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Transition risk:

Investment signals in a decarbonising electricity system

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Abstract
Zero-carbon electricity is a pre-requisite for decarbonisation of the wider economy and many scenarios envisage rapid expansion of renewables. IEA estimates a need to double the annual rate of investment to 2030. A rapid transition to low carbon electricity creates a risk to investors because projects being financed now will generate their revenue in a zero-carbon electricity system for which there is no track record of price formation. Although the cost of renewable power has fallen greatly, future revenues from renewables are still affected by market price risks that are often outside the control of generators. If risks are difficult to quantify, they may be mis-priced, leading to inefficient premiums being added to the cost of capital, which could increase the overall cost of the transition. In this context many countries around the world provide support for low carbon energy, such as the UK Contracts for Difference. In this paper we investigate exposure to price risk caused by uncertainty over the mix of technologies used to achieve decarbonisation, which we term 'transition risk', and how this varies under different technology mixes, and for different policy regimes. We show that exposing investors to transition risk could increase the cost of delivering the renewables needed for a zero-carbon electricity system by around 25% or £7bn/year compared to policy options that reduce exposure to wholesale market price risk. The paper concludes that as long as transition risks remain high, de-risking policy mechanisms can help to minimise the overall cost of achieving net-zero.

Keywords
Risk, investment, renewables, energy transition, wind power, contracts for difference, cost of capital.

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1 Introduction
It is widely acknowledged that near zero-carbon electricity is a pre-requisite for decarbonisation of the wider global economy, with the IEA estimating a need to double the annual rate of investment in energy in the period to 2030 compared to the past 5 years, the bulk of which would need to be in low carbon power generation and electricity grids (1). In line with these international expectations,

the UK government's 2021 Net Zero Strategy (2) suggests that all electricity will need to come from low-carbon sources by 2035, requiring an estimated investment of the order of £280-400 billion. Subsequently, amid heightened concerns about the energy market impacts of Russia's invasion of Ukraine, the 2022 British Energy Security Strategy (3) was published. This reiterated the UK government's commitment to decarbonise the electricity system by 2035, and set out ambitions on delivery of zero-carbon electricity sources including up to 50 GW of offshore wind by 2030, 70 GW of solar by 2035, and 24 GW of nuclear by 2050.

The importance of keeping the costs of raising financial capital as low as possible are underlined in the Net Zero Strategy, which notes that the principal economic costs of net zero arise because of the capital intensity of low carbon power generation. These are huge, equating to something like 1 – 2% of GDP (2). Similarly, the UK Climate Change Committee (CCC) assessments of net zero emphasise the importance of capital expenditure in the initial phases of decarbonisation, noting how this eventually provides a payoff in the form of huge reductions in gross expenditures on fossil fuels (4).

Central to the reduction in cost of capital for renewable power projects is the ability to manage wholesale power market price risk (5). The resulting reduction in the cost of capital helped reduce offshore wind power generation costs in Great Britain from well over £100/MWh to below £40/MWh (2012 prices) between 2015 and 2019, making the levelized costs of offshore wind low compared to almost all other forms of power generation (6).

The key policy instrument for reducing investment risk used in the UK has been the Contracts for Difference (CfDs), designed to stimulate investment in low-carbon generation including both nuclear power and renewables (7). Introduced in the Energy Act of 2013, CfDs for low-carbon generation are a mainstay of the current electricity market design, with 22 GW contracted through four auctions, to be delivered by 2030, predominantly from offshore wind (8).These policy arrangements are currently under review by the UK government. The British Energy Security Strategy (3) committed to undertake a Review of Electricity Market Arrangements (REMA), and various market design options are being considered, with the aim of ensuring delivery of a secure, cost-effective low-carbon electricity system (9).

The low cost of renewables has led some to argue that risk reduction policies are no longer necessary, and that renewables could be funded through a suitably designed market, provided carbon prices are appropriately incorporated into investment decisions, without additional policy support (10). However, in the GB market context, as in many others, the policy design debate is focused on the detailed design of interventions that provide subsidy and/or revenue stability to generators, rather than the more fundamental question of whether to remove such schemes altogether. There is long-standing discussion in the literature of the relationship between market price formation and revenue risk, and the concomitant requirement for policies to de-risk investment as well as to price externalities (11). There is also considerable discussion in the literature of Britain's approach, which combines carbon price with revenue stabilisation for low carbon generators, and a capacity mechanism, see for example (12). It is within this context that the paper situates itself.. Our analysis assesses the impact of such policies on revenue risk, viewed from the perspective of a notional 'merchant' renewable generation investor.

