those two areas is likely to be somewhat limited. Indeed, the recent growth

74 https://www.edie.net/news/8/UK-s-first-carbon-capture-utilisation-demonstration-plant-opens/.
75 REN21 (2018), Renewable global status report.
76 IRENA, About the Biofuture Platform.
77 REN21 (2018), Renewable global status report.
78 REN21 (2018), Renewable global status report.
79 http://www.irena.org/bioenergy.
80 http://resourceirena.irena.org/gateway/dashboard/?topic=3&subTopic=1057.

in the use of Corporate Power Purchase Agreements (PPAs) — long-term contracts under which businesses purchase electricity directly from electricity generators — for solar and onshore wind illustrates the growing understanding and maturing of this market. At the same time, however, uncertainties about eligibility for CFDs might be symptomatic of wider uncertainties regarding the policy treatment of these technologies, which might suggest an increase in policy risk.

Offshore wind

Offshore wind — as one of the less-established technologies — has received more regulatory support than solar or onshore wind. In particular, it was included in the second allocation round of CFDs. We expect to be still subject to a little bit more allocation risk than solar and onshore wind. As a renewable technology, offshore wind could also be expected to bear similar level of policy risk and other renewable technologies. Regarding development and construction risks, the dynamics of risk for offshore wind is perhaps similar to that of solar and onshore wind, but more pronounced. This is because as a less established and more dynamic technology there is more scope for it to improve in terms of know-how, organisational efficiency etc. However, in addition to risks faced by solar and onshore wind, offshore wind has higher exposure to technological risk, which is nevertheless likely to be declining as the technology matures.

CCGT

The types of risks relevant for CCGT are of a different character than those discussed above. Specifically, risks identified by NERA include fuel prices, carbon prices, and revenue volatility, which are all market risks (i.e. risks captured by the systematic relationship between returns of CCGT companies with the returns of the broader market). In addition to those market risks, NERA identified that CCGT is subject to policy and allocation risks. As we argue in section 5.1.4, this risk profile could be viewed as similar to that of a combination of portfolio generators and Drax. Therefore, we do not estimate changes in those individual risks.

The above analysis of how risks have changed in 2015-2018 period are summarised in the table below.

Table 5.3: Changes in the key risk drivers — summary for solar, wind and CCGT

	Risk driver	Change 2015-2018	Interpretation	Asset beta impact
Solar	Allocation	Materially lower	Half of the previous asset beta impact of this factor removed	-0.035
	Policy	Increased	One quarter of the previous asset beta impact of this factor removed	+0.013
	Development	Reduced slightly	5% of the previous asset beta impact of this factor removed	-0.007
	Construction	Reduced slightly	5% of the previous asset beta impact of this factor removed	-0.007
Onshore wind	Allocation	Materially lower	Half of the previous asset beta impact of this factor removed	-0.035
	Policy	Increased	One quarter of the previous asset beta impact of this factor removed	+0.013
	Development	Reduced slightly	5% of the previous asset beta impact of this factor removed	-0.007
	Construction	Reduced slightly	5% of the previous asset beta impact of this factor removed	-0.007

	Risk driver	Change 2015-2018	Interpretation	Asset beta impact
Offshore wind	Allocation	Materially lower	One quarter of the previous asset beta impact of this factor removed	-0.035
	Policy	Unchanged	N/A	0
	Development	Reduced somewhat	One tenth of the previous asset beta impact of this factor removed	-0.014
	Technology	Reduced	One quarter of the previous asset beta impact of this factor removed	-0.048
	Construction	Reduced	One quarter of the previous asset beta impact of this factor removed	-0.035
CCGT	Fuel price	N/A	Reflected in energy market movements	N/A
	Carbon price	N/A	Reflected in energy market movements	N/A
	Revenue	N/A	Reflected in energy market movements	N/A
	Policy	N/A	Reflected in energy market movements	N/A
	Allocation	N/A	Reflected in energy market movements	N/A

Source: NERA (2015), Europe Economics.

Other technologies

Based on the same type of inputs and analysis, we conducted similar analysis for the remaining technologies. Our views are summarised in Table 5.4 below. Key assumptions that are worth highlighting are:

- Given the lack of direct evidence on the size of allocation, development and construction risk for other technologies, where those risks were mentioned, we assumed they are of the same size as we assumed for solar and wind above;
- The portion of asset beta driven by technology risk is estimated as half of the difference between the 2015 asset beta for that technology and 2015 asset beta for the electricity market;
- The portion of asset beta driven by political risk is assumed to be 0.05 for all technologies for which this risk was reported as relevant by NERA's survey respondents;
- For technologies which under our revenue support assumption are largely shielded from the wider electricity market risk but which were nevertheless considered by NERA's survey respondents to be exposed to fuel prices, carbon prices or fuel availability we assume that CFDs would remove any demand risk but not necessarily cost risk. We then deemed that demand risk is about twice as large as cost risk, which meant that of the two thirds of the wider electricity market risk CFD protect the relevant technologies, technologies for which fuel is a risk driver would nevertheless be still exposed to a third of that risk. In numerical terms, despite partial protection from market fluctuations CFD scheme provides, there is an additional 0.017-0.033[81] impact because of cost-side risk associated with fuel.

Table 5.4: Changes in the key risk drivers — summary for remaining technologies

	Risk driver	Change 2015-2018	Asset beta impact
Hydro	Allocation	Materially lower	-0.035
	Policy	Increased	+0.013
	Construction	Unchanged	0.000
Wave	Allocation	Materially lower	-0.035
	Policy	Increased	+0.013
	Technology	Reduced slightly	-0.016
	Construction	Reduced	-0.035

[81] We use 0.033 where two of those fuel-related risks were identified as relevant, and half of that impact (i.e. 0.017) where only one of those risks was identified as relevant. 0.033 is derived as one third of 0.1, which is the part of the wider market risk CFDs are assumed to remove.

	Risk driver	Change 2015-2018	Asset beta impact
Tidal stream	Allocation	Materially lower	-0.035
	Policy	Increased	+0.013
	Technology	Reduced	-0.092
	Construction	Reduced	-0.035
Geothermal CHP	Allocation	Materially lower	-0.035
	Policy	Increased	+0.013
	Technology	Reduced slightly	-0.042
	Construction	Reduced slightly	-0.007
Biomass Dedicated	Allocation	Reduced	-0.017
	Policy	Unchanged	0.000
	Fuel price	Increased	N/A
	Carbon price	Increased	N/A
ACT	Allocation	Materially lower	-0.035
	Policy	Unchanged	0.000
	Fuel price	Increased	+0.017
	Technology	Reduced slightly	-0.023
	Construction	Reduced slightly	-0.007
AD	Allocation	Materially lower	-0.035
	Policy	Unchanged	0.000
	Fuel price	Increased	+0.017
	Technology	Unchanged	0.000
	Construction	Unchanged	0.000
EfW CHP	Allocation	Materially lower	-0.035
	Policy	Unchanged	0.000
	Fuel price	Increased	+0.017
	Fuel availability	Increased	+0.017
EfW	Allocation	Reduced	-0.017
	Policy	Unchanged	0.000
	Fuel price	Increased	N/A
	Fuel availability	Increased	N/A
Landfill	Allocation	Materially lower	-0.035
	Policy	Unchanged	0.000
	Fuel price	Increased	+0.017
	Fuel availability	Increased	+0.017
Sewage Gas	Construction	Unchanged	0.000
	Labour	Unchanged	0.000
	Parts and equipment	Increased slightly	+0.017
CCS	Allocation	Unchanged	0.000
	Policy	Increased	+0.013
	Technology	Reduced somewhat	-0.025
	Construction	Reduced somewhat	-0.014

Note: For technologies which are not eligible for CFDs "allocation risk" should not be understood as the risk of being allocated a CFD.
Source: NERA (2015), Europe Economics.

Those individual impacts on asset beta are combined in the table below. We note that our analysis in Table 5.4 above is often done for categories of technologies (e.g. CCS) rather than the detailed variants of the technologies under consideration in this report (e.g. CCS coal, CCS gas, CCS biomass). To obtain estimates for each of the variants considered here, we adjusted those broader changes proportionately.[82]

[82] For example, we estimated that technology-specific change in asset beta for biomass dedicated is 0.02. To obtain the change in asset beta for biomass CHP we multiplied 0.02 by the ratio of 2015 asset beta for biomass CHP and 2015 asset beta for biomass dedicated. The differences in other instances are often not visible in the table due to rounding.

Table 5.5: Technology-specific changes in asset beta with CFDs available for selected technologies

	Proposed technology-specific asset beta change
Solar	-0.04
Onshore wind	-0.04
Offshore wind	-0.13
Hydro	-0.02
Hydro Large Store	-0.02
Wave	-0.07
Tidal stream	-0.15
Geothermal CHP	-0.08
Biomass Dedicated >100MW	-0.02
Biomass Dedicated 5-100MW	-0.02
Biomass CHP	0.00
ACT standard	-0.05
ACT advanced	-0.05
ACT CHP	-0.05
AD CHP	-0.02
AD	-0.02
EfW CHP	0.00
EfW	-0.02
Landfill	0.00
Sewage Gas	0.02
CCS Gas FOAK	-0.03
CCS Gas NOAK	-0.03
CCS Coal FOAK	-0.03
CCS Coal NOAK	-0.03
CCS Biomass	-0.03
Gas CCGT IED retrofit	-0.03
Gas Reciprocating engine (inc. diesel)	-0.03
Coal plants All retrofits	0.00
OCGT	-0.03

Source: Europe Economics.

5.2.4 Summary of regulatory and technological developments with no CFDs available (revenue support assumption #1)

In this section we present the asset beta changes that are consistent with our revenue support assumption that none of the technologies use CFDs (see section 1.2.1 for details on revenue support assumptions).

In the context of changes in asset betas driven by regulation, this assumption would primarily affect the allocation risk, which would be to a large extent eliminated, at least in its current form. While other forms of allocation risk might persist and new forms might arise, for the purpose of this study we assume that this risk would mostly disappear. Specifically, we assume that 75 per cent of its current size would be eliminated for all technologies which have been eligible for CFDs under our first revenue support assumption. This translates to a fall in asset beta of -0.052 (instead of -0.035 assumed under revenue support assumption #1 for CFD-protected technologies).

This would have the following implications for the technology-specific change in asset betas.

Table 5.6: Technology-specific changes in asset beta with no CFDs available for selected technologies

	Proposed technology-specific asset beta change
Solar	-0.05
Onshore wind	-0.05
Offshore wind	-0.15

	Proposed technology-specific asset beta change
Hydro	-0.04
Hydro Large Store	-0.04
Wave	-0.09
Tidal stream	-0.17
Geothermal CHP	-0.10
Biomass Dedicated >100MW	-0.02
Biomass Dedicated 5-100MW	-0.02
Biomass CHP	-0.03
ACT standard	-0.06
ACT advanced	-0.07
ACT CHP	-0.08
AD CHP	-0.05
AD	-0.04
EfW CHP	-0.02
EfW	-0.02
Landfill	-0.02
Sewage Gas	+0.02
CCS Gas FOAK	-0.03
CCS Gas NOAK	-0.03
CCS Coal FOAK	-0.03
CCS Coal NOAK	-0.03
CCS Biomass	-0.03
Gas CCGT IED retrofit	0.00
Gas Reciprocating engine (inc. diesel)	0.00
Coal plants All retrofits	0.00
OCGT	0.00

Source: Europe Economics.

5.3 Conclusion on asset beta

5.3.1 Revenue support assumption #1: CFDs available for selected technologies

Drawing together the evidence from previous sections, the changes in asset betas (and their new levels, given the 2015 baseline figures) where some technologies are eligible for CFDs are as follows.

