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Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime

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Executive Summary

Background

As part of the wider Electricity Market Reform (EMR) being introduced under the Energy Bill, the UK Government has decided to change its approach to providing incentives for the generation of low carbon electricity. Instead of relying on the existing quantity-based Renewables Obligation ("RO"), renewable and low carbon electricity generators will soon have the option of entering a contract to produce electricity at a pre-agreed strike price. From 2017, it is expected that most new renewable generation will be contracted under these terms. The new support system will be based on Contracts for Difference ("CfDs") through which low carbon generators can receive a guaranteed and stable stream of revenues for their electricity production, composed of a market-determined price for their electricity, plus a "top-up" payment determined by the difference between a fixed "strike price" stipulated in their contract and a market reference price for electricity.

In July 2013, the UK Department of Energy and Climate Change ("DECC") issued a consultation in which, among other things, it proposed draft strike prices for a range of renewable technologies under the CfDs. DECC considered a range of factors in setting strike prices, including:

- technology-specific factors such as capital and operating costs, financing costs as well as any build constraints;
- market conditions such as wholesale prices and the discount which generators face when signing a power purchase agreement (PPA); and
- policy considerations such as the specific contract design, choices about technology mix and meeting the ambition for renewable electricity.

Because the RO and CfD support mechanisms are intended to make investment in renewable electricity generation attractive to investors, they require DECC to make assumptions, inter alia, about how the up-front capital expenditure costs of different technologies will be amortised over time, to ensure that investors earn a fair return on their capital outlay. In particular, this has required DECC to make assumptions regarding the internal rates of return or "hurdle rates" that would be required by investors to finance such projects. Assumptions on hurdle rates have been used by DECC to calculate both the number of Renewable Obligation Certificates ("ROCs") given to each technology under the RO (the banding level), and the draft strike prices being proposed under the CfD regime.

Because the CfD would reduce the exposure of renewables investors to a variety of risks, relative to the RO, DECC has adjusted the hurdle rates originally used in the context of the RO to arrive at new hurdle rates relevant for the calculation of the CfD strike price.[1] Assumptions about the expected changes to hurdle rates under the RO and the new CfD

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223652/emr_consultation_annex_b.pdf

regime were used by DECC to calculate the strike prices published in the July 2013 EMR Delivery Plan consultation document.[2]

Study Objectives

In order to enable DECC to assess the evidence provided through the consultation process and to make final decisions on strike prices, DECC commissioned NERA Economic Consulting to review the available evidence relevant to their assumed reductions in investor hurdle rates required under CfDs. The scope of work included:

- Review the methodology DECC used in its recent consultation on the EMR Delivery Plan, and possible drivers of change in hurdle rates in light of more detailed development of the CfD regime;
- Review EMR consultation responses pertaining to hurdle rates and risk;
- Review analyst and third party reports pertaining to hurdle rates and risk;
- Conduct a limited set of informal interviews to test views on risk, hurdle rates and weighted average cost of capital (WACC) with a range of participants in renewables development and financing, some of whom were already involved in UK renewables, as well as others who were not yet (but who were taking an active interest in current developments); and
- Look for relevant evidence from international comparators.

Because of changes to the UK's electricity markets and to the framework for offering support to renewables, and in particular following the introduction of limits to the levels of overall support via the Levy Control Framework, DECC advised NERA to consider the likely changes in hurdle rate ***relative to a future Renewables Obligation*** as it would have operated during the period relevant to CfDs.[3] As we discuss below, this choice of the future RO "counterfactual" for comparison with CfDs has important implications for our work.

The activities undertaken for the project are summarised in Figure 1 below. We assessed various sources of evidence on the change in risk from the RO to the CfD regime by developing a framework based on standard financial theory to identify risks that may contribute to a material difference in hurdle rates between the two regimes. We use the CAPM framework that focuses on systematic (beta) risk, expanded to account for other factors likely to drive investors' valuation of renewables, namely option values and asymmetric risk. We develop the framework in Section 2.

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[2] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/238867/Consultation_on_the_draft_Delivery_Plan__amended_.pdf

[3] In assessing the change in hurdle rate from the RO to the CfD regime we are concerned with the change in return required by investors that are considering investing in projects taking up support under the proposed CfD scheme when it starts or soon after, relative to the risks currently faced by investors looking to invest in projects under the existing RO scheme. This interpretation avoids the question of how hurdle rates under the RO scheme *would have changed* in future (e.g. to account for the impact of the LCF) had the RO scheme persisted. The precise nature of this future RO is unknown, and may have shared various features in common with what is proposed for the current CfD regime.

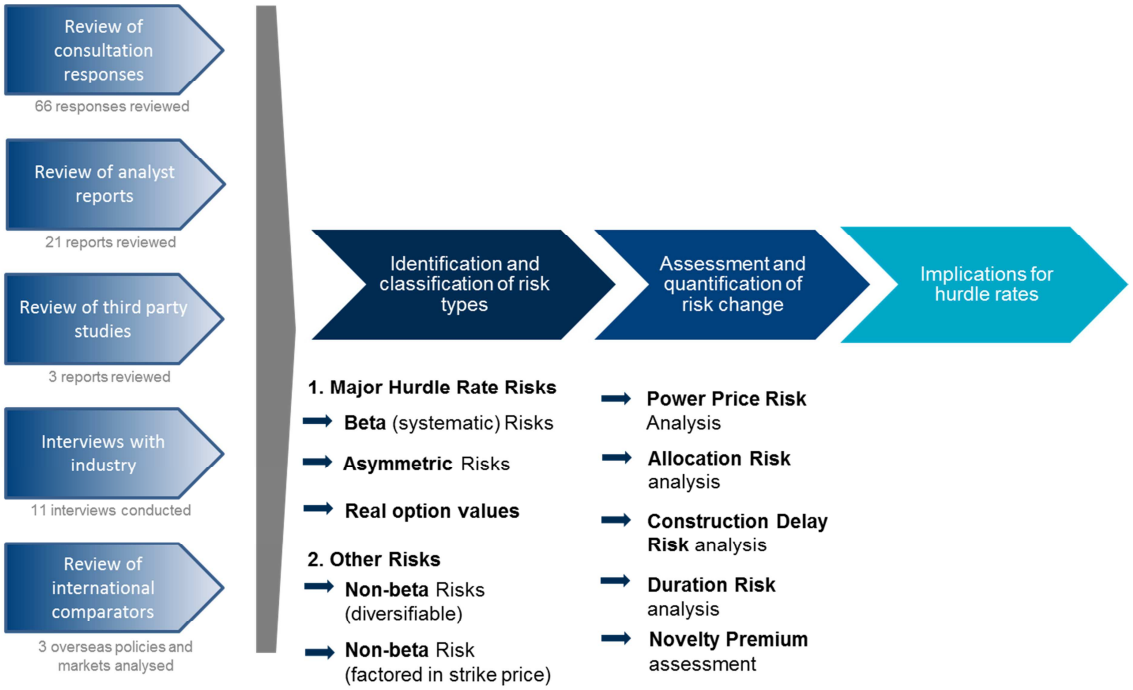
Drawing on the evidence provided to the Consultation, the other sources identified above, as well as NERA's own analysis, we identified, and subsequently quantified, the following "major hurdle rate risks":

- **Market price risk,** which refers to generators' exposure to volatility in wholesale power market prices. The CfD FiT regime reduces exposure to power prices by effectively guaranteeing a certain revenue stream to generators, subject to their ability to achieve the reference market price under the contract through selling electricity on the market (or via Power Purchase Agreements or PPA contracts). We discuss our assessment of this risk in section 6.2 of this report.
- **Allocation Risk,** which refers to the risk that a project is unable to secure support, due to budget constraints under the Levy Control Framework. We note that the advent of more stringent LCF constraints would affect *any* renewable support scheme in the future, including both the proposed CfD and a future RO regime. However, our analysis suggests that the risk of breaching the LCF threshold under the two regimes can differ significantly, in that the subsidy commitment is significantly more uncertain under a CfD regime, because it fluctuates with the wholesale electricity price.[4] We discuss and quantify this risk in section 6.3 of this report.
- **Duration Risk,** which refers to the impact on the expected Net Present Value (NPV) of a project from the difference in price and volume risk arising due to the change in the duration of the support, which typically lasts for 20 years under the existing RO regime, but is expected to last for 15 years, for most technologies under the proposed CfD regime. We discuss this risk in section 6.4 of this report.
- **Construction Delay Risk,** which refers to the impact of unforeseen construction delays to the expected NPV of a project. Under the proposed CfD regime, developers face the risk of 1) reduced support if commissioned capacity is less than certain thresholds expressed relative to the capacity initially committed under the CfD contract; 2) shorter duration of support if commissioning is delayed by a certain amount of time, and 3) loss of support (or renegotiation) if commissioning is delayed very severely (beyond the Long Stop Date). By contrast, in the event of construction delay, developers under the RO face the risk of banding revisions, or banding degressions, as well as loss of support if commissioning is delayed severely. We discuss the impact of this risk on hurdle rates in section 6.5 of this report.
- **Novelty Premium,** which refers to the perceived value that investors attach to waiting for uncertainty around the practical implementation of the new support scheme to resolve. This premium may also arise due to lack of practical experience with managing new risks associated with the framework. In the financial literature, the novelty premium required by investors can be seen as a premium for foregoing the value they derive from holding a *real option*, i.e. the choice of adopting a "wait and see" approach, withholding investment

[4] These risks should be viewed in the context of wider government policy on renewables, including the overall renewable energy target. If in the future the costs of achieving the renewable energy target look likely to exceed the LCF budget, then it is possible that the LCF will be amended and the overall budget increased. We are not in a position to judge which of these constraints (the LCF or the renewables target) will prove stronger.

decisions until institutions/processes are seen to work as anticipated.[5] Investors may require a premium at the early stages of the scheme in order to make them indifferent to foregoing this real option. We discuss the novelty premium in detail in section 6.6 of this report.

Figure 1
Project Overview



NOTE: Third party studies included early reports by Arup (2011)[6], Oxera (2011)[7] and Redpoint (2010)[8]

5 Risk factors that investors may require to see in practice include, but may not be limited to, the ease of obtaining PPA contracts, the magnitude of the basis risk (i.e. ability to achieve the reference price under the contract), the uncertainty around government's commitment to meeting policy targets which may be driven by political process etc.

6 Arup (2011). Review of the generation costs and deployment potential of renewable electricity technologies, available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42843/3237-cons-ro-banding-arup-report.pdf

7 Oxera (2011). Discount rates for low-carbon and renewable generation technologies, available at: http://www.oxera.com/Oxera/media/Oxera/downloads/reports/Oxera-report-on-low-carbon-discount-rates.pdf?ext=.pdf

8 Redpoint (2010), Electricity market reform analysis of policy options, available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42638/1043-emr-analysis-policy-options.pdf

Key Findings

The table below presents a brief summary of the messages about risk and hurdle rates that emerged from the various pieces of evidence that we reviewed.

Table 1
Summary of Key Messages

Source	Stated WACC change	Comment	NERA assessment
Review of existing framework for risk assessment		Existing methodology produces lower cost of capital primarily by allowing higher gearing levels;	We expand on existing framework by considering a number of channels through which WACC is affected, in line with financial theory, and drawing on consultation responses, analyst reports and industry interviews;
Analyst reports		High agreement that lower price volatility will reduce WACC	Analyst reports focus on removed market price exposure; limited consideration of practical/implementation details;
Consultation responses		Quantitative evidence from a small number of respondents suggesting that certain risks increase under CfD, potentially offsetting risk reduction from more stable revenues.	Significant qualitative analysis but not all concerns expressed in consultation responses are relevant WACC risks; Only a few responses provide quantitative analysis.
3rd party reports		Brodies' report (cited by many consultation responses) concludes that there is not enough evidence to conclude a cost of capital reduction	Thorough *qualitative* analysis across risk types, but very limited quantitative analysis or estimates of *materiality* of impacts across different risks.
Industry interviews		In the near term, WACC increases for development stage equity investors due to uncertainty. In longer term, when mechanism details are known and system is established, the stable revenues of the CfD should lower WACC by attracting lower return equity and debt investors into construction and operations stages.	Broad palette of responses from the equity and debt sides. Experience in the UK market, type of investor and stage of project investment all key determinants of responses.
NERA assessment		Depends on technology and on timing.	Biggest impacts on WACC from reduction in wholesale price risk. Novelty premium also a significant consideration, and allocation and construction risk also add to overall assessment.

As illustrated by the table above, the sources reviewed do not point towards a clear consensus that the cost of capital or hurdle rates will either increase or decrease as a result of the introduction of CfDs and the replacement of the RO regime. In particular:

- Analyst reports have highlighted that lower price volatility should reduce the long run cost of capital, but they have tended not to comment on other changes associated with the CfD scheme, such as risks associated with construction delays.
- In contrast, most consultation responses maintained that although the CfD regime would reduce risks associated with electricity price volatility, other risks under the CfD would more than offset this benefit. Few consultation responses provided quantitative evidence to support their arguments, although some referred to increased risks associated with construction delays under the CfD due to all projects being potentially subject to penalties

for late delivery, or even loss of support (in case of failure to commission by the Long Stop Date[9]) and due to the shorter length of the contract period (15 years vs. 20 years under RO). Our own assessment framework expands on the existing evidence DECC has used to date to assess the change in hurdle rates between the RO and CfDs.[10]

Below we summarise NERA's key findings based on our analysis of the consultation responses, analyst reports and interviews:

- First, we note, there is a **diversity of perspectives** regarding the type, hierarchy, magnitude and direction of key changes in risk resulting from the regime change, largely due to differences in investor types (equity vs. debt, development vs. construction vs. operations investors, experienced in UK market vs. new entrants), their knowledge and understanding of the changes in risk arising from the RO to CfD regime change, and their interests in the policy shaping process. The diversity of perspectives was reflected in consultation responses, analyst report and interviews. In our analysis we have sought to bring out these differences where they may be material.
- **International comparators** offer limited lessons as the shift from RO to CfD regime is unique to the UK.
- In our view the central change in risk exposure with regard to the shift from a RO regime to a CfD FiT scheme is the reduction in exposure **to power price risk**. As a fixed-price support scheme, the CfD FiT scheme reduces exposure to wholesale market risk, thereby removing a significant part of the volatility of the revenues of renewable energy projects. We estimate a reduction in hurdle rates as a result of the reduction in wholesale power price risk of between 50 - 175bps, depending on the technology.
- We find that the reduction in power price risk (relative to a future RO system) is largest for **mature technologies such as onshore wind**, because stabilisation of electricity revenues reduces overall revenue volatility more for technologies that receive the lowest level of policy support.
- However, we also find that the shift to the CfD scheme could increase other risks, including "**allocation risks**" and "**construction risks**", and there is also likely to be a "**novelty**" premium associated with uncertainties about the operation of the new CfD mechanism.
- We find that **allocation risks will likely increase** under the CfD, because the amount of subsidy that must be paid in any given year fluctuates with the wholesale electricity price, and is therefore more uncertain. This is an asymmetric risk, in that lower power prices constrain the LCF budget more under the CfD regime than under an RO regime.
- With regard to **construction risks**, we find that the only material difference between the RO and CfD system occurs for construction delays that exceed the Long Stop Date. For smaller delays (beyond the target commissioning window) under the CfD regime, we note that this will reduce the NPV of the project since the delay will affect the duration of the

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[9] The Long Stop Date is defined as that point following the Target Commissioning Window after which the CfD Contract can be terminated, if capacity delivered is below certain pre-defined thresholds.

[10] DECC based the change in the hurdle rates on Redpoint (2010), "Electricity market Reform Analysis of policy options".

subsidy period (i.e. effective number of years over which the subsidy is received). However, in the RO regime, although the subsidy period is unchanged, if the assets are accredited later than expected, the project could be subject to banding degression. Our analysis suggests **these effects broadly offset each other** such that for small delays, the risks under the CfD regime are no higher than under the RO regime.

- For **construction delays beyond the Long Stop Date**, however, the change in risk is much larger as the CfD subsidy either falls away entirely, or needs to be renegotiated. For an offshore wind asset that means that about 2/3 of the project revenues are at risk (see Appendix C). The level of subsidy achievable depends on the availability of funds and available strike prices at the time of application. Under the ROC regime, the developer would also have been exposed to this risk. However, under the ROC regime, the risk of sudden government fund shortages is lower, and consequently, so is the risk that there will be no support. The increased risk is mainly relevant for offshore wind projects, which have high strike prices and more uncertain development and construction periods. Biomass and onshore wind construction times tend to be shorter, and in general these projects are less complex, so it is less likely the government would have time to change the availability of support even with similar relative delays in construction.
- For similar reasons, all else equal, we might therefore expect that **Round 3 offshore wind projects** would face higher risks associated with construction delays under the CfD mechanism than Round 2 projects. Even so, selected Round 2 projects may face technical challenges that are similar to (or even greater than) those faced by (some) Round 3 projects, so in practice this will depend on the characteristics of individual projects.
- A final important consideration is the possibility that a "**novelty premium**" could stop hurdle rates from falling at the start of the CfD regime while investors waited to see that it would work as intended. We are unable to verify the existence of such a premium, but believe that there are plausible reasons that it could affect hurdle rates.
- Overall, we find that it may not be safe to assume an across-the-board reduction in hurdle rates for all technologies immediately.
  - We find the greatest **evidence for a long-run <u>decrease</u> in hurdle rates under CfDs (relative to a future RO system) for <u>mature</u> technologies**, because stabilisation of electricity revenues reduces volatility more the smaller the share of revenue provided by policy support.
  - We find **evidence suggesting hurdle rates may <u>decrease or remain unchanged in the short-run</u> (relative to a future RO system) for <u>emerging</u> technologies with longer construction lead times**, and should decline in the long-run, but less than for mature technologies – because the CfD's stabilisation of electricity revenues has a smaller impact on their overall revenue.
  - Assuming no novelty premium, we conclude that prior estimates of changes to hurdle rates may have been underestimated for some technologies. Table 2 shows the hurdle rates assumed under the RO and CfDs for the draft delivery plan, and presents NERA's own estimates. We provide a range based on our assessment of the plausible ranges of the different risks.

Table 2 summarises the change in hurdle rate associated with the change of policy, split into the individual impacts of the component risks. This is based on NERA's assessment of

evidence from consultation responses, analyst reports and interviews. Where there was insufficient quantitative evidence presented in these sources, NERA conducted analysis to quantify risks identified by consultation responses, analyst reports and interviews.

Table 2
Summary of Hurdle Rate Changes under CfDs (pre-tax, real)

NERA Assessment – Individual Risk Impact on Changes in Hurdle Rates				
	Offshore Wind	Biomass Conversion	Onshore Wind	Comment
1) Wholesale Price Risk	-100 to -50 bps	-125 to -75 bps	-175 to -125 bps	Impact largest for onshore (highest share of market revenues; smallest for offshore (lowest share of market revenues)
2) Allocation Risk	+5 to +40 bps	+5 to +40 bps	+5 to +40 bps	Risk increases due to higher LCF breach risk with lower power prices
3) Construction Delay	+5 to +10 bps	None	None	Risk increases due to higher LCF breach risk with lower power prices; assumed to apply only to offshore wind.
4) Novelty Premium	+0 to +100 bps	+0 to +50 bps	+0 to +50 bps	Novelty Premium is uncertain; may be higher for emerging technologies with higher share of subsidy revenues
Total Change (excl. Novelty premium)	**-90 to 0bps**	**-120 to -35bps**	**-170 to -85bps**	
Total Change (incl. Novelty Premium)	**-90 to +100bps**	**-120 to +15bps**	**-170 to -35bps**	

Note: The allocation risk for onshore wind and biomass is likely to be at the lower end of the range above due to shorter time between pre-development spend and potential action to correct LCF breach. Allocation risk for projects that are on the verge of signing CfD contracts is also very low.

Table 3 provides, as context, an illustration of how these changes in hurdle rate would affect DECC's assumed hurdle rates under CfDs.

We note it has not been within our scope of work to assess whether the absolute level of DECC's assumed RO hurdle rates used in the 2013 Draft Delivery Plan accurately reflect investor requirements under the current or (hypothetical) future RO scheme.

Table 3
Summary of Hurdle Rate Ranges under CfDs (pre-tax, real)

NERA Assessment – Total Risk Impact on Hurdle Rates			
	Offshore Wind***	Biomass Conversion	Onshore Wind
DECC RO WACC*	**10.2%**	**11.6%**	**8.3%**
DECC CFD WACC**	**9.6%**	**10.9%**	**7.9%**
NERA Illustrative Range under CfD	**9.3% - 10.2%**	**10.4% - 11.25%**	**6.6% - 7.45%**
NERA Range with Novelty Premium	**9.3% - 11.2%**	**10.4% - 11.75%**	**6.6% - 7.95%**

Note: * DECC RO WACC assumed for the draft delivery plan July 2013;
** DECC CfD WACC assumed for the draft delivery plan July 2013
*** We show results using the Round 2 offshore wind assumptions set out in DECC's draft delivery plan.

1. Introduction

NERA Economic Consulting was commissioned by the UK Department of Energy and Climate Change ("DECC") to review the existing evidence on the costs of financing low-carbon generation under Contracts for Difference ("CfDs"), and to provide an independent assessment of the existing evidence ("the Project").[11]

The Project was undertaken in the context of DECC's recent *Consultation on the draft Electricity Market Reform Delivery Plan* ("the Consultation").[12] The Consultation seeks views of stakeholders on plans for implementing electricity market reforms, including on the proposed "strike prices" for CfDs for renewable electricity generation technologies ("renewables").[13] The CfD Feed-in Tariffs are intended to remove exposure to wholesale price risks through a long-term contract: if the electricity market reference price is below the strike price, generators will receive a revenue top-up, up to the strike price; if the market price is above the strike price, generators will pay back any difference. The Consultation has been preceded by approximately three years of consultations and analysis, including studies on financing costs to inform the determination of the support levels provided through CfDs. In addition to this existing evidence, new evidence on financing costs under CfDs was gathered through responses to the Consultation (which closed on 25 September 2013).

This Project is concerned with assessing the costs of financing renewable generation using CfDs, and specifically focuses on investors' hurdle rates – that is, the minimum Internal Rates of Return ("IRRs") at which investors would be willing to invest in renewable generation projects.

The strike prices proposed in the Consultation were developed starting from evidence about hurdle rates under the existing RO regime, and then adjusting these rates to reflect estimates of the expected reduction in risk under a CfD FiT regime.

In keeping with DECC's approach in the Consultation, the remit of the current Project is to review the existing estimates of the expected ***changes*** in hurdle rates between an RO regime and a new CfD regime.

Because of recent and upcoming changes to the UK's electricity markets and to the framework for offering support to renewables, including the Levy Control Framework, DECC advised NERA to consider the likely changes in hurdle rates ***relative to a future Renewables Obligation*** as it would have operated during the period relevant to CfDs. As we discuss in more detail below, this choice of counterfactual has important implications for our work.

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[11] DECC, *Financing Low Carbon Generation – project to identify and utilise new evidence on costs of capital for low carbon generation to support DECC's existing evidence base* (Tender Reference Number: 673/09/2013), 3 September 2013.

[12] DECC, *Consultation on the draft Electricity Market Reform Delivery Plan*, 17 July 2013.

[13] In addition, the Consultation consults on a policy proposal of a reliability standard for the Capacity Market.

This report is divided into three parts:

In **Part A,** we review existing evidence on hurdle rates generally and for renewable investment projects in particular, drawn from the following sources:

- **Existing literature** on assessing hurdle rates in general and UK hurdle rates for renewable investments in particular, drawing on work that has been commissioned and used by DECC to date as well as financial theory more generally;
- **Analyst Reports** tracking the UK Utilities sector and/or renewable energy investors in particular;
- **Consultation Responses** submitted to DECC as part of the EMR Draft Delivery Plan Consultation process; and
- **Industry Interviews** conducted with infrastructure investors providing both debt and equity financing.

In **Part B**, we present an international benchmarking exercise to compare the proposed rates of return under the CfD FiT scheme in the UK (as per DECC's initial proposals) to corresponding rates under different incentive schemes in other countries. We reviewed six international renewable support schemes, but present case studies for a sub-set of support schemes that we considered to offer helpful comparisons with the proposed CfD FiT scheme.

Finally, in **Part C**, we set out our own assessment of the key risk factors affecting the cost of capital for renewable investments that change with the advent of CfDs, and provide an indicative range of the magnitude of changes to the associated hurdle rates.

The appendices provide supporting information.

Part A: Review of UK Evidence on Hurdle Rates

2. Methodology and Approach

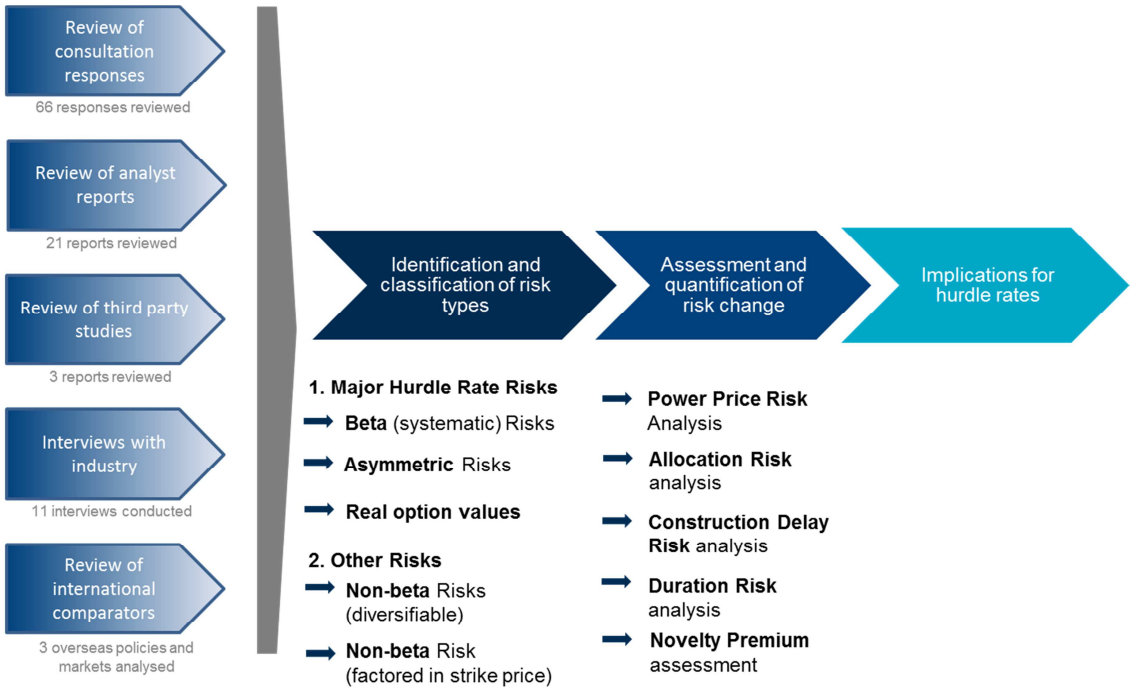
2.1. Overview of Project Methodology

In this section we provide an overview of our approach to the project. We set out the data sources used and the methodological framework that we adopted. Our main aims in this report are to:

- Develop a methodology for assessing and estimating hurdle rates for renewable electricity generators that is founded in economic theory and that also reflects investor practice;
- Provide an international benchmark of hurdle rates required by investors operating under different renewable support schemes; and
- Apply this methodology to the existing literature, consultation responses and DECC's proposed hurdle rate reductions from the change to a CfD scheme with a view to assessing and validating the proposed hurdle rate reductions.

Figure 2.1 provides a graphical overview of project methodology and data sources.

Figure 2.1
Project Overview



2.2. Framework for Risk Assessment

The hurdle rate for a project is determined by the *expected* return on equity and debt that investors require for contributing each respective type of capital, given the risks faced by the target sector. In providing a framework for assessing the reduction in the required rate of return we draw on a model that is based on financial theory but allows for the incorporation of practitioners' approaches as per our consultation with market participants.

We first set out this model in this section before assessing the different categories of risks discussed by stakeholders and how these fit into this framework (sections 2.3 and 2.4).

The starting point for our framework of risk assessment is the Capital Asset Pricing Model (CAPM). The CAPM is the traditional model used by most UK and European regulators for estimating the cost of capital, due to its simplicity and robustness.[14] Moreover, standard corporate finance textbooks and survey evidence suggests that the model remains the leading framework used by practitioners even outside the regulated sectors[15]. It is against this background that we use a framework based on the CAPM, but supplemented to account for asymmetric risk and real option values to assess the likely hurdle rate reduction. By extending the CAPM framework to capture other risk categories particularly relevant to renewables investments, we account for the fact that the marginal investor may well not be using the CAPM.

A key tenet of the CAPM is that any investor *diversifies* his or her stock holdings by combining risky securities into a portfolio. However, complete diversification of risk is not possible since securities all move together to a certain extent.[16] Consequently, the CAPM recognises that there are two types of risks, where in theory only one of them is priced by investors:

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[14] For example, in the recent Final Determination by the Competition Commission on the disputed price determination for Bristol Water, the CC used the CAPM as it found it to be "the best way" or "the most robust way" to determine required return by shareholders. See Competition Commission, Bristol Water Plc, A reference under section 12 (3) (a) of the Water Industry Act 1991, Report presented to Ofwat on 4 August 2010, p. 7 and 64. Accessed at http://www.competition-commission.org.uk/assets/competitioncommission/docs/pdf/non-inquiry/rep_pub/reports/2010/fulltext/558_final_report.pdf

[15] See for example Association for Financial Professionals (2011), *Current Trends in Estimating and Applying the Cost of Capital - Report of Survey Results*, March 2011, which finds that "In estimating the cost of equity, nearly nine of ten organizations use the capital asset pricing model (CAPM)." p.2

Also see the 2013 edition of KPMG's survey of Australian valuation practices, KPMG (2013) Valuation Practice Survey 2013, p.7. 82% of the respondents answered that they "always" use the CAPM as the appropriate rate of return to future cash flows to equity (vs. 8% for the second most preferred response). KPMG concludes that "the CAPM is the most popular model being used to derive a cost of equity estimate, with all participants always or sometimes using the model". (2013) Valuation Practice Survey 2013, p.7.

Standard textbooks confirm that CAPM is widely used due to its simplicity and practicality. See for example, Brealey R.A. and Myers, S.C., 2013, Principles of Corporate Finance, 11th ed, p.201, " … financial manages find it a convenient tool for coming to grips with the slippery notion of risk and why nearly three-quarters of them use it to estimate the cost of capital."

[16] Correlation between assets occurs as a result of the influence of economy wide factors such as interest rates, inflation, and macro economic demand.

- **Beta (systematic) risks**, i.e. risks that are correlated with the market and as such are unavoidable; these risks are non-diversifiable and therefore investors would require a higher return for bearing these risks;
- **Non-beta (non-systematic) risks,** i.e. risks that are specific to individual projects and can therefore be reduced via appropriate diversification.

Despite its widespread use, the CAPM has a number of weaknesses that make it unsuitable as the sole model for assessing the hurdle rate for renewable energy investments.[17] For example, as a one-period model, the standard CAPM framework does not capture the resolution of uncertainty over time. Moreover, the CAPM assumes that the distribution of returns is symmetric, implying that investors are equally exposed to upside and downside risks, which need not be the case for all types of risks. Capturing these effects is necessary in order to fully explain the hurdle rates required by renewable investors. To overcome these shortfalls, we expand the CAPM framework to include:

- **Asymmetric risks:** In the context of investment in assets where the price is not set by market mechanisms (e.g. regulated utilities, renewables), "asymmetric risk" usually refers to a situation where the "base case" for revenues / costs chosen by the regulator (e.g. on the basis of the median or mode)[18] is more optimistic than the expected case ("mean"). In that context, regulatory / governmental choice can lead to expected under-recovery of cost. In principle, such a situation can be remedied by using a central case that properly reflects expected value.[19] However, some regulators have chosen to adjust the allowed rate of return as opposed to the central cost/revenue forecast, which (when done correctly) has the same effect.[20,21]
- **Option Values:** In the economic literature a real option is an option arising in relation to a real investment decision, in which there is flexibility to take decisions in the light of subsequent information. The available options may involve deferral, expansion, contraction, abandonment, or other change of the investment. In the present context, given the uncertainty about the future path of energy policy and the full implications of the EMR, investors may derive value from deferring investment, i.e. adopting a "wait and see" approach, until they see the envisaged arrangements work in practice, and have confidence that no additional uncertainty/risk factors will affect their expected returns under the new

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[17] In fact a number of investors that we interviewed (cf. section 5) told us that they do not use the CAPM at all and instead determine their hurdle rates differently. As such not all investors capture and price risks by way of the CAPM.

[18] The mode refers to the single most likely value while the median refers to the possible outcome that is exactly in the middle of the distribution of all possible outcomes.

[19] The CAA's approach to traffic forecasting at the recently concluded Q6 price review is a case in point. In this case the CAA allowed Heathrow to use a traffic forecast below the "business as usual" forecast because it considered the likelihood of negative shocks to business as usual to be higher than the likelihood of positive shocks, which led to an allowed downward adjustment of expected traffic See Civil Aviation Authority, *Economic regulation at Heathrow from April 2013: Final Proposal*, 3 October. 2013. Available at: http://www.caa.co.uk/application.aspx?catid=33&pagetype=65&appid=11&mode=detail&id=5783

[20] Throughout this report we will first assess whether any risk has already been accounted for in DECC's strike price assessment and only consider a hurdle rate uplift where this has not yet been done.

[21] E.g. Dutch regulator OPTA has allowed asymmetric risk uplift for new networks. See OPTA(2011): Regulation, risk and investment incentives Regulatory Policy Note 06. Also see Ofwat (2013): Setting price controls for 2015-20 – framework and approach: A consultation, p.126.

framework. Consequently, to make investors indifferent between investing now and investing once uncertainty is resolved, DECC would have to provide some compensation for the loss of the option to wait, either through a higher starting value of the strike price or through a hurdle rate that is initially higher. Section 6.6 below provides more detail on the concept of a "novelty premium" as a way of compensating for the loss of a real option.

The approach set out above has previously been applied in the regulatory literature to account for the fact that in practice the CAPM cannot capture all dimensions of risk that matter to investors.[22] In light of the discussion above, we grouped risks into the following two categories:

1. **Major Hurdle Rate Risks**, which we assess and quantify in Section 6. These include:

   - Beta (systematic) risks;
   - "Asymmetric" Risks, to the extent that they significantly affect the expected mean return and are *not* explicitly accounted for in the strike price modelling;[23] and
   - Real Option Values.[24]

2. **Other Risks,** which we assess below. These include:

   - Non Beta (non-systematic) risks, i.e. risks that investors can realistically diversify, e.g. by holding a large portfolio of assets; and
   - Risks accounted for in DECC's strike price modelling – i.e. risks that could affect the expected cashflows/ the discount rate but that have already been addressed by DECC in strike price modelling.

In assessing the hurdle rate impact of the "major hurdle rate risks" set out below we expand on the existing framework used by DECC with a view to setting out in more detail the different channels through which changes in risk can affect the cost of capital, namely i) changes in equity risks, ii) changes in debt risks and iii) changes in capital structure. We discuss the relative importance of these aspects in Appendix A.

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[22] See e.g. Competition Commission (2002): BAA plc: A report on the economic regulation of the London airports companies (Heathrow Airport Ltd, Gatwick Airport Ltd and Stansted Airport Ltd) para 4.71

[23] We note that some risks have already been addressed in DECC's strike price calculation. It is not within the remit of this report to assess DECC's strike price modelling and whether the strike price adjustment is too large / too small to cover these risks in their entirety.

[24] As set out above, the investor can be compensated for foregoing the value of a real option either through a higher initial strike price or by way of a hurdle rate uplift granted in initial years. It is beyond the remit of this paper to assess whether the degression of the strike price contains appropriate compensation for the reduction of the value of the real option over time or whether it merely reflects expected cost savings. Section 6.6 discusses a possible interpretation of the novelty premium as a compensation for the loss of real options and provides an indicative quantification. DECC will want to satisfy itself whether its proposed strike price degression already factors in a novelty premium or whether an additional allowance for the novelty premium is required.

2.3. Major Hurdle Rate Risks

Having reviewed the various risks identified by equity analysts, consultations responses, interviewees, and other industry commentators, we consider that the list below reflects the risks that affect hurdle rates under the CfD FiT regime; for each of these, we define them below and set out our reasons for including them within this category:

- **Volatility of Earnings** refers to the risk that generators face with regard to the volatility of the wholesale market price they can obtain. We distinguish between fixed cost generators (i.e. generators that do not incur fuel cost) and variable cost generators (i.e. generators that incur significant fuel cost). Both types of generators receive revenues that are correlated with the market, to the extent that they market their electricity at competitive wholesale prices; therefore, revenue risk for most generators is pro-cyclical. Equally, input costs for most variable cost generators are pro-cyclical, to the extent that they are correlated with general movements in the market, and more specifically to movements in commodity prices. Therefore, absent any subsidy regime, volatility of earnings is pro-cyclical. However, the relative degree of systematic risk for the variable cost generators depends on the degree to which input costs are correlated with market prices, thereby providing a natural hedge to general market shocks.
- **Allocation Risk** refers to the uncertainty of securing a commitment of support from government through the renewables support policy. With the implementation of a more stringent Levy Control Framework, developers face a risk that they will not receive support, or will receive less support than they had originally expected, if commitments within the LCF are too high. We note that while this risk would exist for *any* future renewable support scheme, including both the proposed CfD and a future RO regime, our analysis suggests that the risk of breaching the LCF under the CfD regime can differ significantly. The subsidy commitment is significantly more uncertain under CfD, because it fluctuates with the wholesale electricity price. This is an asymmetric risk, in that lower power prices constrain the LCF budget more under the CfD regime. (This risk therefore can also be thought of as a beta risk, to the extent that power prices are correlated with general movements in the market.)
- **Construction Delay Risk** refers to the possibility of unexpected construction delays of a project. There is no *a priori* reason to believe that construction risk is more likely to happen in a bull or bear market; however, construction risk poses a down-side risk to cashflows which has no offsetting upside, particularly for more immature technologies without well-established supply chains and logistics, and longer lead times. It is therefore asymmetric, and because of interactions with allocation risk, differs between the RO and CfD.
- **Duration Risk** refers to changes in volume and price risk exposure, or earnings risk, associated with the length of the subsidy period. We review whether the fact that the subsidy period is shorter under CfD than under RO increases or decreases the beta component (i.e. wholesale price risk). Consultation respondents have argued that risk in years 16-20 is higher under the CfD scheme, while there is also an operational flexibility argument that suggests risk is lower as investors realise the full value of the subsidy earlier.
- **Novelty Premium** refers to the perceived risk by investors associated with the uncertainty around the practical implementation of the new support scheme, and/or the lack of practical experience with managing new risks associated with the framework. In the

financial literature, the novelty premium required by investors can be seen as premium for foregoing the value they derive from holding a *real option*, i.e. the choice of adopting a "wait and see" approach, withholding investment decisions until institutions/processes are seen to work as anticipated.