It is important to note that the paper does not seek to advocate for CfDs *per se* or to engage with the broader debate about the role and means of pricing carbon. Instead, we seek to investigate the risk exposure for investors under a defined set of hypothetical policies, using a modelled representation of the transition risk facing investors. We investigate a simplified representation of how the market might try to 'solve' the price cannibalisation problem without direct policy intervention by offering a low-carbon premium above system marginal cost levels. We do not attempt to define how such premium mechanisms could emerge and/or whether they could be delivered in the absence of policy. Carbon is priced in the scenarios we model, at varying levels, so the analysis shows how it interacts with other forms of support/wider market price formation. The reason this focus on how different policy regimes affect revenue risk is important and timely is that irrespective of cost reductions in renewable energy, significant revenue risks exist for low carbon generators. Exposing investors to them may lead to significant increases in the cost of capital, and ultimately the cost of electricity to consumers. In particular, as electricity systems decarbonise, price formation in wholesale electricity markets is likely to change in ways that may further increase investment risk for renewables and other low/zero marginal cost generators, including nuclear power. As electricity markets shift away from fossil fuels towards low carbon technologies with low marginal costs of production, the wholesale price of electricity will tend to drop during periods of high renewable generation – the 'price cannibalisation' effect (13) – which could adversely affect investment signals. This was observed during periods of low demand during the first Coronavirus lockdown in the UK at the start of 2020 (14,15). The effect is even more pronounced for wind plant, as their output tends to be correlated with periods when prices are low, meaning that the average price they receive – the so-called 'capture price' (16) – tends to be below the average for the market as a whole.

The degree of price cannibalisation depends largely on the physical characteristics of the system. In a system dominated by wind power, high levels of colocation of wind in areas where the wind resource is the best will tend to lead to greater correlation of output between different generators. This effect will tend to get stronger as more wind power enters the system, though the scale of the effect depends on the physical nature of the electricity system, and how this affects wholesale market price formation.

The price cannibalisation effect can be partially offset by increasing the flexibility of the electricity system so that it is able to integrate variable sources of power more efficiently. One example is electrolysis for producing green hydrogen (17). This could be a major source of demand to soak up large quantities of power when the wind is blowing, helping to prop-up prices during these periods, and potentially providing a storage solution to address seasonal variations in renewable supply. However, future demand for green hydrogen varies widely depending on decarbonisation pathways for industry, transport and heat. Decarbonisation scenarios from the Great Britain Electricity System Operator, National Grid ESO, indicate between 10-24 GW of electrolysis capacity by 2040, with significantly less in their 'slow progress scenario' (18). Other studies indicate much less green hydrogen in favour 'blue' hydrogen (19) derived from natural gas which would not perform the same flexible demand function. Other forms of flexibility and storage in end-use sectors will also likely play a very significant role (20), including demand response for residential heat and industrial use representing up to 20 GW of flexibility, and storage solutions including from electric vehicles, other types of battery and thermal storage representing up to 21 GW in some scenarios (21).

Long-distance interconnectors can also help increase system flexibility (22) by shifting power over larger geographical areas, smoothing out regional variations in renewable energy supplies. The UK already has 7.9 GW capacity of interconnection (23), with scenarios from 17 to 28 GW by 2040 (21). Total demand for power is also dependent on these pathways.

Uncertainty over possible decarbonisation pathways is compounded by headwinds that make the delivery of the required infrastructure harder including UK trading arrangements (24) and recent interest rate increases (25). Crucially, many of these infrastructure pathway choices are also dependent on public policy, for example in the domestic heating and transport sectors (26,27), which are outside the control of power market participants.

Therefore, whilst the goal of the transition is known – near-zero-carbon electricity – the details of this end-point in terms of technology mix, price formation and degree of price cannibalisation are still uncertain. We use the term 'transition risk' to describe risks that investors face relating to this pathway uncertainty.