Table 5.7: Asset beta conclusions

	2015 baseline asset beta *A*	Electricity market effect *B*	Technology-specific effect *C*	Total change *D = B + C*	New asset beta *E = A + D*
Solar	0.58	+0.05	-0.04	+0.01	0.59
Onshore wind	0.61	+0.05	-0.04	+0.01	0.62
Offshore wind	0.85	+0.05	-0.13	-0.08	0.77*
CCGT	0.66	N/A	N/A	N/A	0.87**
Hydro	0.57	+0.05	-0.02	+0.03	0.60
Hydro Large Store	0.57	+0.05	-0.02	+0.03	0.60
Wave	1.09	+0.05	-0.07	-0.02	1.07
Tidal stream	1.20	+0.05	-0.15	-0.10	1.10
Geothermal CHP	2.30	+0.05	-0.08	-0.03	2.27
Biomass Dedicated >100MW	0.81	+0.15	-0.02	+0.13	0.94
Biomass Dedicated 5-100MW	0.79	+0.15	-0.02	+0.13	0.92
Biomass CHP	1.12	+0.05	0.00	+0.05	1.17
Biomass Conversion	0.89	N/A	N/A	N/A	1.07***
ACT standard	0.89	+0.05	-0.05	0.00	0.90
ACT advanced	1.01	+0.05	-0.05	0.00	1.02

	2015 baseline asset beta A	Electricity market effect B	Technology-specific effect C	Total change D = B + C	New asset beta E = A + D
ACT CHP	1.12	+0.05	-0.05	0.00	1.13
AD CHP	1.23	+0.05	-0.02	+0.03	1.26
AD	1.00	+0.05	-0.02	+0.03	1.03
EfW CHP	0.92	+0.05	0.00	+0.05	0.97
EfW	0.69	+0.15	-0.02	+0.13	0.82
Landfill	0.69	+0.05	0.00	+0.05	0.74
Sewage Gas	0.75	+0.05	0.02	+0.07	0.82
CCS Gas FOAK	1.03	+0.05	-0.03	+0.02	1.05
CCS Gas NOAK	0.82	+0.05	-0.03	+0.02	0.84
CCS Coal FOAK	1.04	+0.05	-0.03	+0.02	1.06
CCS Coal NOAK	0.83	+0.05	-0.03	+0.02	0.85
CCS Biomass	1.04	+0.05	-0.03	+0.02	1.06
Gas CCGT IED retrofit	0.65	+0.15	-0.03	+0.12	0.77
Gas Reciprocating engine (inc. diesel)	0.66	+0.15	-0.03	+0.12	0.78
Coal plants All retrofits	0.70	+0.15	0.00	+0.15	0.85
OCGT	0.66	+0.15	-0.03	+0.12	0.78

Notes: * We note that our Ørsted cross-check (see Section 5.1.4) suggested that the offshore wind asset beta should be somewhat above 0.7, which is consistent with our figures here.
**As a generation technologies portfolio asset, CCGT attributed the average between the asset beta of UK electricity generators and Drax.
*** Biomass conversion estimated based directly on Drax.
Source: Europe Economics.

As a reference point, we note that the average asset beta in 2018 was 0.60 for European electricity companies and 0.66 for UK electricity companies. In that context, we emphasize that under revenue support assumption #1 our finding that the asset betas for solar and onshore wind are similar to (or in the case of solar, slightly lower than) those of portfolio generators and conventional generators is importantly driven by the revenue support assumption here, and in particular the working assumption that these technologies are protected from pricing volatility risk by CFDs. Were that not so, i.e. under our revenue support assumption #2, then (as we shall see below) they would be riskier than conventional and portfolio generation.

5.3.2 Revenue support assumption #2: no CFDs available (revenue support assumption #2)

Under our second revenue support assumption where CFDs are not used by any of the technologies under consideration, there are two changes relative to revenue support assumption #1. Without a CFD, our technologies would be exposed to the full implications of increased electricity price volatility analysed above, which as we have seen raised asset betas in the electricity sector by around 30 per cent between 2015 and 2018.

For onshore and offshore wind and biomass conversion, the protection from wholesale price risk provided by a CFD has previously been estimated by NERA, in 2013.[83] The figures for hurdle rate impacts were:

- Onshore wind: 125 to 175 bps.
- Offshore wind: 50 to 100bps.
- Biomass conversion: 75 to 125bps.

[83] See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/267606/NERA_Report_Assessment_of_Change_in_Hurdle_Rates_-_FINAL.pdf Table 2 page viii. Note that NERA's assessment of merchant risk was not absolute but relative to the Renewables Obligation scheme.

We can convert these hurdle rate impacts into rough asset betas using NERA's assumed equity risk premium of 5 per cent.[84] That gives us approximately[85]

- Onshore wind: 0.25 to 0.35.
- Offshore wind: 0.1 to 0.2.
- Biomass conversion: 0.15 to 0.25.

We can compare these impacts with the assumption that, instead of the 0.05 asset beta rise the CFD-protected technologies experienced under revenue assumption #1, CFD-protected technologies would, if they had not had CFD protection, have experienced a 30 per cent increase in their asset betas since 2015, in line with the proportionate increase experienced across the broader electricity sector. For onshore wind, offshore wind and biomass[86], that assumption would give the following impacts:

- Onshore wind: 0.13.
- Offshore wind: 0.2.
- Biomass conversion: 0.19-0.26.

We see that for offshore wind and biomass, the assumption of a proportionate increase in asset betas produces a figure equivalent to the top end of NERA's 2013 range. That is in line with what one should have expected, given that wholesale price volatility has been particularly acute recently. For onshore wind, this approach gives a figure lower than NERA's. We suggest that that again should be broadly in line with expectations, given that onshore wind markets and technology have matured significantly since 2013.[87]

We shall therefore make the assumption that, instead of the 0.05 asset beta rise the CFD-protected technologies are assumed to have experienced under revenue assumption #1, CFD-protected technologies would, if they had not had CFD protection, likewise have experienced a 30 per cent increase in their asset betas since 2015. Partially offsetting that impact, since they would not have CFDs, they would have a further diminution of the allocation risk associated with CFDs.

We acknowledge that this across-the-board 30 per cent increase assumption is a strong simplifying assumption, made in lieu of more definitive data. An alternative, equally strong, assumption, could have been an across-the-board 0.15 basis points increase under revenue assumption #2, in line with the increase we assumed for non-CFD-protected technologies under revenue assumption #1. The main advantage of the proportionate asset beta rise assumptions is that it is better in line with NERA's previous analysis, which we are here seeking to update, and thus makes richer use of already-developed thinking regarding the impacts of CFDs.

The second key assumption is that allocation risk (insofar as that was relevant, since in most cases it was already very small) is largely eliminated (with only some tiny residual market "equivalent" of allocation risk remaining).

We report below the implications of our two key assumptions for revenue support assumption #2, relative to assumption #1.

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[84] *ibid* p30.

[85] We note that this conversion is not exact since there would be some small distortions created by differences between 2013 and 2018 effective tax rates. Since we are seeking only to use NERA's figures to indicate scale and to inform our approach, rather than directly, we do not seek to make any adjustment for this small effect.

[86] Because biomass conversion is estimated directly from Drax data under revenue support assumption #1, we use the range of figures for other biomass here.

[87] One might, for example, expect that market mechanisms such as Corporate PPAs will, over time, in the absence of CFDs, come forward to allow better risk-return optimisation/apportionment.

Table 5.8: Asset beta conclusions

	Revenue support assumption #1 figure	Electricity market price exposure effect B	Reduced allocation risk effect C	Total change relative to assumption #1 D = B + C	Asset beta under assumption #2 E = A + D
Solar	0.59	0.12	-0.01	0.11	0.70
Onshore wind	0.62	0.13	-0.01	0.12	0.74
Offshore wind	0.77	0.20	-0.02	0.18	0.95
Hydro	0.6	0.12	-0.02	0.10	0.70
Hydro Large Store	0.6	0.12	-0.02	0.10	0.70
Wave	1.07	0.28	-0.02	0.26	1.33
Tidal stream	1.1	0.31	-0.02	0.29	1.39
Geothermal CHP	2.27	0.64	-0.02	0.62	2.90
Biomass Dedicated >100MW	0.94	0.19	-0.00	0.19	1.04
Biomass Dedicated 5-100MW	0.92	0.19	-0.00	0.19	1.01
Biomass CHP	1.17	0.29	-0.03	0.26	1.42
Biomass Conversion	1.07	0.09	-0.02	0.07	1.14
ACT standard	0.90	0.33	-0.01	0.32	1.11
ACT advanced	1.02	0.37	-0.02	0.35	1.25
ACT CHP	1.13	0.40	-0.03	0.37	1.38
AD CHP	1.26	0.32	-0.03	0.29	1.54
AD	1.03	0.25	-0.02	0.23	1.26
EfW CHP	0.97	0.23	-0.02	0.21	1.17
EfW	0.82	0.16	-0.00	0.16	0.88
Landfill	0.74	0.16	-0.02	0.14	0.88
Sewage Gas	0.82	0.17	-0.00	0.17	0.99

Notes: * We note that our Ørsted cross-check (see Section 5.1.4) suggested that the offshore wind asset beta should be somewhat above 0.7, which is consistent with our figures here.
**As a generation technologies portfolio asset, CCGT attributed the average between the asset beta of UK electricity generators and Drax.
Source: Europe Economics.

5.4 Debt beta

The debt betas for 2018 are calculated using the same approach as that used for calculating the debt betas for 2015 in section 1.1.2. The details of this approach are in Appendix: Debt Beta.[88] The key differences since 2015 relevant here are:

- A decline in risk-free rate from 0.7 per cent to 0.0 per cent (see section 2.1);
- A decline in ERP from 7.9 per cent to 6.75 per cent (see section 2.2);
- A decline in probability of default from 2.0 per cent to 1.75 per cent (see Appendix: Debt Beta);
- A decline in debt premia for individual technologies (see section 3.3).

Given those inputs, the results of the calculations are presented in the table below.

Table 5.9: Debt beta assumptions

	2015	2018
Solar	0.150	0.175
Onshore wind	0.200	0.225
Offshore wind	0.225	0.225
CCGT	0.225	0.150
Hydro	0.225	0.175

[88] We also note that we use debt betas for the estimation of equity betas (and thus, cost of equity). For cost of debt, our approach does not involve debt betas but estimating the risk-free rate and debt premium directly from market evidence.

	2015	2018
Hydro Large Store	0.225	0.175
Wave	0.350	0.225
Tidal stream	0.350	0.225
Geothermal CHP	0.350	0.425
Biomass Dedicated >100MW	0.350	0.250
Biomass Dedicated 5-100MW	0.350	0.250
Biomass CHP	0.350	0.250
Biomass Conversion	0.350	0.250
ACT standard	0.350	0.250
ACT advanced	0.350	0.250
ACT CHP	0.350	0.250
AD CHP	0.350	0.225
AD	0.350	0.225
EfW CHP	0.350	0.350
EfW	0.350	0.350
Landfill	0.350	0.175
Sewage Gas	0.350	0.175
CCS Gas FOAK	0.300	0.250
CCS Gas NOAK	0.300	0.250
CCS Coal FOAK	0.300	0.250
CCS Coal NOAK	0.300	0.250
CCS Biomass	0.300	0.250
Gas CCGT IED retrofit	0.225	0.150
Gas Reciprocating engine (inc. diesel)	0.225	0.225
Coal plants All retrofits	0.225	0.150
OCGT	0.225	0.225

Source: Europe Economics.

6 Cost of Equity

In this chapter we present our conclusions on the cost of equity for each of the technologies under consideration. Given the conclusions on gearing (section 4.1.3), asset betas (section 5.3), and debt betas (section 5.4) we calculate equity betas. Given those and our estimates of the risk-free rate and ERP (section 2.1 and section 2.2, respectively) we then calculate the real cost of equity. In section 6.1 we present the results of this calculation under our revenue support assumption #1 (i.e. where CFDs are available for a number of technologies), and section 6.2 provides the results under our revenue support assumption #2 (i.e. where all technologies are employed on a merchant basis).[89]

The cost of equity is derived from the capital asset pricing model, using our real risk-free rate of zero per cent, and ERP of 6.75 per cent.

6.1 Conclusion on cost of equity — revenue support assumption #1

Table 6.1: Betas and cost of equity

	Equity beta	2018 real cost of equity	2015 real cost of equity
Solar	2.23	15.1%	18.7%
Onshore wind	1.98	13.4%	16.7%
Offshore wind	2.63	17.7%	20.3%
CCGT	1.25	8.4%	14.0%
Hydro	1.60	10.8%	11.6%
Hydro Large Store	1.24	8.4%	9.3%
Wave	3.30	22.3%	24.7%
Tidal stream	3.14	21.2%	25.8%
Geothermal CHP	7.15	48.3%	59.5%
Biomass Dedicated >100MW	1.51	10.2%	10.1%
Biomass Dedicated 5-100MW	1.47	10.0%	9.8%
Biomass CHP	1.92	13.0%	14.5%
Biomass Conversion	1.74	11.8%	11.2%
ACT standard	1.74	11.7%	20.0%
ACT advanced	1.99	13.4%	22.0%
ACT CHP	2.25	15.2%	24.0%
AD CHP	3.97	26.8%	28.6%
AD	3.16	21.3%	22.2%
EfW CHP	1.80	12.2%	14.0%
EfW	1.47	9.9%	9.8%
Landfill	1.51	10.2%	9.8%
Sewage Gas	1.69	11.4%	10.8%
CCS Gas FOAK	2.55	17.2%	19.6%
CCS Gas NOAK	1.94	13.1%	14.8%
CCS Coal FOAK	2.58	17.4%	19.8%
CCS Coal NOAK	1.97	13.3%	15.0%
CCS Biomass	2.58	17.4%	19.8%
Gas CCGT IED retrofit	1.11	7.5%	13.7%
Gas Reciprocating engine (inc. diesel)	2.09	14.1%	14.0%
Coal plants All retrofits	1.23	8.3%	15.1%
OCGT	2.09	14.1%	14.0%

[89] Note that under revenue assumption #2 equity betas are different from those under revenue assumption #1 not only because of different asset betas, but also because of different gearing levels.