The unfamiliarity of investors with the CfD regime can potentially increase the option value of waiting under the new policy, relative to the RO. For example, investors may prefer to wait to observe some of the details working in practice. DECC can limit the magnitude of the option by providing clear ex ante information on the functioning of the system; however DECC may still need to provide a hurdle rate or strike price incentive to encourage early investment to the extent that there is remaining uncertainty at the start of the scheme that can reasonably be expected to be resolved.

2.4. Other Risks

- **Basis Risk** refers to the inability of generators to achieve the reference price index under the contract.
  - For **intermittent** generation, the reference price will be set to an hourly day-ahead reference price. This means that the main residual basis risk is effectively *balancing risk,* to the extent that generators do not have perfect foresight of their output. Wind farm output is likely to be negatively correlated with the balancing price, i.e. on average wind farms buy shortfalls when the balancing price is higher than the reference (Hourly Day Ahead Market market) price, and sell excess output when the balancing price is lower than the reference price. Therefore, on average wind farms may achieve a lower price than the reference price. However, generators arguably face similar balancing risk under the ROC system.
  - For **baseload** generation the reference price will be set to a seasonal price. Dispatchable generation is exposed to basis risk in that the reference price is a seasonal average price. If the generator runs baseload, it will capture the seasonal price. If it operates in a regime with relatively volatile prices, it may find that it is more profitable to switch off in low price hours, in which case it will be better off.

  For individual intermittent generators, balancing costs may be pro-cyclical, to the extent that they are a function of the short-term supply curve. In some regimes, a separate balancing premium is paid in addition to the subsidy, which can be changed over time if there are clear indications that balancing costs are changing.

  We understand that DECC has already factored in provisions in the strike price for balancing costs, via the PPA discount.

  The balancing cost is likely to change over time as renewable penetration increases; given the changing nature of electricity markets, however, it is impossible to forecast these costs exactly today.
- **Indexation Risk** refers to the risk of divergence between costs (RPI growth) and revenues (CPI growth) of generators. It is not clear that costs from renewable generators grow with

RPI.[25] There would be a small uncertainty arising due to the difference between the RPI forecasts used to factor into the strike price, and actual future RPI inflation. However, we note that this difference is likely to be small, and symmetric.

- **Collateral Provision** refers to the cost of posting collateral for payments under the contract (i.e. when the reference price exceeds the strike price). We note that the collateral requirement is likely to be small, in that generators are required to make these payments when power prices are high. However, transaction costs allowances should be included in the strike price. We understand that DECC is considering collateral rules which could remove this concern.
- **Credit risk** refers to counterparty risk, i.e. the risk that the counterparty under the renewable support contract is unable to honour their obligations under the contract. Under the RO, the credit risk for ROC revenues is backed up by the pooling mechanism, which was established after the TXU Collapse. This mechanism limits exposure to individual counterparty credit risk. Under the CfDs, the counterparty is explicitly a public entity; our understanding is that DECC is still in the process of finalising the details of the planned instruments under the CfD. However, because of the existence of risk pooling systems under both regimes, we find no material difference in risk under the two mechanisms.
- **Force majeure** refers to risk that the parties will not be able to honour the contract due to matters outside of their control. We note that this risk is not systematic, i.e. extreme events can happen in both an upturn and downturn in the market. We consider that exposure to the downside is broadly unchanged under the CfD relative to the RO.
- **Volume Risk** refers to the inability of some (typically intermittent) generators to perfectly predict or control output in the long-run, which introduces volatility in their revenues. CfD FiTs may exacerbate this risk, in that the subsidy is frontloaded, and therefore concentrated on lower volumes. However, we note that this risk is symmetric, i.e. positive shocks are on balance equally likely as negative shock. Volume risk is also diversifiable i.e. developers can mitigate weather risk by holding a portfolio of wind farms at different locations. This risk is also insurable.
- **Change in Law Risk** refers to the risk that a future law provision could change the revenues or costs of the project. An example of this type of risk would be a change in the level of corporate tax rate. In our view, this risk is political, and not systematic.[26] It is therefore possible for international investors to diversify across different regimes.[27]

We discuss these in more detail in Appendix B.

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[25] One of the main differences between the CPI and the RPI index is that the former accounts for housing costs, i.e. mortgage payments, rents etc.

[26] For example, tax rates can be counter-cyclical, if there is political will to incentivize the economy, or pro-cyclical, if it is politically desirable to fill gaps in government budgets during economic upturns.

[27] Note, by "investors" here we are referring not only to utilities that may have a diversified portfolio of international energy assets. Instead, a fundamental tenet of modern finance theory is that it is rational for all investors to diversify risk by holding a broad portfolio of assets. Moreover, the degree of diversification of the investor base cannot be determined by focusing solely on the assets within a particular (e.g. renewable) fund, but needs to take account of the diversification of investors into the fund. We do not see any strong reasons why the generality of risks from possible changes in laws would be regarded as a beta (i.e. non diversifiable) risk.

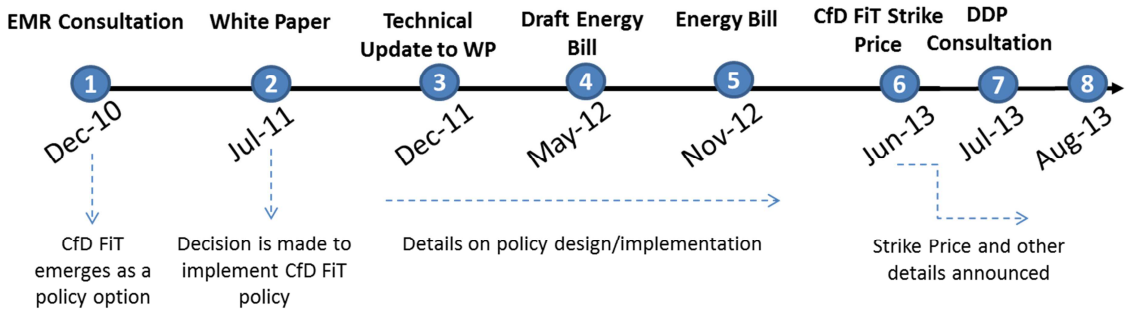
3. Review of Analyst Reports

3.1. High Level Assessment

We reviewed a sample of equity analyst reports, covering large UK renewables investors (i.e. Drax, SSE)[28], and energy utilities more broadly, where the latter commented on the EMR design and the CfD in particular. Most analyst reports addressed market-related risk drivers, or what we categorise as beta risks within the framework set out in Section 2. In contrast to the consultation responses, analyst reports provided little discussion of the practical and legal aspects of the CfD mechanism design.

Details of the CfD policy were discussed, refined and publicly revealed by DECC over the course of the last three years, as set out in Figure 3.1.

Figure 3.1
DECC CfD FiT Policy Design and Implementation Timeline



Our initial assessment included analyst reports over the entire relevant period shown in Figure 3.1, in order to track changes in market perceptions of the CfD policy over the entire relevant period.[29] We also considered assessing quantitative evidence on changes in analyst cost of capital estimates (i.e. for merchant generators such as Drax), in order to get a sense of the cost of capital corrections analysts might have been pricing in as new information was made publically available. [30]

The challenge of assessing quantitative evidence from analyst reports (or market data in general) was that any cost of capital corrections seen in analyst reports through time, or implicitly observed in share prices, would be uncertain, due to the fact that it is difficult to

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[28] We note that most of the other identified renewables companies, i.e. companies whose principle business generating activity is renewable energy generation, are either not publically listed, or not followed by analyst over the relevant observation period.

[29] We chose December 2010 as the relevant starting information date, i.e. the date when the CfD FiT instrument emerged as a policy option, in DECC's EMR Consultation document.

[30] When markets are efficient, information is internalized in prices/valuations as soon as it is made publically available. Therefore, ceteris paribus, we would expect analysts to adjust their WACC assumptions over time, in order to reflect the fact that future cashflows from renewable investments are subject to different set of risks compared to those arising under an RO regime.

attribute the perceived risk reduction to a single policy announcement date, or a clearly defined reference period over which the change in cost of capital will have occurred. As shown in Figure 3.1, uncertainty around the CfD design and implementation resolved gradually, over the course of the last three years. Therefore, cost of capital corrections in analyst reports, or observed in share prices, will have adjusted gradually through time and would be subject to significant uncertainty.

Due to the difficulties with assessing quantitative evidence from analyst set out above, in this report we focused on qualitative analysis, gauging analyst sentiment around the CfD policy as evidenced in more recent analyst reports.[31] Below, we identify and discuss specific risks addressed by analysts related to the CfD policy mechanism.

3.2. Emerging Themes from Analyst Reports

1. Volatility of Earnings

Most analyst reports focused their discussion of the CfD FiT regime around the removed exposure to wholesale price risk, including commodity price risk and carbon tax uncertainty. The consensus analyst view seen in the majority of analyst reports was that the CfD regime reduces the riskiness of renewable investment projects, which leads to lower cost of capital. Some analysts qualified the risk reduction as "dramatic", with most analysts discussing the reduction of commodity and market price risk leading to revenue visibility as the key driver for this change.

Analysts distinguished between *fixed cost* generators, i.e. generators that do not take fuel price risk (e.g. wind farms), and *variable cost* generators i.e. generators that remain exposed to fuel price risk (e.g. biomass). *Fixed cost* generators were identified as the "winners" under the CfD policy, to the extent that the CfD instrument unambiguously stabilizes *earnings* for these types of generators. However, analysts following Drax regularly identified the need to hedge input costs for biomass generators under the new framework, in order to remove earnings volatility from fuel price exposure, allowing that generators can lock in real "bark spreads".

2. Debt capacity

Whilst most analysts discussed reduction in market price risk as the driver behind the cost of capital reductions, a subsample noted the potential for increase in debt capacity and financeability, on the back of a more stable stream of cashflows. We discuss the potential for higher debt capacity in greater detail in Appendix A, where we conclude that the impact of increased debt capacity under the new CfD regime is likely to be small.

3. Uncertainty around Final Decision by DECC

Some of the analyst reports expressed concern regarding the potential risk that DECC may change the Draft Delivery Plan proposals in the final Decision in December 2013, as a result

[31] We focus on evidence in analyst reports published not earlier than a year before Draft Delivery Plan Consultation.

of the Consultation process. This was supported by opinion that DECC has previously changed support levels after consultation.[32]

We note that this concern is not a relevant cost of capital risk to the extent that any uncertainty regarding DECC's final CfD design and implementation will be resolved when the final decision is published.

4. Political Risk/ Sustainability

Finally, we note that some analysts have commented on the sustainability of the policy, particularly for fixed cost generators, to the extent that it removes the potential for windfall profits in the event of high power prices, as higher prices would no longer increase the revenues earned by supported renewables.

The reports we reviewed did not comment on other allocation and political risks, such as the potential constraints imposed via the Levy Control framework, which have been identified by other stakeholders. This lends support to the idea that at present, analysts do not factor in a large allocation risk due to the Levy Control framework.

3.3. Quantitative Evidence of Change in Risk

In section 3.1 above, we discussed the difficulty with estimating the cost of capital corrections priced in by analysts by observing time series data for specific companies. However, we note that a few analysts commented specifically on the possible *changes* in cost of capital from the RO to the CfD regime. We found the following quantitative evidence:

- one analyst agreed with government proposals of a change of c.0.5% - 0.8% in the hurdle rates under the new regime;
- one analyst proposed a 1% reduction in WACC for a biomass generator due to the option to obtain support under the CfD regime.

3.4. Conclusions

Analyst reports we have reviewed find that the CfD regime reduces power price and commodity price risk, thus effectively de-risking the business model for renewable investors, resulting in a reduction in their cost of capital. We found limited evidence on the actual quantification of the effect on the cost of capital. Most analyst reports did not discuss practical or legal aspects of the CfD FiT regime.

[32] Analysts suggested that DECC's final July 2012 decision on ROC banding differed from that announced in the Draft policy decision in October 2011.

4. Review of Consultation Responses

As part of our assessment of the hurdle rates investors would require under the proposed CfD FiT regime, we have reviewed stakeholders' responses to DECC's July 2013 Consultation Document.[33]

This section summarises the views expressed by respondents to DECC's Consultation document. The views represented in this section simply report what consultation responses said, and do not necessarily reflect either NERA's or DECC's views. We do not comment on or assess the consultation responses in this section. NERA's assessment of respondents' views is set out in section 6 of this report.

4.1. High Level Assessment

We have reviewed material from 66 respondents provided to us by DECC. The majority of the respondents (45) commented on some aspect of DECC's hurdle rate assumption. Most respondents (38) stated that the hurdle rates DECC assumed to calculate draft strike prices for the CfD FiT regime were too low. Several respondents (11) questioned DECC's reliance on the Redpoint report, pointing out that it was prepared in 2010 and therefore does not take into account new aspects of the CfD FiT mechanism introduced since then. Instead, many respondents highlighted a report prepared by law-firm Brodies[34] as the most recent analysis of risks associated with the CfD regime. The Brodies report concluded that it was unclear that the CfD regime would lead to a reduction in hurdle rates relative to the RO regime, but did not quantify the different risks or impacts that the firm identified. Some respondents (7) also questioned the logic of the relative risk ordering of the different renewable technologies implied by DECC's hurdle rate adjustment assumptions.[35]

The majority of the responses were qualitative in nature, with limited quantitative evidence provided. Most respondents did not dispute DECC's assertion that the CfD FiT regime would reduce exposure to electricity prices and thus, *all else equal*, would lead to a hurdle rate reduction. However, respondents argued that the new CfD FiT regime would introduce *new* risks relative to the old RO regime, which potentially offset some of the effect of hurdle rate reduction as a result of lower exposure to market prices. One respondent estimated that hurdle rates for wind increase by 20 bps due to allocation risk, and another energy company calculated that hurdle rates for on/offshore wind would increase by 20/30 bps due to higher development risk and by 25/65 bps due to higher construction risk. Respondents did not provide details behind most of the quantified risk estimates.

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[33] DECC, 2013, Consultation on the draft Electricity Market Reform Delivery Plan. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/238867/Consultation_on_the_draft_Delivery_Plan__amended_.pdf

[34] Brodies (July 2013): Electricity Market Reform Comparing Contracts for Difference to the renewables Obligation, available at http://www.scottishrenewables.com/media/uploads/publications/130725_cfd_risk_analysis.pdf.

[35] For example, one stakeholder noted that the reduction of the hurdle rate for offshore wind was larger than for onshore wind, which they believed was counter-intuitive. Because offshore wind receives a smaller percentage of revenue from power prices than onshore wind, removing exposure to power price risk should, *all else equal*, reduce the hurdle rate for offshore wind by less than for onshore wind.

The responses made limited references to market data and/or financial theory. Instead, they provided a discussion of key risks investors would be exposed to under the new CfD regime and offered their views of the effects of these risks on hurdle rates. Respondents discussed each of the risks identified within our framework in Section 6as a Cost of Capital risk, although most respondents focused on individual risk factors that would affect their specific renewable project investments.

As discussed in Section 6, we have reviewed the categories of risk that have been identified by various stakeholders, and divided them according to whether or not we believe they are likely to affect the cost of capital. Our assessment is that only a selection of the risks identified in the consultation responses are likely to affect the cost of capital. For others types of risk, our view is that although they may well have impacts on project values, these impacts are most appropriately factored into the strike price in other ways.

As with evidence reviewed throughout the report, we apply the CAPM framework to assess the evidence on changes to the hurdle rate under the CfD FiT framework. In the section that follows, we present the consultation responses within the categorisation of risks adopted throughout this report, i.e.

- Major hurdle rates risks (i.e. beta risks, asymmetric risks, or option values); and
- Other risks (diversifiable risks and risks accounted for in strike price modelling);

We reserve our own detailed assessment of each of the risk factors addressed by the respondents in Section 6 and Appendix B respectively.

4.2. Response Review

4.2.1. Major Hurdle Rates Risks

The following sections summarise respondents' comments on what NERA has identified as the Cost of Capital risks under the CfD FiT regime.

1. Volatility of Earnings

Responses discuss market price risk in the context of volatility of revenues arising due to market/commodity price exposure. Biomass generators, however, recognize the need to address input costs volatility under the current framework.

Market Price Risk

Most respondents do not dispute that the CfD regime reduces exposure to market price risk compared to RO. For example, one respondent noted that the CfD regime is likely to reduce market risk and consequently the hurdle rates due to:

- reduced exposure to wholesale price volatility;
- reduced exposure to ROC price volatility; and
- reduced exposure to ROC market illiquidity.

Some respondents argued that the CfD regime does not provide revenue certainty in cases when electricity prices are negative. Respondents acknowledged that exposure to negative prices exists under the RO, but they argued that the CfD regime eliminates the upside revenue potential from high electricity prices, thus exposing generators to asymmetric risks.

Input Price Risk and Impact on Earnings

Some respondents argued that the CfD regime does not reduce market risk to the extent assumed by DECC due to retaining exposure to volatility in input prices. This risk was highlighted by biomass generators who face significant input price risks relative to other renewable generators. In this context, some respondents noted that revenue stability does not reduce project risk, under the CfD FiT regime, to the extent that it may introduce volatility in margins as a result of the decoupling of revenues from input costs.

2. Construction Delay Risk

Many respondents noted that the CfD regime increases risk in the event of construction delays relative to the RO, due to all projects being potentially subject to penalties for late delivery, or even loss of support. The respondents identified construction risks along two dimensions. First, any construction delay will result in eroding the length of the support period, the impact of which is exacerbated under the CfD due to the overall shorter duration of the contract. Second, in case of late or under-delivery, the generator faces the risk of strike price reductions with potential termination of CfD support in case of failure to commission by the long-stop date, or delivering less than 70 percent of the contracted capacity. One respondent estimated that hurdle rates for on/offshore wind increase by 25/65 bps due to higher construction risk under the CfD, but provides no details of how the numbers have been calculated.

Some respondents also raised the issue of lower flexibility of phasing under the CfD regime relative to RO.

3. Allocation Risk

Several respondents stated that the risk of projects not being allocated revenue support increases under the CfD regime. Respondents argue that the constraints imposed by the Levy Control Framework (LCF) increase risk that the allocation mechanism would move to a constrained allocation earlier than expected. As a result of the LCF constraints, some eligible projects would not be awarded support, resulting in stranded assets (with development costs to be recouped by the sector as a whole). Consequently, hurdle rates would need to reflect the risk of non-allocation for the sector as a whole.

Some respondents also argue that the CfD regime introduces uncertainty in relation to i) eligibility of projects for support as well as ii) the level of revenue support eventually provided (due to potential annual strike price revisions). One respondent estimated that hurdle rates for on/offshore wind projects would increase by 20/30 bps due to higher development risk, which includes risks associated with allocation and level of support.

4. Duration Risk

Respondents argued that the shorter contract period under the CfD regime exposes investors to larger revenue uncertainty towards the end of the lifetime of the project (in years 16 to 20). One respondent argued that cautious investors would factor in revenue forecasts below P50 as a protection against low prices at the end of the project, resulting in an additional risk premium. The respondent stated that its modelling results show that the benefit of the shorter contract is outweighed by the cost of the risk premium for onshore wind. For offshore wind, the same company stated that the risk premium is even higher with the possibility of asset stranding after 15 years due to opex costs exceeding wholesale revenues.[36]

5. Investor Uncertainty

Some respondents noted that DECC's proposed reductions in rates would only be achievable over a longer period of time, once investors gain confidence in the new CfD regime. An energy company referenced the Committee on Climate Change, which have recognized the potential existence of a "novelty" premium:

> *"in moving from RO support to strike prices, the Government has assumed that the different risk profile under the new regime should mean that developers will accept a lower rate of return. This reduced return may be appropriate as a reflection of reduced risk relating to future electricity prices under CfDs. However,* ***it may not be realisable immediately, before the new mechanisms are proven, and benefits may be offset by increased risks elsewhere*** *(e.g. relating to contract allocation and CfD penalties)."* (emphasis added).[37]

4.2.2. Other Risks

The following paragraphs summarise respondents' comments on what NERA has identified as the risks not related to hurdle rates, i.e. diversifiable or already accounted for in the strike price modelling.

6. Offtake Risk

Respondents argued that the CfD regime may not provide greater revenue certainty, because it reduces the ability of renewable generators to capture the market price due to the lack of supplier obligation to enter in a PPA contract. Respondents appreciate DECC's initiative to establish an offtaker of last resort/backstop PPA.

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[36] We consider the implications of reduced subsidy duration in the context of higher-than-expected operating expenditure in Appendix D.

[37] Committee on Climate Change, *EMR Delivery Plan – clarity over medium-term ambition; proposed strike prices for offshore wind*,9 September 2013, accessed at: http://www.theccc.org.uk/wp-content/uploads/2013/09/CCCtoSofS_-DelPlan_letter_9_Sept.pdf.

7. Basis Risk

Basis risk was raised as a particular issue by intermittent generators (e.g. wind), who argued that they are unable to replicate the reference index.[38] Some respondents also raised a concern about the fact that the reference price has not been established yet, which creates uncertainty around how basis risk will be managed.

8. Indexation Risk

Several respondents pointed out that the indexation mechanism of revenues based on CPI rather than RPI (as per RO) erodes the revenues received by the generator, since costs typically increase with RPI inflation.

9. Collateral Provision

Some respondents point out that under the CfD, generators will be required to provide collateral in the event that reference prices exceed strike prices, which imposes an additional cost/risk to generators.

10. Credit Risk

Respondents considered that legal risks under the CfD FiT regime are larger than under the RO regime. They also expressed a particular concern about the limited liability of the CfD counterparty.

Several respondents considered that the limited liability of the Secretary of State/delivery body as the counterparty increases credit risk under the CfD regime relative to the RO. Respondents noted that this issue has been highlighted by lending institutions.

11. Force majeure

Finally, some respondents also highlight that Force Majeure provisions under the CfD contract are not broad enough.

12. Volume Risk

Volume risk is not discussed in the Consultation responses.

13. Change in Law Risk

Respondents note that the CfD contract provided some protection against changes in law which affect a certain class of renewable generators. However, they note that the protection

[38] One energy supplier provided a stylised example showing 5 per cent under-recovery of the reference price for a wind farm and note that this percentage is likely to increase in the future.

does not cover changes in law which affected the industry as a whole, in which case any resulting costs would need to be absorbed by the generator.[39]

As set out above we do not comment on these statements here but reserve our own detailed assessment of each of the risk factors addressed in Section 6 and Appendix B respectively.

[39] Respondents used the example of a change in tax rate, which under the RO would affect the wholesale electricity price and therefore would also feed through into generators revenues. Conversely, under CfD the additional cost due to higher tax rates would need to be absorbed by the generator.

5. Review of Interview Responses

As part of our work to assess the changes in hurdle rates that investors would require under the proposed CfD FiT regime, we canvassed the views of industry participants about the costs of financing low carbon generation via a series of interviews. In total we conducted initial interviews, and followed up with further questions and clarifications, with 12 active participants in renewables development and financing, some of whom were already involved in UK renewables, as well as others who were not yet (but who were taking an active interest in current developments)[40].

5.1. Interviewee Profiles

Interviewees were selected to achieve a reasonable balance between debt and equity investors but also included participants that could provide an experienced opinion on renewable energy project finance. The organisations, roles of the individuals interviewed, the type of investor and their preferred investment stage across the project lifecycle are presented in Table 5.1 below.

Table 5.1
Overview of Interviews Conducted

Organisation	Interviewee's role	Investor type		Preferred Investment Stage		
		Equity	Debt	Developm't	Constr'n	Oper'ns
Leading European turbine manufacturer	Country director, UK	✓			✓	✓
Infrastructure fund with multiple wind and solar companies in its European portfolio	Renewables director	✓			✓	✓
Investment arm of large Asian industrial conglomerate	Head of power generation	✓				✓
Private Equity firm specialised in renewable energy infrastructure	Head of renewables	✓		✓	✓	✓
North American pension fund	Director asset management team	✓				✓
Access services provider for offshore renewable energy	CEO & former CEO of offshore wind project developer	✓		✓	✓	✓
Boutique low-carbon financial advisory / investment bank	Partner	✓	✓		✓	✓
Renewable Energy Financial Advisors	Advisor	✓	✓	✓	✓	✓
Insurance provider and institutional investor	Managing director and head of RES	✓	✓		✓	✓
Investment Bank	Head of Regulation		✓		✓	✓
Investment Bank	Structured Finance Officer for EMEA		✓		✓	✓
Investment Bank	Head of renewables structured finance		✓		✓	✓

[40] We also received written comments from the utility investor space that broadly confirmed these views. In line with DECC instructions, we focused our more detailed interviews on the financial investors space.

5.2. Topics of Discussion

Interviewees were sent a list of topics for discussion in advance (see Box 5.1), and then in most cases an interview was conducted over the phone or in person by senior NERA staff on the project team in addition to any written comments we received.

Box 5.1
Topics for Discussion

1. As a whole, do you consider that the CfD FiT regime reduces or increases risks relative to the RO?

2. Do you have a sense of the direction that the cost of capital (i.e. full project WACC) for renewable projects or specific renewable technologies will take following the implementation of the CfD? How might the cost of equity, the cost of debt and/or the gearing levels change? If so, do you have a sense of what the magnitude of those changes might be?

3. Can you comment on the level of the hurdle rates assumed by DECC under CfD FiT vis a vis your internal required hurdle rates for this type of investment? See tables page 2 and 3, note they are pre-tax, real.*

4. Do you consider that the changes in hurdle rates assumed by DECC for the different technologies correctly reflect any changes in risk under the CfD regime relative to RO? See table page 3.*

5. Can you give your opinion on whether you expect the risk to increase or decrease between RO and CfD FiT for each following risk types.*

Note: * Tables with hurdle rates from Redpoint's report and from DECC's assumptions for strike price calculations were included, along with a list of risks identified in the Brodies report.

5.3. Review of Responses

This section provides a summary of the topics that were highlighted by interviewees. The views summarised here are not necessarily those of NERA (or DECC), and we reserve our analysis for later sections. Our own analysis in section 6 builds on the mostly qualitative responses given by interviewees in order to arrive at a quantification and plausible range for the effects described by interviewees.

On the whole the interviewees raised a number of different issues that we have grouped below into the risk categories, as set out in section 2. The responses covered both risk factors that will exist under future CfD contracts and factors which represent current policy uncertainty but will be resolved by the time the scheme starts. To the extent that the perception of hurdle rates is driven by the latter we would expect hurdle rates to fall in line with the resolution of uncertainty around these items before contracts are signed. We discuss the issue of uncertainty resolving over time as part of our discussion of the "novelty premium" in section 6.6.

5.3.1. Major Hurdle Risks

1. Volatility of Earnings

Most of those we spoke to agree with the idea that if the CfD regime worked as it was intended to work in theory, the stabilisation of earnings should have a noticeable benefit in reducing costs of capital through lower equity hurdle rates. Some interviewees also suggested that higher debt capacity for project financed investments could also reduce hurdle rates.

Several interviewees noted that in practice, some key risks lay in the details of the CfD mechanism, and that the increase in risk from those could potentially outweigh the risk reduction from less volatile earnings. Moreover, it was often difficult to disentangle interviewees' estimates of the benefits of earnings stability from their estimates of the increased risks that they identified in other components of the proposed CfD regime (e.g. balancing risk, route-to-market / PPA availability, curtailment risks, allocation risk, etc.), and /or whether they viewed these other risks as uncertainties that will be clarified before commencement of the scheme. The responses we received pertaining to those other risk categories are discussed in the subsequent subsections.

When asked to quantify the impact of lower earnings volatility, those who chose to do so often made reference to the differences observed between the WACCs under national systems with fixed FITs (Germany, France) that protect RES generators from price risk and countries like the UK, Sweden, Italy, Spain, Denmark, where generators still faced some level of price risk. Estimates of the difference in project hurdle rates between fixed FIT regimes and price-exposed support systems ranged from 50-200 bps.[41] Interviewees typically cautioned that because of the residual risks associated with the proposed UK CfDs, they did not expect the full benefit of German-style fixed FITs to be realised.

Some interviewees also noted that specific features of the German market – such as the participation of low return equity investors like municipal utilities (stadtwerke) – partly explained the lower hurdle rates observed in Germany. Estimates of the gain from reduced earnings volatility ranged from 0 bps for those who viewed the proposed CfD regime as little different from the RO (although it was not clear that this response separated the effects of improved earnings stability from other perceived problems) to 150 bps, assuming that the CfD regime were made very similar to a fixed FIT.

One interviewee also reported an experience arranging financing for a wind farm outside the UK in which the difference between the IRR required when a fixed (10-year) PPA was offered and the rate required for the same project without a PPA was on the order of 100 bps. This experience would suggest that there is a premium of c.100 bps for the reduction of earnings volatility as afforded by a PPA. Another finance arranger suggested that the greater earnings stability provided by CfDs could result in declining hurdle rates over time, provided other risks were ironed out, as new investor types with appetites for lower but more stable

[41] We control for country risk where possible by focusing our review on those countries with a solid sovereign credit rating, which limits the distortion to hurdle rates introduced by country-specific factors.

returns (including international pension funds) became comfortable with the system and joined the available finance pools.

When discussing the effects of lower earnings volatility on cost of capital, we also tested the idea that greater earnings stability could increase debt capacity. One structured finance lender did not expect levels of gearing (understood here as share of debt relative to total project capital) to be significantly affected by the change – for onshore wind they were already quite high at 70-80 – even 85 percent for a good wind site – and for offshore wind, although the levels of debt were lower (closer to 70 percent), there were other risks that significantly constrained banks' willingness to lend that would not be addressed by the improved price stability. Another concurred that they did not anticipate increased willingness from banks to expand debt shares, especially for emerging technologies. However, a private equity fund manager noted that debt size might at best increase by 3-4 percent as a result of a preference for more stable revenues. Similarly, an arranger of debt suggested that there might be a slight increase in debt capacity through the higher stable revenues of the CfD (relative to the discounted PPAs in RO) for projects whose debt levels were being constrained by Debt Service Coverage Ratios ("DSCRs"), but that he agreed that offshore projects using debt finance were limited by a 70 percent ceiling, and this would not be increased in the foreseeable future. A fund manager also expressed the view that for more mature technologies like onshore wind and solar, better DSCRs might increase gearing levels from 70 to 80 percent. Nonetheless, the majority view was that there was limited scope for expanding the share of debt under CfDs – some projects might see gearing increase from 65 to 70 percent (possibly for offshore wind), but this would not be true in most cases.

We did not explicitly pursue with interviewees the theory that the WACCs of projects could be reduced through higher gearing levels.

One other issue that was raised in interviews with debt providers was that the removal of price risk allowed new groups of investors, which are not willing to take *both* price and volume risk, to invest in RES assets. The interviewees did not explicitly state whether any gains from this expansion of the pool of investors was already priced into the estimates of the reduction of volume risk or whether there might be a secondary effect on the cost of capital that stems from lower hurdle rate investors entering the sector.

2. Construction Delay Risk

Overall, respondents tended to agree that the risks associated with construction delay were higher under CfDs, on the basis that missing the long-stop date would result in termination of the CfD contract. Combined with the perception that allocation risk was also greater under the CfD (see below), this emerged as one of the top areas of concern. One finance arranger agreed that the long-stop date was a definite risk for investors, and noted that the government might have some discretion to differentiate when a project was late due to e.g. technical supply chain issues versus a business led decision to delay the project. One respondent suggested that the ability to phase projects would be more limited under CfDs – and that it would be more difficult to use revenues from one phase to finance a later phase. Another expressed uncertainty about how large projects, expected to be executed in multiple phases, would be treated under the mechanism. There was also the suggestion that construction delay risk would limit debt capacity under the CfD. Other respondents highlighted that for emerging technologies such as offshore wind, construction delay risk was greater as larger

projects were naturally subject to proportionally larger delays, something that they believed the fixed commissioning windows and long-stop date rules did not cater for. None of the respondents ventured to assign a specific basis point difference to the expected cost of capital change attributable to the perceived change in the risks associated with construction delays.

3. Allocation Risk

Allocation risk – the risk that a project would fail to secure a given level of support, or possibly any support at all – was the most frequently mentioned remaining concern among interviewees. As we set out in more detail in section 6, allocation risk applies to the pre-development phase only and recedes with contract signature. The overall impact of allocation risk on the cost of capital depends on the size of pre-development phase expenditure relative to total expenditure.

In interviews it was a concern for both developers, and for investors who did not face development risk but who were taking construction risk. It was also a concern for lenders. However, despite being one of the top risks identified, none of those we interviewed were prepared to assign a basis point value to the associated change in cost of capital. Where discussed, most accepted the idea that allocation risks probably would have applied under a hypothetical future RO regime. Notwithstanding, some interviewees argued that growing political concerns about the overall cost burden of renewables and other "green" policies, implied an increased risk of failing to secure support, and that hurdle rates that might previously have been applicable under the earlier RO were no longer appropriate – whether or not there was a difference between the expected CfD and a hypothetical future RO.

4. Duration Risk

The shorter duration of support under CfDs was highlighted by some interviewees as a source of risk relative to the RO, although the reasons behind their thinking were far from aligned. An equipment manufacturer summarised his concern by saying that the more rigid (CfD) system with a shorter period of support simply meant more risk.

One investor mentioned that they were concerned about the reduction in duration of support, which ought to mean a higher subsidy (the implication being that a higher subsidy was not being provided by DECC). A debt provider noted that shorter duration of support meant shorter debt terms, and therefore possibly lower debt capacity. A fund manager mentioned that more risk-averse investors like pension funds would look at the instrument more broadly and considered that the change of support from 20 to 15 years would not really impact the cost of capital.

5. Investor Uncertainty

During our interviews, a number of interviewees expressed their belief that the potential benefits of the CfD regime in reducing hurdle rates would only materialise after a period of "bedding down" or after a "demonstration effect". Subsequent follow-up discussions with interviewees (requested by DECC) suggested that a majority of them believed that there was a "novelty premium" or a policy "uncertainty premium", although the rationale for its existence varied. Some observed that information about allocation or basis risks would only be known once the system was in full operation; others mentioned uncertainties around

securing long-term PPAs or the levels of discounting that would be requested; still others alluded to the fact that the conjunction of the aggressive strike price degression schedule and the planning and consenting timelines would mean only few projects would have access to the higher strike prices that were available in early years. One mentioned concerns about the viability of the reference price.

There was agreement that such a premium would be added onto hurdle rates only by equity investors, as lenders would seek a standard margin on risk free rates and simply make a "go / no-go" decision. Some interviewees felt that this premium would likely be required chiefly by investors entering at the earlier (development, construction) rather than the later phases (post-commissioning) of a project. As such, estimates of the longevity of the premium in time ranged from 3-5 years or more for the less mature technologies, representing the time for data about the operation of the policy and experience from the CfD mechanism to be gathered and digested by investors.

There were some interviewees who did not accept the existence of a novelty premium. One argued that capital would be priced when risks were known and measured and that the notion of such a premium was purely theoretical. This response may have implied that this participant would not invest until all risks were measurable, ascribing a value to waiting to learn – thus perhaps tacitly recognising the existence of the premium. Another interviewee suggested that once the legislation and policy rules were set down, risks would be priced appropriately and no special "novelty premium" would apply.

We discuss the issue of the novelty premium in more detail in section 6.6 reviewing the theoretical foundations and empirical evidence on the novelty premium.

5.3.2. Other Risks

6. Offtake Risk

The challenges of securing a "route to market" through PPAs was often mentioned as a new risk under the CfDs, although some mentioned that the offtaker of last resort proposal could remedy this concern. Other related risks that interviewees mentioned included levels of PPA discounting, balancing risks, and the risk of curtailment.

7. Basis Risk

Several interviewees underlined basis risk as a new risk but did not provide significant detail about their thinking on the topic. Most interviewees simply referred to the concern that generators might not be able to realise the reference price when they actually went to market with their output. One of the interviewees mentioned concerns that underlying market liquidity could be affected by wider market changes, resulting in reference prices that were not representative. This would affect not only basis risk, but was identified as one of the broader uncertainties (see Investor Uncertainty, above).

8. Indexation Risk

Not mentioned in interviews.

9. Collateral Provision

Not mentioned in interviews.

10. Credit Risk

Interviewees did not mention credit risk of the counterparty as a major concern, and when it was mentioned they either stated that the risk had either been reduced under the CfD or that the recent changes by DECC appeared to address key concerns.

11. Force majeure

Not mentioned in interviews.

12. Volume Risk

Not mentioned in interviews inasmuch as it relates to long-term unpredictability of volumes. Short-term unpredictability of volumes was covered under the heading of basis risk.

13. Change in Law Risk

Only one respondent mentioned change of law (after going through the entire list of risks originally sent in our covering note). The interviewee noted that CfDs provided the benefit of a firm contract that was not subject to policy changes – but that would, on the other hand, now be subject to idiosyncratic risks that might not affect other market participants (for example, a change in tax regime that previously would have been passed through into prices now might not affect the generator in the same way as the rest of the market.

As set out above we do not comment on these statements here but reserve our own detailed assessment of each of the risk factors addressed in Section 6 and Appendix B respectively.

5.4. Conclusions

Interviewees agreed that lower earnings volatility under the CfD should, all other things being equal, reduce cost of capital relative to the RO. The ranges quoted of hurdle rate reductions that interviewees observed in comparable markets with fixed price support mechanisms could suggest that this lower risk could reduce hurdle rates by up to 100 basis points – and possibly more if other features of the CfD were changed to make it more like a fixed FIT.

However, most respondents alluded to several other risks that could potentially offset the above gains, with construction risk, allocation risk, and "route-to-market" risks chief among them. Respondents refrained from ascribing individual basis point values to the change in hurdle rates stemming from these increased risks, except to note that collectively they significantly reduced the potential benefits of CfDs.