This paper uses an open-source electricity system model combined with a financial model to investigate these risks with the following aims:

- To quantify the impact of these transition risks on the cost of capital for renewables,
- To quantify the extent to which different CfD design options reduce exposure to these transition risks,
- To estimate the overall impact of these policy choices on the total system cost of delivering the level of wind and solar power expected to be needed to achieve a zero-carbon electricity system.

2 Methodology

2.1 Approach to Quantifying Transition Risk

The prospect of a rapid energy transition over the next 12 years creates a risk to investors because projects being financed now will generate the bulk of their revenue in a zero-carbon electricity system for which there is no track record of price formation. If risks are difficult to quantify, they may be mis-priced, leading to inefficient premiums being added to the cost of capital, which could increase the overall cost of the transition.

The objective of this research is to provide a quantification these potential cost of capital impacts. In order to model this, we start with a simplified characterisation of the transition as comprising two phases. Firstly, there is a 'build phase', during which fossil fuel generators (which are currently price-setters in the market) are replaced with low-carbon generators (many but not all of which are currently price-takers in the market). The investment decision is assumed to be taken part-way through this build phase during which time the final characteristics of the decarbonised electricity system are still uncertain.

Secondly, the final decarbonised system is treated as a 'steady-state' phase during which the new low-carbon plant will operate and receive most of its revenues.[1] The physical characteristics of this decarbonised system (i.e. generation mix, demand profile etc.) are modelled to determine the system marginal cost of generation which is assumed to be the basis for wholesale price formation. This provides a quantification of market price risk in the future decarbonised system, including the degree of price cannibalisation and curtailment of renewables in the future decarbonised system. The electricity system model is described in Section 2.2.

Different ways in which the effects of price cannibalisation and curtailment may be countered in this future steady-state phase are represented in the analysis as 'policy options'. These include, for example, policies such as CfDs as well as renewable energy premiums that might be negotiated

[1] In reality this will not be 'steady-state' as the electricity system will likely need to grow substantially after it has decarbonised in order to allow for greater levels of electrification of the economy, and the nature of electricity demand will continue to change. We leave analysis of these dynamic effects for future work.

directly through the market. The different policies assessed in this paper are described in Section 2.4.2.

We assume that a hypothetical investor has some expectation about the final physical state of the system in the steady-state phase, that this determines their expectations about the financial performance of their investment, and that they use this to determine their response to the available policy options. For example, these expectations determine how the investor would bid into CfD auctions of various designs, or the kind of renewable premium they would need / expect to negotiate in the market in order to make a reasonable return on investment.

We then stress test these financial cases by introducing physical states of the system that differ from those assumed in the investors initial expectations. These scenarios are described in Section 2.3.

These different physical states of the system create different outturns in the level of cannibalisation and curtailment (described in Section 3.1) and thus different financial returns for the project. This spread of financial outcomes is taken to represent the degree to which an investor would need to increase their overall returns on investment in order to cover the energy transition risk (presented in Section 3.2). This is used as the basis for assessing the impact of transition risk on the overall cost of transition, and the potential for policies to reduce these costs (presented in Section 3.3).

In this paper, we restrict our analysis to the case of investment in renewable generation, but the approach could be used to assess investment risk in all types of generation and storage assets.

2.2 Electricity system model

2.2.1 Overview of ANTARES model

In this study, we make the simplifying assumption that wholesale market prices will be primarily determined by the system marginal cost of generation. We model the system marginal cost using an optimal electricity system dispatch model, building on a model developed by and described in MacIver et al. (28). In that previous study, a European scale transmission system model was developed to model the behaviour of a coupled European electricity market. The model uses ANTARES, an open source electricity market modelling tool developed by French system operator RTE (29). Each European country is represented by a single node (with the exception of the UK and Denmark, each with two nodes denoting separate islanded regions) with modelling of an appropriate generation mix separated by type while constraints are imposed on the maximum net transfer capacity (NTC) of electricity trades that can take place between connected countries.