Source: Europe Economics.

6.2 Conclusion on cost of equity — revenue support assumption #2

Table 6.2: Betas and cost of equity

	Equity beta	2018 real cost of equity
Solar	1.72	11.6%
Onshore wind	1.69	11.4%
Offshore wind	2.21	14.9%
Hydro	1.40	9.5%
Hydro Large Store	1.20	8.1%
Wave	2.86	19.3%
Tidal stream	2.86	19.3%
Geothermal CHP	6.23	42.0%
Biomass Dedicated >100MW	1.68	11.4%
Biomass Dedicated 5-100MW	1.63	11.0%
Biomass CHP	2.07	13.9%
Biomass Conversion	1.63	11.0%
ACT standard	1.80	12.2%
ACT advanced	2.04	13.8%
ACT CHP	2.28	15.4%
AD CHP	3.35	22.6%
AD	2.71	18.3%
EfW CHP	1.89	12.7%
EfW	1.60	10.8%
Landfill	1.49	10.0%
Sewage Gas	1.68	11.3%

Source: Europe Economics.

Table 6.3: Equity betas

	Equity beta under assumption #1	Change associated with asset beta	Change attributed to gearing	Equity beta under assumption #2
Solar	2.23	-0.10	0.23	1.72
Onshore wind	1.98	-0.07	0.20	1.69
Offshore wind	2.63	-0.09	0.29	2.21
Hydro	1.60	-0.06	0.17	1.40
Hydro Large Storage	1.24	-0.02	0.13	1.20
Wave	3.30	-0.12	0.40	2.86
Tidal stream	3.14	-0.08	0.39	2.86
Geothermal CHP	7.15	-0.25	0.95	6.23
Biomass CHP	1.92	0.08	0.20	2.07
Biomass Conversion	1.74	-0.06	0.15	1.63
ACT standard	1.74	0.03	0.20	1.80
ACT advanced	1.99	0.02	0.23	2.04
ACT CHP	2.25	0.01	0.26	2.28
AD CHP	3.97	-0.17	0.47	3.35
AD	3.16	-0.12	0.38	2.71
EfW CHP	1.80	0.04	0.19	1.89
Landfill	1.51	-0.01	0.16	1.49
Sewage Gas	1.69	0.00	0.18	1.68

Source: Europe Economics.

7 Effective tax rates

The assumptions on effective tax rates (ETRs) across technologies used by BEIS in 2016 were based on a detailed analysis conducted by KPMG in 2013.[90] KPMG's estimates were based on a cash flow model that accounted for the impact of capital allowances on corporation tax paid. A replication of a similar methodology to obtain new estimates of for ETRs is outside the scope of this project. Therefore, we update KPMG's ETR estimates in order to reflect changes in the headline corporate tax rate. At Summer Budget 2015, the government announced legislation setting the Corporation Tax main rate (for all profits except ring fence profits) at 19 per cent for the years starting the 1 April 2017, 2018 and 2019, falling to 17 per cent from 1 April 2020. The corporate tax rate assumed in the KPMG report was 20 per cent.

As illustrated in Appendix: ETR the appropriate way to adjust the KPMG 2013-assumed ETRs is to multiply the ETR by the ratio between the 2015 corporation tax rate and the 2020 (or later) corporation tax rate, as follows. In practice, this means multiplying the 2015 ETR by 17 / 20.

Table 7.1: Effective tax rate conclusions

	KPMG ETR	2018 assumed ETR
Solar	12.0%	10.2%
Onshore wind	11.0%	9.4%
Offshore wind	12.0%	10.2%
CCGT	20.0%	17.0%
Hydro	20.0%	17.0%
Hydro Large Store	20.0%	17.0%
Wave	12.0%	10.2%
Tidal stream	20.0%	17.0%
Geothermal CHP	20.0%	17.0%
Biomass Dedicated >100MW	20.0%	17.0%
Biomass Dedicated 5-100MW	20.0%	17.0%
Biomass CHP	20.0%	17.0%
Biomass Conversion	21.0%	17.9%
ACT standard	12.0%	10.2%
ACT advanced	12.0%	10.2%
ACT CHP	12.0%	10.2%
AD CHP	12.0%	10.2%
AD	12.0%	10.2%
EfW CHP	12.0%	10.2%
EfW	12.0%	10.2%
Landfill	12.0%	10.2%
Sewage Gas	20.0%	17.0%
CCS Gas FOAK	20.0%	17.0%
CCS Gas NOAK	20.0%	17.0%
CCS Coal FOAK	20.0%	17.0%
CCS Coal NOAK	20.0%	17.0%
CCS Biomass	20.0%	17.0%
Gas CCGT IED retrofit	20.0%	17.0%
Gas Reciprocating engine (inc. diesel)	20.0%	17.0%
Coal plants All retrofits	20.0%	17.0%
OCGT	20.0%	17.0%

Source: Europe Economics.

[90] See KPMG (2013), "Electricity Market Reform".

8 Hurdle Rates in 2018

Drawing together all the different evidence, we come to the following conclusions. In the table below, we can see that hurdle rates have fallen for all the technologies. We note that, due to the fact that there was no hurdle rate estimated for CCGT CHP in 2015, we needed to apply a different approach to estimate the 2018 hurdle rate for that technology. Specifically, we calculated the average premium a CHP technology required on top of its non-CHP counterpart based on the 2015 hurdle rates.[91] The average premium was around 20 per cent. We then applied this premium to pure CCGT to obtain the hurdle rate for CCGT CHP.

In Table 8.1 we report our estimated hurdle rates, along with its components, under our revenue assumption #1, i.e. where CFDs are available for a number of technologies, and Table 8.2 provides the results under our revenue support assumption #2, i.e. where all technologies are employed on a merchant basis.

Table 8.1: Hurdle rates for 2018 — revenue support assumption #1

	Real cost of debt	Real cost of equity	Effective tax rate	Gearing	Pre-tax cost of capital (hurdle rate 2018)	Hurdle rates 2015
Solar PV	1.96%	15.1%	10.2%	80.0%	5.0%	6.5%
Onshore wind	2.30%	13.4%	9.4%	77.5%	5.2%	6.7%
Offshore wind	2.30%	17.7%	10.2%	77.5%	6.3%	8.9%
CCGT	1.70%	8.4%	17.0%	35.0%	7.5%	7.8%
Hydro	1.96%	10.8%	17.0%	70.0%	5.4%	6.9%
Hydro Large Store	1.96%	8.4%	17.0%	60.0%	5.4%	6.9%
Wave	2.30%	22.3%	10.2%	72.5%	8.6%	11.0%
Tidal stream	2.30%	21.2%	17.0%	70.0%	9.4%	12.9%
Geothermal CHP	3.66%	48.3%	17.0%	72.5%	18.8%	23.8%
Biomass Dedicated >100MW	2.45%	10.2%	17.0%	45.0%	8.1%	9.2%
Biomass Dedicated 5-100MW	2.45%	10.0%	17.0%	45.0%	7.9%	9.0%
Biomass CHP	2.45%	13.0%	17.0%	45.0%	9.9%	12.2%
Biomass Conversion	2.45%	11.8%	17.9%	45.0%	9.2%	10.1%
ACT standard	2.45%	11.7%	10.2%	56.0%	7.2%	12.6%
ACT advanced	2.45%	13.4%	10.2%	56.0%	8.1%	13.6%
ACT CHP	2.45%	15.2%	10.2%	56.0%	8.9%	14.6%
AD CHP	2.30%	26.8%	10.2%	72.5%	9.9%	12.2%
AD	2.30%	21.3%	10.2%	72.5%	8.3%	10.2%
EfW CHP	3.05%	12.2%	10.2%	57.5%	7.6%	9.4%
EfW	3.05%	9.9%	10.2%	57.5%	6.5%	7.4%
Landfill	1.96%	10.2%	10.2%	57.5%	6.1%	7.4%
Sewage Gas	1.96%	11.4%	17.0%	57.5%	7.1%	8.5%
CCS Gas FOAK	2.45%	17.2%	17.0%	65.0%	9.0%	11.3%
CCS Gas NOAK	2.45%	13.1%	17.0%	65.0%	7.3%	9.2%
CCS Coal FOAK	2.45%	17.4%	17.0%	65.0%	9.1%	11.4%
CCS Coal NOAK	2.45%	13.3%	17.0%	65.0%	7.3%	9.3%
CCS Biomass	2.45%	17.4%	17.0%	65.0%	9.1%	11.4%
Gas CCGT IED retrofit	1.70%	7.8%	17.0%	35.0%	7.0%	7.7%
Gas Reciprocating engine (inc. diesel)	2.30%	14.8%	17.0%	70.0%	7.1%	7.8%
Coal plants All retrofits	1.70%	8.3%	17.0%	35.0%	7.4%	8.2%

91 We calculated the difference between the 2015 hurdle rates for: geothermal CHP vs geothermal (8 per cent), biomass CHP vs the average of other biomass technologies (29 per cent), ACT CHP vs the average of ACT standard and advanced (11 per cent), AD CHP vs AD (20 per cent), and EfW CHP vs EfW (27 per cent).

	Real cost of debt	Real cost of equity	Effective tax rate	Gearing	Pre-tax cost of capital (hurdle rate 2018)	Hurdle rates 2015
OCGT	2.30%	14.8%	17.0%	70.0%	7.1%	7.8%
CCGT CHP					9.0%	

Note: * These are the upper bound of NERA's proposed range rather than the hurdle rate determined by BEIS.
Source: Europe Economics.

The hurdle rates under the merchant player assumption (revenue support assumption #2), where relevant, are as follows.

Table 8.2: Hurdle rates for 2018 — revenue support assumption #2 (merchant player-basis)

	Real cost of debt	Real cost of equity	Effective tax rate	Gearing	Pre-tax cost of capital (hurdle rate 2018)
Solar PV	1.96%	11.6%	10.2%	66%	5.8%
Onshore wind	2.30%	11.4%	9.4%	65%	6.0%
Offshore wind	2.30%	14.9%	10.2%	64%	7.6%
Hydro	1.96%	9.5%	17.0%	57%	6.2%
Hydro Large Store	1.96%	8.1%	17.0%	48%	6.2%
Wave	2.30%	19.3%	10.2%	58%	10.4%
Tidal stream	2.30%	19.3%	17.0%	56%	11.7%
Geothermal CHP	3.66%	42.0%	17.0%	57%	23.8%
Biomass Dedicated >100MW	2.45%	11.4%	17.0%	45%	8.8%
Biomass Dedicated 5-100MW	2.45%	11.0%	17.0%	45%	8.6%
Biomass CHP	2.45%	13.9%	17.0%	35%	12.0%
Biomass Conversion	2.45%	11.0%	17.9%	35%	9.8%
ACT standard	2.45%	12.2%	10.2%	44%	8.7%
ACT advanced	2.45%	13.8%	10.2%	44%	9.8%
ACT CHP	2.45%	15.4%	10.2%	44%	10.8%
AD CHP	2.30%	22.6%	10.2%	58%	12.0%
AD	2.30%	18.3%	10.2%	58%	9.9%
EfW CHP	3.05%	12.7%	10.2%	47%	9.1%
EfW	3.05%	10.8%	10.2%	58%	7.0%
Landfill	1.96%	10.0%	10.2%	46%	7.0%
Sewage Gas	1.96%	11.3%	17.0%	46%	8.5%

Note: * These are the upper bound of NERA's proposed range rather than the hurdle rate determined by BEIS.
Source: Europe Economics.

8.1 Hurdle rates for lithium-ion battery storage and demand side response

We treat the hurdle rate estimates for lithium-ion battery storage and demand side response separately from those of other technologies analysed here as the hurdle rate estimates for these rapidly evolving business models are particularly uncertain and provisional, and the estimates produced should be both treated with lower confidence than the estimates above and subject to particular ongoing review.

Until recently, the National Grid Balancing Mechanism market has largely been participated in by large power plants and particular distributed single large sites with generation licenses. However, recently National Grid has been seeking wider access to the Balancing Mechanism, with possible implications for greater use of barry storage and demand side response. There is also an ambition to create a Trans European Replacement Reserves Exchange as part of the development of a pan-European market for balancing energy.

8.1.1 Lithium-ion storage

Lithium-ion storage is a technology whereby electricity is stored in lithium-ion batteries (assumed to be at commercial grid scale, or distribution level connected, storage not household) and then supplied into the electricity grid at periods of peak load. It is therefore subject to some of the same sort of demand and price risks that other peak-demand servicing technologies, such as OCGTs, experience. However there could be important different risks in demand for batteries compared to OCGT / CCGT in at least two ways. First, whilst they both respond to price arbitrage opportunities, gas fired plant can respond to all price signals whereas batteries are constrained by their duration and have to be even more targeted, meaning there could be more upside opportunity with OCGT / CCGT than with batteries. But, secondly, and to an extent offsetting the above effect, since gas prices and electricity prices tend to be correlated, OCGT / CCGT will be gaining, at the margin, only on the spread between gas and electricity rather than, as with batteries, gaining broadly one-for-one as prices rise in peak demand.