The notion of a novelty premium also emerged as a significant theme among respondents, possibly as a catch-all wrapper for the set of new perceived risks under the new CfD system that they were unable or unwilling to individually value. Expectations about the duration of the premium varied, with some believing the uncertainty would be resolved as questions

about the mechanism of allocation became clearer, and others suggesting that only after three or more years of actual project data were available would the premium have subsided. In section 6.6 we discuss this issue in more detail including the question of whether all types of uncertainty currently included in hurdle rate assumptions will remain relevant for the point in time when the CfD scheme starts.

Part B: Assessment of Impacts on Hurdle Rates

6. Assessment of Impacts on Hurdle Rates

6.1. Introduction

This section sets out NERA's assessment of the change in hurdle rates for renewable investments as a consequence of moving from the RO to the CfD regime, based on our review of the evidence (i.e. consultation responses, analyst reports and interviews) detailed in previous sections. In addition, where quantitative evidence presented was insufficient, we have presented our own analysis to quantify these risks (summarised here and detailed in the appendices).

In this report we have focused on the *change* in risk from the counterfactual RO scheme to the proposed CfD scheme. We have therefore focussed on risks where exposure has clearly changed between the two types of schemes, and where there is a clear rationale for the change having an impact on the hurdle rate. In this section, we quantify a range for the hurdle rate impact arising from the change in those risks assessed as "major hurdle rate risks" as per section 2, namely:

- Volatility of Earnings (Power Price Risk);[42]
- Allocation Risk;[43]
- Duration Risk;[44]
- Construction Delay Risk;[45]
- Novelty Premium.[46]

We discuss each of these risks in turn before summarising our view on the range of the overall impact from the regime change, for onshore wind, offshore wind and biomass conversion. Section 2.4 provides more detail on why we do not consider that there is a significant hurdle rate impact from the risks classified as "other risks" in section 2, which are not discussed in more detail in this section. We also refer to Appendix E where we discuss the market testing that we have undertaken and the limitations thereof.

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[42] Our analysis is presented in section 6.2 and Appendix C.

[43] We find that although there is likely to be no immediate risk that the LCF will be breached, the LCF may become constrained as demand on the LCF budget is affected by wholesale prices under CfDs. This risk affects projects currently in early stages of development. This risk is more likely to be material if wholesale prices remain low relative to the strike price, thus posing a cyclical allocation risk not present under the RO. See section 6.3.

[44] See section 6.4.

[45] We have constructed a model, which shows the effect of delays in construction (section 6.5 and D.3). Our conclusion is that compared to a counterfactual RO in the future, construction risk is slightly lower under CfDs for projects just missing commissioning window but higher for projects missing the long stop date. The conclusion is that the balance of risk depends on the likelihood of missing the long stop date.

[46] We review the evidence on the impact of investor uncertainty / novelty of the scheme on required hurdle rates over time in section 6.6. We find that the existence of a novelty premium cannot be ruled out.

6.2. Volatility of Earnings (Power Price Risk)

One of the central changes in risk exposure with regard to the shift from an RO regime to a CfD FiT scheme is the reduction in exposure to power price risk. As a fixed-price support scheme, the CfD FiT scheme reduces exposure to wholesale market risk, thereby removing a significant part of the volatility of the revenues of renewable energy projects.

All evidence we have reviewed in this work acknowledges this reduction in revenue risk. However, in assessing their required rate of return, investors are concerned about the expected volatility in *earnings*, or *net* cashflows that their investment generates. We therefore assess separately the benefits of the CfD scheme for the following types of generators:

- *Fixed cost* generators*:* Generators with very high up-front cost structures and no fuel costs, such as wind farms, which do not face fuel price risk. Hence reducing revenue volatility tends to result unambiguously in a stabilisation of earnings.[47]
- *Variable cost* generators: Generators with a greater share of variable costs, such as biomass generators, are exposed to both wholesale price risk (affecting revenue risk) and fuel price risk (which determines costs). Whilst the CfD instrument stabilises the revenue stream of these generators, they still remain exposed to fuel price risk.[48] To the extent that fuel prices are positively correlated with the price of electricity (e.g. through a correlation with other fuel prices), variable cost generators will have already had some protection of margins, as costs and revenues move in line, while now in principle the correlation of earnings with the market price could become negative.

Concluding from the above we find that removing market price exposure, ceteris paribus, will lower the correlation of earnings with the business cycle for both types of generators, thereby reducing the riskiness of a renewables project. However, little direct market evidence exists that quantifies this impact.

Under the CAPM framework (see section 2) one would estimate company betas for renewables companies operating under different regimes and compare them to derive an estimate of the difference in the cost of capital of the two types of companies. However, this method as well as other financial market models (e.g. discounted cash flow models) would require data on stock prices on "pure play" renewables investment companies that had undergone similar regime changes (and where it was also possible to identify and remove the influence of other time-dependent changes). Unfortunately we are not aware of relevant comparison companies.

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[47] Wind farms do face operating expenses, which may be uncertain – particularly for offshore wind – so there can still be is still some independence of earnings from revenues.

[48] Our understanding is that fuel price risk can be managed, to the extent that biomass generators have the ability to enter into long-term contracts, and lock in real "bark spreads". For example, analyst reports for Drax suggest that hedging is possible although some analysts have questioned the extent to which Drax would be able to fully hedge its fuel costs by procuring sufficient biomass in the event of full conversion of all units. There is reason to believe that fuel price risk is a "negative beta" risk, however – i.e. it causes earnings to vary inversely with the market – so could be used by investors looking to diversify their portfolios.

In the absence of directly observable market evidence on renewables companies that have gone through a regime change from a system in which they were exposed to power price risks to one in which they were not, we have sought other comparators that will provide insight into similar effects drawn from other contexts. The use of comparator analysis to estimate costs of capital is common practice when regulating companies that are not listed.[49]

In the absence of direct financial market data we have compiled a diverse set of information in order to approximate the hurdle rate impact of the proposed regime change, beginning with the material presented in the preceding sections, and including our own analysis from a variety of additional sources of data. Drawing from the existing evidence and in order to quantify this impact, we consider four main strands of evidence in our quantitative assessment:

1. Analyst reports, consultation responses and interviews;
2. Estimate of WACCs from market share price data (drawing on conventional power plants);
3. Comparison of utility WACCs under different regulatory regimes; and
4. Historic volatility analysis.

We also performed international benchmarking exercise as a cross check of the analysis based on the evidence set out above (see Appendix F).

We describe our interpretation of this evidence, our related analysis, and the conclusions that we draw based on these, in the next section.

6.2.1. Evidence from Analyst Reports, Consultation Responses and Interviews

As noted above, most analyst reports did not offer quantitative evidence on the change in the cost of capital for renewable investments under the new regulatory framework. However, where they did, they estimated a *change* in the hurdle rates in line with or slightly larger than the government's proposals resulting in a range for the change from c.0.5 percentage points to 1.0 percentage points.[50]

It is unclear what methodology these analysts used to quantify the impact on the WACC under the new regulatory framework. However, we note that these estimates tend to comment on the *total change* in the WACC under the new regime. As such, these estimates may be viewed as lower bounds of the price risk effect as they may implicitly incorporate other types of risks, which may be offsetting the market price risk.

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[49] For example, in its Final Proposals for the allowed cost of capital for Heathrow and Gatwick (October 2013), the Civil Aviation Authority combined comparator beta estimates of other listed companies with a relative risk assessment comparing the two companies to the comparators. (See CAA, "Estimating the cost of capital: a technical appendix to the CAA's Final Proposal for economic regulation of Heathrow and Gatwick after April 2014", available at: http://www.caa.co.uk/docs/33/CAP1115.pdf)

[50] These estimates appear to be on a pre-tax basis based on how they are used in the reports although it is not stated explicitly whether they are pre- or post-tax.

As set out in section 4, consultation responses accept that in principle lower power price risk reduces earnings risk, but do not provide evidence to quantify the impact, instead focussing more on reasons for why the reduction may not be as significant as DECC assumes. Given the lack of quantitative evidence provided by respondents, the responses do not provide significant guidance on the magnitude of risk reduction.

As noted above, our interviewees provided a range of estimates for the impact of reduced revenue volatility on hurdle rates, drawing primarily on international comparisons but also relying on comparisons between the IRRs required from fixed PPA and merchant-style terms applied to the same development. The estimates of the reduction in the hurdle rate ranged from c.50-200 bps, with some uncertainty about how other perceived risks (both those we have assessed to be major hurdle rate risks and others that we believe are meant to be reflected in the strike price) were reflected in the estimated impact of price risk. We cross-check this estimated magnitude with estimates from our international benchmarking exercise (see Appendix F).

6.2.2. Difference in WACC between Merchant and Contracted Power Plants

In order to further quantify the volatility of earnings risk we considered another indicator of the difference in market price exposure under the RO and CfD FiT regimes, i.e. the difference in risk borne by:

- merchant generators, using conventional power sources and who sell their output on competitive wholesale markets, and
- contracted generators, using conventional power sources and who sell their output under long-term power purchase agreements (PPAs) that fix volumes and prices.

We use a selection of listed merchant and contracted generators as comparators for the current analysis. We apply the CAPM framework to calculate a real, post-tax WACC for each company. To do so we calculate an individual asset beta,[51] gearing level and cost of debt estimate based on information from annual accounts and Bloomberg. In order to avoid any potentially distortionary effects from differences in country risk, we use the same estimates for general market parameters, i.e. the risk-free rate and equity risk premium (2% real risk-free rate and 5% ERP, in line with the CC Bristol Decision[52]). As all companies we look at are located in highly rated (AAA/AA+) countries, any country-specific effects can be expected to be small.

We then compare the WACCs for these different types of generators to provide an indication of the impact on WACC of the revenue stabilisation provided by the shift to CfDs.

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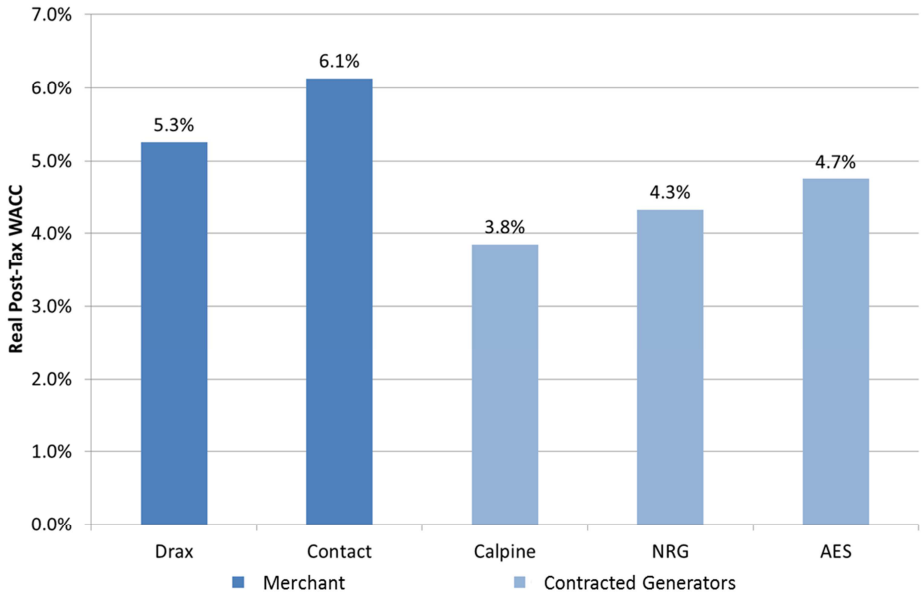
[51] The sample of merchant generators includes Drax (UK) and Contact Energy (NZ). The sample of contract generators includes Calpine, NRG and AES, all of which are listed in the US. Note we use the relevant country market indices in calculating the beta estimates.

[52] See latest UK Competition Commission Decision for a UK regulated utility: UK Competition Commission (2010): Bristol Water plc - A reference under section 12(3)(a) of the Water Industry Act 1991, Appendix N.

Figure 6.1 shows that the differences in the real, *post-tax* WACC between merchant and contract generators, ranges from 60bps (the difference between Drax and AES) to 230 bps (the difference between Contact and Calpine).

Figure 6.1
Real, post-tax WACC for Selected Generators



Source: NERA Analysis of Bloomberg and company accounts data. Long-run inflation assumptions from Consensus Forecasts, 2012.

In the figure above we compare post-tax values in order to avoid any distortionary effects arising from different tax rates across countries. Converting these differences to real pre-tax WACCs using the current UK corporate tax rate of 23% we obtain a range for the differences from 78 basis points to 299 basis points.

The above provides a range for the potential impact of removing power price risk for a generator. While a generator using a PPA will only differ from an otherwise identical merchant plant in terms of its exposure to power price risk, there are a number of caveats around whether the companies we use above are "otherwise identical." As suggested above, PPA contracts typically specify a minimum offtake, which reduces volume risk as well as price risk for the generator to some extent. This reduction in volume risk is likely to account for some of the reduction in the real WACC suggested by the analysis presented in Figure 7.1.

We therefore consider that the effect on the WACC from reduced market exposure under the CfD FiT regime is likely to be smaller than the range observed above. On the other hand, Drax tends to hedge a significant proportion of its output at least two years in advance[53]

[53] See e.g. Drax annual report 2011, which shows c.22TWh (~85% of previous year sales) sold under forward contract for the next year and c.9TWh (~35% of previous year sales) two years ahead. (p.16 & 30)

suggesting that the difference between Drax and the contracted plants is likely to understate the true difference between a fully contracted and a fully merchant plant. Hence, it is likely that the true impact of the change to CfD is somewhere between the two extreme points of the range presented above.

Moreover, it is important to stress that the above analysis is based on a small sample, and is subject to a range of assumptions and uncertainties (for example, when PPAs expire they must be renegotiated, the effect of which may be captured to different degrees within the estimated WACCs). This analysis therefore complements, and is complemented by, the other analysis presented in this section rather than providing a fully stand-alone explanation of the impact of power price risk on the WACC.

6.2.3. Evidence from Review of Betas for UK Utility Sector

In addition to the evidence on PPA vs. merchant generators, which provides a relatively immediate estimate of the impact of price risk on the hurdle rate, the regulated UK utilities sector provides a second set of market evidence that allows us to quantify the influence of reduced revenue volatility on the cost of capital.

Two issues need to be borne in mind, namely that i) in the UK utilities sector it is generally volume risk rather than price risk that is driving earnings volatility and which is removed in the case studies we review and ii) that there are differences in the exposure to other risks that affect the hurdle rate. Bearing these two issues in mind, there still appears to be a role for this analysis as the removal of volume risk in the UK utilities sector provides an example of a situation where i) the main revenue risk faced by the sector is significantly reduced and ii) by looking only at the difference in estimated WACC we ignore the issue of having to insulate the impact of "other factors" on the WACC as these are held constant. One issue that is not easily resolved is a question of whether the reduction in revenue risk observed in these cases is equally large / small as in the case of the switch to CfD. As such, a degree of uncertainty around the comparability remains.

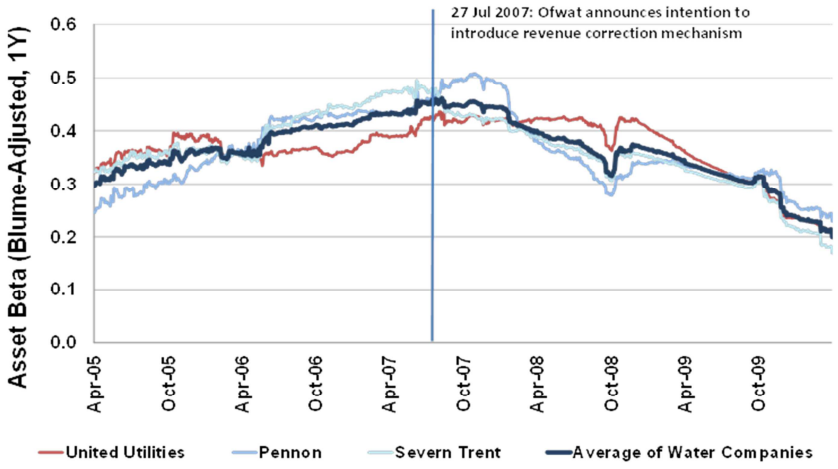
UK Water Sector

Until the price review in 2009, the UK water sector was regulated according to a price cap regime which set price limits over the regulatory period based on expected volumes of sales. This regime exposed water utilities to volume risk, in the event that actual sales differed from those anticipated when the regulatory decision was taken. On 27 July 2007, Ofwat, the Water industry regulator, announced its intention to introduce a "revenue correction mechanism", effectively removing volumes risk, and thereby reducing the volatility of expected earnings.

The impact from the announcement can be seen in Figure 6.2 which shows rolling, short-term (one year) asset betas for the three listed major UK water utilities, as well as the water industry average. Asset betas fell significantly after Ofwat's announcement (from an average of around 0.45 to only 0.2 by the start of 2010), reflecting, in part, the market's expected reduction in the volatility of earnings under the new regulatory framework. We note, however, that it is difficult to disentangle the effect of the change in the regulatory framework from the effect of the financial crisis. (Beta estimates for "defensive stocks" like utilities tend to fall during periods of market turmoil anyway, as they become less risky relative to a more

volatile market, even if absolute risk remains unchanged). In this case, further stabilisation of revenues by eliminating *volume* risk coincided with a reduction in beta of as much as 0.25.

Figure 6.2
Rolling Asset Beta for Selected UK Water Companies pre-and post- Ofwat Announcement

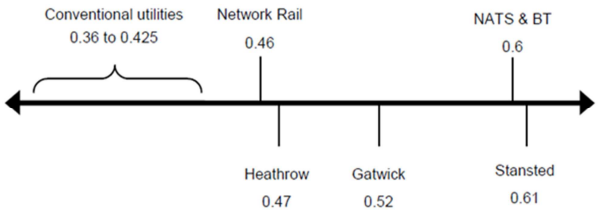


Source: NERA analysis of Bloomberg data.

Other UK regulated utilities

Similar relationships between the stability of revenues and the level of beta can be observed across regulatory regimes. Typically, we see higher betas for companies regulated under a price cap compared to companies regulated under a revenue cap regime. For example, betas for Heathrow (0.47, later raised to 0.50)[54] and Gatwick (0.52, later raised to 0.56), which are regulated under a price cap regime, are higher than those in the UK Water sector (0.32 to 0.43 according to the CC's Bristol Decision but reported as 0.36 to 0.425 in the CAA's Initial Proposals), which is now regulated under a revenue cap.

Figure 6.3
Relative Risk Exposure according to CAA



Source: NERA analysis of CAA Initial Proposals

[54] CAA (2013): Estimating the cost of capital: a technical appendix to the CAA's Final Proposal for economic regulation of Heathrow and Gatwick after April 2014, p.81.

Summary

The impact on a typical utility WACC of these differences in beta can be significant. The estimated post tax real WACC falls by c.50bps for each 0.1 reduction in the asset beta while the pre-tax WACC falls by c. 65 basis points.

Table 6.1
Impact of reduced Asset Beta on Pre-Tax WACC

	Asset Beta		
	0.4	**0.3**	**0.2**
Pre-Tax WACC	7.12%	6.47%	5.82%
Absolute Reduction (relative to 0.4)		-65bps	-130bps
Relative Reduction		-9%	-18%

Source: NERA calculations. To calculate a notional pre-tax WACC –we use 2% RfR and 5% ERP (in line with the CC Decision on Bristol Water), and vary the beta. For CoD, stated as "real, pre-tax" we use an illustrative value of 5% at 80% gearing. [55] *While the overall magnitude of the WACCs would change with different assumptions the general conclusion would not.*

In this sub-section and the previous one, we have presented different examples of how betas and discount rates vary across different contexts that are in certain respects similar to that of the switch from ROC to CfD contracts – i.e. *the removal of a key driver of systematic risk.*

For this purpose we have collected a series of different pieces of evidence including:

- **Comparisons between betas across regulated sectors subject to different regulatory regimes**: We compare price cap and revenue cap regimes, and note that the price cap regimes tend to have asset betas of the order of 0.5 to 0.6 while the revenue cap regimes have betas between 0.3 and 0.4.
- **Changes to the cost of capital within the water sector in response to removal of volume risk:** We find that the shift to revenue cap regime *within* the water sector was associated with a reduction in beta on the order of 0.25 (although some of this reduction is likely to have been due to the credit crisis).

All of the cases considered suggest a relatively narrow range of beta reductions associated with completely eliminating either volume or price risk, of around 0.2 and 0.3 (or possibly more for their combination). Assuming an average reduction of 0.2-0.3 and an equity risk premium of 5%, suggests a range of plausible hurdle rate reductions of approximately 100-150 bps (see Table 6.1), i.e. more towards the bottom end of the range estimated in the previous section. This difference may be explained by the fact that revenue volatility depends on both volume risk and price risk, and the utility examples considered in this section tend to isolate the *volume* component of the revenue risk – whereas the shift from RO to CfD eliminates (the electricity market portion of) the *price* risk.

[55] WACC estimates in Table 6.1 are calculated according to the following formula. Pre-tax WACC = (1-g)*(rfr+ERP*Asset Beta/(1-g))/(1-tax)+g*CoD where g is the level of gearing with the other elements as described in the caption to the above table.

Nonetheless we believe that there are more general lessons that can be taken from these comparisons. Although none of these case studies on its own can be used to evaluate directly the impact of a reduction in price risk for renewable generators, the circumstances of each industry, and the nature of the revenue risks that are affected, differ. However, they all represent situations in which a key systematic risk component is removed, which is also the case when switching from ROCs to CfDs. Collectively, these case studies can be used to inform the overall range of plausible *changes* to beta that might be expected after the removal of a key source of systematic risk. This notion is set out in more detail below. In the second box below we also discuss why we do not consider the case of the offshore transmission operators to be informative with regard to the change in hurdle rate.

Box 6.1
Significance of Utility WACC *Levels*

We believe that the *change* in the beta coefficient associated with reducing revenue volatility is a good indicator of the change we might see in the renewables sectors as a result of a similar reduction in earnings risk due to reduced revenue risk. However, we caution that the level of *WACC* for established regulated network utilities is not one that can be translated directly to renewables – under either the RO or CfDs. The risk profile of regulated utilities differs significantly from those of renewable investment projects. For example, established, mature regulated networks with revenue caps, such as UK gas distribution networks, National Grid or the water utilities, do not face volume risks. They also do not bear the same level of construction risk for their investments as we expect for the offshore wind sector, and possibly for other renewables sectors.

Moreover, (we return to this point below) regulated utility assets typically have a longer regulatory regime history, which may have been changing over time but is generally subject to well-understood processes and rules for change. This differs from the current situation with the renewables sector, which is in a state of flux not only as a result of the shift to CfDs, but also as a consequence of wider developments, including the increasing importance of the Levy Control Framework and the wider changes associated with EMR. These will all affect the level of the WACC, although they will not necessarily affect the *change* in the WACC between the RO regime and a CfD regime.

Some additional protection for regulated network is provided by the absence of substitutes for energy networks while there is a degree of competition amongst renewable generators and potential competition with other forms of CO2 reduction and / or softer targets. Consequently, established regulated utility networks typically face lower political or allocation risks and lower hurdle rates overall. Nonetheless, changes to their risk exposure will also change their hurdle rates. Thus although mature regulated utility networks do not provide suitable evidence for the level of returns required by investors, the changes in WACC that we estimate and observe do strike us as relevant to the RO and CfD regime.

Box 6.2
The Suitability of the OFTO Regime as a Comparator

We also considered the suitability of the cost of capital allowed under the Offshore Transmission Owners (OFTO) arrangement. Ofgem selects the OFTO through competitive tenders. Participants in tenders bid a 20-year revenue stream. The revenue stream bid by the winning party will be incorporated into the OFTO's transmission licence as an allowed revenue stream over the 20-year period indexed to RPI. Unlike onshore regulated networks, OFTOs are not subject to an automatic periodic review of allowed revenues. We find the evidence from the OFTO regime to date is not a suitable risk comparator to the CfD scheme for the reasons set out below.

The competitive auctioning regime and guaranteed revenues limit regulatory and revenue risk under the OFTO regime relative to the CfD FiT scheme. In the event that the offshore wind farm that an OFTO connects ceases to operate, the OFTO will continue receiving the revenues from the onshore TSO, i.e. there is no volume and stranding risk. Also, the revenue stream will not be contingent on the output or availability of the offshore wind farm(s) connected to the transmission assets. However, it will be contingent on the availability of the OFTO's infrastructure through a scheme designed to incentivise OFTOs to maximise the availability of their assets[56], exposing the OFTO to operating risk.

A major difference between the CfD regime and the OFTO regime is the lack of construction risk associated with the OFTO tenders. Participants in the initial tenders (e.g. "Round 1" and "Round 2" developments) are bidding for the rights to "own and operate" the OFTO networks but do not bear any constructions risk at the point of sale. A number of interview respondents noted that construction risk carried a 2-3 per cent premium.

OFTO transactions to date have been for assets that have already been built by the offshore generators. As a consequence, the overall risk for new renewable generation projects and OFTO "own and operate" projects are not comparable. The existence of construction risk as a continuing theme of many interviews helps to explain why the OFTO regime not a suitable comparator.

6.2.4. Analysis of Historical Revenue Volatility for Wind Generators

In order to further quantify the volatility of earnings risk, a final piece of evidence considers directly two of the key renewable energy technologies in the UK (onshore and offshore wind) that will be subject to the change in renewable support regime. To understand better the extent to which more stable revenues from electricity prices would affect wind generation, we have developed a set of stylised modelling simulations that allows us to derive a quantitative

[56] Ofgem has indicated that performance availability targets will be set for each OFTO on a case-by-case basis, informed by the design of the transmission assets, recommended maintenance programmes and the requirements of wind farm developers connecting to the transmission assets.

indication of the impact of stable revenues on both existing assets and new assets. Details of our analysis are presented in Appendix C.

We find that the reduction in total volatility for offshore wind is only about half as large as the reduction for onshore wind. This finding is based on simulations of revenues, focusing on actual wind assets and historical variability of wind yield and prices. Using historical information on prices and volumes, we analyse what revenue volatility would have been for the period 2005-2013 if the subsidy regime had been a CfD regime instead of a ROC regime. (We also present analysis of new capacity and consider how future price volatility might affect the comparison of CfDs and the RO.)

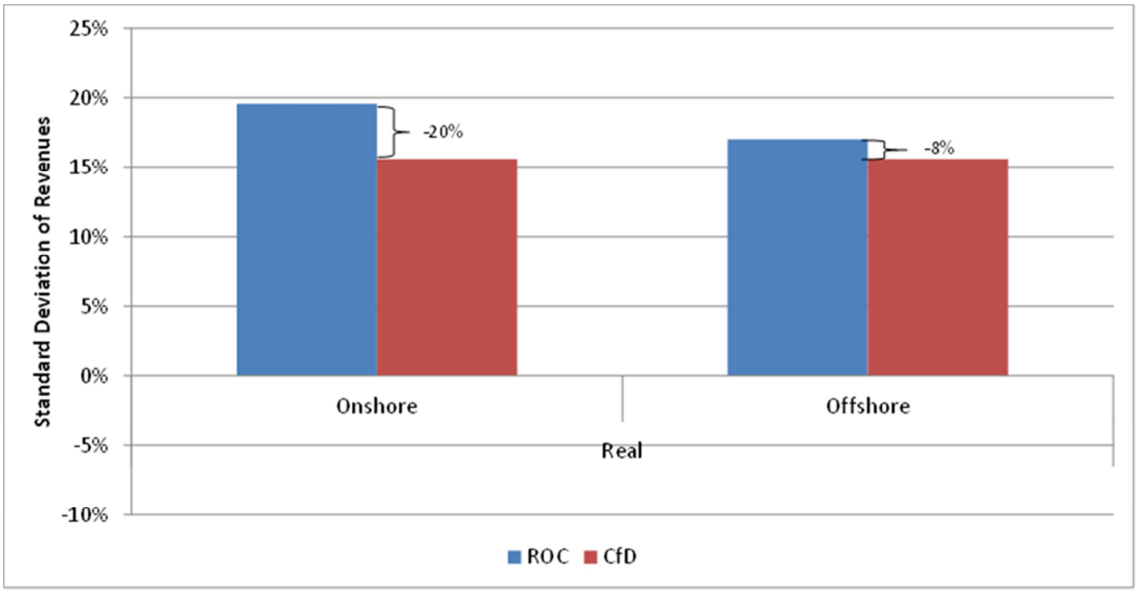
Figure 6.4 below shows the estimated reduction of revenue risk for *existing* assets associated with the CfD regime, compared to the RO. The bars shows that the revenue of a hypothetical portfolio of five operational onshore wind farms in the UK would have had a standard deviation of 20 percent under the RO, taking into account the actual variation in electricity prices and ROC prices over the period 2005-2013[57] and historical wind yields (volume). The red bar shows that under a stylised CfD regime, the revenue volatility would have been lower, about 15 percent (assuming a constant strike price). In other words, under a CfD scheme the standard deviation of revenues for onshore wind would have been around 20 percent less than the standard deviation under the RO. The chart shows the corresponding reduction in standard deviation would have been significantly smaller for offshore wind, at around 8 percent.

These results should be interpreted with caution:

- The volatility represented by the standard deviations shown below reflect the *total* risk affecting revenue, some of which (for example, volume risk) may not contribute to the equity portion of the WACC, because it is diversifiable. It is not straightforward to estimate how systematic each of the different risks is; and
- The estimates are based on a limited set of observations, and are therefore sensitive to the various data points, including inflation assumptions.

[57] Calculated as the standard deviation of the natural logarithm of annual cashflows (real 2013 GBP) for the period 2005-2013. For example, a 20 per cent standard deviation means cashflows over the period varied by about +/-40 per cent around the average. For this analysis, we use volatility as the key risk indicator, measured as the annualised standard deviation. The standard deviation is a risk measure which is easy to grasp intuitively and to relate to the underlying variable (e.g. it is expressed in the same units as the underlying variable whose dispersion we are measuring).

Figure 6.4
Relative Reductions in Volatility of CfD vs. ROC



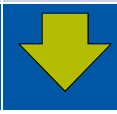
This analysis refers to the overall volatility of revenues associated with its main drivers: i.e. volume and price. It is important to note that although volume risk affects revenue volatility (and may affect the debt capacity of the asset), it is to some extent diversifiable, which means it is less important for the overall determination of the hurdle rate. Thus, although the CfD regime appears to eliminate a relatively small proportion of the overall revenue volatility, we cannot conclude from this analysis alone how this will affect the beta or an associated overall project WACC, without quantifying the extent to which other risks affecting the asset are correlated with the beta.

Due to lack of data we have not analysed other sources of renewables such as biomass. For these asset classes, the reduction of market price risk may be less important than for onshore wind if strike prices are higher (as for offshore wind). In addition, because a larger proportion of costs are variable, they are likely to have a greater influence on the asset beta.

6.2.5. Summary: Effect on WACC of Removing Power Price Risk

Figure 6.5 summarises our qualitative assessment of the impacts of the change from RO to CfD on the power price risk facing renewable generators.

Figure 6.5
Impact of Price Risk on WACC

Item	Comment	Impact
Exposure to Short Term (Annual) Volatility	• Power prices are one of several drivers of short term revenue volatility. Volatility coming from price is mitigated almost entirely	
Exposure to Long Term Volatility	• Power prices are a key long term risk driver. The exposure to this macro-economic risk mitigated almost entirely	
Exposure to Negative Prices	• Subsidy is capped at strike price such that the captured subsidy is reduced. However, the effect on present value is very limited.	
Net Impact	• Significant reduction of power price exposure	

One of the central changes in risk exposure with regard to the shift from an RO regime to a CfD FiT scheme is the reduction in exposure to power price risk. All evidence we have reviewed in this work acknowledges this reduction in revenue risk. In providing a quantification of the impact of reduced power price risk on the WACC it is important to assess the degree of power price risk exposure under the current scheme. For example, offshore wind farms currently obtain a larger share of total revenues from ROCs than onshore wind farms. Therefore, we would expect that at this stage removing power price risk has a smaller effect for offshore wind, than for other technologies such as onshore wind, where power price risk affects a larger share of total revenues. The case for other technologies such as biomass is less clear-cut, and will depend on their own balance of subsidy to power revenues, as well as the interaction between fuel price risk and other "beta" risks. These theoretical considerations are supported by our historic volatility analysis for commissioned offshore wind assets (see section 6.2.4).

The above suggests that the reduction in hurdle rate for offshore wind is likely to be the lowest across the technologies considered, and sitting at the lower end of the ranges set in the preceding discussion. The reduction for onshore wind is greatest, with biomass sitting in the middle of the range.

Table 6.2 summarises the estimates that we have drawn from the evidence above of the impacts on hurdle rates of reduced power price risk.

Table 6.2
Hurdle Rate Impact of Reduced Power Price Risk (bp, pre-tax)

Evidence	Offshore Wind	Onshore Wind	Biomass
Analyst Reports and Consultation			-50 to -100*
Industry Interviews	-50 to -200*		
WACC from Share Prices	-75 to -300		
Utility and other Beta Comparison	-100 to -150		
Historical Volatility Analysis	lowest	highest	moderate
NERA "most likely" Range	**-50 to -100**	**-125 to -175**	**-75 to -125**

Source: NERA analysis of various sources. We aim to report pre-tax numbers where possible. In cases marked with an asterisk the original source is not clear on whether pre-tax or post-tax numbers are used.

Based on a number of different sources, Table 6.2 provides a relatively wide but broadly consistent range for the reduction in hurdle rates. In deriving a "most likely" range for onshore wind, offshore wind and biomass conversion, we take into account the aforementioned points on "significance of subsidy as part of total revenues" as well as our historical volatility analysis. The historical volatility analysis does not provide absolute estimates of the change in hurdle rate but provides an indication of the relative change for offshore wind as compared to the relative change for onshore wind. As noted in the previous section, the impact of power price risk on the volatility of onshore wind revenues appears to be significantly larger than the impact on offshore revenues.

In arriving at a final estimate of the reduction in hurdle rates for each technology, we have taken account of the significance of price risk, relative to other risk factors affecting the cost of capital, including construction risk (which will also differ across technologies) and how these may have changed as well (see next sections).

Our overall conclusion is that the switch from ROC to CfD changes the nature of risks to generators markedly. Importantly, the risk from one of the key drivers of systematic risk, the power price risk, is reduced significantly. There are, however, several risks affecting the hurdle rate of a renewable generator apart from power price risk (see next sections). Moreover, even a removal of all revenue risk would not completely eliminate beta or the correlation with market risk – for example, due to OPEX risk, fuel price risk for biomass generators, etc. Appendix E provides a discussion of the possibility of market testing this reduction.

6.3. Allocation Risk

6.3.1. NERA Assessment of Allocation Risk

Increased allocation risk was one of the most commonly cited concerns mentioned in the consultation responses and identified during industry interviews. This section presents NERA's overall assessment of how the switch from a hypothetical future RO regime to CfDs affects exposure to allocation risk. Figure 6.6 summarises our assessment of these risks, which we discuss in more detail below and in Appendix D.

Investors have said their concerns over allocation risks are increasing for a variety of reasons, including:

- the increasing share of renewable electricity, and
- growing concerns about impacts on consumer bills,

leading to a perception of an increased likelihood that the LCF will be constrained in future years. We note, however, that

- The LCF is not new and the risk of breach of LCF limits would also have existed under the RO; and
- These risks should be viewed in the context of wider government policy and legal obligations on renewables, including the overall renewable energy target. If in the future the costs of achieving the renewable energy target look likely to exceed the LCF budget, then the legal obligation to meet the 2020 renewable energy target implies that the LCF would have to be amended and the overall budget increased. We are not in a position to judge which of the constraints (the LCF or the renewables target) will prove stronger.

However, it is important to recall that our remit from DECC is to compare the expected future CfD to the corresponding future RO. This RO would itself be subject to the LCF, and therefore developers seeking future RO support would face increased allocation risk for the reasons outlined above. Consequently, although we agree that hurdle rates under *any* future renewables support regime are likely to reflect increased concerns about allocation risk, this risk is largely outside our scope, because in most cases it does not differ between the RO and the CfD.[58]

Even so, our analysis suggests that there are a number of ways in which the RO and CfD regimes may differ with respect to allocation risk, which we discuss below. We conclude that most of these differences are unlikely to affect the relative hurdle rates of the two policies, but we find that one – the increased risk of breaching the LCF under the CfD regime – could result in potentially material differences in hurdle rates.

[58] This reasoning also applies to a circumstance in which the Government decided to move to "constrained allocation" for specific technologies in advance of the full LCF budget becoming binding – that is, this policy decision seems no more likely under the CfD regime than under the RO.

Figure 6.6
Impact of Allocation Risk

Item	Comment	Impact
Allocation Lock-In	• Early allocation means little exposure to allocation risk compared to ROC • Compared to current ROC regime this change is less important • Early lock-in would have happened anyway	
Shocks to Fund Availability	• Risk of sudden government fund shortage higher; Increased allocation risk pre allocation due to locked-in government funds	
Net Impact	• Early lock-in would have happened anyway • Relationship to power price means availability of government funds is subject to shocks	

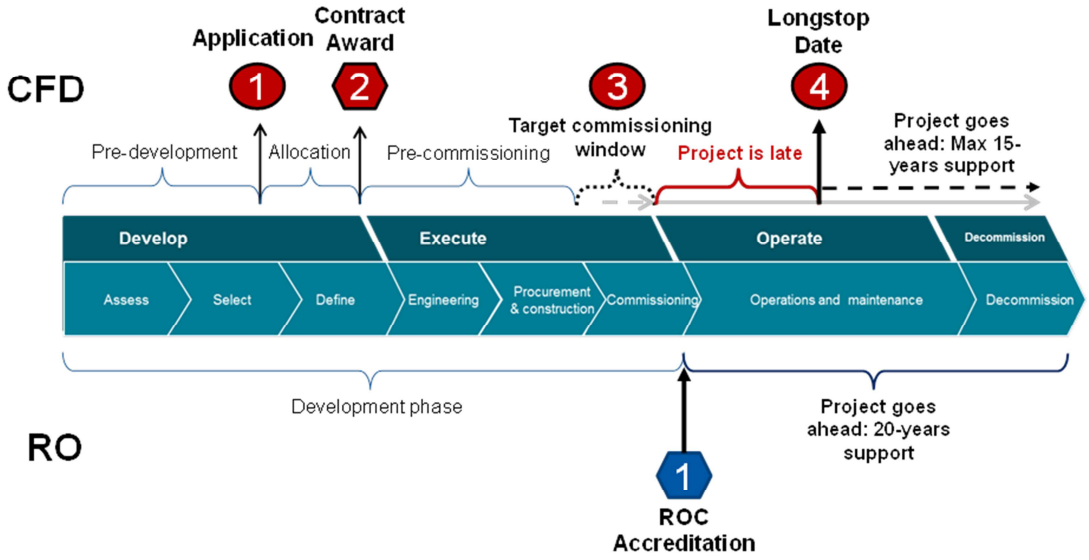
Note: Lock-in refers to the provision of an advance commitment to projects that they would receive support at a given level.