The implementation takes the form of a unit commitment (UC) model that determines a schedule of generation units that minimises “the overall system operation cost over a week, taking into account all proportional and non-proportional generation costs, as well as transmission charges and “external” costs such as that of the unsupplied energy (generation shortage) or, conversely, that of the spilled energy (generation excess)” (30). It is constrained by the minimum and maximum production of each generation type, the maximum rate of change of production from each generator and the minimum amount of time for which it must be on if committed to run or run if it is not needed. ANTARES is capable of running in different modes. For the current study, each run represents a single year, modelled as a sequence of 8760 hours, coupled by time-related constraints such as generation ramp rates. The model is solved in weekly blocks, which are coupled for the whole year with constraints respecting hydro-reservoir storage capacities. Transmission system flows are driven by price differences between the modelled nodes assuming a perfectly coupled market with within-week foresight. Renewable generation availability is modelled across Europe with reference to real historical outputs which respect temporal and spatial correlations.

The structure of the ANTARES model set-up and methodology used for the current study is largely the same as described in MacIver (28), and the reader is referred to that paper for a fuller description of the methodology. Key features and specific updates unique to this work include:

- Future projections of generation, storage, interconnector capacity and demand for non-GB European Countries are taken from the Ten Year Network Development Plans (TYNDP) of the European Network of Transmission System Operators for Electricity (updated in this work from ENTSO-E 2018 scenarios (31) to ENTSO-E 2020 scenarios (32), being the latest available at the time of that work).
- Future projections of generation, storage, interconnector capacity and demand for GB are modelled with reference to the Future Energy Scenario decarbonisation pathways outlined in Section 2.3. The rest of Europe is modelled using the same ENTSO-E scenario, so we can see the impacts of just changing GB with respect to a fixed background.
- Thermal generation for each European country is split down into separate generating units of each type, with assumed sizes of each unit and with representation of different types of generator in terms of efficiency levels, ramp rates and financial criteria.
- Hydro generation is divided into three categories: run-of-river (output varies from month to month based on historic data but is dispatched evenly across each hour within a given month), reservoir storage hydro (optimised weekly) and pumped storage (optimised daily).
- Wind and solar generation are dispatched as pre-defined time-series for each node within the model. The time-series used are based on historical country by country output data synthesised in Renewable Ninja (33). This gives an expected hour by hour country level output in percentage terms that is then scaled to the generation capacity of wind and solar for each country within the generation background scenario being considered. With the aim of preserving the cross-correlations that would have been present between climatic conditions (weather & hydrological conditions) and demand profiles, a single historical year of data for 1984 is chosen as this matches with one of the three historical climatic years used for developing the ENTSO-E demand scenario (34), and has detailed wind profile data for the UK.
- Demand profiles are taken from ENTSO-E projections for 'average year' profiles scaled to the expected total demand associated with each considered future year.
- Transmission connections are represented by single transmission links between countries with import and export constraints defined independently and fixed across the study year based on NTC projections from ENTSO-E. Onshore transmission losses are included in the modelling via a fixed 2% increase in the demand within each country such that additional generation is required to meet typical onshore system losses. In addition, a financial hurdle cost of €1/MWh is applied to mainland Europe cross border flows so that a trade is only made if the benefit of the trade exceeds the approximate cost of losses to accommodate it.
- Great Britain interconnection with Europe involves larger distances, and for this reason the associated line and converter losses are modelled explicitly on these links.

2.2.2 Representation of system flexibility

It is important to capture the effects of additional system flexibility, given that this is a key feature of the way electricity markets and pricing will respond to increased levels of variable renewable generation. Some flexibility options were already included in the previous model. In particular, this included representation of pumped storage facilities modelled with 72% round trip efficiency and the ability to charge/discharge over a 24-hr cycle to minimise system costs. This effectively represents 10-hr storage capacity at maximum output, which approximately matches the combined storage capacity of GB pumped storage facilities.

Interconnection is also already inherently built into ANTARES, so the same methodology was used as for MacIver (28). Many of the scenarios considered show considerable scale-up in the degree of interconnection between GB and Europe. In this study we make the simplifying assumption that existing interconnector routes are simply scaled-up to accommodate the additional capacity

For this study, additional flexibility options for GB were added to represent demand-side management (DSM), batteries and hydrogen electrolysis, each of which offer flexibility that can absorb cheap, surplus wind power).