On costs, the construction costs per kilowatt of production capacity for Lithium-ion batteries are currently more comparable to those of CCGT's than OCGT's though this is likely to change given the significant cost reduction potential for lithium-ion batteries predicted by many industry experts.

On revenues, the proportion of bankable revenue streams for batteries (CM revenue) is likely to be more comparable to CCGTs rather than OCGTs, as batteries are able to participate in wholesale price arbitrage, as well as offer the other balancing services for the grid.

Lithium-ion battery storage is still a nascent technology with significant cost reductions expected and with business models still being tested and developed. Benchmarking the hurdle rates for this technology to comparable established technologies (in terms of costs and revenue streams) is currently considered the best method to proxy the possible hurdle rates for this technology over the longer term. For 2018, under our main revenue support assumption (#1) the hurdle rates for CCGT and OCGT are 7.5 per cent and 7.1 per cent respectively. We suggest that a natural approach is to take a hurdle rate rounding up the midway point through this 7.1 to 7.5 per cent range, namely 7.3 per cent.

8.1.2 Demand side response (DSR)

Demand side providers contribute to grid balancing by either reducing their demand or taking advantage of onsite generation. DSR can be of two types: turn down DSR and behind the meter back-up generation. We shall use the former as our representative technology here.

The costs involved in DSR include metering, aggregation and putting together systems and operations in place with the risk of actual providers moving to other aggregators.[92] We shall use smart meters used in the electricity sector as a comparator for the metering costs of DSR. Previous recent studies have used a real cost of capital of 6 per cent for smart meter assets and installation costs and 10 per cent for IT costs associated with smart meters.[93] We shall assume an 8 per cent pre-tax real hurdle rate for DSR metering and systems costs our purposes here.

As with battery storage, DSR will be subject to demand-side volume and price risks akin to that of other peak-demand servicing technologies such as OCGT. On the other hand, again, it seems plausible that DSR has bankable revenues proportions more similar to those of CCGT than OCGT. We suggest that a rough reasonable range for the DSR hurdle rate is therefore 7 to 8 per cent, and we propose 7.5 per cent as a working point estimate hurdle rate.

[92] We note that while other technologies can of course be aggregated this is less common than comparing with a DSR business model where DSR is frequently aggregated across diverse small components and which relies on providing suitable bespoke metering solutions to harness each component.

[93] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/567168/OFFSEN_2016_smart_meters_cost-benefit-update_Part_II_FINAL_VERSION.PDF

Appendices

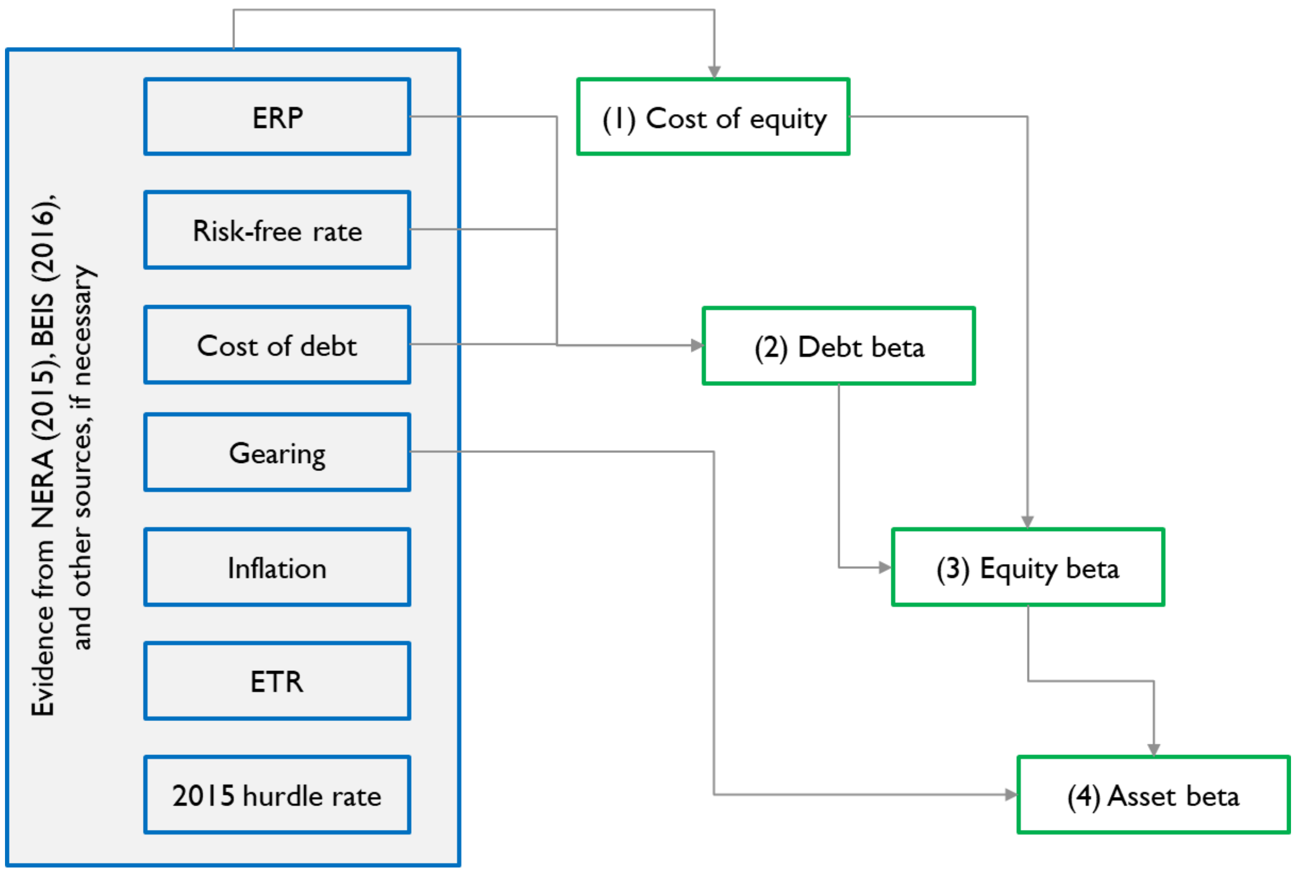
Europe Economics

9 Appendix: 2015 Starting Point

9.1 Decomposition inputs and assumptions

Knowing the final hurdle rate, as well as parameters such as cost of debt, gearing, risk-free rate, ERP, inflation and ETR, we can decompose the 2015 hurled rates into cost of debt and cost of equity, from which we can derive equity and asset betas. The approach is illustrated in the figure below.

Figure 9.1: Decomposition approach — graphic representation



Source: Europe Economics.

Specifically, we first translate the real pre-tax hurdle rates to post-tax nominal rates:

$$pre\_tax\ nominal\ hurdle\ rate = (1 + pre\_tax\ real\ hurdle\ rate) \cdot (1 + i) - 1$$

and

$$post\_tax\ nominal\ hurdle\ rate = pre\_tax\ nominal\ hurdle\ rate \cdot (1 - ETR)$$

Given those inputs we can use the following formula to derive the nominal cost of equity.

$$r_E = \frac{(post\text{-}tax\ nominal\ hurdle\ rate - r_D \cdot (1 - ETR) \cdot gearing)}{1 - gearing}.$$

Given the cost of equity, as well as the risk-free rate and ERP, we can then use the following formula to derive equity beta:

$$\beta_E = \frac{r_E - RFR}{ERP}.$$

Given the equity beta, we can derive the implied asset beta with the following formula:

$$\beta_A = \beta_E \cdot (1 - gearing) + \beta_D \cdot gearing,$$

For the purpose of this study, we assume a non-zero debt beta for 2015 (see Appendix: Debt Beta).

The table below summarises the information we used in the decomposition of the 2015 hurdle rates from NERA's report.

Table 9.1: NERA's inputs on cost of debt and gearing

	Nominal cost of debt NERA (2015)	Gearing NERA (2015)
Solar	4.8%	80%
Onshore wind	5.2%	77.5%
Offshore wind	5.5%	72.5%
CCGT & OCGT	—	70%
Hydro	5.5%	—
Biomass	6.5%	45%
ACT / AD	6.5%	56%
Landfill / EfW	6.5%	58%
CCS (coal)	6.0%	65%

Source: NERA (2015).

Other parameters relevant for deriving 2015 equity betas are:

- Inflation of two per cent, which we use to translate nominal inputs into real ones;[94]
- Nominal risk-free rate (RFR) ranging from 2.4 to 3.0 per cent, with the point estimate being the average of the two, i.e. 2.7 per cent (translating to 0.7 per cent in real terms);
- Nominal equity risk premium (ERP) ranging from 7.9 to 8.2 per cent, with the point estimate being the average of the two, i.e. 8.1 per cent (translating to 7.9 per cent in real terms).

All the technology-specific inputs used for deriving the cost of equity for each of the technologies are presented in Table 9.2 below.

Table 9.2: 2015 inputs used in the decomposition of 2015 hurdle rates

Technology	Nominal cost of debt	Gearing	Hurdle rate pre-tax real	ETR
Solar	4.8%	80.0%	6.5%	12%
Onshore wind	5.2%	77.5%	6.7%	11%
Offshore wind	5.5%	72.5%	8.9%	12%
CCGT	5.5%	70.0%	7.8%	20%
Hydro	5.5%	70.0%	6.9%	20%
Hydro Large Store	5.5%	60.0%	6.9%	20%
Wave	6.5%	72.5%	11.0%	12%
Tidal stream	6.5%	70.0%	12.9%	20%
Geothermal CHP	6.5%	72.5%	23.8%	20%
Biomass Dedicated >100MW	6.5%	45.0%	9.2%	20%
Biomass Dedicated 5-100MW	6.5%	45.0%	9.0%	20%
Biomass CHP	6.5%	45.0%	12.2%	20%
Biomass Conversion	6.5%	45.0%	10.1%	21%
ACT standard	6.5%	56.0%	12.6% **	12%
ACT advanced	6.5%	56.0%	13.6% **	12%
ACT CHP	6.5%	56.0%	14.6% **	12%
AD CHP	6.5%	72.5%	12.2%	12%

[94] We use the Fisher formula: $(1 + nominal\ rate) = (1 + real\ rate) * (1 + inflation)$.

Technology	Nominal cost of debt	Gearing	Hurdle rate pre-tax real	ETR
AD	6.5%	72.5%	10.2%	12%
EfW CHP	6.5%	57.5%	9.4%	12%
EfW	6.5%	57.5%	7.4%	12%
Landfill	6.5%	57.5%	7.4%	12%
Sewage Gas	6.5%	57.5%	8.5%	20%
CCS Gas FOAK	6.0%	65.0%	11.3%	20%
CCS Gas NOAK	6.0%	65.0%	9.2%	20%
CCS Coal FOAK	6.0%	65.0%	11.4%	20%
CCS Coal NOAK	6.0%	65.0%	9.3%	20%
CCS Biomass	6.0%	65.0%	11.4%	20%
Gas CCGT IED retrofit	5.5%	70.0%	7.7%	20%
Gas Reciprocating engine (inc. diesel)	5.5%	70.0%	7.8%	20%
Coal plants All retrofits	5.5%	70.0%	8.2%	20%
OCGT	5.5%	70.0%	7.8%	20%

Note: * Our starting point is the upper bound of NERA's proposed range rather than the hurdle rate used by BEIS.
Source: NERA (2015), BEIS (2015), ADB, Tanahu Hydropower Project (for hydro gearing), IREDA (2014) "Study on Tidal & Waves Energy in India" (for tidal stream gearing).

9.2 Results of decomposition of 2015 hurdle rates

The results of the decomposition — real cost of equity, equity beta and asset beta — are summarised in the table below.

Table 9.3: Cost of equity and betas implied by 2015 hurdle rates

	Implied real cost of equity	Implied equity beta	Implied asset beta
Solar	18.7%	2.28	0.58
Onshore wind	16.7%	2.03	0.61
Offshore wind	20.3%	2.48	0.85
CCGT	14.0%	1.69	0.66
Hydro	11.6%	1.38	0.57
Hydro Large Store	9.3%	1.09	0.57
Wave	24.7%	3.05	1.09
Tidal stream	25.8%	3.18	1.20
Geothermal CHP	59.5%	7.46	2.30
Biomass Dedicated >100MW	10.1%	1.19	0.81
Biomass Dedicated 5-100MW	9.8%	1.16	0.79
Biomass CHP	14.5%	1.75	1.12
Biomass Conversion	11.2%	1.34	0.89
ACT standard	20.0%	2.45	1.27
ACT advanced	22.0%	2.70	1.39
ACT CHP	24.0%	2.96	1.50
AD CHP	28.6%	3.53	1.23
AD	22.2%	2.72	1.00
EfW CHP	14.0%	1.68	0.92
EfW	9.8%	1.16	0.69
Landfill	9.8%	1.16	0.69
Sewage Gas	10.8%	1.29	0.75
CCS Gas FOAK	19.6%	2.40	1.03
CCS Gas NOAK	14.8%	1.79	0.82
CCS Coal FOAK	19.8%	2.43	1.04
CCS Coal NOAK	15.0%	1.82	0.83
CCS Biomass	19.8%	2.43	1.04

	Implied real cost of equity	Implied equity beta	Implied asset beta
Gas CCGT IED retrofit	13.7%	1.65	0.65
Gas Reciprocating engine (inc. diesel)	14.0%	1.69	0.66
Coal plants All retrofits	15.1%	1.82	0.70
OCGT	14.0%	1.69	0.66

Source: Europe Economics.