There is one specific way in which the RO and CfD regimes do differ with respect to allocation risk, because we find an increased risk of breaching the LCF under the CfD regime. We discuss this below, after presenting an overview of "allocation risk" in Appendix D.

Figure 6.7 shows the differences in the allocation processes between the CfD to the ROC regime. The main difference is that the CfD subsidy allocation takes place after pre-development (red hexagon-shaped "2"), whilst the ROC accreditation only takes place once the project is commissioned (blue hexagon-shaped "1"). The ROC system thereby leaves investors exposed to the risk of (for example) a banding review. On the other hand, under the CfD, early accreditation may leave investors with less room to adjust their plans—for example, in response to changes to relative costs of different turbine designs or other technical developments.[59] At the time of writing this report, under the CfD, deviations from the agreed installed capacity will be associated with an automatic reduction of the strike price. The allocation procedure is discussed in further detail in Appendix D.

[59] At the time of writing this report, the design of the specific flexibility provisions within CfDs is one of the was one of the areas that is being reviewed actively by DECC.

Figure 6.7
Allocation Timing



The value of certainty of accreditation depends on (i) the proportion of development (and, where relevant, construction) costs that are sunk prior to accreditation/allocation and (ii) the probability of accreditation, i.e. of qualifying to receive support. Under the *existing* RO scheme, all pre-development, development and construction costs are effectively sunk before accreditation. Under the CfD scheme, only the pre-development costs are sunk at the time that support is (conditionally) allocated. We present an analysis of the benefits of early lock-in of support in Appendix D.

There are three key differences between the proposed CfD and the *existing* RO regime:

- The subsidy allocation is locked in earlier, which, all else equal, increases certainty for the investor;
- A corollary is that the allocation is less flexible (because it commits the government to a certain expectation about impacts on the LCF), which makes project developers less able to adjust their project in response to changes in installation costs or technologies, or to re-scale projects; and
- The total subsidy commitment is significantly more uncertain under CfD, *because it fluctuates with the wholesale electricity price.* This increases the risk of forced (unforeseen) changes to the system, and therefore reduces certainty of availability of funds, particularly in later years.[60] *We find that this final difference is an important feature when comparing the two policies, as we discuss below.*

[60] Again, this risk that funding might not be available should be seen in the wider context of the UK's commitment to its renewable energy targets.

Before we turn to our analysis of LCF exposure to electricity price movements, we focus on the first two bullets above.

In summary, we find that:

- Compared to the allocation risk in the RO regime as it has existed up until now, there is no significant benefit associated with the early commitment of support to a project;
- Compared to the allocation risk under a future RO subject to the LCF, there would be a benefit associated with the early commitment of funds, as it would reduce risks.

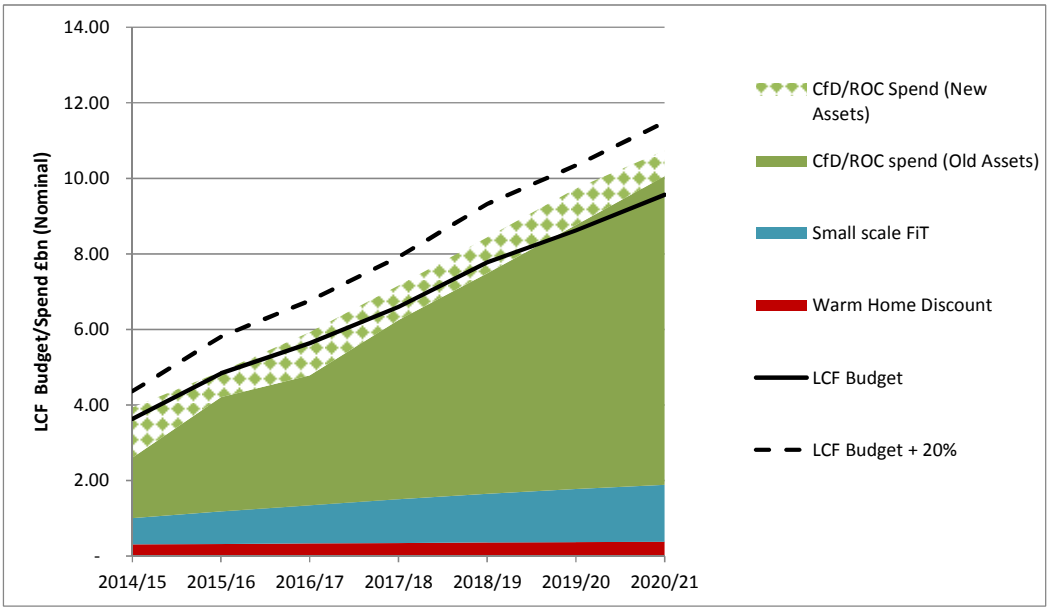
Because of the risks and costs associated with failure to secure an early allocation (which we analyse in Appendix D) we conclude that the most plausible hypothetical future RO would have been one in which developers also sought earlier confirmation from DECC about the level of support to which they would be entitled, and in return for this earlier certainty, DECC required some assurances from developers to help it plan for the expected LCF commitments and be able to project remaining future requirements.

We come to this conclusion based on our own assessment of LCF commitments, which we believe is similar to the analysis that an investor would undertake when considering whether or not to invest in a renewable project dependent on policy support. It therefore seems likely that a hypothetical future RO would also have incorporated elements of early commitment to ensure that developers continued to invest in renewables projects.

In order to assess how realistic we think investors may view this risk we have projected LCF spend to 2020 using NERA estimates[61]. Our analysis (presented in Figure 6.8 which shows the total Levy spend in colour, against the Levy budget, the black line), suggests that there is a reasonable chance that the LCF will bind in the next few years. This could put pressure on the government to limit funding to certain project developments. It seems unlikely to us that the government would be able to sustain a policy in which it could delay the accreditation of a project until as late as the commissioning date without providing some assurances to the project developer that they could expect an allocation of support. Otherwise, the risks to developers would be too great, and there would be a risk that development activity would cease. It therefore seems likely that a hypothetical future RO would also have incorporated elements of early commitment to ensure that developers continued to invest in renewables projects.

[61] Please note that these are not DECC projections.

Figure 6.8
Levy Spend: Pre-Committed vs. In-Year



Source: NERA analysis on data from www.elexonportal.co.uk; DECC

However, the allocation risks associated with the early lock-in of CfD support are significantly higher than those under a future RO, *due to the relationship between power prices and subsidy payments.* This is particularly an issue for projects seeking to apply for accreditation and secure their subsidy allocation toward 2019/2020 as discussed in the following section.

6.3.2. Risk of Rapid Changes due to Government Budget Constraint

NERA has undertaken illustrative analysis to consider how investors may view the LCF budget constraints. This illustrative analysis suggests that the LCF budget may be sufficient to reach the government's 2020, at least within the 20% threshold. However, the analysis set out in Appendix D suggests that the risk of a severe budget overrun (and subsequent rapid intervention) is significantly greater under the CfD scheme than under the ROC scheme because the total amount of subsidy payments under the CfD is directly related to power prices, and is therefore very potentially subject to significant volatility.[62]

[62] Government has set the LCF budget to allow for uncertainty over wholesale prices.

Faced with sudden shocks to the budget, investors may believe the government could be forced to rapidly respond by tightening rules or lowering subsidies for accreditation at very short notice, thereby exposing developers who have sunk pre-development costs. At the extreme, investors may fear that a drop in the power prices could lead the government to *completely stop accrediting new projects*.

This risk is more likely to affect projects that seek accreditation in later years (when a greater proportion of subsidy will be subject to swings in the power price) and is unlikely to be relevant to projects that have already sunk most of their pre-development costs and that are therefore on the verge of accreditation already. It also may be more relevant for projects that are more complex and more technically demanding, as these may have longer pre-development periods.

Figure 6.9 presents an estimate of the impact on hurdle rates of the reduced availability of funds for new assets by 2019/2020 as a function of power prices (shown in rows) and level of expense associated with development (or pre-accreditation) costs. The approach assumes that strike prices are not changed[63] and that the government 2020 renewables target is achieved. This shows a strong positive relationship between the power price and the fund availability: If the power price goes below its current level of £50/MWh, funds could be significantly constrained.

Even if this prospect is viewed by investors as unlikely, the mere *risk* that this could happen means developers who expect significant development costs face the potential stranding of those costs.

Figure 6.9
Required WACC adder (bp) due to Allocation Risk from Power Price (2019/2020)

Power Price (£/MWh)	LCF Availability	% Capital Cost Sunk Pre Allocation Announcement							
		0%	1%	5%	10%	25%	50%	75%	100%
<20	0%	.	.	.	.	.	.	.	.
20-30	12%	0	97	456	856	1865	3270	4108	4108
30-40	29%	0	32	155	300	702	1287	1644	1644
40-50	52%	0	12	60	120	290	554	719	719
50-60	81%	0	3	15	31	76	150	198	198
60-70	100%	0	0	0	0	0	0	0	0
70-80	100%	0	0	0	0	0	0	0	0
80-90	100%	0	0	0	0	0	0	0	0
90-100	100%	0	0	0	0	0	0	0	0
>100	100%	0	0	0	0	0	0	0	0
Uncond. Avg	**65%**	**0**	**7**	**35**	**70**	**172**	**333**	**436**	**436**

Source: NERA analysis. Assumes 1/3 of revenues from power market revenues, which means a project will commission regardless of subsidy allocation if more than 2/3 of development costs are sunk. Unconditional average is the average LCF availability including the low probability of very low power prices and LCF availability.

[63] An alternative approach to reducing availability would be to adjust strike prices which would render some projects unviable, and reduce penetration. The *expected value* of subsidy from that approach would be similar to simply reducing allocations.

Compensation for this risk of asset stranding can either be factored into the strike price or added to the hurdle rate. If it is added to the hurdle rate, we estimate that project hurdle rates would need to increase by between 5-40 bps[64] if their pre-development costs were between 1-10% of total construction costs. (Our understanding based on information from DECC is that pre-development costs tend to concentrate at the lower end of this range, although the figure will vary from project to project, and will not necessarily be known in advance.)

These results are indicative, and depend on a number of assumptions. Factors to note include:

- This approach does not take into account the *systematic* element of this risk – that is, the fact that the LCF is more likely to bind under "bear market" conditions (low power prices) and close to zero for "bull market" conditions (high power prices). To take this correlation into account, rational investors may wish to apply an *additional* uplift to the hurdle rate.[65]
- The required WACC adder is sensitive to baseline assumptions of probability of LCF breach. It has been outside the scope of this report to undertake power market modelling, so we have estimated the probability of different future power prices assuming the price moves with volatilities and mean reversions similar to those observed in the past. (To the extent investors assess these probabilities differently, it would be straightforward to recalculate the estimated hurdle rate "adders" by adjusting the probabilities assigned to each power price path, and, based on this, calculate a new availability of funds. The estimate also varies significantly by year.

6.4. Duration Risk

The duration of the CfD contract for most technologies is expected to be 15 years, whereas under the RO the duration of support was typically 20 years.[66] In this section we discuss the change in risks associated with the shorter subsidy horizon. In summary, we find that the duration risk in itself does not merit a change in the risk premium, as depicted in Figure 6.10.

[64] The table shows the illustrative results for 2019/20, which ranges from 7-70 bps for the 1%-10% range of sunk pre-allocation costs. The reported 4-40 bps range is based on an average of the results for our 2018/19 and 2019/20 modelling, which we use to reflect a representative impact on projects being developed for accreditation in later years.

[65] This is because CAPM assumes that payoffs in "good" market conditions are less valuable than payoffs in "bad" market conditions. Investors might proxy this by placing greater emphasis on the scenarios in "bad states" of the world than "good states".[65] In practice, this corresponds to using a conservative (i.e. lower than average) "expected allocation probability".

[66] https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/the-renewables-obligation-ro

Figure 6.10
Effects of Duration Risk on WACC

Item	Comment	Impact
Market Risk in Year 16-20	• Under both regimes the generator is exposed to the same power price risk in years 16-20. • The importance of subsidy revenues is shifted from years 16-20 to years 1-15 compared to the ROC system	
Enhanced Operational Flexibility	• The frontloading of subsidies means the generator does not have to run if prices (or more accurately, expected margins net of any operating costs) below zero after year 15.	
Net Impact	• Market risks unchanged. Operational flexibility has limited value to generator	

This is because the asset has similar or reduced market exposure compared to the ROC system:

- **Under a CfD a generator is exposed to the same market risk as under the RO in years 16-20:** Under both regimes the generator is exposed to power price risk in years 16-20. Although the relative proportion of revenues coming from market-revenues is increased in years 16-20 compared to the ROC system, this simply reflects a change in the timing of the receipt of subsidies, with a smaller proportion from market revenues in years 1-15 and an unchanged NPV of the subsidy stream.
- **The frontloading of subsidies enhances operational flexibility in year 16-20**: Changing the timing of subsidies does not in itself lead to a change in risk. However in the existing ROC system the generator is forced to run for all hours for 20 years to extract the entire expected subsidy – even at times when there are negative power prices. The frontloading of subsidies means the generator does not have to run if prices (or more accurately, expected margins net of any operating costs) fall below zero after year 15. This optionality tends to reduce exposure to variable OPEX inflation and negative power prices after year 15, which is relevant to both dispatchable and non-dispatchable technologies. The net impact of this benefit on the value of the asset under CfDs is limited due to discounting.

6.5. Construction Delay Risk

As noted above, construction risk, and the perceived risks to support levels associated with delays that miss key CfD milestones, are one of the most commonly cited concerns appearing in the consultation responses and voiced during our interviews.

Construction risk refers to the impact of unforeseen construction delays on the expected NPV of a project. We find that risks associated with construction delays are smaller in the CfD regime than in the ROC system for small delays but potentially larger if delays extend beyond the long stop date.

As with allocation risk, our assessment of differences in exposure to construction risk is based on our analysis of the different timelines associated with the two policies and the impacts of a construction delay on expected cash flows in each case. As for allocation risk, we find that one of the principle differences between the two policies is in sensitivity to variations in the electricity price. In the case of long construction delays beyond the "long-stop date" – after which allocations of support can be revoked – developments are again subject to allocation risk, which in turn differs because of different sensitivity to power price movements.

Within the "long-stop" period the two regimes (the CfD and the hypothetical future RO) are likely to be similar, unless the future RO did *not* implement the early allocation provisions discussed above. In that case, an RO project that was delayed beyond its expected start date would be subject to banding degression (or banding review) that would reduce its revenue per unit output.

As summarised in Figure 6.11, we estimate that construction risk outside of the contract has increased slightly under the CfD regime, largely due to volatility of availability of government funds.

Figure 6.11
The Impact of Construction Delay

Item	Comment	Impact
Short Construction Delay	• Early allocation means little exposure to allocation risk compared to ROC • Known revenue loss upon delay (loose individual subsidy years); limited exposure to degression so long as asset can stay within contract	
Long Construction Delay	• Risk of sudden government fund shortage higher; Increased allocation risk pre allocation due to locked-in government funds • Significant uncertainty about strike price degression upon construction delay beyond long stop date	
Net Impact	• Early lock-in would have happened anyway • Relationship to power price means availability of government funds is subject to shocks	

The impact from a project delay for offshore wind is sketched in Figure 6.12, assuming perfectly comparable regimes (taking into account that ROC banding degression increases the risk of construction overruns by reducing support received by projects that commission later than anticipated). [67]

[67] We assume a predefined banding degression consistent with the degression of strike prices. The ROC banding is set consistent with strike price degression such that an asset with planned commissioning in 2019 receives strike price of 135 £/MWh or 1.54 ROCs. We assume an asset commissioned in 2015 receives 2 ROCs or strike price of 155 £/MWh.

1. **Within Commissioning Window:** These delays have similar effects in RO and the CfD regimes as all revenues are simply shifted into the future. The cost of a short delay is approximately equal to the real WACC percent per year.

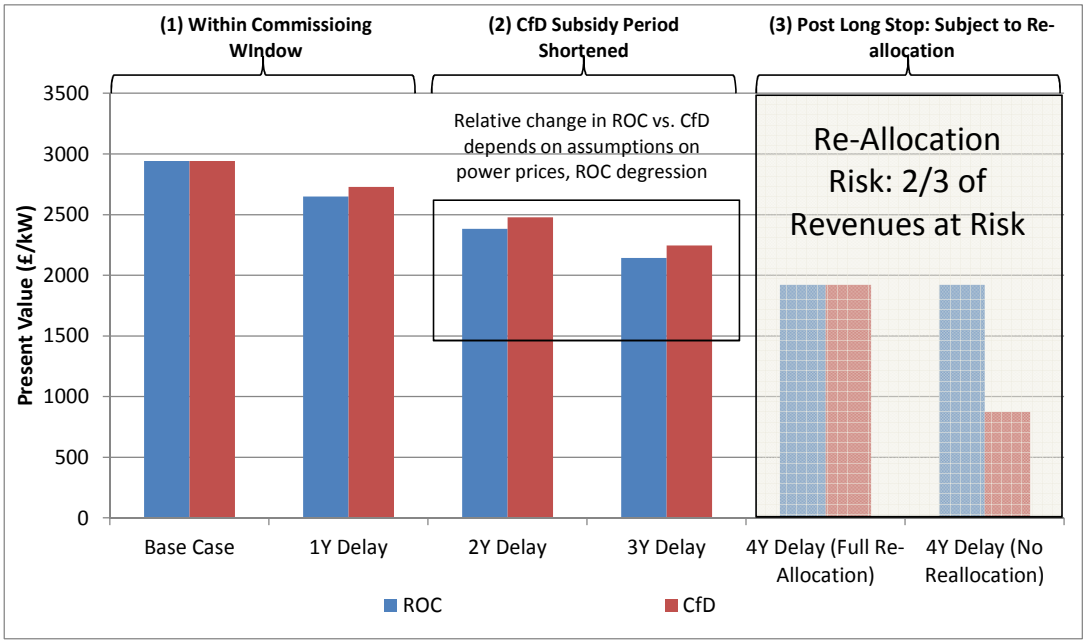
2. **Beyond Commissioning Window:** For delays which exceed the commissioning window, the delay starts affecting the subsidy years achieved in the CfD. For offshore, a delay of up to 2 years after the end of the commissioning window (Illustrated as a "3Y delay" from the beginning of the commissioning window) has the effect of reducing the NPV of revenues by approximately 24 percent. This is the result of the combined effect of 3 years of discounting at the WACC (~-25 percent) plus the loss of two years of discounted subsidy (-7 percent of revenues) and higher power prices and inflated strike price due to later commissioning (+8 percent). In the ROC regime the subsidy period is unchanged. However, because the assets are accredited later than expected, the project would be subject to banding degression. Given the current embedded banding degression for offshore wind this leads to a slightly larger effect than the loss of one year of subsidy in the CfD regime (29 percent).[68] However, the exact relationship depends on the assumed banding degression and could be either higher or lower than the CfD mechanism.

3. **Beyond Long Stop Date** by default means the CfD subsidy either falls away entirely, or needs to be renegotiated. For an offshore wind asset that means that about 2/3 of the project revenues are at risk. The level of subsidy achievable depends on the availability of funds and available strike prices at the time of application. Under the ROC regime, the developer would also have been exposed to this risk. However, in the ROC regime the risk of sudden government fund shortages is much lower, so there is no sudden jump in the re-allocation risk.

Note that for illustration, the example illustrated in the figure assumes – contrary to our suggestion in the previous section on allocation risk – that the hypothetical future RO regime does *not* implement some kind of pre-commitment period in which allocation of support is reserved for developers undertaking significant investments over long development periods. This is manifested in the exposure to degression risk under the RO, which does not apply under the CfD. This amplifies the differences between the RO and CfD regime in early years in this example. However, our view remains that such an arrangement under the RO would have been unlikely because of the significant risks it would have placed on developers.

[68] The difference is sensitive to the assumption of ROC degression. For comparability between the CfD system and the ROC system we have assumed all projects would be NPV neutral in absence of any shocks. This means there is an implied banding degression of the ROC regime. With no banding the reduction after 3 years would be 19 percent of value for the ROC regime.

Figure 6.12
Effect of Construction Delay for Offshore Wind



Source: NERA analysis Note: The difference in impact of construction delays shorter than the long stop date is sensitive to the assumption about the counterfactual future RO regime. If the currently planned ROC degressions are included in the framework the risks in CfD appear lower than in the RO regime. If the future RO is assumed to commit to supporting developments at a pre-determined level, subject to certain milestones, then the red and blue bars would not look very different until the long-stop date was reached.

The impact of a project delay is smaller for biomass and onshore wind, which rely less on subsidy. Additionally, the risk of exceeding the long stop date may be smaller, as these technologies are less subject to for example weather conditions and other non-controllable risks, and their construction is also better understood. The impact is also likely to be greater for larger, more complex projects that are more technically demanding. All else being equal, we might therefore expect that Round 3 offshore wind projects would face this risk to a greater extent than Round 2 projects. Even so, selected Round 2 projects may face technical challenges that are similar to (or even greater than) those faced by (some) Round 3 projects, while some Round 3 projects may have similar challenges to a typical Round 2 site, so in practice this will depend on the characteristics of individual projects.

As with the allocation risk set out above, the biggest difference between the two regimes when there is a construction delay arises for delays that pass the long-stop date that are also confronted with significant breaches of the LCF. As for allocation risk generally, the CfD is more susceptible to such risks because of the greater volatility of LCF support in response to fluctuations of the electricity price.

If we assume that the risk of exceeding the long stop date is between 2-10 percent,[69] the expected loss of NPV under the CfD regime due to the confluence of,

- this assumed construction risk; and
- the risk of low power prices, leading to reduced availability of support

is between 0.2 and 0.5 percent. Although the relative probability that these two risks coincide is small, the downside impact could be very large, if it meant (for example) that a largely built asset was unable to secure any support. The effect on the *expected NPV* of a development, under such circumstances, would be equivalent to a 5-10 bp *increase* in the WACC, relative to the RO regime.

6.6. "Novelty Premium"

With specific details of the CfD mechanism still to be determined, there is still a significant amount of uncertainty surrounding the proposed CfD regime. A number of interviewees raised the idea that this uncertainty would lead to a "novelty premium". Some of this uncertainty will naturally be resolved as details of the regime are finalised and contracts are signed. However, uncertainty regarding the *operation* of the regime and about the magnitude and significance of various potential risks will remain and will only diminish as market participants acquire and digest operational information and experience with the new system.

Item	Comment	Impact
Lack of Experience with System	• Implications of system are not known	
Lack of Investor Information	• Investors do not fully understand system	
Net Impact	• Novelty Premium	

During our interviews, a number of interviewees expressed their belief that the potential benefits of the CfD regime in reducing hurdle rates would only materialise after a period of "bedding down". Subsequent follow-up discussions with interviewees suggested that a

69 In order to gauge the risk of construction delays beyond the long stop date we reviewed construction delays data for a subsample of UK's installed offshore wind farms. Publically available evidence on construction delays was limited, but suggested that construction delays are mostly within the 2 years (equal to the allowance provided before the long stop date). However, a key issue in estimating construction delays is the relevant reference point, i.e. the starting point for when expectation was formed, which is compared with the actual construction time in order to quantify the delay. Under CfDs, expected construction times are set quite early in the process, i.e when signing the CfD contract. Data available in the public domain on "expected completion date" may not refer to construction delays relative to expectations formed that early in the process. We also note that due to the complexity and size, R3 projects are likely to have greater expected delays than existing projects. Based on this observation, we assume risk of exceeding the long stop date could be anywhere between 1 and 10%, depending on the project specific circumstances.

majority of them believed that there was a "novelty premium" (or "policy uncertainty premium"), although some did not.

These concerns are similar to those raised by the Committee on Climate Change (and cited above, among the consultation responses) that the benefits of lower hurdle rates "may not be realisable immediately, before the new mechanisms are proven".

Interviewees cited different specific reasons for the novelty premium. Some cited concerns that allocation or basis risks would only be known once the system was in full operation; others cited uncertainties associated with securing long-term PPAs; while others alluded to the fact that they believed that the conjunction of the aggressive strike price degression schedule and the planning and consenting timelines would mean only few projects would receive the early, higher strike prices.

It was not clear from the interviews whether investors have clearly separated out risks that would have also been inherent in the counterfactual RO scheme that would have continued. In this case the interview responses may overstate the magnitude of the novelty premium. In addition, some of these risks are ones that we either do not think should affect the cost of capital, or ones that we believe may be quantified and priced – and that are already accounted for in our assessment. Other risks are outside the scope of our work, because they would be similar under either the hypothetical future RO or the CfD regime.

Even so, there are some risks associated with the introduction of CfDs that seem inherently difficult to quantify or whose impacts are difficult to assess at present. These include the risk that reference prices will not develop as intended (or may be affected by other changes associated with Electricity Market Reform (EMR)), or that government will make adjustments to the new and unfamiliar CfD mechanism that will adversely affect the market or investments, or simply that the increased allocation risk associated with the LCF (even allowing for early accreditation) is not yet well enough understood or managed. (As noted above, the last of these is outside our scope of work because it applies to any future support regime, but nonetheless is likely to affect the cost of capital relative to the *current* RO.)

Acceptance of the existence of a novelty premium is not universal, and several interviewees noted that its existence would depend on the type of investor (debt providers would not add a premium but rather would make go / no-go decisions, whereas equity investors would consider a premium). Most agreed, however, that uncertainty about the CfD would not be resolved simply with the publication of final rules, sample contracts or even with the signing of early stage CfDs.

Estimates of the period over which such a premium would persist ranged from one year to as many as five years from finalisation of the legislation. Most estimates of its magnitude ranged from zero to 200 basis points.

The existence of a novelty premium is also evident in other industries, e.g. regulated networks. Rating agency Moody's stated the following in a report on German network regulation in 2010 (one year after incentive regulation started in Germany):

> *In summary, in comparing the stability and predictability of the German regulatory framework to that of the UK, Moody's regards it as appropriate to* ***make a distinction for the German regulatory regime compared to other, more established, regulatory models.*** *This distinction would likely result in German network companies being* ***rated at least one notch lower*** *compared with energy networks of a similar financial profile that are subject to UK regulation. Wider notching may be appropriate where certain company-specific business risk factors may warrant this. This rating differentiation is* ***largely based on the uncertainty associated with the new framework in Germany and the related tariff regime, which remains relatively untested.*** *However, Moody's notes that the risks associated with a new and untested framework are somewhat offset by the fact that the German framework is based on internationally established regulatory models. It is applied in the context of a strong institutional framework, with court decisions already available to clarify the application of the new regime. (…) We also note that as the new incentive-based regulatory regime in Germany becomes more established and predictable, the perceived uncertainty that is associated with an untested regime could decrease over time, and as a result the initial ratings differential could diminish.*[70]

Interestingly this premium had not gone away in 2013 (4 years after the start of incentive regulation) when Moody's rated one of the major German TSOs:

> *On a European comparison, Moody's considers the German regulatory framework as modestly riskier in terms of transparency and predictability than the UK framework that we use as a benchmark. This assessment reflects Moody's view that, despite a track record of cost-plus regulation in Germany, the overall regulatory framework and tariff regime for energy transmission and distribution networks is undergoing a period of change, following the introduction of an incentive-based regime on 1 January 2009. (…) Furthermore, given the increasing pressure on household bills, linked to the renewable energy policy, we believe that there may be some risk of political interference.*[71]

More generally Moody's rating methodology states that Moody's requires a track record of 15 years to score a regime at Aaa in the "regulatory stability and predictability" category while a new system in an advanced jurisdiction would at best score a rating of A/Baa.[72] Given the Moody's scoring system and the weight attached to the importance of "regulatory stability and predictability", all else equal, a network would face a novelty premium of around one notch (i.e. e.g. a reduction in rating from Baa1 to Baa2), which is equivalent to 10-20 bps at current rates.[73] While the above is a stylised calculation for a network it

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70 Moody's (6 Oct 2010): Incentive-Based Network Regulation in Germany. (Emphasis added)

71 Moody's (20 Jun 2013): Eurogrid Credit Opinion, available at: http://www.50hertz.com/en/file/Eurogrid_Credit_Opinion_20_June_2013.pdf

72 See Moody's (Aug 2009): Moody's Global Infrastructure Finance – Regulated Electric and Gas Networks, p.11.

73 Moody's assigns 15% weight to the factor "regulatory predictability and stability" and values of "1" to "Aaa", "6" to A and "9" to Baa. Assuming average rating of A/Baa we use a score of 7.5, i.e. an increase in the "regulator predictability" score of +6.5. This leads to an overall increase in the total score of +0.98 (15% times +6.5). The difference between the mid-point of e.g. Baa1 and Baa2 is 1.0 (overall scoring ranges of 7.5 to 8.49 and 8.5 to 9.49 respectively). See Moody's (Aug 2009): Moody's Global Infrastructure Finance – Regulated Electric and Gas Networks, p.7. In practice the impact

provides an illustration of the potential magnitude of the "novelty premium" although this novelty premium on debt may understate the premium required by equity investors.

In addition, to see whether we could identify a change in WACC directly for renewables under different support policies when they were changed / introduced and then as they became established over time, NERA analysed trends in estimated WACCs over time for the UK RO and the German FIT regime. Although estimates of WACCs tended to decline for both countries across a range of technologies, once we controlled for changes in general market parameters (stemming from the financial crisis) and for perceived maturation of technologies, these trends disappeared, and we were left with no clear evidence of a novelty premium added by investors in the early stages of these support policies.[74]

Despite this absence of evidence, we believe it is necessary to consider the possibility that there is in fact a novelty premium associated with the introduction of CfDs. The changes to the other two policies that we compared to (the introduction of banding to the RO, and the incremental changes to the operation of the German system) represented policy evolution, rather than the more significant regime change represented by the move from the RO to the CfD. Moreover, these evolutionary changes were not accompanied by wholesale reforms to the wider electricity market and underlying institutions. It therefore seems plausible to us that there could be a novelty premium associated with the new UK regime, and that it could persist for an extended period.[75] (For example, if some of the uncertainty is due to questions about the operation of the reference prices and their relationship to actual prices received, or about whether the wholesale market will be sufficiently liquid for the reference prices to function as intended, it may be years before enough CfDs are signed and generators are commissioned to begin to collect enough relevant data to evaluate the performance of the reference prices.)

This value from waiting to see how a funding / regulatory system develops is an established concept in the theoretical literature on real options. A real option is an option which arises in relation to a real investment decision, in which there is flexibility to take decisions in the light of subsequent information. In a series of papers, Hausman and co-authors show that these real options can be substantial and inhibit investment where regulators / governments do not allow for the loss of such options when a company is to invest before the uncertainty has been resolved.[76]

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is going to be slightly larger still as lower scores are given a higher weight in Moody's calculations.
The iBoxx Non-Financials indices for A and BBB rated debt have been on average c.40 basis points apart over the last year. Given there are three notches between A and BBB (there no iBoxx indices for individual notches) the difference for a single notch would have been around 13 basis points.

74 One issue with controlling for market parameters is that while there is a clear measure of government bond yields (as a proxy for the risk-free rate) there is no agreed measure of the current market risk premium, which makes it impossible to quantify changes in the short-run market risk premium exactly.

75 This possibility would seem to be confirmed by Moody's view of German network regulation (see above). Despite the fact that there was a long history of experience with network regulation in similar countries Moody's advocated a risk uplift for the untested German system and has maintained it for a period of several years.

76 See e.g. Hausman, J. (1997): "Valuing the Effect of Regulation on New Services in Telecommunications" Brookings papers: Microeconomics; Hausman, J. (1999): "The Effect of Sunk Costs in Telecommunication Regulation"; in J. Alleman and E.Noameds, The New Investment Theory of Real Options and its Implications for Telecommunications

While most UK regulators have not allowed for real options in the past arguing that the RCV guarantees the return on investment and removes uncertainty, regulators have allowed for real options in situations where the outlook for the asset is more uncertain, e.g. in telecommunications (for new fibre networks)[77] and for Heathrow's Terminal 5.[78]

In sum, we do not think it is possible to definitively rule out the possibility that there is a novelty premium. Depending on DECC's policy aims, it may be prudent to assume that there is one. The premium is extremely difficult to quantify, however. It is possible that it could have no impact on hurdle rates, but it is also possible that investors will either demand higher returns, or simply wait on the sidelines observing the system's operation until they become more comfortable with the new policy.

Given the uncertainty, we have included a range of 0-50 bp for our estimates of the impact on more established technologies like onshore wind and biomass where the subsidy accounts for a smaller portion of total revenues, and a wider range of 0-100 bp to reflect the impact on less mature technologies where the subsidy accounts for a larger proportion of total revenues, like offshore wind.

Moreover, we believe a wider range is likely to apply to technologies requiring higher subsidies, because a given capital investment in these technologies is more dependent on the policy for its returns than investments in lower cost technologies.

In this context, it is also worth noting that a rational investor would apply a higher "novelty premium" at the moment when there is a larger number of unknowns than at the start of the CfD scheme when some of these unknowns (but possibly not all) will have been resolved, e.g. through information provided through the FiD enabling programme; this suggests that the top end of the novelty premium range from our interviews is unlikely to bind once more details about the policy have emerged.

Economics; Hausman, J, Myers S. (2002): "Regulating the United States Railroads: The Effect of Sunk Costs and Asymmetric Risk"; Journal of Regulatory Economics.

77 OPTA(2011): Regulation, risk and investment incentives Regulatory Policy Note 06.

78 Competition Commission (2002): BAA plc: A report on the economic regulation of the London airports companies (Heathrow Airport Ltd, Gatwick Airport Ltd and Stansted Airport Ltd) para 4.71.

7. Conclusions

In summary, we estimate the following ranges for adjustments to the cost of capital or hurdle rates associated with the shift from a hypothetical future Renewables Obligation to the Contracts for Difference regime. This assessment draws on the consultation responses, market reports and interviews and our evaluation as set out above of this evidence. Table 7.1 summarises the change in hurdle rate associated with the change of policy, split into the individual impacts of the component risks. Table 7.2 provides, as context, an illustration of how these changes in hurdle rate would affect DECC's assumed RO hurdle rates, and NERA's indicative ranges.

It has not been within our scope of work to assess whether DECC's RO hurdle rates accurately reflect investor requirements under the current or (hypothetical) future RO.

Table 7.1
Summary of Hurdle Rate Changes under CfDs (pre-tax, real)

NERA Assessment – Individual Risk Impact on Changes in Hurdle Rates				
	Offshore Wind	Biomass Conversion	Onshore Wind	Comment
1) Wholesale Price Risk	-100 to -50 bps	-125 to -75 bps	-175 to -125 bps	Impact largest for onshore (highest share of market revenues; smallest for offshore (lowest share of market revenues)
2) Allocation Risk	+5 to +40 bps	+5 to +40 bps	+5 to +40 bps	Risk increases due to higher LCF breach risk with lower power prices
3) Construction Delay	+5 to +10 bps	None	None	Risk increases due to higher LCF breach risk with lower power prices; assumed to apply only to offshore wind.
4) Novelty Premium	+0 to +100 bps	+0 to +50 bps	+0 to +50 bps	Novelty Premium is uncertain; may be higher for emerging technologies with higher share of subsidy revenues
Total Change (excl. Novelty premium)	**-90 to 0bps**	**-120 to -35bps**	**-170 to -85bps**	
Total Change (incl. Novelty Premium)	**-90 to +100bps**	**-120 to +15bps**	**-170 to -35bps**	

Note: The allocation risk for onshore wind and biomass is likely to be at the lower end of the range above due to shorter time between pre-development spend and potential action to correct LCF breach. Allocation risk for projects that are on the verge of signing CfD contracts is also very low.

Table 7.2
Summary of Hurdle Rate Ranges under CfDs (pre-tax, real)

NERA Assessment – Total Risk Impact on Hurdle Rates			
	Offshore Wind***	Biomass Conversion	Onshore Wind
DECC RO WACC*	**10.2%**	**11.6%**	**8.3%**
DECC CFD WACC**	**9.6%**	**10.9%**	**7.9%**
NERA Illustrative Range under CfD	**9.3% - 10.2%**	**10.4% - 11.25%**	**6.6% - 7.45%**
NERA Range with Novelty Premium	**9.3% - 11.2%**	**10.4% - 11.75%**	**6.6% - 7.95%**

Note: * DECC RO WACC assumed for the draft delivery plan July 2013;
** DECC CfD WACC assumed for the draft delivery plan July 2013
*** We show results using the Round 2 offshore wind assumptions set out in DECC's draft delivery plan.

Our findings suggest that:

- The long-term hurdle rate reduction for offshore wind is likely to be in line with the magnitude assumed by DECC in the Draft Delivery Plan. Depending on the strength of the novelty premium the change to a CfD may however increase required hurdle rates initially;
- The long-term hurdle rate reduction for biomass is likely to be in line with the magnitude assumed by DECC in the Draft Delivery Plan. Depending on the strength of the novelty premium the initial hurdle rate reduction may be small to non-existent however; and
- The long-term hurdle rate reduction for onshore wind is likely to be larger than assumed by DECC in the Draft Delivery Plan with even the initial hurdle rate reduction potentially larger than proposed by DECC.

In Appendix E we discuss whether there is a way of "market testing" our conclusions. Below we summarise other key findings:

- First, we note, there is a **diversity of perspectives** regarding the type, hierarchy, magnitude and direction of key changes in risk resulting from the regime change, largely due to differences in investor types (equity vs. debt, development vs. construction vs. operations investors, experienced in UK market vs. new entrants), their knowledge and understanding of the changes in risk arising from the RO to CfD regime change, and their interests in the policy shaping process. In our assessment we have sought to bring out these differences where they may be material.