10 Appendix: Cost of Debt

Below we provide additional evidence relating to the cost of debt.

10.1 Credit ratings for relevant technologies

A couple of reports suggest that project finance bonds for solar and wind should be expected to be at the lower end of investment grade. For example, the following table is based on Fitch (2017) assessment. [95]

Table 10.1: EMEA Energy & Water Infrastructure Public Project Ratings

		Class A1 / Class A / Short-dated / Senior debt	Class A2 / Class B / Long-dated
Andromeda Finance (Italy)	Solar	BBB+	BB
Solar PV Portfolio (Spain)	Solar	BBB	
Breeze Finance (Germany and France)	Onshore wind	B-	CC
CRC Breeze Finance (Germany and France)	Onshore wind	B-	CC
Western European Project	Offshore wind	BBB-	
WindMW GmbH (Germany)	Offshore wind	BBB-	BBB

Source: FitchRatings (2017) "EMEA Renewables Peer Review".

Another Fitch report[96] remarks: "Renewables Outlook Stable: The stable sector outlook for renewables is supported by the continuing commitment from European governments. New renewable projects are becoming increasingly cost competitive as evidenced by the low bids submitted in recent tenders, particularly for offshore wind. Although the pace of new capacity additions has slowed in recent years, the share of renewable energy is set to grow. Storage technologies will also accelerate penetration, particularly in the solar PV space, although widespread application may not be imminent."

Other sources suggest that the Meerwind project was assigned a credit rating of BBB- by Standard & Poors.[97]

For hydro around the world, recent Moody's ratings ranged from B2 (equivalent to B in Fitch's rating structure) to Baa1 (equivalent to BBB+):

- Moody's affirms Baa2 [BBB] issuer rating of Norsk Hydro ASA, upgrades the baseline credit assessment to baa2 from baa3, stable outlook;[98]
- Moody's affirms Statkraft's Baa1 [BBB+] ratings; stable outlook;[99]
- Moody's downgrades Hydro One Inc to Baa1 [BBB+] from A3 [A-]; rating outlook stable. Moody's "downgraded the ratings for Hydro One Inc. (HOI), including its senior unsecured ratings and its Medium Term Note program to Baa1 [BBB+] from A3 [A-]. The Prime-2 commercial paper rating has been affirmed. The rating outlook has been changed to stable from negative";[100]
- Moody's upgrades EDA's rating to Ba2 [BB]; outlook stable;[101]
- Moody's changes outlook on EEM's B2 [B] rating to positive from stable; affirms rating.[102]

95 FitchRatings (2017) "EMEA Renewables Peer Review".

96 Fitch (2017) "2017 Mid-Year Outlook: EMEA Energy and Water Infrastructure".

97 https://www.bloomberg.com/news/articles/2018-04-09/offshore-wind-churns-out-big-bank-payoff-as-deals-jump-to-record

98 https://www.moodys.com/research/Moodys-affirms-Baa2-issuer-rating-of-Norsk-Hydro-ASA-upgrades--PR_363663.

99 https://www.moodys.com/research/Moodys-affirms-Statkrafts-Baa1-ratings-stable-outlook--PR_343767.

100 https://www.moodys.com/research/Moodys-downgrades-Hydro-One-Inc-to-Baa1-from-A3-rating--PR_385523.

101 https://www.moodys.com/research/Moodys-upgrades-EDAs-rating-to-Ba2-outlook-stable--PR_384664.

102 https://www.moodys.com/research/Moodys-changes-outlook-on-EEMs-B2-rating-to-positive-from--PR_372041 NB EEM generates electricity using hydro, but also wind technologies. It is also involved in transmission, distribution and

For EfW and landfill credit ratings ranged from BB- to BBB:

- Moody's downgrades Covanta to Ba3 [BB-] from Ba2 [BB]; outlook stable;[103]
- Moody's assigns (P)Ba2 [BB] rating to MEIF Renewable Energy UK's GBP190 million Notes; outlook stable;[104]
- Moody's changes Waste Management's outlook to positive; affirms Baa2 [BBB].[105]

For biomass the ratings ranged from BB to BB+:

- Fitch Assigns Final 'BB+' Rating to Drax; Outlook Stable;[106]
- Moody's assigns (P)Ba2 [BB] rating to MEIF Renewable Energy UK's GBP190 million Notes; outlook stable.[107]

For geothermal the ratings ranged from CCC to BB-, with the latter being more recent.

- Moody's assigns a definitive Ba3 [BB-] rating to Star Energy's senior secured notes;[108]
- Moody's downgrades Coso Geothermal Power Holding's pass-through trust certificates to Ca [CCC] from Caa2 [CCC]; Rating outlook revised to stable from negative.[109]

Although technology is not the only determinant of credit rating (which could also be affected by factors such as gearing[110] or debt term), the evidence provided above might be nevertheless considered as a useful reference point or indication.

10.2 Spreads on bonds of a given rating

We compared the results we obtained directly from corporate bonds of various ratings available from Thomson Reuters with spreads on a GBP-denominated iBoxx index of bonds rated BBB issued by non-financial companies. The spread relative to the 10-year government bond was around 188bps at the beginning of May 2018 and 210bps at the end of May 2018.

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commercialization of energy (see http://www.yellowpages.pai.pt/ms/ms/empresa-de-electricidade-da-madeira-sa-services-9000-054-funchal/ms-90068412-p-3/.

103 https://www.moodys.com/research/Moodys-downgrades-Covanta-to-Ba3-from-Ba2-outlook-stable--PR_368240.

104 https://www.moodys.com/research/Moodys-assigns-PBa2-rating-to-MEIF-Renewable-Energy-UKs-GBP190--PR_316965 “MEIF Renewable Energy UK Plc is the new parent company of two businesses, Energy Power Resources Limited (EPRL) and CLP Envirogas Limited (CLP), which own and operate, respectively, five biomass-fired power plants (which use poultry litter, straw and meat and bone meal as fuels) and 68 landfill gas generating engines across 25 sites in Great Britain and with a total installed capacity of around 174MW.”

105 https://www.moodys.com/research/Moodys-changes-Waste-Managements-outlook-to-positive-affirms-Baa2-assigns--PR_361112 “Waste Management, Inc. is the largest provider of comprehensive waste (hazardous and non-hazardous) management services in North America. In addition to providing waste collection, transfer, recycling and resource recovery and disposal services, the company is also a leading developer and owner of landfill gas-to-energy facilities.”

106 https://af.reuters.com/article/africaTech/idAFFit998221

107 https://www.moodys.com/research/Moodys-assigns-PBa2-rating-to-MEIF-Renewable-Energy-UKs-GBP190--PR_316965 “MEIF Renewable Energy UK Plc is the new parent company of two businesses, Energy Power Resources Limited (EPRL) and CLP Envirogas Limited (CLP), which own and operate, respectively, five biomass-fired power plants (which use poultry litter, straw and meat and bone meal as fuels) and 68 landfill gas generating engines across 25 sites in Great Britain and with a total installed capacity of around 174MW.”

108 https://www.moodys.com/research/Moodys-assigns-a-definitive-Ba3-rating-to-Star-Energys-senior--PR_381393

109 https://www.moodys.com/research/Moodys-downgrades-Coso-Geothermal-Power-Holdings-pass-through-trust-certificates--PR_304932

110 Note that, given that we do not use the data above mechanically, we do not regard it as proportionate to report gearings for all the firms mentioned.

Figure 10.1: Spread between iBoxx 10-year BBB bond index and 10-year government bond

Source: Thomson Reuters, Europe Economics' analysis.

10.3 Spreads on loans

For completeness we also report here data on loans' spreads available from Thomson Reuters. The table below shows some statistics on spreads on loans taken for project finance for UK projects using the relevant technologies. It is worth noting that the spreads are on top of LIBOR or EURIBOR (which are generally shorter-term interest rates). This means they are not directly comparable to our "debt premium" which is defined as the spread versus the benchmark 10-year government bond. Moreover, evidence for loans issued before 2015 is not directly relevant given the purposes of this study.

Table 10.2: Spreads on loans for relevant technologies

	Count	Spread (bps) Average	25th percentile	Median	75th percentile	Issue year range
Solar PV	6	271	228	273	310	2009-2015
Onshore wind	14	182	155	160	210	2009-2017
Offshore wind	13	194	150	190	250	2012-2018
CCGT	10	172	175	175	175	1999-2008
Offshore and onshore wind	1	375	375	375	375	2009
EfW	16	312	245	275	325	2004-2017

Source: Thomson Reuters, Loan Connector, Europe Economics' analysis.

We can also look how spreads evolved over time. Table 10.3 shows the average spreads on loans issued in a given year across all the relevant technologies jointly and for each technology separately.

Table 10.3: Average spreads on loans over time

		Average spread (bps)					
Issue year	**Count across all relevant technologies**	**All relevant technologies**	**Solar PV**	**Onshore wind**	**Offshore wind**	**CCGT**	**EfW**
1999	1	120				120	
2000	7	175				175	
2001	0						
2002	1	135				135	
2003	0						
2004	3	135		110			135
2005	0						

Issue year	Count across all relevant technologies	Average spread (bps)					
		All relevant technologies	Solar PV	Onshore wind	Offshore wind	CCGT	EfW
2006	0						
2007	0						
2008	4	265				235	275
2009	8	191	225	155			
2010	3	318	318				
2011	0						
2012	5	250			250		
2013	4	254		210			385
2014	5	429		225			480
2015	4	186	223		150		
2016	9	227		220	160		281
2017	5	202		160	183		385
2018	1	125			125		

Source: Thomson Reuters, Loan Connector, Europe Economics' analysis.

11 Appendix: Asset Beta

11.1 Returns volatility and asset beta

Below we provide a formal proof of the relationship between volatility in returns and asset betas.

At a given point in time, the relationship between the asset beta in year 1 and average market returns can be written as:

$$R_1 = \alpha_1 + \beta_1 R_m + e_1 \tag{1}$$

Where R_1 is the excess return for year 1, R_m is the excess return on the market, β_1 is year 1's beta coefficient and α_1 is its alpha coefficient. e_1 is the non-systematic component of the return in year 1.

Our modelling is intended to incorporate only systematic components of risk. Provided this is fully achieved, $e_1 = 0$ and the above equation becomes:

$$R_1 = \alpha_1 + \beta_1 R_m \tag{2}$$

Using the mathematical properties of variance, we can write the variance of R_1 as follows:

$$\mathrm{var}(R_1) = \mathrm{var}(\alpha_1 + \beta_1 R_m) = \beta_1{}^2\ \mathrm{var}(R_m) \tag{3}$$

In the same way, we can derive an equivalent statement for year 2:

$$\mathrm{var}(R_2) = \beta_2{}^2\ \mathrm{var}(R_m) \tag{4}$$

Dividing equation 4 by equation 3, we obtain the following relationship:

$$\frac{\mathrm{var}(R_2)}{\mathrm{var}(R_1)} = \frac{\beta_2{}^2\ \mathrm{var}(R_m)}{\beta_1{}^2\ \mathrm{var}(R_m)} = \frac{\beta_2{}^2}{\beta_1{}^2} \tag{5}$$

The standard deviation σ of the excess return for each year is simply the square root of the relevant variance. Hence, we can take the square root of equation (5) to give:

$$\frac{\sigma_2}{\sigma_1} = \frac{\beta_2}{\beta_1}$$

Q.E.D.

11.2 Energy sector equity beta

As a cross-check to our estimates of changes in asset betas for electricity companies, we analysed the evolution of Thomson Reuters' index for UK energy sector. The index comprises a wide range of companies many of which are in the oil sector (e.g. integrated oil and gas, and oil equipment and services) and thus these results should be viewed as only partially comparable to the analysis we present in the main body of the report.

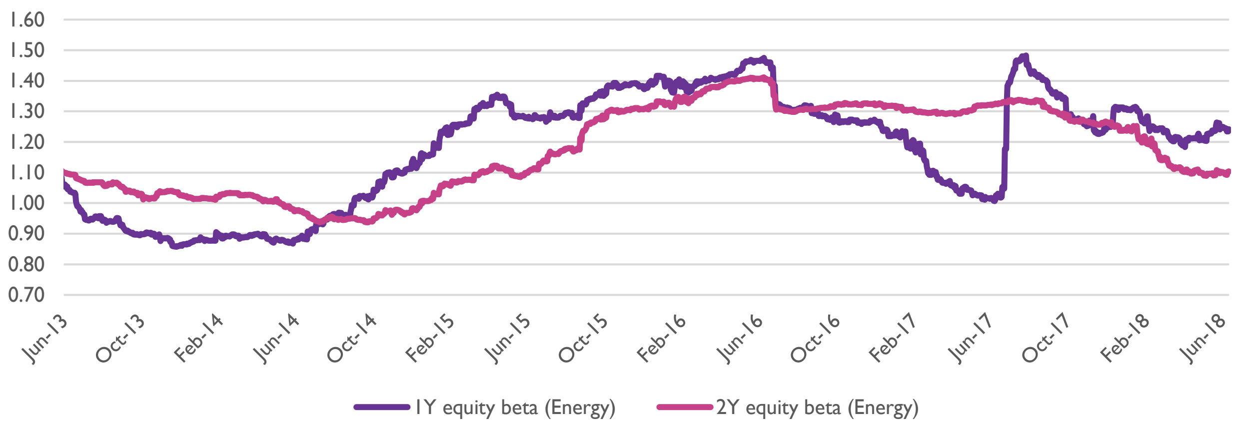
However, as indicated in Reboredo (2015) around 30 per of the systematic risk of renewable energy comes from (presumably) demand risk cross-overs from oil.[111] This means that changes in the oil markets can indirectly feed into the functioning of the electricity markets.

We see that since the start of 2014, energy sector betas have risen quite materially, from below 1.0 (with the two-year averaging 0.98 in 2014 and the one-year averaging at 0.96) to peaks in 2016 (averaging 1.34 on the two-year and 1.35 on the one-year in 2016), before falling back somewhat in 2018 (to averages of 1.14

[111] See https://www.sciencedirect.com/science/article/pii/S0140988314003259.

and 1.24 in 2018). If we assumed a gearing of anything between 30 and 50 per cent, these movements equate to a rise in asset beta of around 0.1 from 2014 to 2018.

Table 11.1: Equity betas for the energy sector



Source: Thomson Reuters, Europe Economics analysis

11.3 Fundamental Beta Model

Estimating beta with a fundamental beta model is done in two steps. The first step is to take a large number of public companies, for which beta can be estimated directly from market data, and develop an econometric model (a linear regression) which captures a relationship between betas and financial metrics such as revenues, growth rates etc.

The second step involves applying that model to relevant private companies, for which the data required for a direct beta estimation does not exist but for which we have financial metrics. In this case, the relevant companies are electricity generating firms which use at least one of the technologies under consideration.

11.3.1 Estimating fundamental beta model for FTSE companies

While estimation based on a fundamental beta model is often viewed as unreliable in terms of predicting beta *levels* (partly, as is the case here as well, because of the low statistical explanatory power of the models), it could be used to estimate the *change* in betas over time.

For the first step of the estimation, we obtained data on 300 companies which are constituents of FTSE All Share index. The data included variables such as: total assets, net debt, EBIT, EBIT margin, EBITDA, EBITDA margin, operating expense, fixed asset turnover, three-year CAGR of income after tax margin, net book capital, total liabilities, accounts payable, cash & equivalents, total capital, net total property plant & equipment.

We also obtained all the market data necessary to calculate betas (i.e. market capitalisation, net debt, enterprise value, and total return), and based on that data estimated one-year and two-year asset betas (and equity betas).

Based on that dataset we developed two models: one where one-year asset beta is determined by EBIT margin, fixed asset turnover and income margin growth, and a second where one-year asset beta is determined by EBIT margin and fixed asset turnover. We report the summary statistics for these two models below.

Table 11.2: Four-variable model

Dependent Variable: B1
Method: Panel Least Squares
Sample: 2018 2018

Periods included: 1				
Cross-sections included: 301				
Total panel (balanced) observations: 301				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.609322	0.025169	24.20935	0.0000
EBIT_M	0.002369	0.001032	2.294734	0.0224
FAT	-0.000237	0.000130	-1.827013	0.0687
IN	0.001260	0.000775	1.624423	0.1053
DUMMY_FIN	-0.194075	0.054976	-3.530146	0.0005
R-squared	0.065213	Mean dependent var		0.610674
Adjusted R-squared	0.052581	S.D. dependent var		0.321904
S.E. of regression	0.313326	Akaike info criterion		0.533328
Sum squared resid	29.05931	Schwarz criterion		0.594908
Log likelihood	-75.26592	Hannan-Quinn criter.		0.557970
F-statistic	5.162459	Durbin-Watson stat		0.000000
Prob(F-statistic)	0.000493			

Source: Europe Economics.

Table 11.3: Three-variable model

Dependent Variable: B1				
Method: Panel Least Squares				
Sample: 2018 2018				
Periods included: 1				
Cross-sections included: 301				
Total panel (balanced) observations: 301				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.616547	0.024841	24.81974	0.0000
EBIT_M	0.002222	0.001031	2.154731	0.0320
FAT	-0.000231	0.000130	-1.780017	0.0761
DUMMY_FIN	-0.197822	0.055079	-3.591594	0.0004
R-squared	0.056880	Mean dependent var		0.610674
Adjusted R-squared	0.047354	S.D. dependent var		0.321904
S.E. of regression	0.314189	Akaike info criterion		0.535559
Sum squared resid	29.31837	Schwarz criterion		0.584823
Log likelihood	-76.60163	Hannan-Quinn criter.		0.555272
F-statistic	5.970751	Durbin-Watson stat		0.000000
Prob(F-statistic)	0.000579			

Source: Europe Economics.

11.3.2 Applying the fundamental beta model to electricity companies

Given the models presented above we can calculate what the implied asset beta is for any company (as long as information on its EBIT margin, fixed asset turnover and — potentially — income margin growth is available). We use the four-variable model where possible, and default to the three-variable model only when income margin growth data is not available.

The table below summarises the number of companies to which we applied our fundamental beta model.

Table 11.4: Number of electricity generation companies used for beta estimation

	Overall identified as potentially relevant	Useable with three-variable model	Useable with four-variable model	Useable all
Solar	19	4	0	4
Onshore wind	20	3	1	4
Offshore wind	5	3	2	5
CCGT	13	3	2	5

Source: Europe Economics.

In Table 11.5 we present the results of that analysis, i.e. the changes in asset betas for solar, onshore and offshore wind implied by our fundamental beta model.

Table 11.5: Implied changes in asset beta by technology

	Change in asset beta implied by fundamental beta model
Solar	-0.02
Onshore wind	+0.01
Offshore wind	+0.04

Source: Thomson Reuters, Europe Economics' calculations.

11.4 Yieldcos

An indirect evidence regarding the cost of equity in the renewable electricity generation is performance of yieldcos, i.e. public funds which invest directly in operating assets such as wind and solar farms. Due to the fact that they invest in already operating assets, they do not capture risks associated with development or planning.

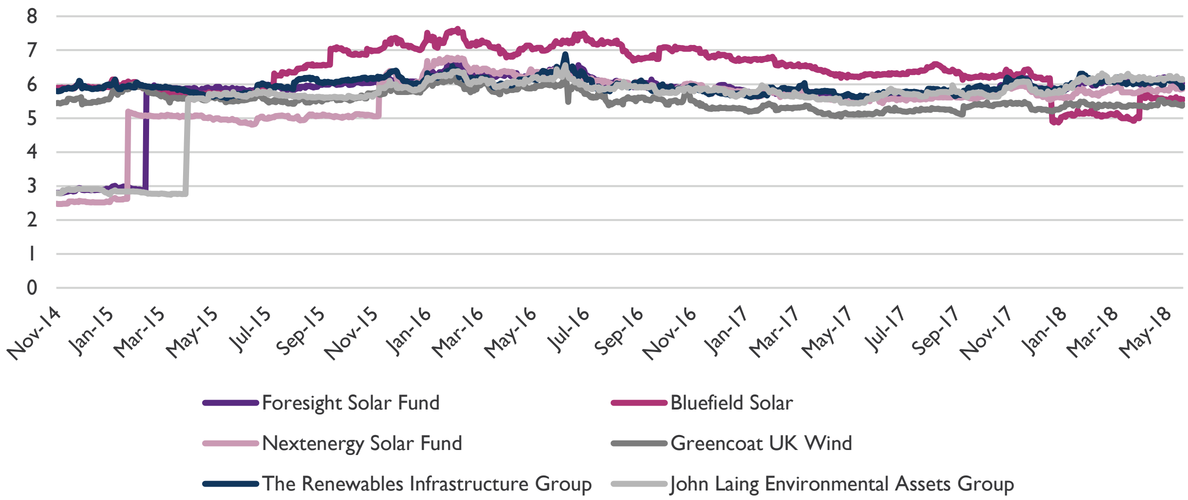
Figure 11.1 illustrates dividend yields for six major yieldcos investing in solar and wind assets. As we can see, the yields increased slightly since 2015. The average across all six yieldcos as of end of March 2018 was 5.74 per cent, compared to 5.14 per cent as of the end of March 2015.

If we were to assume that the average expected long-term growth rate in earnings of those funds has not changed in that period (although it might have), this would suggest a 0.3-0.5 percentage points increase in the cost of equity (depending on the exact period under consideration). With both the risk-free rate and ERP falling, according to our earlier analysis, that suggests some rise in yieldco asset betas over the period. Although yieldco cost of equity changes do not scale very straightforwardly into changes in the cost of equity in the underlying assets,[112] a rise in yieldco asset betas does at least suggest that we should assume asset betas for solar and wind technologies have risen, even if it is not straightforward to infer by how much.

[112] Amongst other reasons for this:

- yieldcos are likely to have some assets covered by the Renewables Obligation, whilst the analysis here is restricted to Contracts for Difference support;
- yieldcos are likely to have a mix of international assets, probably including US assets.

Figure 11.1: Dividend yields for yieldcos



Source: Thomson Reuters.

11.5 Energy market regulation

11.5.1 CFD

Solar

The *administrative* strike prices (ASP) — i.e. the upper limit of the subsidy — during the first allocation round (as stated in the budget notice[113] and expressed in 2012 prices) were as follows: 120 £/MWh for 2014/15 and 2015/16, 115 £/MWh for 2016/17, 110 £/MWh for 2017/18 and 100 £/MWh for 2018/19. The final report on the first allocation round states that 5 project out of 27 were based on solar PV technology. The actual strike prices in the auction were 50 £/MWh for projects to be delivered in 2015/16 and 79.23 £/MWh for projects to be delivered in 2016/17.

Solar PV — as one of the more established technologies included in Pot 1 — was not included in the second CFD allocation round, which was limited to Pot 2.

Onshore wind

Onshore wind project were included in the first round allocation of CFD. 15 out of 27 projects awarded with CFD subsidies were based on onshore wind technology. The strike prices for these projects were 79.23 £/MWh for projects to be delivered in 2016/17, 79.99 £/MWh for projects to be delivered in 2017/18 and 82.5 £/MWh for projects to be delivered in 2018/19.

Onshore wind, being an "established" technology, was not eligible for the second allocation round held on February 2017. However, there are public domain reports of a change in the Government's decisions for the future subsidies for onshore wind projects using CFD, specifically that new onshore projects will be considered in the third round allocation for CFD which will be held in spring 2019, and this could be embodied to some extend in investor expectations.[114]

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[113] BEIS (2015), "Budget Notice for CFD Allocation Round 1" 2nd October 2014 and "Budget Revision Notice for CFD Allocation Round 1" 27th January 2015 https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference#key-documents-relating-to-the-first-round-october-2014-to-march-2015.s

[114] The Telegraph: https://www.telegraph.co.uk/business/2018/06/06/government-greenlight-onshore-wind-subsidies-long-island/, 06/06/2018.

Offshore wind

In the first CFD auction, only 2 out of 27 awarded projects were based on offshore wind technology. The strike prices for these projects were higher than the strike prices for onshore wind and solar PV. Indeed, the first project, which was to be delivered n 2017/18 obtained a strike price of 119.89 £/MWh. The second project, which was to be delivered in 2018/19 had a strike price of 114.39 £/MWh.

In the second allocation round, 3 out of 11 projects were based on offshore wind technology. There has been a significant reduction in the strike prices from the first to the second round allocation. The project awarded that is supposed to be delivered in 2021/22 had a strike price of 74.75 £/MWh, while the other two projects with a delivery date set for 2022/23 have a strike price of 57.5 £/MWh.

For new projects, since the RO scheme has been closed in 2017, CFD will be the only form of subsidies for this technology.

Biomass Conversion

Biomass Conversion was included in Pot 3 (which is specifically for conversions of coal fuelled generation to biomass fuelled generation), but no budget was allocated neither in the first nor the second round of CFD allocation. However, in the first allocation round the ASP was defined for this technology and it was set at £105/MWh for all the delivery years. No Biomass Conversion project was awarded during the first and the second allocation round.