- **International comparators** offer limited lessons as the shift from RO to CfD regime is unique to the UK.
- In our view, and as identified by consultation responses, analyst report and interviews, the central change in risk exposure with regard to the shift from a RO regime to a CfD FiT scheme is the reduction in exposure **to power price risk**. As a fixed-price support scheme, the CfD FiT scheme reduces exposure to wholesale market risk, thereby removing a significant part of the volatility of the revenues of renewable energy projects. We estimate a reduction in hurdle rates as a result of the reduction in wholesale power price risk of between 50 - 175bps, depending on the technology.
- We find that the reduction in power price risk (relative to a future RO system) is largest for **mature technologies such as onshore wind**, because stabilisation of electricity revenues reduces overall revenue volatility more for technologies that receive the lowest level of policy support.
- However, we also find that the shift to the CfD scheme could increase other risks, as identified by consultation responses, analyst report and interviews. These include "**allocation risks**" and "**construction risks**", and there is also likely to be a "**novelty**" premium associated with uncertainties about the operation of the new CfD mechanism.
- We find that **allocation risks will likely increase** under the CfD, because the amount of subsidy that must be paid in any given year fluctuates with the wholesale electricity price, and is therefore more uncertain. This is an asymmetric risk, in that lower power prices constrain the LCF budget more under the CfD regime than under an RO regime.
- With regard to **construction risks**, we find that the only material difference between the RO and CfD system occurs for construction delays that exceed the Long Stop Date. For smaller delays (exceeding the commissioning period) under the CfD regime, we note that this will reduce the NPV of the project since the delay will affect the duration of the subsidy period (i.e. effective number of years over which the subsidy is received). However, in the RO regime, although the subsidy period is unchanged, the assets are accredited later than expected, and the project would be subject to banding degression. Our analysis suggests **these effects broadly offset each other** such that for small delays, the risks under the CfD regime are no higher than under the RO regime.
- For **construction delays beyond the Long Stop Date**, however, the change in risk is much larger as the CfD subsidy either falls away entirely, or needs to be renegotiated. For an offshore wind asset that means that about 2/3 of the project revenues are at risk. The level of subsidy achievable depends on the availability of funds and available strike prices at the time of application. Under the ROC regime, the developer would also have been exposed to this risk. However, under the ROC regime, the risk of sudden government fund shortages is lower, and consequently, so is the risk that there will be no support. The increased risk is mainly relevant for offshore wind projects, which have high strike prices and more uncertain development and construction periods. Biomass and onshore wind construction times tend to be shorter, and in general these projects are less complex, so it is less likely the government would have time to change the availability of support even with similar relative delays in construction.
- For similar reasons, all else equal, we might therefore expect that **Round 3 offshore wind projects** would face higher risks associated with construction delays under the CfD mechanism than Round 2 projects. Even so, selected Round 2 projects may face technical

challenges that are similar to (or even greater than) those faced by (some) Round 3 projects, while some Round 3 projects may have similar challenges to a typical Round 2 site, so in practice this will depend on the characteristics of individual projects.

- A final important consideration is the possibility that a "**novelty premium**" could stop hurdle rates from falling at the start of the CfD regime while investors waited to see that it would work as intended. We are unable to verify the existence of such a premium, but believe that there are plausible reasons that it could affect hurdle rates.
- Overall, we find that it may not be safe to assume an across-the-board reduction in hurdle rates for onshore wind, offshore wind and biomass conversion immediately.
  - We find the greatest **evidence for a long-run <u>decrease</u> in hurdle rates under CfDs (relative to a future RO system) for <u>mature</u> technologies**, because stabilisation of electricity revenues reduces volatility more the smaller the share of revenue provided by policy support.
  - We find **evidence suggesting hurdle rates may <u>decrease or remain unchanged in the short-run</u> (relative to a future RO system) for <u>emerging</u> technologies with longer construction lead times**, and should decline in the long-run, but less than for mature technologies – because the CfD's stabilisation of electricity revenues has a smaller impact on their overall revenue.
  - Assuming no novelty premium, we conclude that prior estimates of changes to hurdle rates may have been underestimated for some technologies. Table 7.2 shows the hurdle rates previously assumed under the RO and proposed for CfDs, and presents NERA's own estimates. We provide a range based on our assessment of the plausible ranges of the different risks.

Appendix A. Details on the Theoretical Framework for Assessing Hurdle Rate Changes

A.1. The Framework

In this section we set out the theoretical framework we use to assess the impact on the cost of capital from change in the renewable support scheme when assessing evidence submitted through consultation responses, analyst reports and interviews, and market evidence for our own analysis. In doing so, we expand on the existing literature on hurdle rate changes in the UK.

In undertaking this work we have assessed whether there are other dimensions not (fully) captured by the existing approach, but raised by consultation responses, analyst reports and interviews in response to DECC's Draft Delivery Plan .

Under standard financial theory, the cost of capital of an asset is determined by the fundamental **(systematic) risk** of the asset, and not (just) its capital structure, under certain assumptions including no corporate taxes.[79] Systematic risk is typically captured within the CAPM framework, under which asset risk is quantified by the asset's beta coefficient, i.e. the degree to which project cashflows are correlated with the market.

The riskiness of project cashflows as quantified by the asset beta could affect the capital structure of a company. For example, lower asset betas may allow investors to take on higher leverage, on the back of more stable expected streams of cashflows[80]. However, the simple argument that debt issuance is cheaper than equity, so higher gearing must mean cheaper financing, overlooks the impact on equity costs of an increase in leverage. The relationship was first set out by Modigliani and Miller (1958)[81], who showed that equity costs increase with higher leverage, because higher gearing increases the riskiness of shareholders' capital.[82] Therefore, as stipulated in the initial Miller-Modigliani Capital Irrelevancy Proposition,[83] weighted cost of capital is constant over the capital structure of the company.

In practice, however, there is an increased benefit to holding debt in that it effectively reduces a company's tax liability. In the presence of taxes, a company can benefit from higher leverage solely via the tax shield. In fact, Miller-Modigliani showed in a subsequent 1963 paper – which introduced corporate taxation and assumed interest is a tax deductible cost –

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79 The Modigliani-Miller proposition also requires no transaction costs, and that individuals can borrow at the same rate as corporates.

80 In principles, we note that cashflows can have a high degree of volatility which is uncorrelated with the market., which will in turn affect financieability and potential for gearing. This discussion assumes that a lower asset beta implies a more stable cashflow stream (i.e. non-volatile in absolute terms).

81 Modigliani, F.; Miller, M. (1958), *"The Cost of Capital, Corporation Finance and the Theory of Investment"*.

82 When the gearing is zero, the asset's cost of capital equals the cost of equity. As gearing rises, the cost of equity increases to remunerate equity investors for the higher risk they bear from the increasing use of debt financing.

83 This relationship is mathematically stated as follows: $$R_e = R_a + \frac{D}{E}(R_a - R_d)$$ where R_e is the required return on a company's equity, R_a is the required unlevered return on capital, and D/E is the ratio of the company's debt to equity.

that the cost of capital declined linearly with leverage, suggesting a 100% debt-financed model minimises financing costs.

However, market evidence shows that firms do not behave in this way. Further academic papers recognised that the extra fixed-obligations of more debt increase the risk of bankruptcy, and this leads to a tax-cum-bankruptcy model in which optimal company leverage is determined by a trade-off between the tax advantages of debt and the prospective costs of bankruptcy or financial distress. Most economic regulators and financial practitioners tend to consider that the essence of the MM holds: that increased leverage leads to higher equity risks and correspondingly higher equity costs. Therefore, this adjustment *limits* but does not rule out the ability to lower financing costs overall by making more use of the lower debt costs.[84] However, there are other important aspects at play that have not been made fully explicit in previous work (although they were implicitly accounted for to a large extent).

Based on the above, we set out the following theoretical framework to explain the movements in the cost of capital from the proposed change in the renewable support scheme:

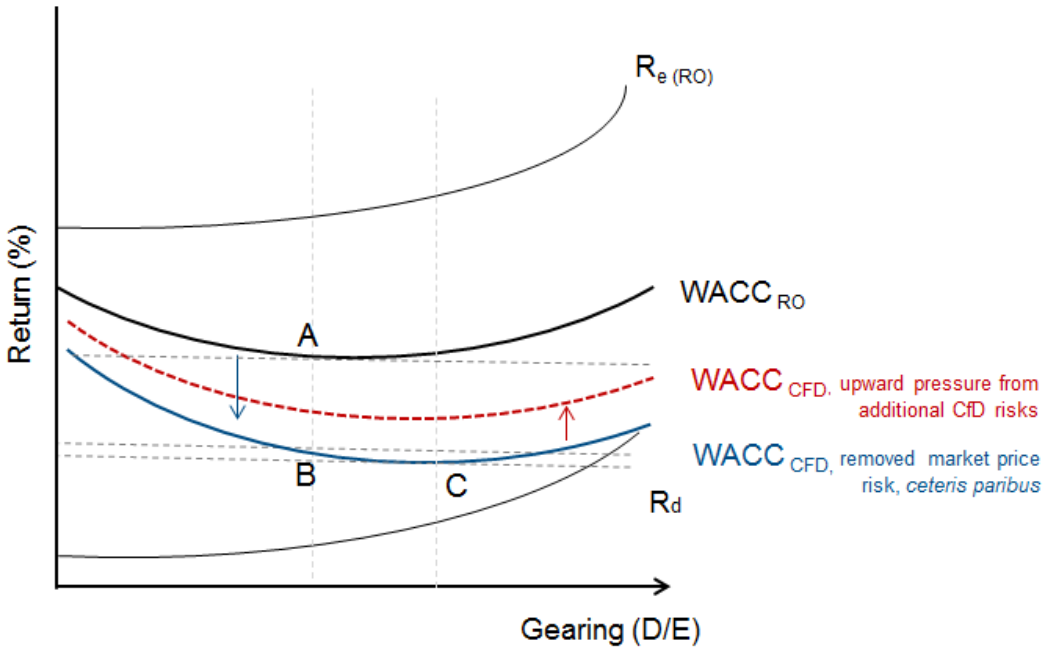
- **CfD contracts remove market price risk, thereby lowering the asset betas of renewable projects**. CfD contracts decouple renewables project cash-flows from the general movements in the market by effectively guaranteeing a fixed price of electricity (subject to basis risk). CfD contracts therefore stabilize revenues, and reduce the degree of correlation with general market movements. *Ceteris paribus,* removing market price exposure lowers the asset beta, thereby decreasing the project's cost of capital across *all* levels of gearing. Figure A.1 illustrates this point. The cost of capital moves from point A, under the RO regime (see black shaded line, showing the $WACC_{RO}$ schedule), to point B, found on the lower $_{WACCcfd}$ schedule (blue shaded line). The magnitude of this effect will depend on the extent to which CfD exposure removes overall correlated volatility in earnings, as measured by the fall in the expected asset beta and potentially also debt cost.
- **However, CfD Contracts introduce new risks which may, to some extent, offset the impact from lower market price exposure.** As we discussed above, some features of the CfD framework could be perceived as new risks for investors, not present under the existing RO framework. In section 2.3, we identified that these additional risks can be associated with construction delays, the new allocation process and changing duration of support; additionally, we also discussed that investors may be factoring in a novelty premium as a result of the uncertainty regarding the practical implementation of the framework.
- Some of these risks may directly affect project asset betas, to the extent that they offset the lower market price exposure by introducing additional sources of cyclicality (i.e. allocation risk, duration risk and counterparty risk). Other types of risk may introduce asymmetry and in particular downside risk (i.e. construction delays). Moreover, the real option value arising from investors' uncertainty about the implementation of the system, could exercise a significant upward pressure in the immediate period after CfDs are

[84] For example, The Competition Commission in its price limits determination for Bristol Water investigated the effect of gearing on pre-tax WACC. The Commission found that "while a level of gearing above the company's actual gearing may lead to a lower WACC, the effect does not seem likely to be large" See Competition Commission (September 2010), "*Bristol Water plc Price Limits Determination*".

launched. Therefore, the reduction in the cost of capital under CfDs due to removed power price risk could be materially offset by the new risks introduced by the framework. The actual cost of capital under the CfD regime may therefore fall less than envisaged and will depend on the relative magnitude of these risks, as shown in Figure A.1.

- Finally, to the extent that there is an overall reduction in equity risk (asset beta) after the net effect of 1) and 2) above, **CfD FiTs may allow for renewable projects to benefit from higher leverage**. This benefits developers by allowing them to capture a higher tax shield, moving *along* the $WACC_{cfd}$ curve from point B to C in Figure A.1 . However, as discussed above, most regulators and financial practitioners accept that the essence of the MM theory holds, i.e. that increased leverage leads to higher risks to equity holders, thereby increasing the cost of equity and limiting the ability to lower financing costs overall by incurring higher leverage. Therefore, the benefit from the tax shield is typically very small (see below).

Figure A.1
Impact on Cost of Capital from Change from RO to CfD Regime



Note: For illustration only; figure not drawn to scale.

In summary, we conclude the following:

- The CfD FiT scheme inherently differs from the RO scheme in that it removes wholesale price risk, thus lowering the degree to which expected project cashflows are correlated with the market, which leads to lower asset betas and cost of capital;
- The magnitude of this effect will depend on the degree to which additional risks introduced under the new scheme offset the benefit from lower exposure to commodity price risk. Investors may not be able to realize the full reduction in cost of capital, particularly in the immediate period after the introduction of the new regime, due to a

potential novelty premium that they may require before the system matures, to compensate them for the option of waiting and seeing how the system works in practice.

- Investors may also be able to increase project gearing levels, but standard financial theory suggests that the effect of this alone on the cost of capital is likely to be small.

A.2. An Empirical Assessment of the Strength of the different Aspects

Below we assess whether the main driver of the change in hurdle rates is likely to be the impact of lower systematic risk or increased debt-bearing capacity alone.

Table A.1 shows the magnitude of reduction due to the debt tax shield alone that is achieved for different gearing levels (across columns) and assumed asset betas (across rows).[85]

Table A.1
Effect from Higher Gearing on the Real, Post-tax WACC for Different Asset Betas

	Level of Gearing						
Asset Beta	50%	60%	70%	75%	80%	85%	90%
0.3	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
0.4	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%
0.5	4.4%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%
0.6	4.8%	4.8%	4.7%	4.7%	4.7%	4.7%	4.7%
0.7	5.3%	5.2%	5.2%	5.1%	5.1%	5.1%	5.1%
0.8	5.7%	5.6%	5.6%	5.5%	5.5%	5.5%	5.5%
0.9	6.1%	6.1%	6.0%	6.0%	5.9%	5.9%	5.8%
1	6.6%	6.5%	6.4%	6.4%	6.3%	6.3%	6.2%

Source: NERA Analysis

Note that in Table A.1 we further make the further simplifying assumption that the cost of debt remains constant. In practice it is likely that ceteris paribus investors will eventually require a higher return on debt for investing in a very highly leveraged structure (unless there are other risk-reducing features at work, e.g. a reduction in equity risk that would also work at the same level of gearing). As such the results, if anything overstate the impact of the tax shield from gearing changes alone.

Table A.1 shows, the increase in the WACC from higher gearing is only evident at higher asset betas. For example, increasing gearing from 70% to 80% given an asset beta of 0.3, has no significant impact on the WACC. The same change in the level of gearing, results in c. 10 bps reduction in the WACC for an asset beta of 0.7. On the whole, we recognise throughout

[85] To capture the tax-shield effect, we use the Modigliani–Miller adjustment of the equity beta to calculate the real, post-tax Cost of Equity taking into account higher leverage (Betalevered = Betaunlevered *(1 + (1-Tax)*D/E)). We also assume a real risk-free rate of 2% and equity risk premium of 5% (These assumptions are broadly consistent with Ofgem's assumptions for the recent RIIO decisions.) across all scenarios, and a UK corporate tax rate of 23%. (See HMRC , "Corporation tax rates", 2013, available at: http://www.hmrc.gov.uk/rates/corp.htm)

that the effect from higher gearing is likely to be small, as the increase in gearing is offset by the higher return on equity required by investors to hold the asset whose riskiness will have increased, due to higher leverage.

Overall, the analysis above shows that increasing gearing on its own has a small effect on the WACC level, whilst the effect from changing the asset beta is more significant.

Appendix B. NERA Commentary on "Other Risks"

In section 6 we discuss in detail the quantitative effect of the risks that we have identified as major hurdle rate risks in section 2. Below we provide commentary on those risks that we classified as "other risks", i.e. as risks not having a significant on the hurdle rate. Below we also set out our assessment of the comments raised on these points in interview and consultation responses.

Basis Risk refers to the inability of generators to achieve the reference price index under the contract, leading to exposure to the balancing mechanism, or the difference between the day-ahead and the within-day electricity market price. This risk is different from volume risk, which refers to the exposure to long-run uncertainty about volumes.

- For **intermittent** generation, the reference price will be set to an hourly day-ahead reference price. This means that the main residual basis risk is effectively *balancing risk*, to the extent that generators do not have perfect foresight of their output. Wind farm output is likely to be negatively correlated with the balancing price, i.e. on average, wind farms buy shortfalls when the balancing price is higher than the reference (Hourly Day Ahead Market market) price, and sell excess output when the balancing price is lower than the reference price. Therefore, on average wind farms may achieve a lower price than the reference price. However, generators arguably face similar balancing risk under the ROC system.
- For **baseload** generation the reference price will be set to a seasonal price. Dispatchable generation is exposed to basis risk in that the reference price is a seasonal average price. If the generator runs baseload, it will capture the seasonal price. If it operates in a regime with relatively volatile prices, it may find that it is more profitable to switch off in low price hours, in which case it will be better off.

Balancing cost is likely to change over time as renewables penetration increases. Given the changing nature of electricity markets, however, it is impossible to forecast these costs exactly today.

For individual intermittent generators, balancing costs may be pro-cyclical, to the extent that they are a function of the short-term supply curve.[86] In some regimes a separate balancing premium is paid in addition to the subsidy, which can be changed over time if there are clear indications that balancing costs are changing. We understand that DECC has already factored provisions for balancing costs into the strike price, via the PPA discount.

Respondents argued that the CfD regime does not provide greater revenue certainty than the RO because it reduces the ability of renewable generators to capture the market price due to the lack of supplier obligation to enter in a PPA contract. Respondents appreciate DECC's initiative to establish an offtaker of last resort/backstop PPA. However they highlighted that there is a large degree of uncertainty around the arrangements of this mechanism, which currently do not provide investors with assurance that interests of both debt and equity

[86] The balancing price is a function of the cost incurred by the TSO in order to balance the system, which depends on the short-term supply curve. This curve becomes steeper when commodity prices increase.

holders will be protected. Other related risks that interviewees mentioned included levels of PPA discounting, balancing risks, and the risk of curtailment.

Similarly, basis risk was raised as a particular issue by non-dispatchable generators (e.g. wind), who argued that they are unable to replicate the reference index.[87] Some respondents also raised a concern about the fact that the reference price has not been established yet, which creates uncertainty around how basis risk will be managed. Several interviewees underlined basis risk as a new risk but did not provide significant detail about their thinking on the topic. Most interviewees simply referred to the concern that generators might not be able to realise the reference price when they actually went to market with their output. One of the interviewees mentioned concerns that underlying market liquidity could be affected by wider market changes, resulting in reference prices that were not representative. This would affect not only basis risk, but was identified as one of the broader uncertainties (see section 7).

We understand that there is currently a significant amount of uncertainty about the eventual design and workings of the offtake arrangements. However, we assume that there will be clarity when investors take their decisions and as such we would expect any impact of offtake risk to be resolved at the start of the scheme.

Indexation Risk refers to the risk of divergence between costs (RPI growth) and revenues (CPI growth) of generators. Several respondents pointed out that the indexation mechanism of revenues being based on CPI rather than RPI (as per RO) erodes the revenues received by the generator, since costs typically increase with RPI inflation.

In our view it is not clear that costs from renewable generators grow with RPI.[88] We also understand from DECC that this issue is not one that the CfD expert group or respondents raised when DECC took the RPI / CPI decision. Even if there were evidence that RPI inflation was a better indicator of renewable project cost inflation, this should be factored into the strike price calculations, rather than in the hurdle rate. In that case the impact on the hurdle rate would be small as the only additional uncertainty introduced would be arising due to the difference between the RPI forecasts factored into the strike price and actual future RPI inflation. However, we note that this difference is likely to be small, not per se larger than the same difference for CPI and symmetric.

Collateral Provision refers to the cost of posting collateral for payments under the contract, i.e. during situations when the reference price exceeds the strike price. Some respondents point out that under the CfD, generators will be required to provide collateral in the event that reference prices exceed strike prices, which imposes an additional cost/risk to generators.

We note that the collateral requirement is likely to be small, in that generators are required to make these payments when power prices are high, i.e. during times when they are earning significant wholesale revenues. In addition we understand from DECC that this position is

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[87] One energy supplier provided a stylised example showing 5 per cent under-recovery of the reference price for a wind farm and note that this percentage is likely to increase in the future.

[88] One of the main differences between the CPI and the RPI index is that the former accounts for housing costs, i.e. mortgage payments, rents etc, which are unlikely to play a role in the context of renewable generators.

still under review with a view to addressing this issue. We do note that in any case transaction costs allowances should be included in the strike price. We understand that DECC is considering collateral rules which could remove this concern.

Credit risk refers to counterparty risk, i.e. the risk that the counterparty under the renewable support contract is unable to honour the obligations under the contract. Under the RO, the credit risk for ROC revenues is backed up by the pooling mechanism, which was established up after the TXU Collapse and which reduces credit risk exposure to any one single party. Under the CfDs, the counterparty is a public entity; our understanding is that DECC is still in the process of finalizing the details of the planned instruments under the CfD. However, because of the existence of risk pooling systems under both regimes that limit exposure to an individual counterparty, we find no material difference in risk under the two mechanisms.

Force majeure refers to risk that the parties will not be able to honour the contract due to matters outside of their control. We note that this risk is not systematic, i.e. extreme events can happen in both in an upturn or downturn of the market.

Volume Risk refers to the inability of some (typically intermittent) generators to perfectly predict or control output in the long-run, which introduces volatility in their revenues. CfD FiTs may exacerbate this risk, in that the subsidy is frontloaded, and therefore concentrated on lower volumes overall. However, we note that this risk is symmetric, i.e. positive shocks are on balance equally likely as negative shocks. Volume risk is also diversifiable i.e. developers can mitigate weather risk by holding a portfolio of wind farms at different locations. Investors can also insure against it. No respondents specifically raised this issue.

Change in Law Risk refers to the risk that a future law provision could change the revenues or costs of the project. An example of this type of risk would be a change in the level of corporate tax. In our view, in most cases this risk is political, and not systematic. For example, tax rates can be counter-cyclical, if there is political will to incentivise the economy, or pro-cyclical, if it is politically desirable to fill gaps in government budgets over economic upturn. It is therefore possible for international investors to diversify across different regimes.

Respondents note that the CfD contract provided some protection against changes in law which affect a certain class of renewable generators. However, they note that the protection does not cover changes in law which affected the industry as a whole, in which case any resulting costs would need to be absorbed by the generator.[89]

Only one respondent mentioned change of law (after going through the entire list of risks originally sent in our covering note). The interviewee noted that CfDs provided the benefit of a firm contract that was not subject to policy changes – but that would, on the other hand, now be subject to idiosyncratic risks that might not affect other market participants (for example, a change in tax regime that previously would have been passed through into prices now might not affect the generator in the same way as the rest of the market.

[89] Respondents used the example of a change in tax rate, which under the RO would affect the wholesale electricity price and therefore would also feed through into generators revenues. Conversely, under CfD the additional cost due to higher tax rates would need to be absorbed by the generator.

Appendix C. Significance of Earnings Volatility for CfD vs. RO

In this section we present our analysis of how different factors contribute to the volatility of earnings for on- and off-shore wind. This analysis contributes to our overall assessment of the potential for CfDs to reduce hurdle rates as a result of their stabilisation of revenue volatility.

C.1. Earnings/Price Risk

By earnings/price risk we define changes in market condition which adversely affect the value of the asset driven by power market risk (incl. negative prices) and volume risk. To understand better the extent to which more stable revenues from electricity prices would affect wind generation, we have developed a set of modelling simulations that allows us to quantify the impact of stable revenues on both existing assets and new assets.

Figure C.1
Impact of Price Risk on WACC

Item	Comment	Impact
Exposure to Short Term (Annual) Volatility	• Power prices are one of several drivers of short term revenue volatility. Volatility coming from price is mitigated almost entirely	↓
Exposure to Long Term Volatility	• Power prices are a key long term risk driver. The exposure to this macro-economic risk mitigated almost entirely	↓
Exposure to Negative Prices	• Subsidy is capped at strike price such that the captured subsidy is reduced. However, the effect on present value is very limited.	→
Net Impact	• Significant reduction of power price exposure	↓

Our findings are based on simulations of revenues using two techniques:

- **Historical simulation of existing assets**: Using historical information on price and volumes, we analyse what revenue volatility would have been for the period 2005-2013 if the subsidy regime had been a CfD regime instead of a ROC regime; and
- **Scenario based analysis of hypothetical new assets**: Using a set of different scenarios for the power price evolution we analyse the impact on the present value of a hypothetical new asset of various shocks, including price variation.

This section focuses on *absolute* risk and the importance of the main revenue volatility drivers of electricity generators, i.e. volume vs. price risk. It should be noted that although volume risk affects revenue volatility, and therefore possibly the level of achievable gearing, it is to some extent diversifiable, which means it is less important for the overall determination of the hurdle rate.

In order to translate the reduction of absolute risk directly into an impact on beta, we would need to quantify the relationship between wholesale power prices and the market index, which we have not attempted here. This analysis can therefore be used only to assess qualitatively the *direction of beta risk* and the *relative risk* reductions between technologies and cannot be seen as stand-alone evidence of the magnitude of beta-risk reduction or the impact on the hurdle rate.

C.1.1. Historical Simulation: *Revenue Volatility*

The objective of the historical simulation is to analyse how the two regimes would have performed if applied to actual, observable market data and load factors, focussing on the revenue volatility.[90] We proceeded as follows:

1. Using historical hourly generation and power prices since 2005 we reconstructed the revenues as they would have been under ROC vs. CfD scheme for existing assets;
2. We then compare the volatility under the two regimes; and
3. Finally, we present a breakdown of the relative importance of volume and price risk.

Using this approach, we find that earnings volatility would have been significantly lower under the CfD system than under the ROC system. In particular, we find that market price risk, which is largely eliminated in the CfD regime, is much more important for onshore wind than offshore wind. In turn, we expect the reduction in discount factor to be larger for onshore wind than offshore wind. Due to lack of data we have not analysed other sources of renewables such as biomass. For these asset classes, the reduction of market price risk is likely to be less important than onshore wind, because a larger proportion of costs are OPEX and therefore not sunk at the time of investment.

C.1.1.1. Summary of Historical Data Analysis

Table C.1 shows the simulated assets together with the date of the first reliable data. On the basis of these individual assets we constructed hypothetical onshore and offshore portfolios consisting of all of the assets (equally weighted).

[90] The main benefit of this approach is that, rather than making subjective assumptions about scenarios for the future, we look at how revenues would have responded to historical events under the two schemes. The main drawback of this approach is that it only shows "one path" and that it only appropriate for assets which have been constructed.

Table C.1
Simulated Assets

Name	Capacity (MW)	Registration Date	Data Since	ROCs
Offshore				
Walney Offshore Wind Farm Unit 1	182	01/11/2010	Feb 12	2
Greater Gabbard Offshore Windfarm	180	18/12/2009	Feb 11	2
Thanet Offshore Wind Unit 1	99	30/04/2010	Aug 10	2
Onshore				
Kilbraur Windfarm	47.5	14/12/2007	Jun 08	1
An Suidhe Windfarm	19.4	05/05/2010	Nov 10	1
Black Law Wind Farm	134	01/04/2005	Apr 05	1
Beinn Tharsuinn	29.7	02/12/2005	Feb 06	1
Braes of Doune	74	04/09/2006	Sep 06	1

Source: Platts Powervision

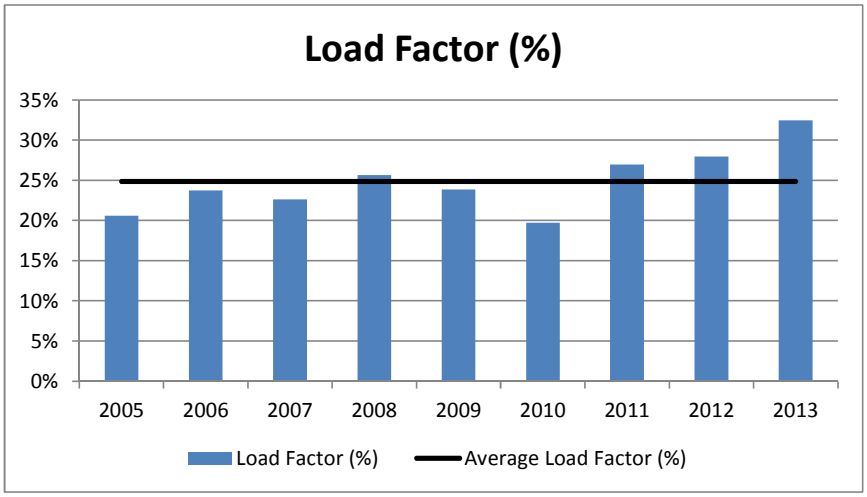
Figure C.2 shows the achieved load factor for the onshore portfolio for the period 2005-2013.[91] The average load factor is 25 percent but varies considerably between years, typically by +/-5 percent points.

Figure C.3 shows the reconstructed (ROC) and counterfactual (CfD) revenues for a portfolio of onshore portfolio assets under the two different subsidy regimes. The revenue stream varied by approximately +/- 20 percent around the mean (£40/kW), under the ROC scheme, and +/-12 percent around the mean (£25/kW), under the CfD scheme.[92] This is affected significantly by the higher price in 2008.

[91] The load factor is an average of the wind farms in the portfolio from the date where we have reliable data. 2005 is therefore based on only a single wind farm whilst 2012-2013 contained a portfolio of 5 wind farms.

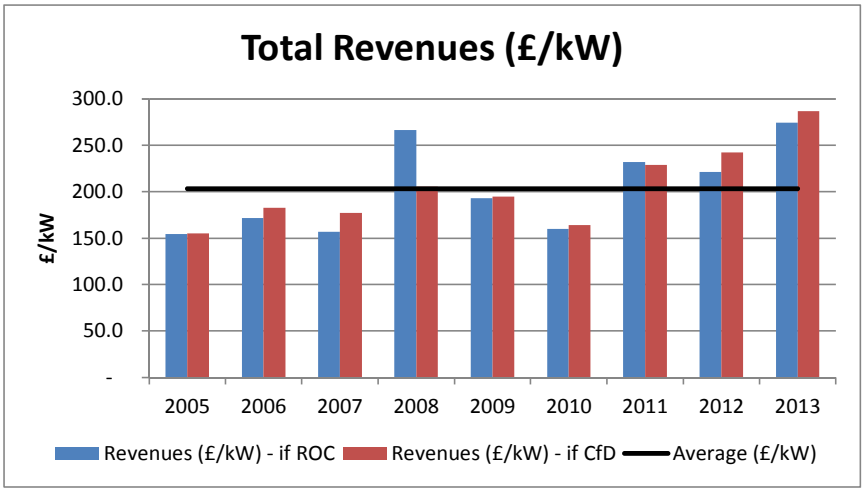
[92] For this analysis we assume that the CfD price was set such that the present value of the asset under CfD is exactly identical to the present value under the ROC regime, such that *annual revenue volatility*. In practice, of course, the power price cannot be forecasted so a ROC "revenue forecast" need not be the same as the outcome. This aspect is addressed separately in the next section.

Figure C.2
Load Factor for Onshore Portfolio



Source: NERA analysis on data from Platts Powervision

Figure C.3
Reconstructed Revenues for Onshore Portfolio ROC vs. CfD



Source: Platts Powervision and UKPX (www.elexonportal.co.uk), NFPA e-roc data, and NERA analysis

C.1.1.2. Risk Reduction for Different Assets: Onshore vs. Offshore

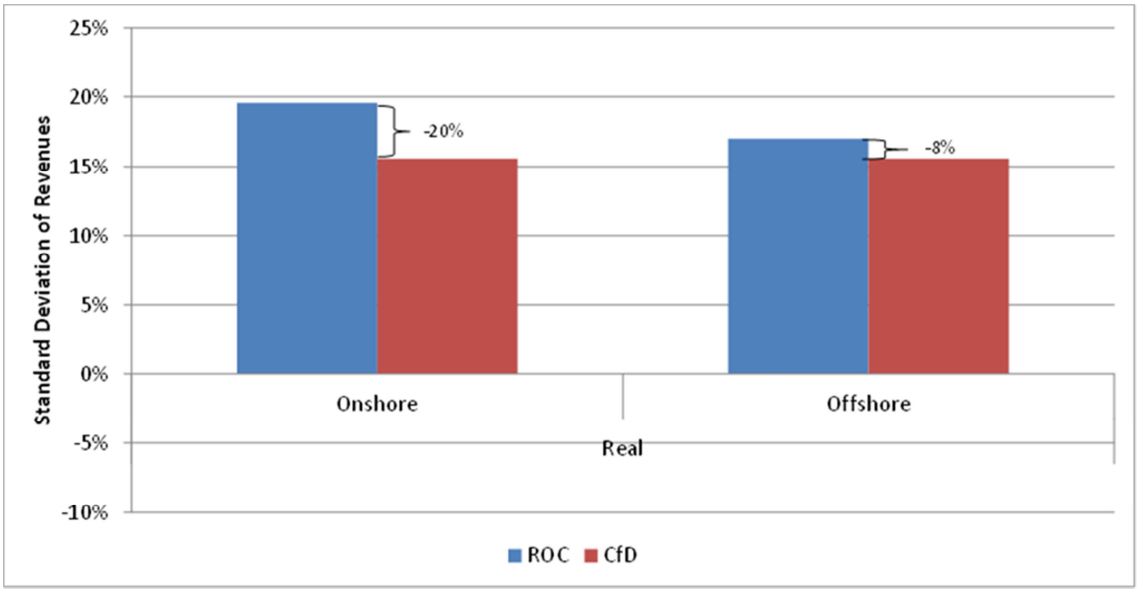
Figure C.4 shows the estimated reduction of risk in the CfD regime compared to the RO. The bars shows that the revenue of a hypothetical portfolio of the 5 selected onshore wind farms in the UK would have had a standard deviation of 20 percent under the RO, taking into account the actual variation in electricity prices and ROC prices over the period 2005-2013

and historical wind yield (volume). The red bar shows that under a CfD regime, the revenue volatility would have been lower: about 15 percent (assuming a constant strike price). In other words, under a stylised CfD scheme the standard deviation[93] of revenues for onshore wind would have been about 20 percent less than the standard deviation under the RO . The chart shows the corresponding reduction in standard deviation would have been significantly smaller for offshore wind, at around 8 percent.

These results should be interpreted with caution:

- The volatility represented by the standard deviations shown below reflect the *total* risk affecting revenue, some of which (for example, volume risk) may not contribute to the equity portion of the WACC, because it is diversifiable. It is not straightforward to estimate how systematic each of the different risks is; and
- The estimates are based on a limited set of observations, and are therefore sensitive to the various data points, including inflation assumptions.

Figure C.4
Risk Reduction of CfD

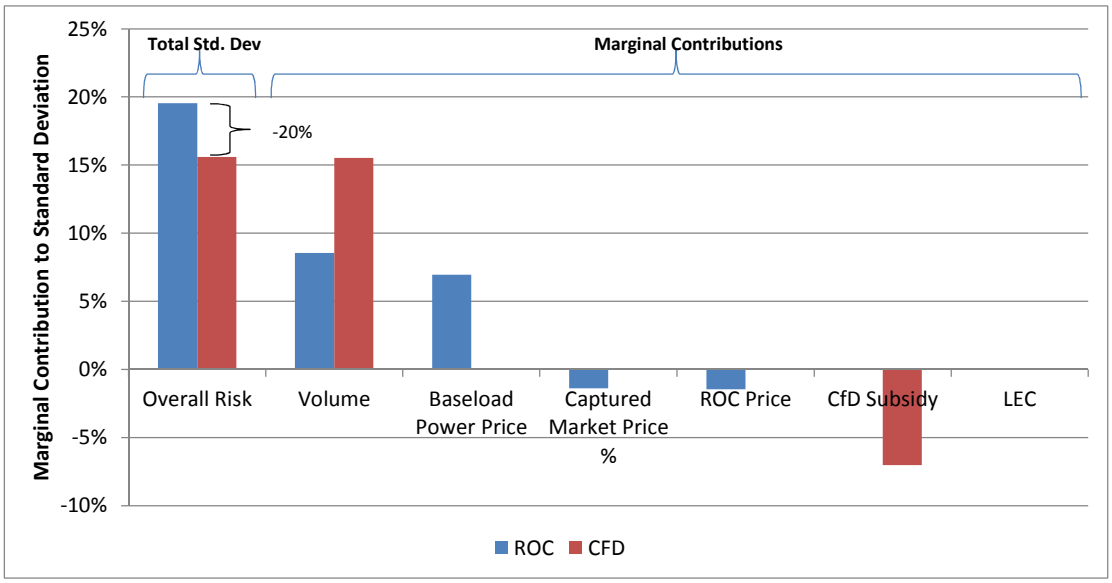


There are some further observations to make about this analysis. The relatively small change in overall risk under the CfD regime implies that there are a number of other factors affecting the volatility of wind farm revenues beyond the price risk that is mitigated by the CfD. We analyse these factors further in the discussion below.

[93] For this analysis we use volatility as the key risk indicator, measured as the annualised standard deviation. The standard deviation is a risk measure which is easy to grasp intuitively and to relate to the underlying variable (e.g. it is expressed in the same units as the underlying variable whose dispersion we are measuring.).

Figure C.5 shows a breakdown of the historical volatility for the onshore wind portfolio (Note that the risks are not additive as the overall risk is a product of the different risk distributions, and the different factors are correlated).

Figure C.5
Sources of Risk for Existing Assets: Onshore



Source: Platts Powervision and UKPX (www.elexonportal.co.uk), NFPA e-roc data, and NERA analysis

Note: The marginal contribution to the standard deviation of revenues is calculated as the standard deviation of the revenues, minus the standard deviation of revenues where the individual component is set to the average over the period. The variables are multiplied and interact with each other so are not additive. "Captured Market percent" refers to the ratio of baseload prices captured by the generator (We assume an hourly reference index for generation from CfD so it falls away). The analysis shows the captured price percent is lower for high wind years, so contributes negatively to volatility.

- To the right of the Total Standard Deviation (repeated from above as the first pair of bars), the additional bars break down the total volatility into six contributing factors. The "marginal contribution" of each component to overall volatility is calculated by removing each volatile component one at a time. So for example, if volume (the first factor) is fixed at the average annual volume, the residual volatility would be about 12 percent under the RO and would completely disappear (that is, the remaining volatility would be zero) under the CfD scenario. Therefore, we calculate the marginal contribution of the volume risk to be 20 percent – 12 percent = 8 percent in the ROC scenario and 15 percent for CfD.[94]

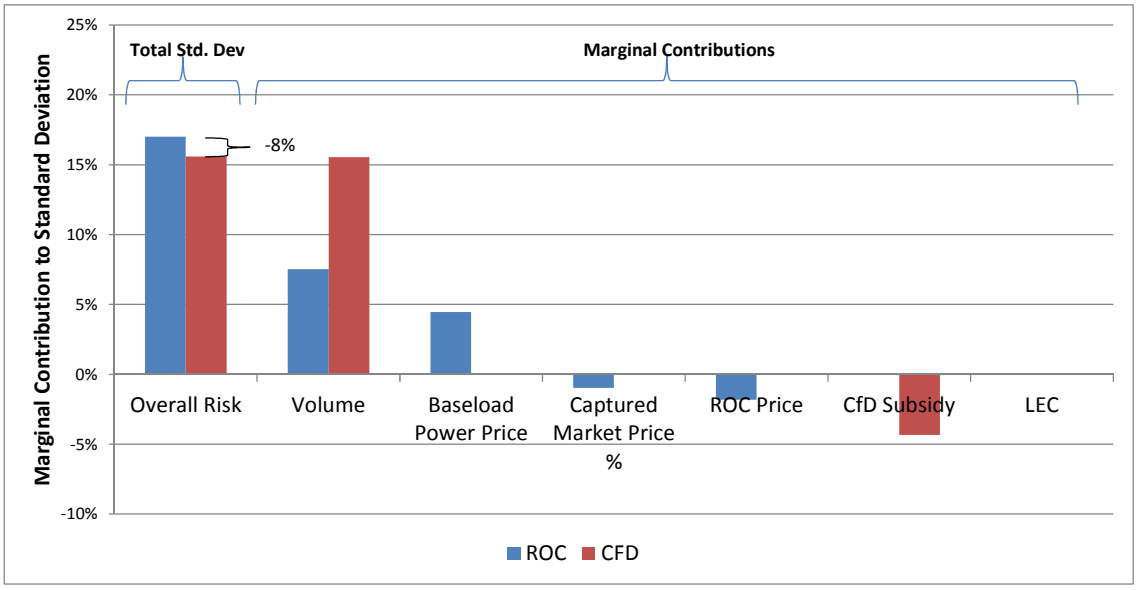
[94] The "marginal contribution" to the standard deviation of revenues is calculated as the standard deviation of the revenues, minus the standard deviation of revenues where the individual component is set to the average over the period. As the risks are not perfectly correlated the marginal contributions decline with the number of risk sources, so the sum of each marginal risk source is smaller than total risk. "Power price" refers to baseload power price. "Basis risk" refers to the captured power price being different form the baseload power price. As we assume an hourly reference index and perfect day-ahead foresight of generation this is (nearly) zero for the CfD mechanism.

- The result for the second individual factor shows that the overall volatility of revenues drops by around 7 percent points when we remove power price risk by fixing baseload power prices at their average level over the period. Since the generator is not exposed to the baseload power price under the CfD regime, fixing this price does not affect revenue, and there is no associated impact on volatility (so no red bar shown for Baseload Power Price).
- The fourth set of bars, "Captured Market Price %" refers to the proportion of annual baseload power prices captured by the generator. The negative contribution to volatility for the ROC regime suggests that in the historical period considered, high wind years may have been associated with slightly higher "haircuts" to the baseload price. There is no difference in the "Captured Market Price %" for the CfD contract, which (in this example) we assume always captures the strike price regardless of the power price.[95]
- The fifth set of bars shows the impact of the ROC price. The small negative contribution from ROC prices is because ROC prices are moderately negatively correlated with output.
- The sixth set of bars shows the contribution from CfD payments, which contribute negatively to revenue volatility – that is, they stabilise revenue – in the CfD scheme.
- The overall change from the ROC system to the CfD system therefore incorporates (i) reduction in baseload price risk (ii) loss of the volatility associated with the captured market price percent, which mitigates the overall volatility and (iii) loss of the mitigating effects from the ROC price.

Figure C.6 shows the corresponding results for offshore wind. Here, the reduction in risk is smaller due to (i) the smaller contribution of risk from the power price and (ii) larger loss of counteracting effect from the ROC price. Both differences are due to the fact that electricity market revenues are a much smaller proportion of total revenues for offshore assets, because they receives 2 ROCs instead of 1 per MWh.

[95] In fact, some "basis risk" remains under the CfD for wind generators, because the captured revenue actually depends on the day-ahead reference price, rather than the price actually captured by the generator. We have not reflected the differences between day ahead and spot prices in the stylised example presented here.

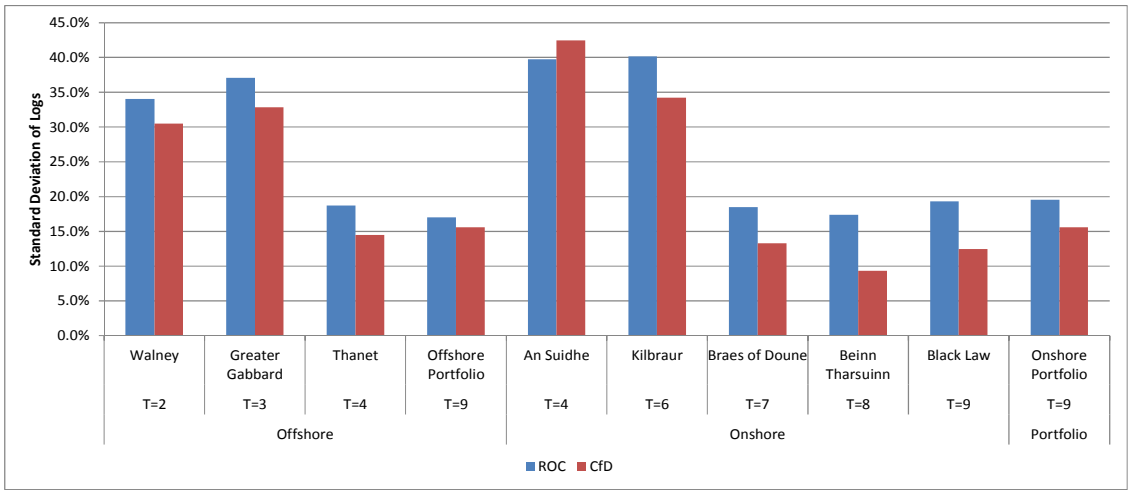
Figure C.6
Sources of Risk for Existing Assets: Offshore Wind



Source: Platts Powervision and UKPX (www.elexonportal.co.uk), NFPA e-roc data, and NERA analysis

The above analysis is constructed for a portfolio of multiple assets. To validate these results, we conducted a similar analysis for each individual asset. The resulting standard deviations are shown in Figure C.7. As evident from this figure, the revenue volatility is consistently lower for assets under the CfD regime than under the ROC regime. The magnitude of the reduction of standard deviation, however, varies considerably across different assets. The wind farms represented in Figure C.7 also differ in age, and the figure groups the wind farms by location and in order of age.

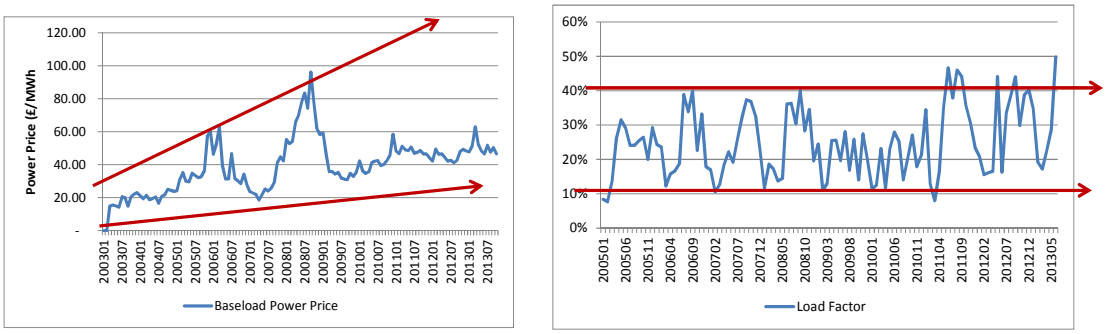
Figure C.7
Aggregate Risk Reduction for Existing Assets



Source: Platts Powervision and UKPX (www.elexonportal.co.uk), NFPA e-roc data, and NERA analysis

Figure C.8 shows the time series characteristics for the power price and the load factor. This illustrates how the *power price risk increases over time*, whilst load factor / volume risk *does not.*[96] In other words, the longer the holding period, the higher relative importance of price risk compared to volume risk.

Figure C.8
Time Series Characteristics for Power Price and Wind Output (2005-2013)



Source: NERA analysis on data from Platts Powervision and UKPX (www.elexonportal.co.uk)

C.1.2. Scenario-Based Analysis: Long Run Revenue Uncertainty & Negative Prices

Whilst the previous section focused on risks to existing assets over a limited period, this section is analyses the change of risks for the life of an asset from development through to construction/operation. We also make allowances for the likelihood that power price volatility could increase in coming years as more intermittent generation comes on the system. We find that:

- **Overall Price risk** is smaller under CfD than the ROC system, in line with the historical analysis;
- **Adverse effect of negative prices on valuation is limited.**

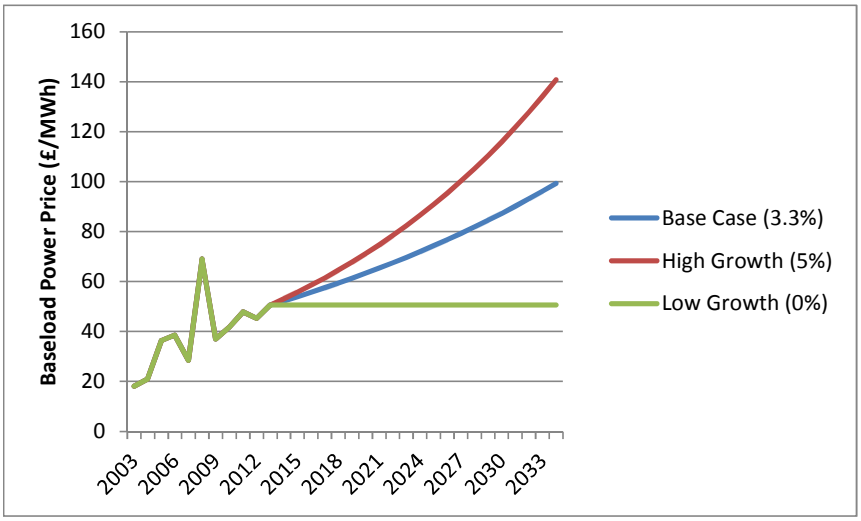
In order to perform this analysis, we created a hypothetical new offshore wind asset with an assumed commissioning date of 2015. By construction, and consistent with the government's current proposals, the NPV of the expected revenue stream over the life of the asset is set identical in the CfD and the ROC regime. We then analysed the impact on the project value of varying the outturn world from the initial expectation in both subsidy schemes.

For the purpose of illustration we assume inflation is 2 percent, £155/MWh strike price and WACC of 10 percent. We assume the ROC price and LEC prices grow in line with inflation.

[96] Formally, the time series properties of power prices and load factors are different: the autocorrelation coefficient for power prices is much higher than for load factors, possibly even a *random walk*. This means that, whilst load factor and power price risks in any given year may give rise to similar risk, over the long run, load factor risk averages out, whilst power price risk does not..

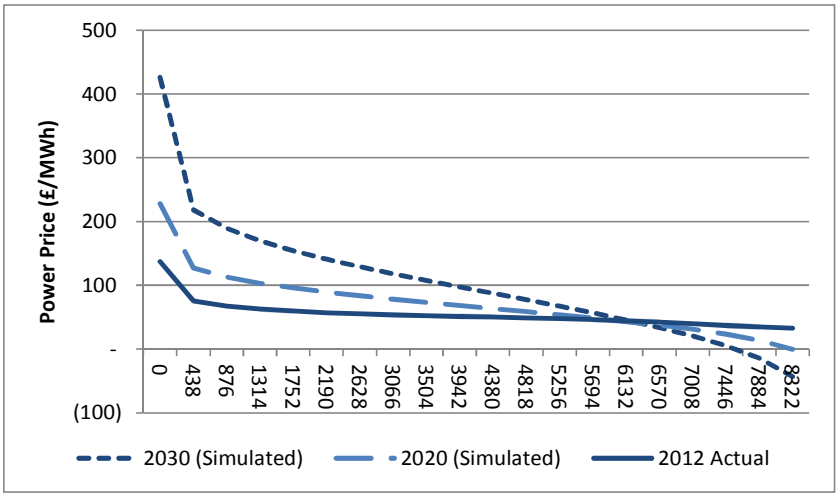
Figure C.9 shows 3 illustrative scenarios for the evolution of the power price. In the base case, we assume a 3.3 percent growth in the power price consistent with the trend from 2003-2013. We then created two illustrative scenarios around this, with a high case of 5 percent annual growth and a low case of 0 percent growth.

Figure C.9
Illustrative Scenarios for Baseload Power Price



Additionally, we created a *volatile price scenario* where the baseload price is as in the base case, but where the within-year variation increases significantly, such that prices occasionally become negative. (In this scenario we assume 5 percent of prices are negative by 2020[97]).

Figure C.10
Illustrative Volatile Price Scenario: Price Duration Curve

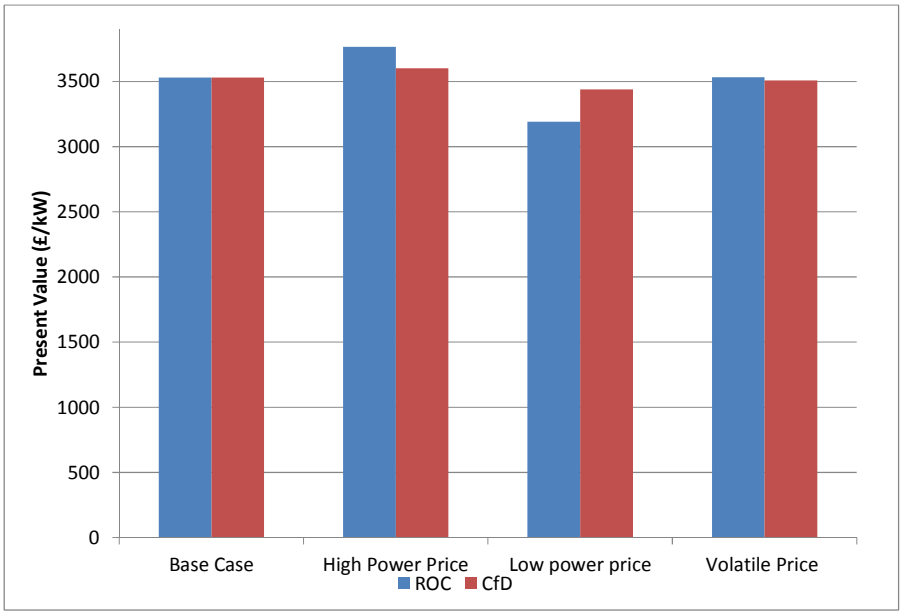


[97] Please note that this is likely to be more extreme that the reasonable range of uncertainty.

Figure C.11 shows the changes in present value in response to different price assumptions. Column 4 shows the effect of a volatile price scenario, where we assume prices go negative and subsidy top-up is capped at the strike price. We find that:

- The NPV of an asset under ROC subsidy responds more to power changes than CfD; and
- In theory, if the probability of negative prices is ignored when setting strike prices the CfD performs slightly worse than the ROC system, but our estimates suggest the impact is too small to change required actual strike prices.

Figure C.11
Exposure to Power Price Changes and Negative (Volatile) Power Prices



Source: NERA analysis

Appendix D. Quantification of Time-Related Risks

This section sets out the quantitative analysis we have undertaken to analyse the differences between the CfD and the ROC subsidy schemes on four key sources risks as raised in the consultation responses, analyst reports and interviews:

- **Duration Risk:** Risks arising due to the shorter duration of support offered under CfDs.
- **Allocation risk**: Risk that unexpectedly high budget commitments under the Levy-Control Framework (designed to limit the total cost to consumers of renewable support policies) result in government action to reduce support for *future* renewables capacity. (We assume that the government honours "grandfathering" obligations to capacity that is already commissioned and receiving support.)
- **Construction Risk:** Impact on project value of construction delay.

D.1. Duration Risk

The duration of the CfD contract for most technologies is expected to be 15 years, whereas under the RO the duration of support was typically 20 years.[98] In this section we discuss the change in risks associated with the shorter subsidy horizon. In summary, we find that the duration risk in itself does not merit a change in the risk premium, as depicted in Figure D.1.

Figure D.1
Impact of Duration Risk on WACC

Item	Comment	Impact
Market Risk in Year 16-20	• Under both regimes the generator is exposed to the same power price risk in years 16-20. • The importance of subsidy revenues is shifted from years 16-20 to years 1-15 compared to the ROC system	
Enhanced Operational Flexibility	• The frontloading of subsidies means the generator does not have to run if prices (or more accurately, expected margins net of any operating costs) below zero after year 15.	
Net Impact	• Market risks unchanged. Operational flexibility has limited value to generator	

This is because the asset has similar or reduced market exposure compared to the ROC system:

- **Under a CfD a generator is exposed to the same market risk as under the RO in years 16-20:** Under both regimes the generator is exposed to power price risk in years 16-

[98] https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/the-renewables-obligation-ro

20. Although the relative proportion of revenues coming from market-revenues is increased in years 16-20 compared to the ROC system, this simply reflects a change in the timing of the receipt of subsidies, with a smaller proportion from market revenues in years 1-15 and an unchanged NPV of the subsidy stream.

- **The frontloading of subsidies enhances operational flexibility in year 16-20**: Changing the timing of subsidies does not in itself lead to a change in risk. However in the existing ROC system the generator is forced to run for all hours for 20 years to extract the entire expected subsidy – even at times when there are negative power prices. The frontloading of subsidies means the generator does not have to run if prices (or more accurately, expected margins net of any operating costs) fall below zero after year 15. This optionality tends to reduce exposure to variable OPEX inflation and negative power prices after year 15. However, as our analysis shows, the net impact of this benefit on the value of the asset under CfDs is limited due to discounting.

Although the shorter duration of CfDs does create a **potential for a magnification of volume risk**, this is largely symmetrical and/or diversifiable, so we would not expect this to affect the hurdle rate or WACC.

To quantify the value of the operational flexibility identified in item 2, above, we construct a hypothetical generation asset and simulate its cash flows under four different simplified scenarios – a Base Case and three others – and we then calculate the net present value (NPV) of these cash flows. We compare the NPV under an RO regime lasting 20 years to the NPV under a CfD regime lasting 15 years.

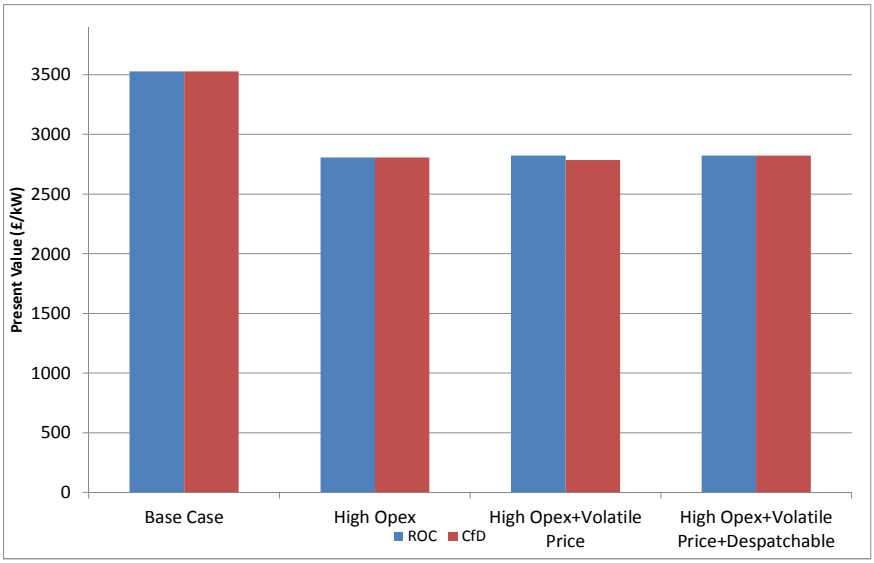
To isolate the potential impact of operational flexibility, we construct a scenario in which the potential differences are deliberately starker than they might be in a real-world example.

Figure D.2 shows the present value effect of a very large (£30/MWh) increase in the generator's OPEX in three scenarios:

1. **High Opex:** We introduce an OPEX shock of £30/MWh. This leads to a drop in NPV of approximately 20 percent under both subsidy regimes.
2. **Power price volatility:** Introducing negative prices leads to a slightly poorer performance of CfD due to the capping of support paid to generators at a level no more than the value of the strike price. In this scenario, both the RO-supported and the CfD-supported generator lose revenue if they generate when power prices are negative, but the RO regime also provides an up-side when power prices are high, which the CfD does not provide.
3. **Allow for despatch of generator:** Allowing the generator to treat the £30/MWh estimated opex as a fully variable cost would bring the NPV of the CfD-supported project back on par with (slightly above) the ROC system. This is because of the increased flexibility of operation after year 15.[99]

[99] Although variable operating expenses are more relevant for technologies relying on fuels, such as biomass, wind and solar technologies also have operating expenses, which it may be profitable to avoid if revenues from power generation are expected to be very low.

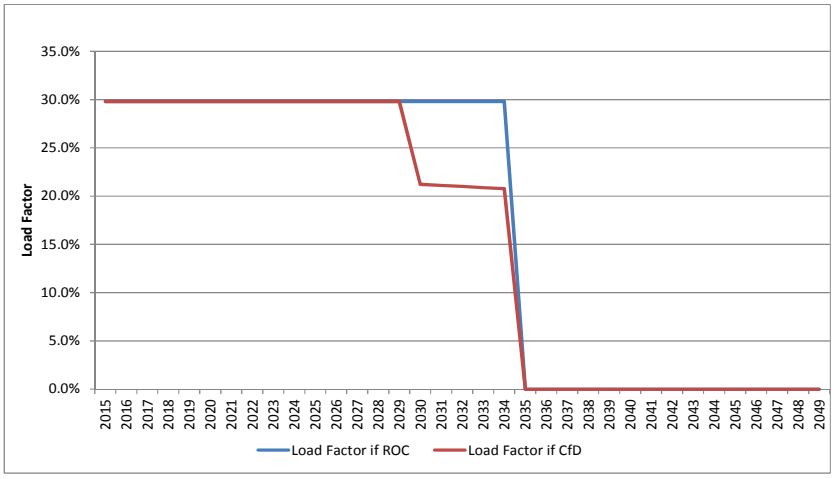
Figure D.2
Exposure to OPEX



Source: NERA analysis

Figure D.3 shows the achieved load factor for different years, using a high OPEX assumption. This shows that the generator chooses to reduce output significantly after year 15 in the CfD regime in response to the increased OPEX, because this *increases* the overall profit to the generator. This does not happen under the ROC system because the generator would forego significant subsidy by choosing not to generate.

Figure D.3
Load Factor in response to OPEX shock



Source: NERA analysis

D.2. Allocation Risk

Increased allocation risk was one of the most commonly cited concerns mentioned in the consultation responses and identified during industry interviews. By allocation risk, we mean the risk that unexpectedly high commitments under the Levy-Control Framework (designed to limit the total cost to consumers of renewable support policies) result in government action to reduce support for *future* renewables capacity, either in the form of a reduced subsidy or reduced accreditation probabilities. (We assume that the government honours "grandfathering" obligations to capacity that is already commissioned and receiving support.)

There are three key differences between the proposed CfD and the *existing* ROC regime:

1. The subsidy allocation is locked in earlier, which, all else equal, increases certainty for the investor;
2. A corollary or related feature is that the allocation is less flexible (because it commits the government to a certain expectation about impacts on the LCF), which makes investors less able to adjust their project in response to changes in installation costs or technologies, or to re-scale projects; and
3. The total subsidy commitment is significantly more uncertain under CfD (because it fluctuates with the wholesale electricity price), leading to the risk of forced (unforeseen) changes to the system. This reduces certainty of availability of funds, particularly toward 2020.

We find that:

- Compared to future allocation risk under an RO *without* early lock-in, there does appear to be a benefit of the CfD's early lock-in, which reduces risks. Compared to WACCs *as they would have been with an unchanged ROC procedure* by 2015-2016, the WACC is likely to be lower with the early accreditation as in the CfD than late accreditation (as in the ROC regime).
- Compared to the allocation risk in the RO regime up until now, we find no significant benefit of the early lock-in: To date, precedent for the ROC regime has been that there has been no significant constraint on the amount of projects which could be accredited ROCs[100] and banding reviews have been announced in advance, synonymous with a very high accreditation probability. Compared to the *current* allocation risk in the ROC regime, it is therefore unlikely that the effect of the early allocation has a significant effect on the WACC.
- Compared to a counterfactual in which the ROC allocation procedure would have been adapted to the narrowing LCF bands, thus there is no direct effect. However, due to uncertainty of government expenditure, the policy risk of the CfD risk is higher than under the ROC scheme.

[100] Apart from dedicated biomass, which had a quota associated with it.

As shown in Figure D.4 we find that the net impact of these differences in allocation risk alone results in a net increase in allocation risk compared to the relevant counterfactual RO regime.

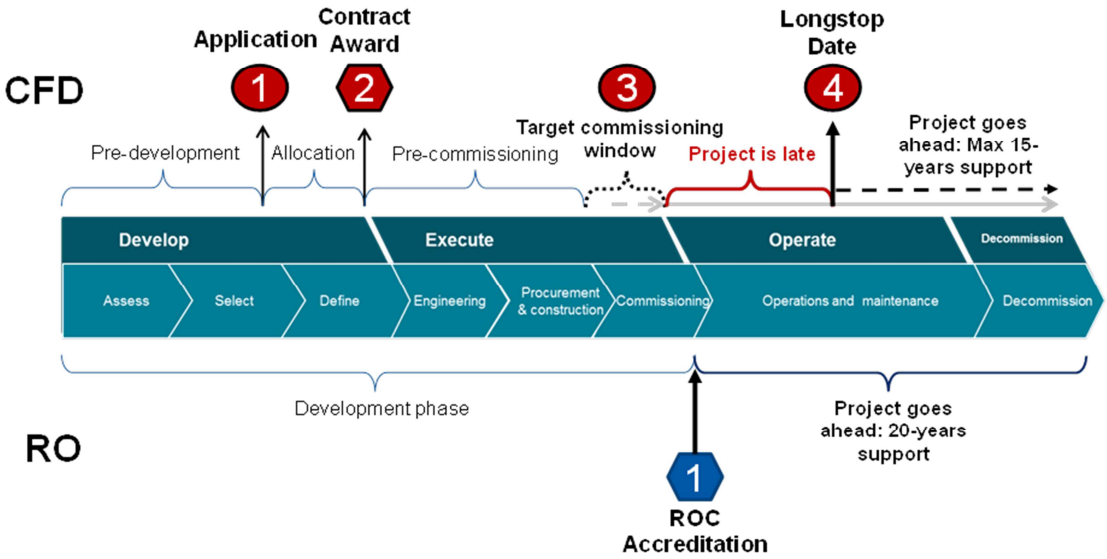
Figure D.4
Impact of Allocation Risk on WACC

Item	Comment	Impact
Allocation Lock-In	• Early allocation means little exposure to allocation risk compared to ROC • Compared to current ROC regime this change is less important • Early lock-in would have happened anyway	
Shocks to Fund Availability	• Risk of sudden government fund shortage higher; Increased allocation risk pre allocation due to locked-in government funds	
Net Impact	• Early lock-in would have happened anyway • Relationship to power price means availability of government funds is subject to shocks	

D.2.1. The allocation process

Figure D.5 shows the differences in the allocation processes between the CfD to the current ROC regime.

Figure D.5
Allocation Timing



Under the existing ROC system the commissioning date determines the relevant banding level (Highlighted as the hexagon-shaped "1" on the blue background). Until the commissioning date there is no formal security of support and the support level (banding) also remains subject to change.

The allocation process for CfD system is more complex. There are a series of key dates with (highlighted in steps 1-4 on a red background):

1. **Application date:** Projects are eligible to apply at early stage of project development. For example, wind is eligible when it has secured planning permission and accepted a network connection offer. The developer needs to provide the government with a "level of certainty that the projects are likely to progress to construction."
2. **Contract Award date:** Contracts will initially be awarded on a "First Come First Served" basis. Later, the government plans to move to allocation rounds. Following contract award, all CfDs need to meet certain milestones from an early stage in project development (c.1year). Failure to provide financial milestone may result in termination of the CfD contract.
3. **Commissioning Window:** Each project has a set commissioning window. This is a period of time within which a project must commission in order to enjoy full value of CfD for full duration of the contract. Support is granted for a maximum of 15 years from the last day of commissioning window. If the project is delayed beyond this date it starts to lose support for the duration for which the project is late.
4. **Longstop Date:** If less than 95 percent[101] of the originally planned project is commissioned by the Longstop date the strike price is gradually adjusted downward, in proportion to the capacity shortfall. If less than around 70 percent of the planned capacity is commissioned, the CfD contract will be terminated, and the developer would have to re-apply for support.

The key difference between the systems is that support allocation in the CfD (Red hexagon with a "2") happens much earlier than in the existing ROC scheme (Blue hexagon with a "1").

The early allocation has no effect so long as all projects can be sure of accreditation/allocation. However, if the accreditation probability is less than 100% an uplift is required to either the strike price or the WACC in order to compensate for the probability of stranded development costs. The more capital is sunk before notification, the higher the required uplift. For example, with a 90% accreditation probability, 10% development costs and a 10% WACC, developers would expect to lose 1% of revenues due to allocation risk on average. In order for developers to earn the required average return of 10%, an uplift of around 15bp would be required on the cost of capital, assuming a 20 year asset life. This is shown in Figure D.6.

[101] DECC (2013): "Electricity Market Reform Market– Contract for Difference: Contract and Allocation Overview", https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/233004/EMR__Contract_for_Difference__Contract_and_Allocation_Overview_Final_28_August.pdf

Figure D.6
Required WACC Uplift to Compensate for Allocation Risk Under Different Allocation Probabilities and % Capital Sunk Pre- Allocation

Impact on Cost of Capital (bp)	% Capital Cost Sunk Pre Allocation Announcement							
Accreditation Probability	0%	1%	5%	10%	25%	50%	75%	100%
5%	0	242	1057	1898	3973	6696	8585	8585
10%	0	117	542	1009	2180	3808	4732	4732
20%	0	53	254	487	1103	1985	2510	2510
30%	0	31	151	294	687	1262	1609	1609
40%	0	20	98	193	459	860	1103	1103
50%	0	13	66	130	313	597	772	772
60%	0	9	44	87	213	410	536	536
70%	0	6	28	56	139	271	356	356
80%	0	3	17	33	82	162	213	213
90%	0	1	7	15	37	73	97	97
100%	0	0	0	0	0	0	0	0

Source: NERA analysis. The figure assumes 1/3 of revenues come from the electricity market. This means it is optimal to commission the project regardless of the allocation status if the sunk capital is beyond 2/3 of NPV of revenues.

CfD subsidy allocation takes place after pre-development phase, whilst the ROC accreditation only takes place once the project is commissioned. The ROC system thereby leaves investors exposed to the risk of for example a banding review, or the introduction of limiting subsidy availability. On the flipside, early accreditation leaves investors with little room to change plans in response to for example changes to relative costs of different turbine designs or similar. For example, deviations from the initially announced installed capacity will be associated with an automatic reduction of the strike price.

D.2.2. The effects of the allocation process and allocation lock-in

(i) When comparing the RO regime to the CfD regime in this context, it is critical to state clearly our assumptions about what regime the CfD should be compared to.

- Allocation risk is becoming increasingly important due to the existence of the Levy Control Framework, which stipulates a maximum spend of £7.6bn (2012 prices) by 2020. Allocation risk is important for a potential renewable developer to the extent significant funds have been sunk prior to allocation – i.e. confirmation that the renewable generator will receive support at a specified level for each unit of output. If a developer fails to secure an allocation of funds at the desired level (or fails to secure any allocation at all) the investment up to that point could potentially be wasted, or could result in a stranded asset.
- As noted in Section 6 of the main report, above, NERA's remit has been to assess the difference between the expected final CfD regime and a *hypothetical future* RO regime that would, for example, be subject to the constraints imposed by the LCF. This implies that developers would face the risk of lower support levels, or none at all, under the RO. It seems plausible that, faced with this increased risk, developers and Government would both find it helpful to have early commitments of support *under*

the RO, rather than to wait, as is currently the case, until commissioning for the level of support to be fixed.

(ii) Based on this assumption, the differences in relation to the early allocation fall away, and the only remaining difference with a possible influence on WACC would be the third one:

- Under the current RO, there has been no significant expectation of constraint on the volume of projects which could be accredited. Compared to the current allocation risk in the ROC regime, there is therefore no significant benefit of the early lock-in offered by the CfD, and therefore we would not expect WACCs relevant to *past* RO projects to differ from those relevant to CfD projects that benefit from early lock-in.
- Under a *future* RO system that was left unchanged – so that there was increased allocation risk because of the lack of early commitment – the early commitment offered by the CfD regime would help to reduce risks (potentially offset in part or in full by associated reductions in flexibility), and therefore could have an impact on the WACC.
- Finally, under a future RO system in which there was early commitment to provide comfort to developers that they would not miss out on an allocation, there would be no difference between the RO and CfD in this respect, so there would be no expected difference in WACC.

D.2.3. The LCF and shocks to availability of funds

The Levy-Control-Framework places a limit on the amount of money which can be passed through from energy consumers to renewable energy in the form of direct subsidies and stipulates that DECC is required to take action if the subsidy exceeds the budget by 20 per cent. The government recently published an extension to the budget of £7.6bn (2012) by 2020.

In order to assess how realistic we think investors may view this risk we have projected LCF spend to 2020 using NERA estimates. NERA's own analysis suggests that although this budget may, given an assumption of rising real power prices, be sufficient to reach the government's 2020 renewable targets (at least within the 20% LCF threshold), the risk of a severe budget overrun (and subsequent rapid intervention) is significantly greater under the CfD scheme than under the ROC scheme because the size of subsidy payments under the CfD is directly related to power prices, and therefore very uncertain.[102]

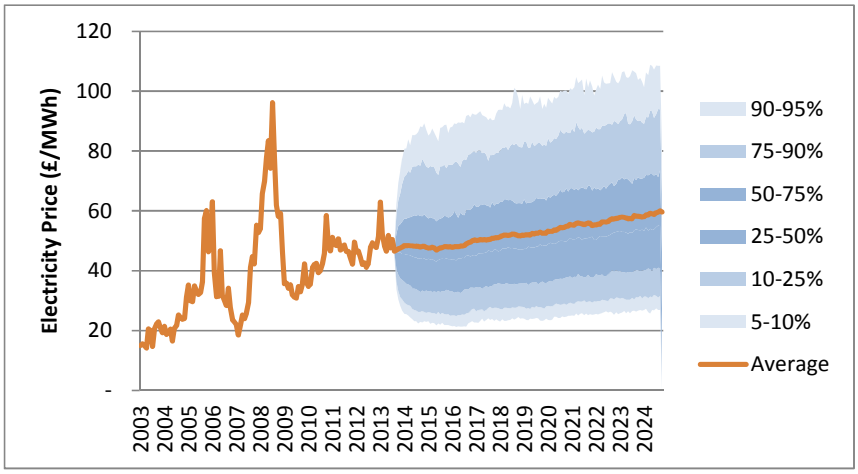
[102] Government has set the LCF budget to allow for uncertainty over wholesale prices and other factors.

Investors may fear that, if power prices were to fall significantly below expectations in one year, this would create significantly additional pressure on the LCF, because every project supported under CfDs would need to be paid more in support. Under the RO, in contrast, renewable generators would simply receive lower revenues – like all other generators. Given the impact sudden shocks to the budget that can occur under the CfD regime, investors may have concerns that the government might be forced to respond rapidly by tightening rules or lowering subsidy levels for accreditation at very short notice, thereby exposing developers who have sunk pre-development costs. At the extreme, investors may fear that a drop in power prices could lead the government to *completely stop accrediting new projects*.

In order to analyse the significance of the relationship between government expenditure and power prices under the CfD regime, NERA created a simple simulation of 1600 power price paths based on historical volatility. For illustration purposes we have kept the average power price constant in real terms. This simulation is designed for illustration purposes only based on historical data, and does not necessarily represent the views of either DECC or NERA about the likely future path of prices, as it was beyond the scope of NERA's work to undertake detailed power price modelling.

The resulting distribution of power prices is shown in Figure D.7. This figure shows the dispersion of power prices in 2015, which widens out to 2020 and beyond. The simulation is based on historical power price volatility and mean reversion rates. For each price path we analyse the impact on government expenditure, assuming penetration of renewables as set out in Table D.1. These capacities assuming the mix of generation implied by the government's Renewable Energy roadmap (2011), shown in Table D.2.