Biomass CHP

Biomass with CHP were included among the "less established" technologies. During the first allocation round[115] the ASP for this technology was set at £125/MWh for all the delivery years, but no Biomass with CHP project was awarded during this allocation round.

Biomass with CHP was also eligible for the second allocation round.[116] During this auction, the ASP was set at a lower level than that in the first allocation round: £115/MWh for both delivery years (i.e. 2021/22 and 2022/23). Two Biomass with CHP project were awarded during this round, with a strike price of £74.75/MWh and delivery year 2021/22.

ACT / AD

Advanced Conversion Technologies (ACT) and Anaerobic Digestion (AD) were included in Pot 2, among the "less established" technologies. For ACT, the ASPs were set at £155/MWh for projects to be delivered in 2014/15 and 2015/16, £150/MWh for 2016/17 projects and £140/MWh for 2017/18 and 2018/19 projects. The ASPs for AD projects were set at £150/MWh for 2014/15, 2015/16 and 2016/17, and at £140/MWh for 2017/18 and 2018/19. Only three ACT projects were successful during the first auction: two of them were expected to be delivered in 2017/18, and their strike price was set at £119.89/MWh. The third project, with delivery year 2018/19, had a strike price of £114.39/MWh.

During the second allocation round the ASPs for ACT were slightly lower than in the first auction: £125/MWh for 2021/22 and £115/MWh for 2022/23. The Anaerobic Digestion's ASPs were set at £140/MWh and £135/MWh for 2021/22 and 2022/23, respectively. Only ACT projects were awarded during this auction. Among them, all the projects with delivery year 2021/22 had a strike price of £74.75/MWh (five out of six). The project with delivery year 2022/23 had a strike price of £40/MWh.

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[115] https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-one-outcome.
[116] https://www.gov.uk/government/publications/contracts-for-difference-cfd-second-allocation-round-results.

Landfill / EfW

Both Landfill and EfW technologies were included among the "established" technologies and for this reason they were eligible only for the first allocation round. The ASP for Landfill gas was set at £55/MWh for all the delivery years (i.e. 2014/15, 2015/16, 2016/17, 2017/18 and 2018/19). The ASP for EfW was set at £80/MWh.

During this first auction, only two EfW with CHP projects were successful during this auction and their strike prices were equal to the ASP.

Sewage gas

Sewage gas was included among the "established" technologies. The ASP was set at £75/MWh. No sewage gas project was awarded during the first auction in the CFD scheme.

Hydro

Hydro is the only water-based technology in the "established" technologies group but only projects with capacity between 5 and 50 MW were included.

The ASP for Hydro was set at £100/MWh for all the delivery years, but during the auction no Hydro projects was successful.

Wave / Tidal

Wave and Tidal Stream are included among the "less established" group. The ASPs for Wave and Tidal stream were set at £305/MWh for all the delivery years, but neither Wave nor Tidal stream projects were awarded during this auction.

During the second allocation round the ASPs for Wave were set at £310/MWh for 2021/22 and £300/MWh for 2022/23, while the ASPs for Tidal were slightly lower: £300/MWh for 2021/22 and £295/MWh for 2022/23. Also in this auction no wave or tidal projects were successful.

Geothermal

Geothermal technology is included among the "less established" technologies. During the first allocation round, its ASPs were set at £145/MWh for 2014/15, 2015/16 and 2016/17. For projects delivered in 2017/18 and 2018/19, the ASP was set at £140/MWh. During the second allocation round, the ASP was set at £140/MWh for both delivery years. No geothermal project was successful during the allocations rounds.

11.5.2 Capacity market

CCGT

CCGT companies account for the largest share of capacity provided, and thus obtained the largest proportion of capacity payments.

- In 2015 "Around half of the acquired capacity obligations were provided by CCGTs (totalling around 47%), 16% by Nuclear, and 10% by generators using coal or biomass as a fuel. CCGT, coal/biomass and nuclear capacity had success rates of around 80%, 60% and 100% respectively." [117]
- In 2016/17 "Almost half (43%) of the acquired capacity obligations by volume was provided by CCGTs, 15% by Nuclear, and 9% by generators using coal or biomass as a fuel."[118]

Biomass or coal

Biomass or coal as fuel provided 10 per cent of the total capacity awarded in the T-4 auction in 2015. In 2016/17, the capacity awarded to generators using Biomass or coal was nine per cent.

[117] Ofgem (2015), "Annual Report on the Operation of the Capacity Market in 2015".
[118] Ofgem (2017), "Annual Report on the Operation of the Capacity Market in 2016/17".

OCGT and storage

These technologies provided less than 10 per cent of the total capacity awarded in 2015. Looking at 2016/17 report for storage capacity "[t]he 2016 T-4 Auction was the first auction that battery storage won agreements in. Of the 3.2GW of storage capacity that entered the auction, only 18MW exited. While the majority of the successful capacity (2.5GW) was existing transmission-connected storage, 454MW of New Build distribution connected storage also won agreements. Storage comprised just over 6% of total awarded capacity."[119] Since the total capacity awarded to OCGT and storage combined was less than 5GW, the proportion of total capacity awarded to OCGT must be even less than six percent.

CHP and autogeneration

In the capacity market auction there is no reference on the fuel used in the Combined Heat and Power. The capacity awarded slightly increased from 2015 to 2016/17. However, the de-rated capacity awarded to this technology has been lower than five GW during both auctions, which is less than ten percent of the total awarded capacity.

Hydro

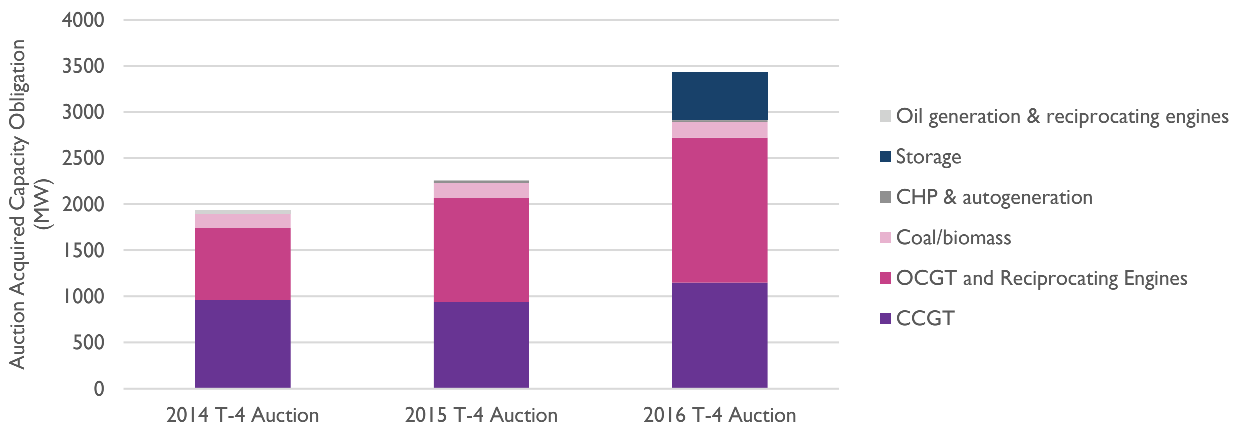
Hydro was awarded with less than 10 per cent of the total capacity.

Evolution in new build capacity since 2014

The total capacity awarded in the 2015 four-year ahead auction was around 46 GW, which increased to over 52 GW in 2016.[120] The clearing price was £18.00/kW/year in 2015 and £22.50/kW/year in 2016/17.[121] We note that there are also other forms of auction.

Looking at the new build capacity installed from 2014 to 2016 there was a considerable increase for some technologies. As we can see from the figure below the new capacity installed for OCGT & reciprocating engine and Storage increased from 2014 to 2016: the first technology increased from ca. 750 MW in 2014 to 1450 MW in 2016, while the capacity awarded to storage was null during the 2014 auction and increased to ca. 500 MW in 2016.

Figure 11.2: Successful New Build capacity by fuel and technology type in the T-4 auctions



Source: Ofgem (2017), "Annual Report on the Operation of the Capacity Market in 2016/17".

[119] Ofgem (2017), "Annual Report on the Operation of the Capacity Market in 2016/17".
[120] https://www.emrdeliverybody.com/CM/T-4-Auctions.aspx
[121] Ofgem (2015) and Ofgem (2017) Annual Report on the Operation of the Capacity Market.

12 Appendix: Debt Beta

The cost of new debt for renewable energy projects is higher than the risk-free rate — there is a "debt premium". That means, by definition, that market participants (rightly or wrongly) believe there is some probability of renewables projects defaulting on their debts. Such defaults create a wedge between the risk-free rate and the cost of new debt in two ways. First, a default probability creates a wedge between the promised cost of debt and the expected cost of debt: because the amount promised might sometimes not be paid, the expected cost of debt must (by definition) be lower than the promised cost of debt.

$$expected\ return\ on\ debt = prob(default) \cdot \%\ loss\ given\ default + \left(1 - prob(default)\right) \cdot promised\ cost\ of\ debt.$$

Secondly, if there is a correlation between when defaults are most likely to occur, or the losses on default when defaults occur, and the broader returns cycle, there will be a yield cost reflecting the systematic risk borne — i.e. a debt beta.

The CAPM applies to any asset — an electricity grid, a plastics bottle-making machine, an equity claim on a telecoms firm or a debt claim on a renewable energy project. So the expected cost of debt can be expressed, in the CAPM, as

$$expected\ return\ on\ debt = RFR + \beta_D \cdot ERP,$$

It is worth observing the relationship between the probability of default, the loss given default and the debt beta. For any given debt premium, the lower the probability of default and loss given default, the higher the debt beta must be. Conversely, the lower the debt beta, the higher the probability of default and loss given default must be. The assumption of a zero debt beta is equivalent to the assumption that all of the debt premium is to be accounted for by the probability of default and loss given default and that no default risk has a systematic component. That will not typically be correct.[122]

In order to determine the appropriate level of debt beta, we proceed as follows.

We recall the definition of the expected return on debt.

$$expected\ return\ on\ debt = prob(default) \cdot \%\ loss\ given\ default + \left(1 - prob(default)\right) \cdot promised\ cost\ of\ debt.$$

The definition of the debt premium is that

$$debt\ premium = promised\ cost\ of\ debt - RFR,$$

where RFR stands for risk-free rate, and which is equivalent to:

$$promised\ cost\ of\ debt = RFR + debt\ premium\,.$$

From those two equations it follows that:

$$expected\ return\ on\ debt = prob(default) \cdot \%\ loss\ given\ default + \left(1 - prob(default)\right) \cdot (RFR + debt\ premium)$$

[122] However, when adjusting for small differences in gearing, it is often mathematically convenient to assume a debt beta of zero because even with a debt beta of 0.1 or 0.2, the mathematical impact would only arise at the second or third significant figure.

As noted above, from the CAPM we know that:

$$expected\ return\ on\ debt\ =\ RFR\ +\ \beta_D \cdot\ ERP,$$

and therefore

$$\beta_D\ =\ \frac{\big(1 - prob(default)\big) \cdot\ debt\ premium - prob(default) \cdot\ (RFR\ + \%\ loss\ given\ default)}{ERP}.$$

RFR, ERP and $debt\ premium$ are WACC components which we estimate in this report. With probability of default and percentage loss given default based, we could calculate a debt beta.

We can derive rough implied probabilities of default and loss given default from the debt beta assumptions used by regulators. For example, in its 2017 cost of capital analysis, Ofwat uses a debt beta of 0.125, with a debt premium for new debt of 1.57 per cent, a risk-free rate of 0.0 and an ERP of 6.75 per cent.[123] That calibrates to a probability of default of 1.75 per cent and a loss given default of 40 per cent.[124]

If we assume the same parameters for investment-grade renewables debt in 2018, and assume that probabilities of default may have fallen modestly between 2015 and 2018 (as debt premiums fell, modestly), we obtain debt betas as follows.

Table 12.1: Debt betas calculations

	"Probability of default"*	Debt premium	Real risk-free rate	"Loss given default"*	ERP	Debt beta**
2015						
Solar	2%	2.05%	0.7%	40%	7.9%	0.150
Onshore wind	2%	2.44%	0.7%	40%	7.9%	0.200
Offshore wind	2%	2.73%	0.7%	40%	7.9%	0.225
Gas CCGT & OCGT	2%	2.73%	0.7%	40%	7.9%	0.225
Hydro	2%	2.73%	0.7%	40%	7.9%	0.225
Hydro Large Store	2%	2.73%	0.7%	40%	7.9%	0.225
Wave	2%	3.71%	0.7%	40%	7.9%	0.350
Tidal stream	2%	3.71%	0.7%	40%	7.9%	0.350
Geothermal CHP	2%	3.71%	0.7%	40%	7.9%	0.350
Biomass Dedicated >100MW	2%	3.71%	0.7%	40%	7.9%	0.350
Biomass Dedicated 5-100MW	2%	3.71%	0.7%	40%	7.9%	0.350
Biomass CHP	2%	3.71%	0.7%	40%	7.9%	0.350
Biomass Conversion	2%	3.71%	0.7%	40%	7.9%	0.350
ACT standard	2%	3.71%	0.7%	40%	7.9%	0.350
ACT advanced	2%	3.71%	0.7%	40%	7.9%	0.350
ACT CHP	2%	3.71%	0.7%	40%	7.9%	0.350
AD CHP	2%	3.71%	0.7%	40%	7.9%	0.350
AD	2%	3.71%	0.7%	40%	7.9%	0.350

[123] See p3 of Europe Economics (2017), "PR19 — Initial Assessment of the Cost of Capital".