Figure D.7
NERA Simulated Power Prices



Source: NERA analysis on data from www.elexonportal.co.uk

Table D.1
Indicative Renewable Energy Capacity Assumptions

Renewables Assumptions		2013	2014	2015	2016	2017	2018	2019	2020
Existing And Under Construction									
Onshore Wind	GW	4.90	6.53	6.66	6.63	6.63	6.63	6.63	6.63
Offshore Wind	GW	2.68	3.64	3.93	4.22	4.22	4.22	4.22	4.22
Biomass	GW	1.17	1.68	1.91	1.35	1.35	1.35	1.35	1.35
Other Renewables	GW	-	-	-	-	-	-	-	-
Biomass Cofiring	GW	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53
Hydro	GW	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49
Total		10.77	13.87	14.51	14.22	14.22	14.22	14.22	14.22
New									
Onshore Wind	GW	-	-	-	0.55	1.35	2.19	3.05	3.87
Offshore Wind	GW	-	0.45	1.62	2.80	4.32	5.90	7.52	9.11
Biomass	GW	-	-	0.18	1.21	1.69	2.20	2.72	3.22
Other Renewables	GW	-	0.03	0.06	0.09	0.12	0.15	0.19	0.22
Biomass Cofiring	GW	-	-	-	-	-	-	-	-
Hydro	GW	-	-	-	-	-	-	-	-
Total		-	0.48	1.86	4.65	7.49	10.44	13.47	16.42
Grand Total	GW	10.77	14.35	16.37	18.86	21.70	24.65	27.68	30.64

Table D.2
Energy Roadmap Renewables Mix

	Energy Production (TWh)			Capacity (GW)			Implied Load Factors (%)			Share of Total (%)		
	Low	*High*	*Average*	*Low*	*High*	*Average*	*Low*	*High*	*Average*	*Low*	*High*	*Average*
Onshore Wind	24	32	28	10	13	12	27%	28%	28%	27%	23%	24%
Offshore Wind	33	58	46	11	18	15	34%	37%	36%	37%	41%	39%
Biomass	32	50	41	4	6	5	91%	95%	93%	36%	35%	35%
Marine	1	1	1	0	0	0	57%	38%	48%	1%	1%	1%
Total	90	141	116	25	37	31				100.0%	100.0%	100.0%

Source: NERA analysis based on DECC (2011) UK Renewable Energy Roadmap[103]

Figure D.8 shows NERA's analysis of the resulting distribution of government expenditure by 2020 for different power prices. According to these simulations, there is a 40 percent risk that the government's £7.6bn budget would be exceed by more than 10 percent by 2020[104] if RES targets are met and the government does not respond in some other way to power price fluctuations.[105] The corresponding risk under the ROC scheme is close to 0 percent.

Note that our simulation focuses exclusively on the risk of breaching the LCF due to unforeseen changes in the wholesale electricity price. It does not consider rationing of subsidies that would have taken place in both regimes – for example, because of higher than expected uptake or lower technology costs.

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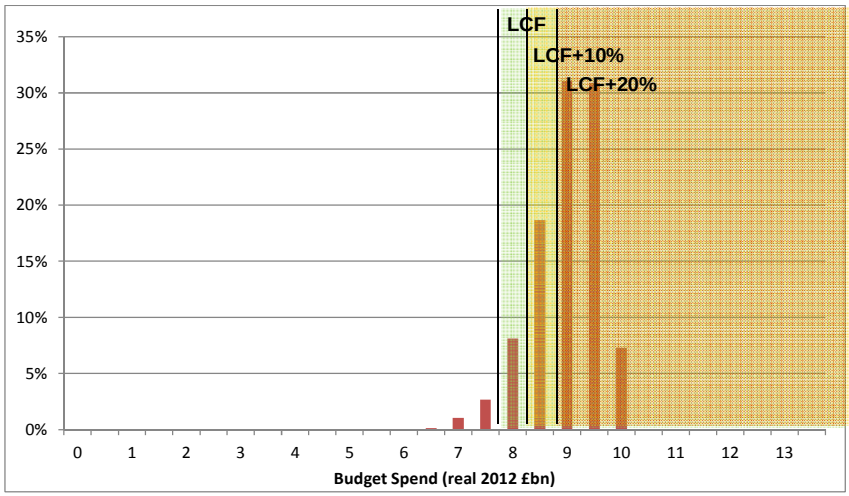
[103] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48128/2167-uk-renewable-energy-roadmap.pdf

[104] Please note that the central projection of spend in 2020/21 is significantly more than targeted by DECC

[105] The objective of the simulation is to show an approximate range of outcomes of power prices based solely on a simplified analysis of historical volatility of power prices. We recognise that the volatility of power prices may differ from the past but it is outside the scope of this project to analyse this aspect in detail,

Figure D.8
Government Expenditure by 2020



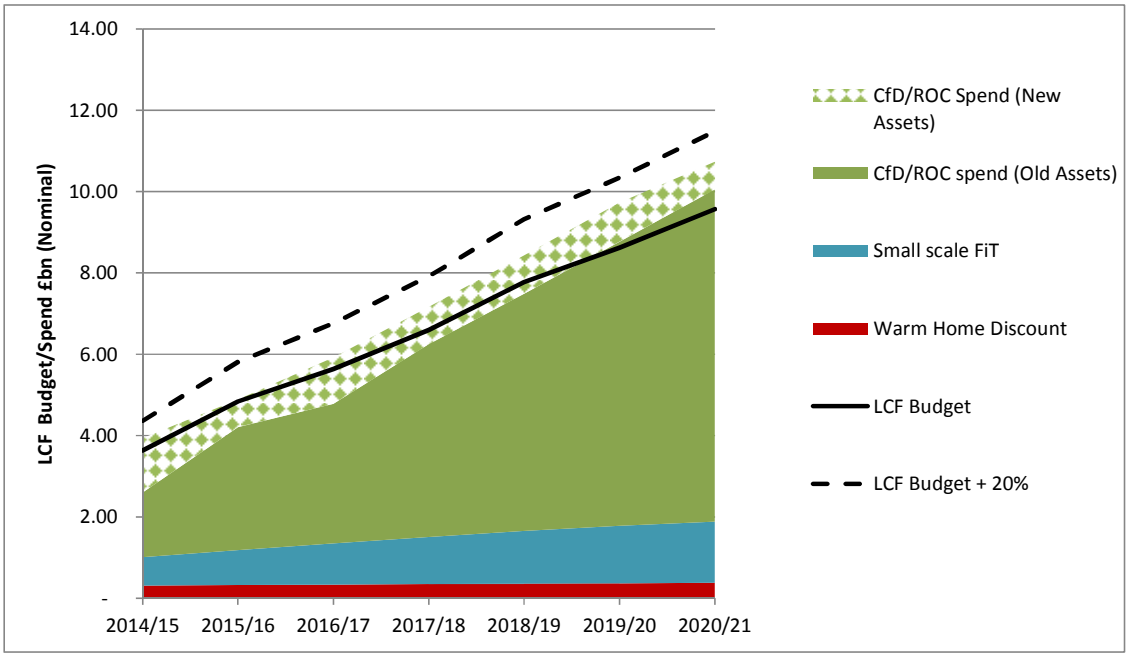
Source: NERA analysis on data from www.elexonportal.co.uk; DECC

In practice, we expect that the government would take action prior to 2020 if the levy-spend were significantly above the threshold. However, the government's ability to do this depends on how many projects have secured an early commitment under the CfD, as explained in the following. Figure D.9 shows our baseline projected levy-spend distributed by type. The vast majority of spend is related to ROC/CfD expenditure. For the purposes of illustration, we show the CfD/ROC spend in two different categories:

1. "Old Assets": Levy-spend to assets of past vintages, which cannot be changed by the government without retroactively changing either banding or strike prices for those assets, i.e. abandoning the "grandfathering" principle; and
2. "New Assets": Levy-spend on assets which are commissioned a particular year, support for which may more easily be changed without violating the "grandfathering" principle.

The chart suggests that the government budget will, *in expectation*, be sufficient to meet the targets. However, there *is significant risk it is not sufficient*.

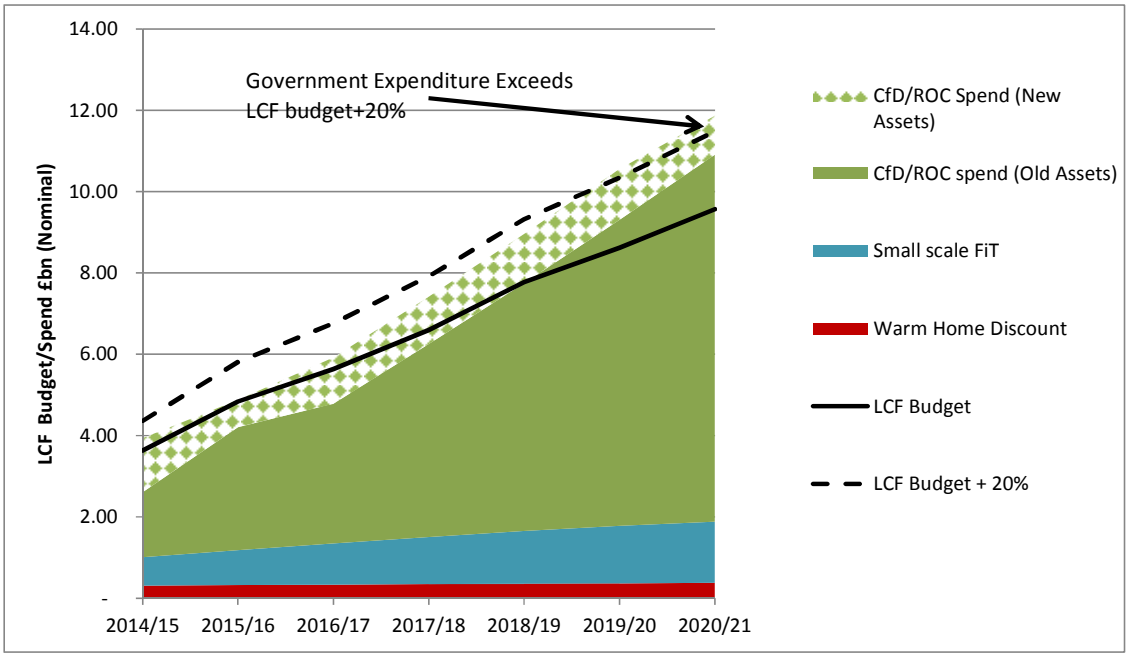
Figure D.9
Budget Spend: Pre-Committed vs. In-Year



Source: NERA analysis on data from www.elexonportal.co.uk; DECC

Figure D.10 shows the government levy-spend in a low electricity price scenario.

Figure D.10
Budget Spend on Low Power Prices (10th Percentile)

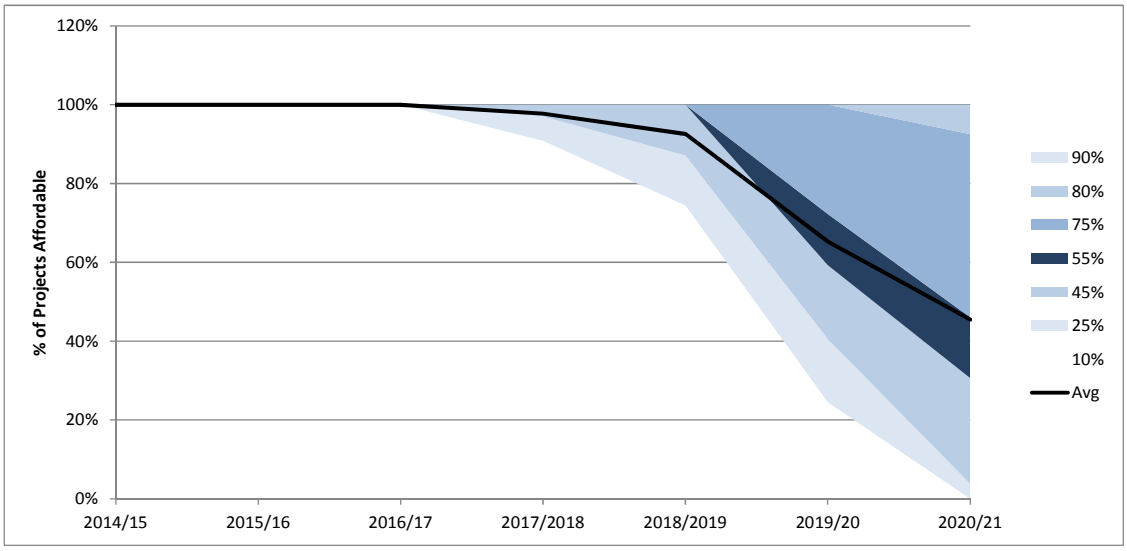


Source: NERA analysis on data from www.elexonportal.co.uk; DECC

Here, the government budget is exceeded by more than 20 percent (indicated by the arrow). Also note that a growing proportion of the subsidy stream is *pre-committed*. This pre-committed ("Old") levy-spend relates to assets which cannot be touched without violating the grandfathering principle. In turn, the only tool available, changing new asset allocations, becomes increasingly blunt. For instance, in this scenario the government would have to respond by reducing allocations by 25 percent just to be within the LCF+20 percent. In practice the government's ability to control budget overruns will be even more limited than the chart suggests, because the early allocation means there is a significant lag to response. This situation would not arise under the ROC scheme, where subsidy payments do not depend on the power price as in the CfD system, and the government is therefore much more able to forecast expenditure.

The strong relationship between the LCF spend and the power price combined with the large fund lock-in, leads to significant allocation risk in the event of low power prices by 2020. Figure D.11 shows the number of new projects affordable given a 10% LCF threshold. [106]

Figure D.11
% of new projects fundable given a 10% threshold



An allocation probability of 93% (2018/2019) and 66% (2019/2020) would translate into an addition to the WACC of between 1-11 bp (2018/2019) and 7 and 70bp by 2019/2020 respectively (as shown in Figure D.14) for pre-development costs of 1-10% of total costs. In summary, an adder of between 5-40bp might be appropriate. However, the magnitude of this figure highly sensitive to the assumptions on power prices and the government's response to policy overruns.

[106] There is a hard threshold of 20%. We have selected 10%, as a figure half way between 0 and 20% for government intervention intended to reflect that it DECC will think about allocation procedures *before* it reaches the hard limit of 20% in order to make sure that it does not breach it.

As noted previously, we understand that Government has tried to set the LCF budget envelope to accommodate the uncertainty of spend under CfDs, and there is some flexibility or "headroom" built in to estimates. We have reflected our estimates of this in our simulations. If in the future the costs of achieving the renewable energy target look likely to exceed the LCF budget, then the legal obligation to meet the 2020 renewable energy target could result in the LCF budget being revised. As noted above, we are not able to judge which of these two policy constraints would be likely to prove stronger.

Figure D.12
Required WACC Uplift (bp) to Compensate for Allocation Risk under Different Power Prices (2019/2020)

Power Price (£/MWh)	LCF Availability	% Capital Cost Sunk Pre Allocation Announcement							
		0%	**1%**	**5%**	**10%**	**25%**	**50%**	**75%**	**100%**
<20	0%	.	.	.	.	.	.	.	.
20-30	12%	0	97	456	856	1865	3270	4108	4108
30-40	29%	0	32	155	300	702	1287	1644	1644
40-50	52%	0	12	60	120	290	554	719	719
50-60	81%	0	3	15	31	76	150	198	198
60-70	100%	0	0	0	0	0	0	0	0
70-80	100%	0	0	0	0	0	0	0	0
80-90	100%	0	0	0	0	0	0	0	0
90-100	100%	0	0	0	0	0	0	0	0
>100	100%	0	0	0	0	0	0	0	0
Uncond. Avg	65%	0	7	35	70	172	333	436	436

Source; NERA analysis. Assumes 1/3 of revenues from power market revenues, which means a project will commission regardless of subsidy allocation if more than 2/3 of development costs are sunk. Unconditional average is the average LCF availability including the low probability of very low power prices and LCF availability.

D.3. Construction Risk

We refer to the impact on value of unforeseen construction delay as construction risk. As shown in Figure D.13, construction risk is smaller in the CfD regime than in the ROC system for small delays but potentially larger beyond the long stop date.

Our analysis suggests that the impacts of a construction delay are broadly similar under the CfD and a hypothetical future RO regime, once expected degression is taken into account, but that there is a potentially significant difference arising from the differences in allocation risk that are set out above.

Figure D.13
Impact of Construction Delay on WACC

Item	Comment	Impact
Short Construction Delay	• Early allocation means little exposure to allocation risk compared to ROC • Known revenue loss upon delay (loose individual subsidy years); limited exposure to degression so long as asset can stay within contract	
Long Construction Delay	• Risk of sudden government fund shortage higher; Increased allocation risk pre allocation due to locked-in government funds • Significant uncertainty about strike price degression upon construction delay beyond long stop date	
Net Impact	• Early lock-in would have happened anyway • Relationship to power price means availability of government funds is subject to shocks	

The impact of a project delay for offshore wind is sketched in Figure D.14, assuming perfectly comparable regimes, taking into account that ROC banding degression has recently increased the risk of construction overruns.[107] Delays can be divided into three types of delays:

1. **Within Commissioning Window:** These delays have similar effects in RO and the CfD regimes as all revenues are simply shifted into the future. The cost of a short delay is approximately equal to the real WACC percent per year.
2. **Beyond Commissioning Window:** For delays which exceed the commissioning window, the delay starts affecting the subsidy years achieved in the CfD. For offshore, a delay of up to 2 years after the end of the commissioning window (Illustrated as a "3Y delay" from the beginning of the commissioning window)has the effect of reducing the NPV of revenues by approximately 24 percent. This is the result of the combined effect of 3 years of discounting at the WACC (~-25 percent) combined with the loss of two years of subsidy discounted (-7 percent of revenues) and higher power prices and inflated strike price due to later commissioning (+8 percent). In the ROC regime the subsidy period is unchanged. However, because the assets are accredited later than expected, the project would be subject to banding degression. Given the current embedded banding degression for offshore wind this leads to a slightly larger effect than the loss of one year of subsidy in the CfD regime (29 percent).[108] However, the exact relationship depends on the

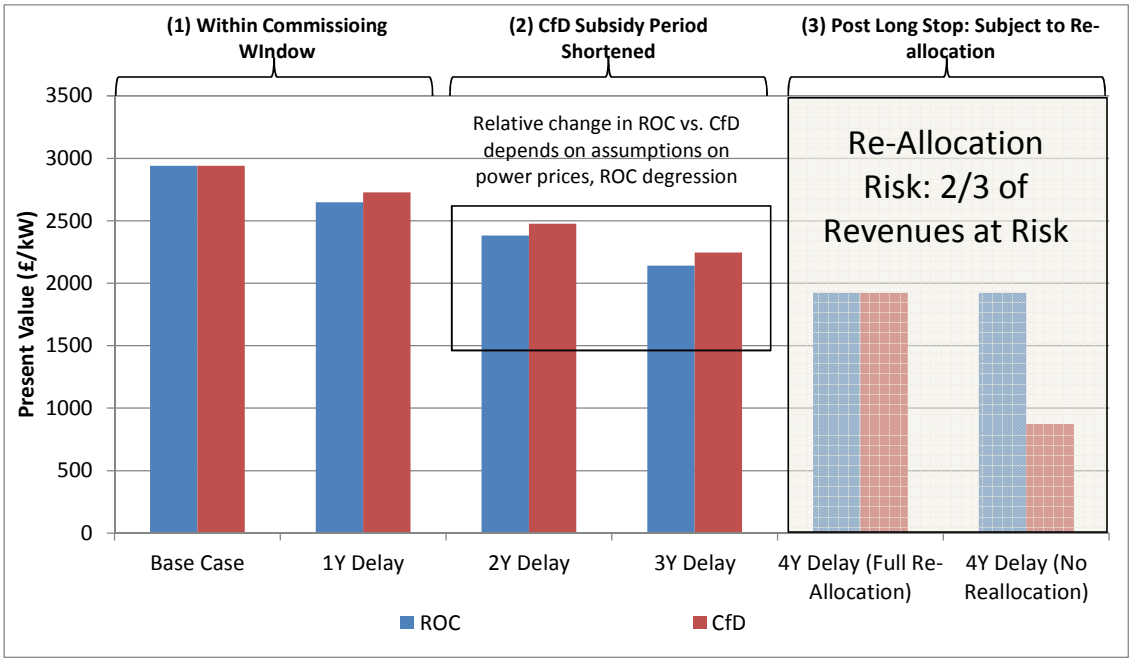
[107] We assume a predefined banding degression consistent with the degression of strike prices. The ROC banding is set consistent with strike price degression such that an asset with planned commissioning in 2019 receives strike price of 135 £/MWh or 1.54 ROCs. We assume an asset commissioned in 2015 receives 2 ROCs or strike price of 155 £/MWh.

[108] The difference is sensitive to the assumption of ROC degression. For comparability between the CfD system and the ROC system we have assumed all projects would be NPV neutral in absence of any shocks. This means there is an

assumed banding degression and could be either higher or lower than the CfD mechanism. .

3. **Beyond Long Stop Date** by default means the CfD subsidy either falls away entirely, or needs to be renegotiated. For an offshore wind asset that means that about 2/3 of the project revenues are at risk. The level of subsidy achievable depends on the availability of funds and available strike prices at the time of application. Under the ROC regime, the developer would also have been exposed to this risk. However, in the ROC regime the risk of sudden government fund shortages is much lower, so there is no sudden jump in the re-allocation risk.

Figure D.14
Effect of Construction Delay for Offshore Wind Asset



Source: NERA analysis

In order to quantify this re-allocation risk we build on the analysis of allocation risk as set out in the previous section.[109] Table D.3 sets out a simplified calculation of the expected loss and equivalent WACC adder compared to the ROC scheme in the event of missing the long stop date. There is a notable increase in expected loss risk if power prices are below £30/MWh *and* delay risk is more than about 10 percent. This is because:

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implied banding degression of the ROC regime. With no banding the reduction after 3 years would be 19 percent of value for the ROC regime.

[109] Note the difference in timing in this case, relative to previous allocation analysis (i.e. "immediate" commissioning)

- **Achievable strike prices** upon re-application vary by power price due to LCF budget:
  - Power prices above £50/MWh: no strike price reduction required; and
  - Power prices below £30/MWh: Significant strike price reductions or allocations.
- **Expected loss depends on delay risk:**
  - For a delay risk of 5 percent, the expected loss is approximately 0.2 percent
  - For a delay risk of 25 percent, the expected loss is just over 1 percent.

Table D.3
Expected Loss due to Re-Allocation after Construction Delay

Power Price	Required Strike	Risk of Delay Exceeding Long-Stop Date							
£/MWh	Price Reduction	0%	1%	2%	5%	10%	25%	50%	100%
<20	-68%	0.0%	-0.6%	-1.2%	-2.9%	-5.8%	-14.5%	-28.9%	-57.8%
20-30	-40%	0.0%	-0.4%	-0.7%	-1.8%	-3.7%	-9.2%	-18.4%	-36.7%
30-40	-15%	0.0%	-0.1%	-0.3%	-0.7%	-1.3%	-3.4%	-6.7%	-13.4%
40-50	-2%	0.0%	0.0%	0.0%	-0.1%	-0.2%	-0.5%	-0.9%	-1.8%
50-60	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
60-70	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
70-80	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
80-90	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
90-100	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
>100	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average Expected Loss:		**0.0%**	**0.0%**	**-0.1%**	**-0.2%**	**-0.5%**	**-1.2%**	**-2.4%**	**-4.8%**

Table D.4
WACC Adder (bp) due to Re-Allocation after Construction Delay

Power Price £/MWh	Required Strike Price Reduction	Risk of Delay Exceeding Long-Stop Date 0%	1%	2%	5%	10%	25%	50%	100%
<20	-68%	0	8	15	38	76	186	360	681
20-30	-40%	0	5	10	24	48	119	234	450
30-40	-15%	0	2	4	9	18	44	88	173
40-50	-2%	0	0	0	1	2	6	12	24
50-60	0%	0	0	0	0	0	0	0	0
60-70	0%	0	0	0	0	0	0	0	0
70-80	0%	0	0	0	0	0	0	0	0
80-90	0%	0	0	0	0	0	0	0	0
90-100	0%	0	0	0	0	0	0	0	0
>100	0%	0	0	0	0	0	0	0	0
Average Expected Adder		**0**	**1**	**1**	**3**	**6**	**16**	**32**	**64**

Source: NERA analysis

We have limited evidence on the risk of exceeding the long stop date but have conducted high level research on construction overruns of existing offshore wind farms. This suggests a very low rate of delays exceeding the long stop date,[110] and that the probability is no larger than approximately 10 percent.

If we assume the risk of exceeding the long stop date is between 2 percent and 10 percent, the expected loss due to allocation/construction risk is between 0.2 percent and 0.5 percent which would correspond to a 5-10bp addition to the WACC for Offshore Wind compared to the ROC regime.

The increased risk is mainly relevant for Offshore Wind developments which have very high strike prices combined with the risk of sudden dry-ups of government funds. Biomass and Onshore Wind construction times are so short that it is less likely the government would be able to change much even with substantial construction overruns.

[110] This may be due to selection bias as we only wind farms commissioned. The delay risk may also be higher for new wind farms to the extent they are larger or further from shore.

Appendix E. Market Testing the Estimated Hurdle Rate Reductions

E.1. Market Testing

In section 6.2.5 above, we concluded that the impact of the changes in risk exposure, most notably from removing power price risk was likely to be of the order of between 50 and 175 bps basis points in real pre-tax WACC terms depending on technology.

If one assumes the cost of debt remains fairly constant (we return to this assumption below) a WACC reduction of 50-175bps on a pre-tax basis implies a reduction in the cost of equity of c. 125-450 bps for an illustrative gearing level of 70%.[111]

As the upper end in particular implies a very significant reduction in the required return on equity DECC asked NERA to "market test" the results from removing power price risk, so as to confirm that the expected reduction in the WACC is consistent with the associated expected reductions in the cost of equity and debt.

In this context it is worth bearing in mind that this range was derived using market evidence from a number of related sources that were chosen to approximate the impact on the renewables sector in the absence of direct market data on that sector. Hence the estimates themselves are already market-tested to a degree.

We discuss below what further market evidence we used to cross check our empirical findings on the effect from reduced market exposure, and we caveat the difficulties associated with isolating the effect on individual WACC components.

E.2. Theoretical Issues with Testing Individual WACC Components

One limiting factor associated with possible market testing is the difficulty associated with assessing just one aspect of the change from the RO to the CfD FiT scheme. Under standard financial theory, a reduction in the (systematic) volatility of cashflows will, at least in theory, result in two conflicting changes to the **Cost of Equity**, i.e.:

1. A lower asset beta for renewable projects under the CfD FiT scheme would **lower** the required return on equity**,** all else equal. This follows directly from the CAPM relationship described in section 2 and would also apply in other models that consider other factors alongside systematic volatility. It is difficult to test this empirically from share-price data because there are no listed pure play renewables generators with liquid stock and sufficient data history. However, there is an emerging consensus from analyst reports which supports this argument (see section 3).
2. However, lower volatility of revenues would lead to companies taking on more debt. A higher gearing level increases the riskiness of shareholders' returns, *all else equal*, which in turn leads investors to require a **higher** return on equity for the same investment.

[111] A pre-tax range from 50-175bps implies a post-tax range from 39-125bps, which translates into a range of c.125-450bps when we assume the whole impact is on the 30% equity share.

Therefore, we would expect a higher gearing level to at least in part offset the reduction in the required return on equity described under 1).

The above shows that it would be difficult to isolate the effect on the Cost of Equity from a reduction in power price exposure, to the extent that we would expect it to be accompanied by changes in the other WACC parameters (i.e. higher gearing levels).

Similarly, standard financial theory would suggest that there are two effects on the **Cost of Debt**:

1. Lower power price exposure could lead to lower cost of debt financing, on the back of more stable cashflows.
2. However, as we discussed above, revenue stability would in theory allow investors to take on more debt. The Cost of Debt would rise as a consequence, as the extra fixed-obligations from higher leverage increase the risk of default or bankruptcy.

The above shows that it is difficult to isolate the *individual* impact on the Cost of Equity and Debt (as opposed to the impact on the WACC as a whole) from reduced power price exposure. It would therefore appear most promising to test the WACC impact rather than the cost of equity or debt impact separately.

E.3. Practical Issues with Market Testing Individual WACC Components

A more important practical problem with market testing the evidence is that there is a limited sample of listed, pure play renewables companies whose betas we can observe (in fact, Drax and PNE Wind are the only candidates for this exercise).[112] However, neither of these provide good "market tests" as Drax share price is still significantly influenced by the development of its coal-fired units while PNE Wind's exposure to the UK market is too limited to be meaningful. For these reasons, we also use equity analyst reports and stakeholder interviews to sense check our conclusions on the WACC / cost of equity impact of the power price reductions.

As set out in detail in section 3, analysts have reported a *"significant reduction in risk"* suggesting that a significant reduction in the required cost of equity would seem plausible. In addition a number of interviewees confirmed the broad range of DECC's proposed reduction in the hurdle rate, which is towards the low end of the range that we quantified based on market data in section 6.2.2 and 6.2.3. Others did not see any proven case for a hurdle rate reduction. However, it is worth bearing in mind that there is likely to have been a strategic element involved in these answers.

One other emerging theme from the interviews and analyst reports was that it is unclear whether there is scope at present for the gearing effect discussed above to take place. In fact, there appears to be a general consensus amongst industry interviewees that it is unlikely that

[112] There are several other pure play renewables companies which are listed; however, their share prices are not liquid, due to which inferences may be misleading and / or they may not have a sufficient history of data.

projects under the CfD will see significant increase in debt capacity relative to the RO levels. Instead, the majority of interviewee responses suggested that there is at best limited scope for expanding the debt share, to the extent that gearing levels were already quite high under the current RO arrangements (i.e. 70-80% for onshore wind farms, and close to 70% for offshore wind). Based on industry response, the increase in gearing is not likely to exceed c.5% (see section 5).[113] Consultation responses do not discuss a significant impact from gearing either.

Financial theory suggests that a reduction in risk should affect both the cost of equity per se and gearing capacity. We don't observe this latter effect here - in our market consultations – potentially because of the offsetting impacts of novelty premium / construction risk etc., which investors may be pricing into the required return on equity, as discussed in section 6.6. Feedback from both consultation responses and industry interviews suggests that such a novelty premium may exist, which would make it impossible to isolate the impact on the cost of equity from the reduction in power price alone. Again, it is worth bearing in mind however, that there is likely to have been a strategic element involved in these answers.

E.4. Conclusions

The analysis above shows that there are theoretical and empirical issues with identifying the impact of a single factor on the cost of debt and equity individually. These are confounded by the fact that there is no direct pure-play listed UK renewables comparator with sufficient history and stock liquidity that we could use to "market test" directly.

Instead we have undertaken extensive consultation of market participants in order to test our postulated hypotheses on the issue of a possible reduction in the required return on equity. One central element emerging from our market testing was that investors do not expect gearing capacity to increase significantly, which would seem incompatible with a reduction in the equity hurdle rate towards the top end of the initial range. It is worth bearing in mind however, that there is likely to have been a strategic element involved in these answers and that in the long-run there may be some scope for increased gearing as e.g. German onshore wind projects have seen higher debt levels. These results from the market testing align with our conclusions that there may be significant long-term effects but smaller short-run effects.

[113] We note that based on our review in Part B, i.e. evidence from Germany, that German retail investor-owned wind farms are often 90% leveraged suggesting that in the long-run higher gearing levels may be achievable. However, the limited experience with the CfD FiT framework may explain investors' current reluctance to use higher leverage.

Appendix F. International Benchmarking

F.1. Selection of Case Studies

In this section we perform an international benchmarking of the proposed rates of return under CfDs in the UK (as per DECC's initial proposals) against those under different incentive schemes in other countries. To the extent that information is publicly available we have collected international evidence mainly from primary local sources, i.e. ministries, regulators and companies as well as consultancy and academic reports.

In the absence of direct evidence on the change in hurdle rate from an RO system to a CfD system we have collected evidence on the *levels* of hurdle rates under different support schemes. In connection with a view on the relative risk of such schemes compared to the proposed CfD scheme these estimates can provide an indication of minimum and maximum bounds for the expected hurdle rate under the new CfD scheme in the UK.

Together with DECC we identified the following criteria for selecting RES support schemes as potential case studies:

- Broadly comparable RES support scheme to either the proposed CfD FiT or the existing RO scheme;
- Availability of authoritative evidence on hurdle rates either from market data, analyst reports or surveys;
- "Relevance" of the technology as shown by either significant existing roll-out or at least substantial roll-out plans at a stage where investors will have had to form a view on hurdle rates.

According to these criteria we selected the following countries and technologies for closer review:

- Germany – onshore wind, offshore wind, solar PV and biomass;
- Denmark – onshore and offshore wind;
- Sweden – onshore wind;
- Ireland – onshore wind;
- Netherlands – various.

We chose not to focus on e.g. the Spanish experience, which had also seen a significant renewables boom as earlier estimates of the cost of capital for renewable generation (as estimated by the Comisión Nacional de Energía, "the CNE", in 2010[114]) are unlikely to be representative of current rates of return and there is strong evidence that there was a large gap between available outturn rates of return and expected rates of return, making it impossible to derive a hurdle rate from market data.

[114] The CNE, *CÁLCULO DE LAS TARIFAS Y PRIMAS APLICABLES A NUEVAS INSTALACIONES A PARTIR DE 2012*, 14 September 2010.

In evaluating the available rates of return reported for different countries and technologies we take account of differentiating factors such as:

- Political risk and government default risk;
- The existence of financeability mechanisms (e.g., low cost of debt financing through state-owned development banks);
- Investor profiles active in the sector;
- Experience with and complexity of the system.

To the extent possible we quantify differences in hurdle rates attributable to other factors, e.g. by reviewing differences in country default risk or using financial market data to assess difference in the cost of debt financing.

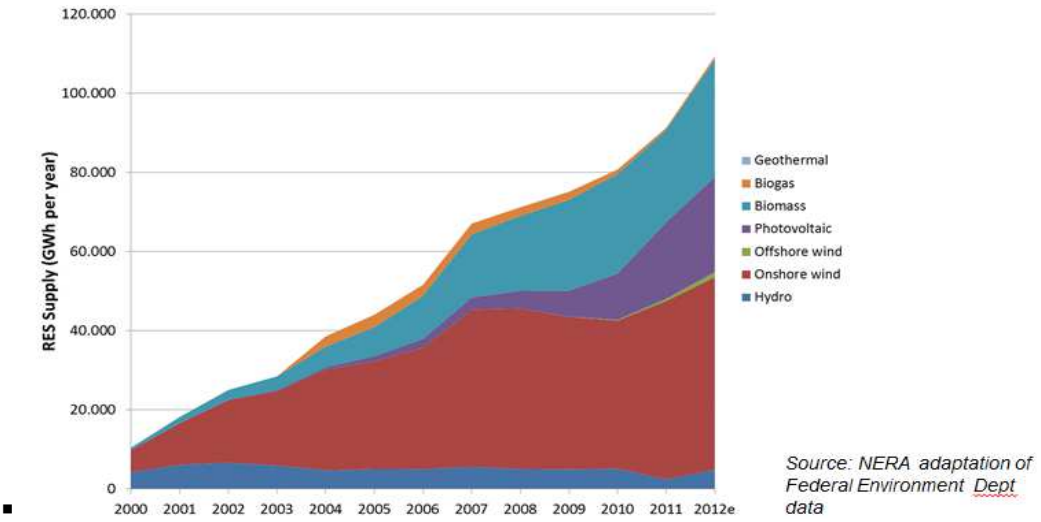
We discuss the main findings from this analysis below with detailed case studies from Germany and Denmark and more high-level views on the other target countries before concluding in Section F.5.

F.2. Germany

F.2.1. Framework

As one case study we review evidence on hurdle rates for German renewable energy developments. Germany has seen significant development of renewable capacity since the introduction of the "Renewable Energy Law" (EEG) in 2000. The main developments have been in the areas of solar, onshore wind and biomass (see Figure F.1).

Figure F.1
Deployment of Renewables in Germany



Historically Germany has offered a Fixed feed-in tariff (FiT) system[115] to all renewable generators with FiTs differentiated by technology and in some cases also within technology (e.g. wind farms in lower wind yield locations receive higher FiTs). This differentiation was designed to achieve rates of return in line with market expectations for all technologies while FiT setting also contained a strong political element.

Under the standard system the FiT is guaranteed in nominal terms for 20 years, in some cases with a stepped profile that involved higher payments in early years and lower payments in later years. The support profile for offshore wind is somewhat different to other technologies in that it offers a shorter subsidy period but higher FiTs during that period.

There is no cap on the total volume of support under the FiT regime that is made available but concern about the electricity price increases associated with the recent increase in the amount of power supplied by highly subsidised PV units has led to the introduction of automatic monthly (for solar) adjustments of FiTs in line with the speed of deployment in the previous months. In addition there have been a number of revisions to the EEG that brought adjustments to the FiTs available for technologies where there was a notion that costs and revenues had moved out of line (e.g. EEG 2004, EEG 2009, and EEG 2012).

The 2012 revision of the EEG has seen the introduction of an optional CfD FiT scheme as of 1 Jan 2012. Generators can opt in and out of this scheme at monthly intervals. Under this scheme compensation for each technology consists of i) market revenues from power sold, ii) the difference between the average market value of all power generated by that technology during the past month and the FiT that this generator would have obtained and iii) a "management premium" of 1ct/kWh for wind/solar and 0.25ct/kWh for dispatchable generators.

By setting a technology-specific reference price under (ii) and allowing operators to switch back to the fixed FiT the German system lowers the risk of the CfD FiT relative to the proposed UK system. In addition the German system made the switch to CfD attractive for wind in particular by setting what was considered to be a generous "management premium" that at 1ct/kWh provided a high absolute top up relative to the low fixed FiT for wind. As the relative magnitude of the "management premium" was smaller compared to the FiT for biomass and solar, take-up of the CfD system amongst these was less pronounced. At the end of 2012 80 percent of wind generators, 39 percent of biomass and 7 percent of solar PV generators were using the CfD FiT option according to the government's monitoring report.[116]

Before comparing hurdle rates realised in Germany to the likely hurdle rates required under the UK CfD FiT system it is worth noting that a significant amount of the renewables development in Germany has been financed by small-scale private or municipal investors.

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[115] The German fixed feed-in tariff in Germany fixes a guaranteed price (in nominal terms) per kWh for the duration of 20 years. There are specific rules applying for offshore wind.

[116] Fraunhofer ISI (2013): Erste Ergebnisse im Rahmen des Projekts „Laufende Evaluierung der Direktvermark-tung von Strom aus Erneuerbaren Energien" gefördert durch das Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit, p.7.

E.g. According to the regulator's register of power stations in Germany[117] the "Big 4" energy companies (E.ON, RWE, Vattenfall and EnBW) own less than 5 percent of total onshore wind capacity while 80 percent of solar PV installations are rooftop size owned by private retail investors,[118] often benefitting from cheap debt finance from state-owned KfW bank.[119]

The German literature on hurdle rates recognises that these investors are likely to have different hurdle rates than institutional investors and utilities, a finding documented and explicitly recognised in German studies and their hurdle rate estimates. (see e.g. Fraunhofer, 2012)

F.2.2. Estimates of the Hurdle Rates for Different Technologies in Germany

F.2.2.1. Onshore Wind

In a first step we have attempted to locate stock-market listed companies that construct, own and operate onshore wind farms in Germany. To this end we reviewed companies listed in the RENIXX renewable stocks index. However, the only German wind companies listed in this index are Nordex (a supplier of components) and PNE Wind, which acts primarily as a developer but does not own a significant portfolio of completed wind farms. PNE Wind would therefore act as an upper bound on the risk of a wind farm over the life cycle.

We have reviewed analyst reports and market data on PNE Wind. As PNE Wind is not part of the major stock indices analyst coverage is relatively limited. As per those analyst reports that provide an estimate of the WACC for PNE Wind we find an estimate of around 8 percent post-tax, nominal with a slight implied downward trend.[120] When calculating the beta for PNE Wind over the last year using its stock price we calculate an asset beta of 0.55, higher than regulated networks but lower than pure merchant generators such as Drax.

In order to get a broader view of required hurdle rates we have reviewed investor surveys of hurdle rates. Figure F.2 shows the evolution of reported hurdle rates for German onshore wind over time as derived from a range of investor surveys over time, undertaken by a number of different research institutes.

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117 Kraftwerksliste Bundesnetzagentur, dated 22 July 2013.

118 Knut Kübler. EEG-Förderung der Photovoltaik: Über den Anfang nach dem Ende. ENERGIEWIRTSCHAFTLICHE TAGESFRAGEN 63. Jg. (2013) Heft 9

119 See e.g. Frontier (2013): Comparing international support for onshore wind, p. 2.

120 Given the lack of information about how the estimates are derived, it is not possible to calculate a like-for-like real, pre-tax WACC but generally real, pre-tax WACCs are close to nominal post-tax WACCs in terms of magnitude. Moreover, there is a degree of concern about the robustness of these estimates as the implied reduction in the WACC appears to be driven by an analyst applying the same cost of equity and debt to the (significantly) changing level of actual gearing for PNE Wind. The analyst reports do not provide any further evidence on why this approach is chosen.

Figure F.2
Estimates of the Hurdle Rate for German Onshore Wind

Technology	Real Pre-tax WACC	NERA Comment
Allowed Return as per original EEG (2000)	3.3% - 5.3%*	Chosen to provide a rate of return comparable to a safe asset in 2000 (5% -7% nominal, pre-tax)
Deutsche Windguard (2008)	6.3%*	as cited in Schwabe et al (2011). Dt Windguard based on investor interviews
Dt Windguard (2010)	5.8%	Based on discussions with financiers, experience from work as project development adviser
BMU (2011)	5.1% - 5.4%*	Based on Deutsche Windguard supporting report (2011), which was based on consultation / experience with developers. DWG endorsed top end
DLR et al (2012)	6%	Assumed
Dt Windguard (2012)	4.8% - 5.3%*	As above. Shows lower hurdle rates than previously but doesn't discuss reasons
Fraunhofer ISE (2012)	4.2%-5.3%*	Based on "detailed" discussion with investors, explicitly accounts for non-market rates of retail / municipal investors. Original did not distinguigh pre-tax or post-tax

*Source: NERA Analysis. *Inflation assumption: 1.7%..*

The above table includes (amongst others) a series of hurdle rate estimates by engineering consultancy Deutsche Windguard (DWG), which undertakes regular surveys of wind investors. DWG's estimates have been widely quoted including in the international report for the US NREL[121] and in the documentation of the reasons for the 2012 revision of the EEG as provided by the German Ministry of the Environment.[122] The estimates reported by Deutsche Windguard have shown a downward trend from 2008 to 2012 that can be traced to higher gearing levels that investors are now willing to accept while the costs of debt and equity have remained unchanged.[123] Other estimates of the hurdle rate for German onshore wind have been provided by research institutes DLR and Fraunhofer ISE. Of those two the latter are more likely to be informative of current required hurdle rates as these are based on detailed investor surveys while the former use a common discount rate assumption across all technologies (an approach confirmed by one of the major utilities we interviewed but not one that is common across the board).

It is worth noting that the estimates quoted here are explicitly based on a sample that contains both what can be classified as commercial investors and private and municipal investors. The

[121] Schwabe, P.; Lensink, S.; Hand, M. (2011). IEA Wind Task 26 – Multi-national Case Study of the Financial Cost of Wind Energy; Work Package 1 Final Report. NREL Report No. TP-6A20-48155.

[122] BMU. EEG Erfahrungsbericht 2011 – Entwurf. May 2011.

[123] Elsewhere in this paper (section 4 and 5 and 0) we review whether there is likely to be a similar impact on gearing in the UK and whether this is likely to be the main driver of hurdle rate reductions.

German literature explicitly recognises that the former are likely to have higher discount rates than the latter two and that the results reflect this. Our interviews with institutional investors that invest in both Germany and the UK confirm this notion of higher required hurdle rates in Germany with infrastructure funds and other institutional investors reporting hurdle between 6.5 and 10 per cent nominal, post-tax.[124]

F.2.2.2. Solar PV

With a view to assessing the hurdle rate for solar PV we first reviewed market evidence on Capital Stage AG, a stock-market listed company that owns and operates large and medium-scale solar PV installations across Germany. However, its stock price proved insufficiently liquid to estimate a beta and there was insufficient analyst coverage to estimate to source a robust estimate of the WACC in that manner.

As a second step we reviewed estimated hurdle rates for solar PV from different sources. Compared to onshore wind the availability of data is more limited and the majority of those estimates that are available (e.g. IE&ZSW, 2011 and BMU, 2011) are based on conjecture drawn from evidence on realised returns rather than investor surveys.

Fraunhofer (2012) provides a recent estimate of the hurdle rate for solar PV that explicitly takes into account the fact that the vast majority of solar PV installations in Germany are owned by private individuals and not international investors; with the former having a lower hurdle rate. The resultant estimates are shown in Figure F.3.

[124] Nominal, post-tax rates are generally comparable to real, pre-tax rates with small differences potentially arising depending on the investor's inflation assumptions and effective tax rates.

Figure F.3
Estimates of the Hurdle Rate for German Solar PV[125]

Technology	Real Pre-tax WACC	NERA Comment
Allowed Return; original EEG (2000)	3.3% - 5.3%*	Chosen to provide a rate of return comparable to a safe asset in 2000 (5% -7% nominal, pre-tax)
IE & ZSW	4.3% - 5.3%	For DoEnv: Show (higher) outturn returns and speculate that 6-7% (nominal, post support cut) would be sufficient as increase to 5% four years prior led boom
BMU (2011)	3.3%	Apparently identical for rooftop and large-scale. Based on consultant report that assumes constant WACC across different types of PV investment
Fraunhofer (2012)	2.7% - 4.0%	Based on "detailed" discussion with investors, explicitly accounts for non-market rates of retail / municipal investors

*Source: NERA Analysis. *Inflation assumption: 1.7%.*

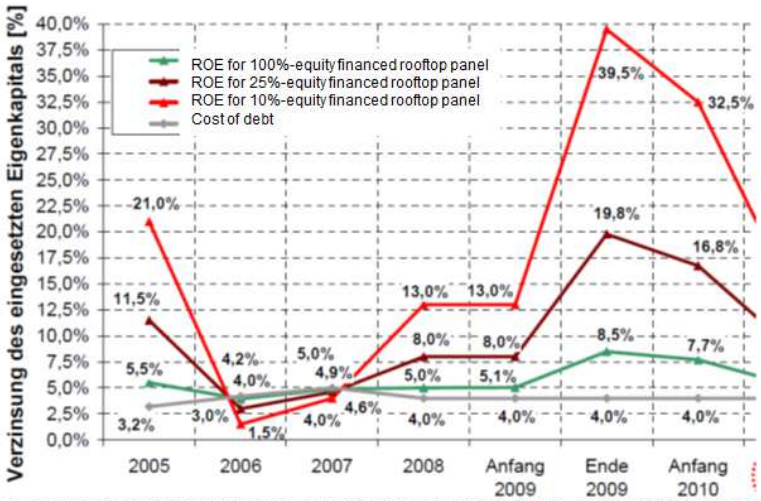
A review of available rates of return for solar PV suggests that these hurdle rates have not actually been market-tested to a significant degree as available rates of return for solar PV have been significantly in excess of the rates reported in Figure F.4.

As shown in Figure F.4 German FiTs for small-scale solar installations (which make up 80 percent of total capacity) coupled with falling prices led to achievable returns far in excess of the hurdle rates reported above. Development since 2010 saw significant reductions in FiTs (63 percent since January 2010) as well as costs for solar panels (c.50 percent since 2010)[126] and interest rates (e.g. the German government bond rate fell from c.4 percent in 2008 to c.1.5 percent in 2012). Combined with the continued rapid expansion of solar PV shown in Figure F.4 these developments suggest that achievable rates of return have remained well above hurdle rates making it hard to assess whether the rates reported in Figure F.4 truly reflect rates at which German investors are willing to commit funding for solar PV projects.

[125] A number of these estimates are of questionable robustness, e.g. IE&ZSW show outturn rates and then speculate on the difference between the hurdle rate and the outturn rate. In addition it is not clear whether the BMU (2011) estimate that assumes rooftop and large-scale PV WACCs are the same and reverse engineers the required rates of return on equity is justified.

[126] Monpolkommission (2013): Sondergutachten Energie

Figure F.4
Available Rates of Return for German Solar PV[127]



Source: NERA adaptation of IE&ZSW report for Federal Environment Dept (2010). We cut the "2010 proposed" values in the original paper as the reduction in the FiT that was used as a basis for the calculation was not implemented in the same form

So far we have not been able to verify these hurdle rates against evidence provided by institutional investors, given the limited number of solar PV investors active in Germany.

F.2.2.3. Biomass

The available evidence base for biomass investments in Germany is even more limited than it is for solar PV while those pieces of evidence that are publicly available are not robust market-tested evidence, e.g. because they are not explicitly derived (e.g. DLR et al.) or because they are derived using implausible assumptions, e.g. a higher cost of debt than cost of equity (BMU, 2011). We therefore do not attach any significant weight to the figures reported in Figure F.5.

[127] It is unclear from the IE&ZSW paper whether these reported rates are pre-tax or post-tax.

Figure F.5
Reported Hurdle Rates for German Biomass

Technology	Real Pre-tax WACC	NERA Comment
Allowed Return; original EEG (2000)	3.3% - 5.3%*	Chosen to provide a rate of return comparable to a safe asset in 2000 (5% -7% nominal, pre-tax)
BMU (2011)	4.5% - 5.9%	BMU Experience report does not actually list any WACC but supporting document by research institute DBFZ estimates range from 4.5% to 5.9% on a real, pre-tax but warning that many estimates are based on self-supply by wood companies rather than purely commercial considerations
DLR et al (2012)	6%	Assumed identical for all technologies

*Source: NERA Analysis. *Inflation assumption: 1.7%.*

F.2.2.4. Offshore Wind

Evidence from offshore wind is, in some ways, potentially more informative as investment is commonly undertaken by utilities which are more likely to have market hurdle rates. However, offshore wind is a relatively new technology to be rolled-out in Germany, meaning it has the least actual market testing from which to draw conclusions.

In Germany there are potentially higher asymmetric risks borne by the generator for offshore wind than in the UK. For example, the generator can only reclaim approximately 90 percent of lost sales revenue in the event of a distribution disruption, such as a cable break. Additionally, there are certain technical conditions that can make building a wind farm more complex, including the requirement that all developments be out of sight from the shoreline.

We have relied on both industry and financier sources, commissioned by different parties to the debate. The KPMG (2010) and Fichtner & Prognos (2013) WACC estimates were commissioned by industry participants, whereas the BMU is the Federal Environment Ministry of Germany. The estimates are shown below in Figure F.6. The apparent reduction out to 2023 may be in doubt, given a gradual scaling back of the offshore wind target.

Figure F.6
Reported Hurdle Rates for German Offshore Wind

Technology	Real Pre-tax WACC	NERA Comment
Allowed Return; original EEG (2000)	3.3% - 5.3%*	Chosen to provide a rate of return comparable to a safe asset in 2000 (5% -7% nominal, pre-tax) This allowance did not trigger any new build
Schwabe et al (2008)*	8.0%	Based on Deutsche Windguard (2008); WACC derived as risk uplift relative to onshore wind
KPMG (2010)	>8.44%	Achievable rate based on modelling using developer data; deemed insufficient
BMU (2011)	7.8% - 8.2%	Based on DWG paper (2011) following consultation with financiers; warns that these are mostly estimates as there is limited mkt-tested data
Fraunhofer ISE (2012)	8.1 – 10.5%	Based on "detailed" discussion with financiers
Fichtner & Prognos (2013)	7.85%	Determined during a finance workshop with industry and financiers (limited info on what was discussed there) Projected increase in gearing capacity (assuming unchanged ROE) Main driver is increased familiarity / tech progress (seemingly based on optimistic construction assumptions)
Fichtner & Prognos (2023) – forecast in 2013 study	5.68%	

*Source: NERA Analysis. *Inflation assumption: 1.7%.*

The available evidence shows fairly consistent estimates for the pre-tax WACC of approximately 8 percent with the potential to fall over time, although, as noted, the Fichtner & Prognos 2023 forecast may overestimate the reduction if deployment is scaled back. However, if we account for the reduction in the risk-free rate between 2008 and 2013, this actually implies an increase in hurdle rate over time, across the sources. This is not necessarily unreasonable given various drawbacks encountered in the sector in Germany. Given the limited roll-out of offshore wind to date, the estimates that we present have not been fully market tested and therefore should be treated with due caution.

F.2.3. Plausibility Testing and Limitations

F.2.3.1. The Need for Plausibility Testing

We note that due to the lack of stock-market listed close comparators the majority of the evidence on hurdle rates is derived from surveys among industry participants including investors and financial analysts. We note that one weakness of survey-based methods is that these can be "gamed" by survey respondents who may have an incentive to either overstate their hurdle rate (if they believe that this will lead to e.g. higher strike prices) or understate their hurdle rate if their incentive is to paint a picture that their preferred technology is "cheap" and by implication worthy of further support.

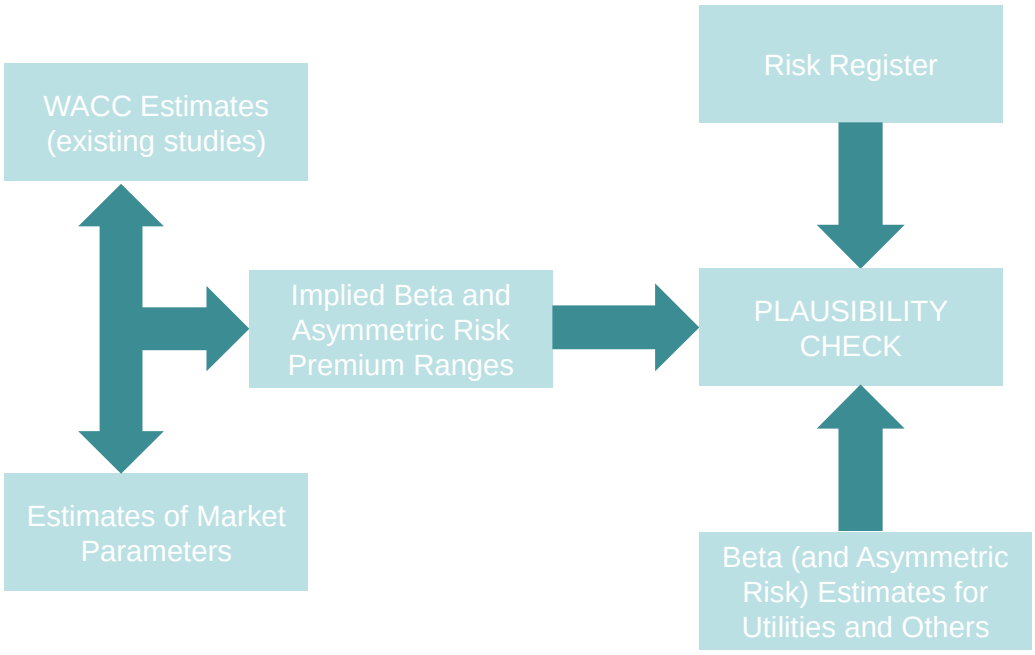
So far the estimates derived from such methods have not generally been referenced back to commonly used financial models such as the CAPM, which is the standard model in financial decision-making or the DGM or variants thereof, which account for asymmetric risk such as

the Third Moment CAPM and others. Below we undertake this referencing of the theoretical model as a fresh approach to the issue that complements the existing evidence.

Recognising the difficulty in finding suitable comparators for estimating the hurdle rate using the CAPM we back-solve for the implied ranges of CAPM parameters that are embodied in the survey evidence in order to arrive at a model-based plausibility check of the existing results. Drawing on generally accepted estimates of general market parameters (risk-free rate and ERP), gearing and the cost of debt we can back-solve for the implied beta estimates.[128]

Figure F.7 illustrates our approach to plausibility testing.

Figure F.7
Illustration of model-based Plausibility Check of existing studies



F.2.3.2. Plausibility Testing the German Estimates

Below we report the asset betas implied by the recent Fraunhofer ISE study using current estimates of the risk-free rate and equity risk premium. Note that the Fraunhofer study did not explicitly survey whether the estimates quoted were pre-tax or post-tax.[129] We therefore

[128] Note that these give an upper bound of the implied beta that investors use as they may also be applying adders for "asymmetric risk", which would further lower the asset beta.

[129] We did confirm with one of the authors of the study that the reported values were nominal but that investors had not explicitly been asked whether the quoted values were pre-tax or post-tax.

provide a range that incorporates both options, assuming that the quoted values are pre-tax (Figure F.8) and assuming that the quoted values are post-tax (Figure F.9).[130]

Figure F.8
Implied Asset Betas (assuming pre-tax values)

		Source	PV-min	PV-max	Onshore	Offshore
a	**Nom, pre-tax CoE**	Fraunhofer	**6.50%**	**7.50%**	**9.0%**	**14.0%**
b	Tax Rate	NERA example	30%	30%	30%	30%
c	**Nom, post-tax CoE**	**a*(1-b)**	**4.6%**	**5.3%**	**6.3%**	**9.8%**
d	Nom RfR	Latest 1Y	2.00%	2.00%	2.00%	2.00%
e	MRP	consistent with BoE	6.00%	6.00%	6.00%	6.00%
f	**Equity Beta**	**(c-d)/e**	**0.43**	**0.54**	**0.72**	**1.30**
g	Gearing	Fraunhofer	80%	70%	70%	60%
h	**Asset Beta**	**f*(1-g)**	**0.09**	**0.16**	**0.22**	**0.52**

Figure F.9
Implied Asset Betas (assuming post-tax values)

		Source	PV-min	PV-max	Onshore	Offshore
a	**Nom, pre-tax CoE**	Fraunhofer	**6.5%**	**7.5%**	**9.0%**	**14.0%**
b	Tax Rate	NERA example				
c	**Nom, post-tax CoE**	**a*(1-b)**	**6.5%**	**7.5%**	**9.0%**	**14.0%**
d	Nom RfR	Latest 1Y	2.00%	2.00%	2.00%	2.00%
e	MRP	consistent with BoE	6.00%	6.00%	6.00%	6.00%
f	**Equity Beta**	**(c-d)/e**	**0.75**	**0.92**	**1.17**	**2.00**
g	Gearing	Fraunhofer	80%	70%	70%	60%
h	**Asset Beta**	**f*(1-g)**	**0.15**	**0.28**	**0.35**	**0.80**

Source: NERA Analysis

In summary implied German hurdle rates range from 0.09-0.28 for solar PV and 0.22 to 0.35 for onshore wind.[131] It is noteworthy that these are at or below the level of a regulated network (e.g. Ofgem used implied asset between 0.32 and 0.42 for the RIIO price controls).

This may reflect the fact that investors do not face any regulatory reviews over the life of the asset although one would expect there to be some offsetting pressure from inherent policy risk for renewable energy, which a priori would appear to be higher than for regulated networks due to the non-substitutability of networks while there are potentially alternative sources of low carbon energy.

In addition it is worth noting that a large share of German onshore wind and solar PV investments have not been undertaken by globally diversified utilities with a diversified portfolio but rather by retail investors who may not be applying the standards of a globally

[130] Our modelling also assumes investors use "current" estimates of risk-free rate and ERP. Based on long-run estimates (as e.g. used by Ofgem in its RIIO price controls) implied betas are marginally lower still.

[131] We do not discuss the implied offshore wind estimates in much detail as offshore wind is a relatively untested technology in Germany and therefore investors are likely to apply hurdle rate uplifts outside the CAPM.

diversified investor (CAPM).[132] In fact the Fraunhofer study, on which this plausibility check is based explicitly accounts for the fact that many of the RES investors in Germany are retail investors who are not able to build a fully diversified portfolio and for whom the CAPM is thus not the right benchmark.

These findings may explain why the implied asset betas shown above appear very low compared to UK estimates. Another factor, confirmed by the author of the study was the perception that the German EEG support system is a long-established stable system with minimal risk for existing assets.

F.2.3.3. Potential Gap between reported German offshore hurdle rates and actions of the „Big Four"

Various pieces of evidence suggest that the UK may be a more attractive destination for offshore wind investment than the German market. E.ON has one German offshore wind farm under construction, but its main focus in the sector is on the UK. Further, Peter Terium, RWE's CEO, was quoted as saying that the company views the UK as a less risky market for offshore wind development.[133]

There have also been several delays in the financing and construction of German offshore farms. RWE's annual results, released in March 2013, noted a delay in the commissioning of the Nordsee Ost offshore wind farm by more than a year. Similarly EnBW has indefinitely postponed the construction of the offshore wind farm "Hohe See" and Strabag, an Austrian construction company, has postponed planned German offshore wind investments.

These examples again highlight that offshore wind is a relatively immature sector, particularly in Germany, and the hurdle rates for which we have found evidence have not been fully market tested for robustness.

F.2.4. High Level Summary: German Experience shows lower hurdle rates than DECC proposal but note limited commercial market testing of these rates

- The German system has a mature fixed FIT scheme in place for all technologies with the option to switch in and out of the CfD mechanism on a monthly basis. The majority of biomass and onshore wind have made the switch to the CfD mechanism. There is limited evidence of a change in the WACC over the period that the CfD element was introduced, at the beginning of 2012. However, we have been able to obtain informative evidence of WACC levels under the mature FIT system.
- In Germany there has been significant recent deployment of onshore wind, solar PV and biomass (including many retail and municipal investors) but limited deployment of offshore wind, which is still very much in its infancy. Across the technologies for which

[132] As we are looking at the reported cost of equity only the impact of state-backed debt finance should not play a role in this case.

[133] Wind Power Offshore. Debt forces RWE to scale back offshore ambitions. 5 March 2013.

we obtained data points, the German discount rates are consistently estimated at 200bps or more below UK CfD estimates across a range of studies.

Technology	UK RO Pre-tax WACC	UK CfD Pre-tax WACC	GER FiT Pre-Tax WACC
Onshore Wind	8.3%	7.9%	4.8% - 6.0%
Solar PV	6.2%	5.8%	<4%
Offshore Wind	10.2% - 12%	9.6% - 11.3%	7.85%

Source: NERA Analysis

- However, we do not believe that DECC should set rates based solely on the German experience. A significant share of investment in renewables in Germany has come from municipal or domestic investors which tend to have lower return requirements. This has been corroborated through our interviews with investors that suggested commercial entities have a hurdle rate closer to that of the UK.[134]
- Another important factor to bear in mind is that the German regime is more established and investors may therefore have a greater understanding of the support scheme and place more confidence in achieving their expected returns. That said, the CAPM plausibility check that we carried out shows betas for solar and to an extent onshore wind that look low compared to asset betas that commercial investors have been able to accept in other low risk investments. Additionally, limited deployment in offshore wind has meant that the hurdle rates reported for this segment may not be fully market tested technology.

[134] Note, however, that this is based on a small sample of investors who may have self-interested motives to suggest a higher hurdle rate.

F.3. Denmark

F.3.1. Introduction

This section sets out evidence on discount rates from Denmark, which has a long history of providing subsidies for renewable electricity generation.

Table F.1 summarises subsidy regimes in Denmark for onshore and offshore wind.

Table F.1
Danish Subsidy Regime

	Subsidy	Details
Offshore Wind	Fixed FiT/One-sided CfD for first x TWh of generation (max 20 years)	Strike determined in **auction:** **Horns Rev II (2009):** 51.8 ore/kWh **Rodsand II (2010)** 62.9 ore/kWh; **Anholt (2013):** 105.1 ore/kWh
Onshore Wind	**2014+:** Asymmetric CfD for 6600 hours **2008-2013:** Premium FiT for 22 000 hours **2005-2008:** Premium FiT for 20 years **2003-2004:** One-sided CfD for 20 years **2000-2002:** One-sided CfD for 22000 hours	Subsidy grandfathered by vintage. Plans for certificate system in 2001 initially postponed have since been abandoned.

Source: Energistyrelsen[135]

The table shows that the Danish subsidy regime for onshore wind has undergone a number of relatively minor adjustments since 2000.[136] It currently supports new developments with a premium FiT for 2.5 years of full load, corresponding to around 10 years of generation at a load factor of 25%. However, from 2014, the subsidy period will be shortened significantly to 0.75 years of full load, or just 3 years assuming a load factor of 25%. Additionally, the current premium FiT will be replaced by a one-sided CfD in the form of a top-up payment to the market price which is gradually phased out for higher electricity prices. In contrast to the proposed UK system there is no actual claw-back in the event of high electricity prices.[137] We understand that balancing responsibility lies with the generator but that a separate subsidy (2.3 ore/kWh) is provided to reflect balancing costs.

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135 http://www.ens.dk/sites/ens.dk/files/undergrund-forsyning/el-naturgas-varmeforsyning/el/elproduktion/stoette-vedvarende-energi/oversigt_over_afregning_og_stoette_for_ve_22.04.13.pdf

136 Subsidies have been grandfathered such that different vintages receive different subsidy allocations.

137 The asymmetric nature of the prices appears to be reflected in the strike prices, which are generally significantly lower than in the UK. For example, the premium for onshore wind is currently 25 ore/kWh (approximately £22/MWh), only just over half the price of a ROC. Danish wholesale power prices are generally similar to, or lower, than UK prices

Large scale offshore wind farm subsidies are generally allocated through a tendering process, and effectively take the form of a fixed FiT, but recent tenders have failed to attract significant interest.[138] Subsidies are granted for a pre-specified volume of output (in MWh), typically corresponding to around 20 years of expected generation. Additionally, there is a cap on the number of years of subsidy (maximum 20 years). The strike prices vary greatly between wind farms but are all significantly below those discussed for the UK, even taking into account the shorter duration of the UK subsidies. The recent strike price on the Anholt wind farm (105.1 ore/kWh, 2012/2013) was more than double the first successful tender at Horns Rev (51.8 ore/kWh, 2009) but is still significantly lower than the prices currently being discussed for the UK wind farms (£155/MWh).[139] Moreover, unlike the proposed UK strike prices, the Danish strike prices are not index-linked.

F.3.2. WACC Estimates

Table F.2 shows WACC estimates from different sources, based on observations for assets from 2010-2012. These suggest WACC estimates of approximately 7-10 percent for onshore wind and 8-11 percent for offshore wind (Nominal, post tax).

The offshore estimates from EA Energianalyse are based on an analysis of internal rates of return derived based on approximate capital expenditure announcements and assumptions on OPEX. The calculation is sensitive to OPEX cost assumptions.

The Onshore wind calculations are based on less reliable sample data from small wind assets. They may lack comparability to the UK due to the nature of investors (i.e. partly municipals and co-operative investors).

[138] Deloitte (2011) http://www.ens.dk/sites/ens.dk/files/undergrund-forsyning/vedvarende-energi/vindkraft-vindmoeller/havvindmoeller/planlaegning-fremtidens/Deloitte%20Havvind%20-%20hovedrapport.pdf

[139] The strike prices may not be directly comparable to the UK strike prices due to differences in construction costs, the amount of transmission charges associated with the generators etc.

Table F.2
WACC Estimates, Denmark[140]

	WACC (Nominal, Post Tax)	WACC (Real, Pre Tax)	Details
Onshore Wind, EA Energianalyse (2010)	7-10%	6.7%-10.6%	Assumptions made for project finance according to law allowing for "local ownership". Sample of 5 onshore wind farms. (1 municipal wind farm and 1 positive outlier excluded)
Offshore Wind, EA Energianalyse (2010)	9%-10.8%	9.3%-11.6%	Based on Internal Rate of Return of Auctioned strike price on Rodsand II, Horns Rev II and Anholt.
Offshore Wind, Deloitte (2011). [Beta assumptions from Dexia (2007) & Green-X (2004)]	7.9%-9%	7.8%-9.3%	Specific to Anholt and potential farm at Kriegers Flak. The 7.9% reflects (1) inclusion of a capex reserve and (2) fewer penalties for construction delay.

Source: Deloitte[141] and EA Energianalyse,[142] cross checked againstfor example Hvidovre Vindmoellelaug[143]. Real Pre tax WACC calculated assuming corporate tax rate of 25% and inflation of 2.5% (average of 2010-2012)

These WACC estimates are likely to reflect the differing nature of the policy support offered to each technology, so we must take care when making comparisons across technology and across country. In particular, the riskiness of assets in Denmark generally appears to be *higher* for onshore and slightly *lower* for offshore than would be the case under the proposed UK CfD system. For instance:

- **Danish Onshore Wind** appears more risky for investors than the UK CfD proposal, for two important reasons. First, for assets constructed over the period 2008-2013 (the period from which estimates of the WACC are derived) the **duration** of subsidy has been shorter, limited to approximately 10 years of normal operation. Second, **the nature of subsidy** is different – in particular, the Premium FiT means assets are directly exposed to market prices (as they are under the current UK ROC system, but would not be under the proposed CfD regime).[144]

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140 We performed a high level cross-check of the calculations performed by EA Energianalyse for IRRs of offshore wind and estimated a range of 8.4 percent-10.5 percent, not 9 percent-10.8 percent using the assumptions stated by EA Energianalyse. The results are sensitive to the OPEX assumption. All calculations are based on WACCs over the full life of the asset, regardless of the duration of the support.

141 http://www.ens.dk/sites/ens.dk/files/undergrund-forsyning/vedvarende-energi/vindkraft-vindmoeller/havvindmoeller/planlaegning-fremtidens/Deloitte%20Havvind%20-%20hovedrapport.pd, p85

142 http://www.ea-energianalyse.dk/reports/811_vindmoellers_oekonomi.pdf, p67. Overview: p72.

143 http://www.hvidovrevindmollelaug.dk/nyheder/tegningsmateriale.pdf

144 For assets built for the period 2008-2013, there is a limit of 22000 full load hours which corresponds to around 10 years of operation at a load factor of 25 percent. For assets commissioned from 2014, the subsidy horizon will be much shorter (6600 full load hours) corresponding to around 3 years of subsidy at a 25 percent load factor.

- **For offshore, the risks differ by development:**
  - **Risks for Anholt Offshore** wind farm (~9%) may be comparable to UK CfD proposals to some extent as there were special arrangements for ensuring commitment from the winning bidder, including a significant penalty on **construction delay**. A report by Deloitte suggests there was significant time pressure on the project construction.[145]
  - Risks for the **proposed offshore Kriegers Flak** wind farm (~8%) were lower than those for Anholt Offshore Wind farm due to smaller penalties for construction delay and the allowance of a reserve for construction overrun.
- **Risks for other offshore** developments (9-12%) may differ due to factors including; lower **development delay risk** as the subsidy is granted on full load hours, rather than for a fixed period; little **eligibility** risk, i.e. little capital needs to be sunk before the support level is secured via the auction; and finally, we understand the construction risk may have been lower as the TSO played a larger role in the grid connection. For comparison with the other estimates we should subtract about 1% due to variations in the risk free rate, i.e. the range is approximately 8-11% on a comparable basis. [146]

F.3.3. Conclusion

Subject to the caveats noted above and the uncertainties associated with the WACC estimates, the findings from Denmark for onshore of 7-11 percent (pre tax, real) might be an upper bound of the WACC for UK onshore assets (given the higher risk associated with the 2008-13 Danish support regime) and the IRRs for offshore (8-12 percent, pre tax, real) might act as a rough guide to a plausible minimum range of WACCs for UK offshore.

This suggests the WACC for particularly onshore wind is lower in Denmark than those suggested for the UK CfD.

F.4. Sweden

F.4.1. Introduction

This section sets out evidence on discount rates from Sweden, which provides support to renewable energy using a ROC scheme not dissimilar to the current UK system. According to the Swedish Energy Agency the system came in to force on the 1st of May 2003 and is intended to increase the production of renewable electricity in a cost-efficient manner. The system replaced earlier public grants and subsidy systems.

As the ROC support is not banded in Sweden the focus of development has so far been on biomass and onshore wind. Note that Sweden has a significant amount of hydro production

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[145] http://www.ens.dk/sites/ens.dk/files/undergrund-forsyning/vedvarende-energi/vindkraft-vindmoeller/havvindmoeller/planlaegning-fremtidens/Deloitte percent20Havvind percent20-percent20hovedrapport.pdf

[146] The risk free rate was approximately 1% higher when Rodsand II and Horns Rev II were constructed (10 year govt bond was 3.6% in 2009) than when Anholt was commissioned (10 year govt. bond was 2.7% in 2011). Source: Danmarks Nationalbank (http://nationalbanken.statistikbank.dk/nbf/98226)

but that a large share of this production is not remunerated under the ROC scheme.[147] We also understand that there are generally no PPAs but only limited hedging.[148]

Sweden and Norway have combined their certificates market as of 2012. Over the period until 2020, the two countries aim to increase their production of electricity from renewable energy sources by 26,4 TWh according to the Swedish Energy Agency. The joint market will permit trading in both Swedish and Norwegian certificates, and producers receive certificates for renewable electricity production in either country.

Given the limited availability of hedging and the existence of an unbanded certificates market the Swedish hurdle rate estimates provide a plausible upper bound on the hurdle rate for the UK.

F.4.2. WACC Estimates

The majority of renewables developments in Sweden have been undertaken by small players with 96% of generators being classified as "small" by the Swedish Energy Agency and the top three players only accounting for 21% of total RES volumes. [149]

Consequently, there is generally a limited amount of information on the hurdle rates used by investors in the Swedish market. However, one detailed case study is provided by the San Giorgio Group's (2013) review of the financing of the Jadraas onshore wind farm on which the next paragraphs draw heavily. [150]

The Jadraas onshore wind farm was the largest onshore wind farm in Sweden and Scandinavian Europe at commissioning in May 2013. It was sponsored by a consortium of a UK PE fund and a Swedish developer with debt capital provided by commercial banks and a Danish pension fund, the latter backed by the Danish Export Credit Agency. The case study implicitly reports a real, pre-tax WACC of 6%.[151] The case study further describes that the financing arrangements for the wind farm included a guarantee provided by the Danish Export Credit Agency (EKF) in order to incentivise non-bank participation on the debt side. However, as the EKF is required to lend on commercial terms under state aid rules the implied hurdle rate of 6% can be considered to be on market terms.

Subject to the caveats that there may have been spillover effects from the export guarantee (despite the provisions about headline rates) and the fact that this is only one data point the Swedish hurdle rate estimates provide a potential "high" estimate of the hurdle rate for the UK.

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147 See Swedish Energy Agency (2013): The electricity certificate system 2012

148 Based on CPI (2013): San Giorgio Group Case Study: Jädraås Onshore Windfarm

149 See Swedish Energy Agency (2013): The electricity certificate system 2012

150 Based on CPI (2013): San Giorgio Group Case Study: Jädraås Onshore Windfarm

151 The case study does not actually report a number for the cost of capital as opposed to the internal rate of return but it can be inferred from comparisons between the published IRR (and its sensitivities) and the (undisclosed) hurdle rate what the assumed cost of capital / hurdle rate will have been.

This suggests the WACC for onshore wind is lower in Sweden than what is currently suggested for the UK CfD scheme, which is surprising given the higher risks faced by Swedish generators.

F.5. Conclusion on International Benchmarking Exercise

Our review of international evidence on hurdle rates suggests that hurdle rates required in other countries are generally lower than those proposed by DECC, e.g.

- German estimates of the hurdle rate for onshore wind, offshore wind and solar PV are c.200-400bps below DECC's current estimates of the CfD hurdle rate for a system that is moderately less risky than the proposed CfD scheme;
- Danish estimates of the hurdle rate for onshore wind and offshore wind are towards the bottom of the range proposed DECC estimates despite facing higher risks (onshore) or slightly lower risks (offshore) than in the UK;
- Swedish estimates show a hurdle rate for onshore wind that is significantly below DECC's estimates despite investors facing higher risks.

We also reviewed evidence from other countries including the Netherlands and Ireland. However, we did not find any new evidence on hurdle rates required in these countries beyond what has already been reported in previous reports for DECC. In Ireland there are no listed renewables generators for which hurdle rates could be derived from market data while the regulator who we contacted chose not to share its model. In the Netherlands there are no listed developers either and to our knowledge there is no more recent evidence available than the studies quoted in previous work for DECC (e.g. ECN).

While this may suggest that DECC's proposed hurdle rates are comparatively generous[152], there are a number of factors that need to be taken into account when comparing rates across countries, as follows:

- German studies explicitly account for lower return requirements of municipal / retail investors and preferential debt rates, while in Sweden there may have been a spillover effect from the state guarantee even if debt terms are required to be at arms' length;
- Germany, Sweden and to a slightly lesser extent Denmark have mature / established system of FiTs/certificates;
- In Germany the option to switch from a fixed FiT to a CfD-type arrangement and back provides additional protection;
- Our financial model-based plausibility check for Germany shows unrealistically low betas for solar in particular; and
- German offshore wind hurdle rate not fully market-tested due to limited deployment.

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[152] We do note that Frontier Economics found hurdle rates for Polish onshore wind investments that were comparable to estimates for the UK. However, these may not be fully comparable to the UK because of differences in country risk (Poland is only rated A-/A) and risk around the stability of the support scheme (cf. Frontier Economics, 2013, pp. 136-137.)

Taking account of the above factors suggests that DECC should carefully consider the comparability of the international evidence before concluding that the international precedent implies that its own estimates are too high or low.

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