[124] We note that this probability and loss given default should not be over-literalised, since the 0.125 debt beta estimate embodies an off-model assumption of an illiquidity premium which we do not include here. Rather, they should be seen as calculation parameters. We also note that S&P (2016) "Annual Global Corporate Default Study" shows that the median default rate in the energy and natural resources industry is 1.58 per cent, while the weighted average is 2.91 per cent, which is broadly consistent with the 1.75-2.00 per cent assumptions we use in this report.

	"Probability of default"*	Debt premium	Real risk-free rate	"Loss given default"*	ERP	Debt beta**
EfW CHP	2%	3.71%	0.7%	40%	7.9%	0.350
EfW	2%	3.71%	0.7%	40%	7.9%	0.350
Landfill	2%	3.71%	0.7%	40%	7.9%	0.350
Sewage Gas	2%	3.71%	0.7%	40%	7.9%	0.350
CCS Gas FOAK	2%	3.22%	0.7%	40%	7.9%	0.300
CCS Gas NOAK	2%	3.22%	0.7%	40%	7.9%	0.300
CCS Coal FOAK	2%	3.22%	0.7%	40%	7.9%	0.300
CCS Coal NOAK	2%	3.22%	0.7%	40%	7.9%	0.300
CCS Biomass	2%	3.22%	0.7%	40%	7.9%	0.300
Gas CCGT IED retrofit	2%	2.73%	0.7%	40%	7.9%	0.225
Gas Reciprocating engine (inc. diesel)	2%	2.73%	0.7%	40%	7.9%	0.225
Coal plants All retrofits	2%	2.73%	0.7%	40%	7.9%	0.225
OCGT	2%	2.73%	0.7%	40%	7.9%	0.225
2018						
Solar	1.75%	1.96%	0	40%	6.75%	0.175
Onshore wind	1.75%	2.30%	0	40%	6.75%	0.225
Offshore wind	1.75%	2.30%	0	40%	6.75%	0.225
Gas CCGT & OCGT	1.75%	1.70%	0	40%	6.75%	0.150
Hydro	1.75%	1.96%	0	40%	6.75%	0.175
Hydro Large Store	1.75%	1.96%	0	40%	6.75%	0.175
Wave	1.75%	2.30%	0	40%	6.75%	0.225
Tidal stream	1.75%	2.30%	0	40%	6.75%	0.225
Geothermal CHP	1.75%	3.66%	0	40%	6.75%	0.425
Biomass Dedicated >100MW	1.75%	2.45%	0	40%	6.75%	0.250
Biomass Dedicated 5-100MW	1.75%	2.45%	0	40%	6.75%	0.250
Biomass CHP	1.75%	2.45%	0	40%	6.75%	0.250
Biomass Conversion	1.75%	2.45%	0	40%	6.75%	0.250
ACT standard	1.75%	2.45%	0	40%	6.75%	0.250
ACT advanced	1.75%	2.45%	0	40%	6.75%	0.250
ACT CHP	1.75%	2.45%	0	40%	6.75%	0.250
AD CHP	1.75%	2.30%	0	40%	6.75%	0.225
AD	1.75%	2.30%	0	40%	6.75%	0.225
EfW CHP	1.75%	3.05%	0	40%	6.75%	0.350
EfW	1.75%	3.05%	0	40%	6.75%	0.350
Landfill	1.75%	1.96%	0	40%	6.75%	0.175
Sewage Gas	1.75%	1.96%	0	40%	6.75%	0.175
CCS Gas FOAK	1.75%	2.45%	0	40%	6.75%	0.250
CCS Gas NOAK	1.75%	2.45%	0	40%	6.75%	0.250
CCS Coal FOAK	1.75%	2.45%	0	40%	6.75%	0.250

	"Probability of default"*	Debt premium	Real risk-free rate	"Loss given default"*	ERP	Debt beta**
CCS Coal NOAK	1.75%	2.45%	0	40%	6.75%	0.250
CCS Biomass	1.75%	2.45%	0	40%	6.75%	0.250
Gas CCGT IED retrofit	1.75%	1.70%	0	40%	6.75%	0.150
Gas Reciprocating engine (inc. diesel)	1.75%	2.30%	0	40%	6.75%	0.225
Coal plants All retrofits	1.75%	1.70%	0	40%	6.75%	0.225
OCGT	1.75%	2.30%	0	40%	6.75%	0.150

Notes: *See footnote 124. ** Rounded to the nearest 0.025 as we do not consider this approach to be sufficiently robust to justify more than such coarse-grained estimates.
Source: Europe Economics.

13 Appendix: ETR

The specific way in which the one percentage point reduction in corporation tax results in an update in ETR can be illustrated by using a stylised example, as set out below.

Table 13.1: Illustrating of the approach to update ETRs

	2015	2020
Profits	1,000,000	1,000,000
Losses	100,000	100,000
Breaks	60,000	60,000
Capital allowances	20,000	20,000
Taxed profits	820,000	820,000
Rate	20%	17%
Effective Tax Paid	164,000	139,400
ETR	16.4%	13.94%

Source: Europe Economics.

The effective tax rate is the tax paid as a percentage of profits made. In our example in Table 13.1 the firm has headline profits of 1,000,000 but carries forward losses of 100,000 from previous years, has 60,000 in special government subsidies, equivalent to a tax break, and gains 20,000 from capital allowances. So its taxable profits are only 820,000. At a corporation tax rate of 20 per cent, that means tax paid is 164,000, or 16.4 per cent of headline profits. At a corporation tax rate of 17 per cent, tax paid would fall to 139,400 or 13.94 per cent of headline profits.

An alternative way to obtain the 13.94 per cent rate would be by multiplying the 2015 ETR by the ratio between the 2020 rate and the 2015 rate (i.e. 16.4 * (0.17/0.20) = 13.94). Accordingly, we adjust the KPMG 2013-assumed ETRs by the ratio between the 2015 corporation tax rate and the 2020 (or later) corporation tax rate, as follows.

14 Appendix: Inflation

There are three main indices quoted in the UK: the Consumer Prices Index (CPI), the Consumer Prices Index including owner occupiers' housing costs (CPIH) and the Retail Prices Index (RPI). Of these, CPIH is the ONS preferred measure of inflation, CPI is the Bank of England's inflation target, and RPI has been deemed not to be an inflation statistic since 2013 owing to methodological inadequacies.

14.1 Coverage

These indices are based on slightly different sets of goods and services. In particular, as explained by the ONS,

> "[t]he most significant differences in coverage relate to the treatment of housing costs, particularly owner-occupier costs, which are included in CPIH and RPI but excluded from the CPI. There are also differences in the population covered, RPI covers only private households but excludes the top 4% of households by income and pensioner households who receive at least three-quarters of their income from benefits. The CPIH and CPI, by contrast, cover the expenditure of all private households, institutional households and visitors to the UK".[125]

14.2 Calculation

The RPI and CPI/CPIH use different mathematical formulae to construct the overall index value out of the individual pricing components. The RPI series uses arithmetic averaging, whereby price changes in the appropriately weighted products were summed and then divided by the total number of products. To take a stylised case, suppose in an economy there were two products consumed initially in equal volumes, the RPI were 100 in the base year, and the price of one product went up by 25 per cent whilst the price of the other product went down by 20 per cent. Then the RPI in the next year would be $(125 + 80)/2 = 102.5$, so RPI inflation would be 2.5 per cent.

By contrast, CPI inflation is calculated using geometric averaging, whereby the average of a set of N values is obtained by multiplying all the values together and taking the Nth root. Taking our stylised example again to illustrate, if the CPI were 100 in the base year, it would become $\sqrt{125 \cdot 80} = \sqrt{10000} = 100$ in the following year, so CPI inflation would be zero.

These two averaging methods equate to two underlying economic assumptions. The RPI arithmetic averaging method is equivalent to the assumption that as the prices of goods and services change, household do not change their consumption patterns in response. The CPI geometric averaging method is equivalent to the assumption that, as a good's or service's prices change, households change their consumption so as to keep the amount of money spent on each good or service unchanged — e.g. if the price of a good rises by 25 per cent, households consume only four fifths as much of that good.[126]

The assumption of constant amounts of money being spent on goods as prices change is a feature of some simple economic models[127] and is arguably a more realistic assumption in a modern economy in which most goods purchased are not necessities and in which consumers can borrow and lend to smooth consumption over time.

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125 ONS (2017), Quality and Methodology Information (QMI): Consumer Price Inflation (includes all 3 indices — CPIH, CPI and RPI).

126 $1.25 \cdot 4/5 = 1$.

127 Technically-minded readers might observe that this will, for example, be a consequence of log utility functions.

14.3 Role

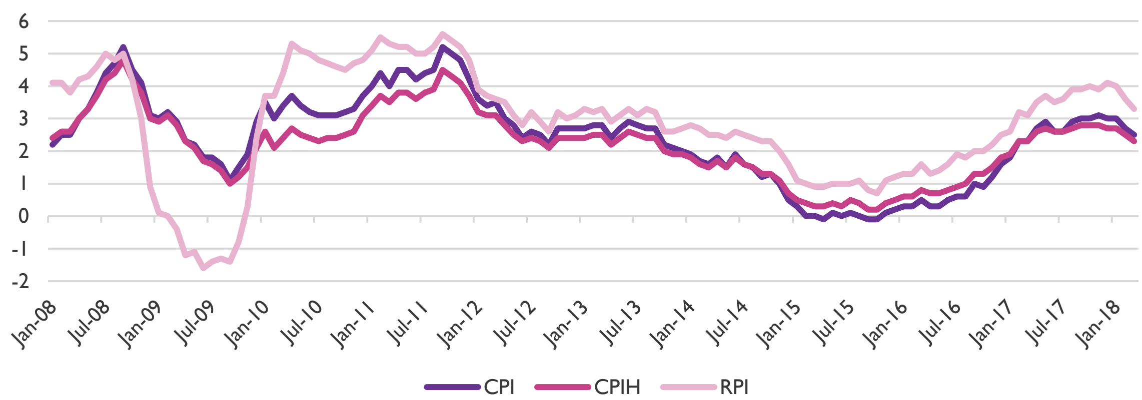
The relevance of each of these measures is as follows:

- CPIH — CPIH was designated by the UK Statistics Authority as a National Statistic[128] and was recommended to become the main measure of inflation.[129]
- CPI — is currently the benchmark set for the Bank of England in its inflation targeting. Until the Office of Budget Responsibility (OBR) starts developing CPIH forecasts,[130] CPI continues to be the best approximation of future CPIH levels.
- RPI — a majority of the industry's inflation-linked instruments as well as government bonds continue to be linked to RPI rather than CPI or CPIH. RPI is not, however, an official inflation statistic and has been de-designated as a national statistic since 2013, with the National Statistician concluding that the formula used to produce the RPI does not meet international standards.

14.4 Recent history

The evolution of CPI, CPIH, and RPI over the last ten years is illustrated in Figure 14.1 below. We can see that, on average, there is a positive wedge between RPI and CPI/CPIH. As a result, real figures that are obtained by deflating nominal values by RPI tend to be lower compared real figures obtained by deflating nominal values by CPI or CPIH.

Figure 14.1: CPI, CPIH and RPI — 2008-2018



Source: ONS.

14.5 Approach in this project

Our approach, as set out by BEIS, will to use CPI as the preferred measure of inflation and, therefore to use CPI-deflated values in order to obtaining real figures. With an inflation rate of π, the relationship between a nominal rate (r_N) and the real rate (r_R) is given by the Fisher formula:

$$1 + r_N = (1 + r_R)(1 + \pi) \rightarrow r_R = \left(\frac{1 + r_N}{1 + \pi}\right) - 1$$

[128] UK Statistics Office (2017) Letter from Ed Humpherson, Director General for Regulation: "National Statistics status of Consumer Prices Index including Owner Occupiers' Housing".

[129] See UK Statistics Authority (2015), "UK Consumer Price Statistics: A Review".

[130] As stated by the OBR: "The ONS also publishes several other inflation measures, such as CPIH, but as these do not currently affect the public finances, we do not need to forecast them". See OBR (2017), "Economic and fiscal outlook", March 2017.