DSM and batteries are both represented in a similar way, essentially as storage facilities with the ability to push or pull power from the GB node if that helps to minimise overall system operation cost. Both are implemented with a fixed maximum hourly capacity, using data from the chosen GB decarbonisation pathway and both are assumed to have a maximum storage capacity equivalent to 2 hours continuous operation at maximum output. DSM is treated as lossless, whilst batteries are assumed to have an 80% round-trip efficiency. ANTARES allows for optimisation of these facilities across either daily or weekly cycles. In this case, DSM operates on a daily cycle to allow smoothing of the daily demand curve while battery charge/discharge is optimised across each week. Model constraints are used to ensure that efficiency adjusted energy flows to and from these facilities are balanced across the optimisation cycles and that the maximum storage level is never exceeded.

Representation of hydrogen electrolysis is implemented in a simplified way by representing electrolysis as a negative source of generation (i.e. demand) within the GB node. The level of electrolysis demand in a given hour is pre-determined as a model input, and is calculated as a function of the residual load (i.e. total GB demand less the variable renewable supply in that hour). When residual load is at its minimum (implying low prices), electrolysis demand is assumed to operate at its maximum hourly capacity. Conversely, when residual load is at its maximum (implying high prices), electrolysis demand is assumed to fall to zero. A sloped step function is applied in between these extremes, using the scenarios described in Section 2.3 to calibrate the total amount of electrolysis demand over the year. In this way, we approximate likely operating peaks and troughs of electrolysis demand based on model inputs (GB demand less wind and solar generation), rather than using electricity prices which are a model output and would rely on iterating the model.

2.2.3 Other input data sources and assumptions

The modelling framework described above has been populated with data available in the public domain. Table 1 sets out the key assumptions and sources of this input data.

Table 1. Input data sources and assumptions

Model input	Assumptions	Data source
Technology CAPEX, non-energy OPEX and performance	Based on BEIS 2040 figures. Hydrogen CAPEX and non-fuel OPEX assumed to be the same as CCGT.	BEIS Electricity Generation Costs 2020 (35)
Fossil fuel prices	Future Energy Scenarios 2040 fuel prices	FES 2021 Data Workbook (18) (Sheet CP1)
Average GB solar capacity factor	Renewables.ninja calculation of GB average based on 1984 solar	Renewables.ninja (36) European solar data set version 1.1

	irradiation patterns.	
Average GB wind capacity factor	Recalibrated Renewables.ninja average GB capacity factors based on future fleet scenario.[2]	Renewables.ninja European wind data set version 1.1
Hourly demand profiles	Hourly demand profiles from ENTSO-E, with demand variability scaled to match the peak and average demand specified in each scenario	ENTSO-E 10 year network development plan (32)

2.3 Characterising Decarbonisation Pathway Uncertainty

We characterise the degree of decarbonisation pathway uncertainty by comparing the impact of different scenarios within our modelling framework. This uncertainty relates to physical characteristics of the system such as the type of generation on the system, the shape and scale of demand, and the availability of different types of flexibility options such as interconnectors, hydrogen etc.. We have based this analysis on the four National Grid ESO Future Energy Scenarios (FES) for 2040 (21).

Three of the FES scenarios published in 2021 meet net zero goals:

- **Consumer Transformation (CT-base)**. Based on electrified heating, consumers willing to change behaviour, a high level of energy efficiency and a high degree of demand-side flexibility and interconnection to Europe. Wind power reaches 116 GW by 2040. We use CT-base as our reference scenario for assessing investment risk.
- **System Transformation (ST-base).** Based on a greater role of hydrogen for heating, consumers being less inclined to change behaviour, lower energy efficiency and a greater reliance on supply-side flexibility, interconnectors and electrolysis. Wind capacity reaches 97 GW by 2040.
- **Leading the Way (LW-base).** Based on the fastest credible rate of decarbonisation across the economy as a whole, implies significant lifestyle changes, and includes a mix of hydrogen and electrification of heating. Wind capacity reaches 117 GW by 2040.

The final FES scenario fails to make enough progress to be compatible with net zero goals:

- **Steady Progression (SP-base)**. Based on the slowest credible rate of decarbonisation, minimal behaviour change, slow decarbonisation rates in power and transport, and heat fails to decarbonise. Wind power reaches 77 GW, and there is more than 40 GW of unabated gas power remaining on the grid in 2040.

The role of the FES scenarios in our work is simply to illustrate some of the uncertainties that surround the composition and characteristics of a notional future power system. We use them to

[2] The hourly GB wind generation profile in the model is based on a recalibration of hourly data from Renewables.ninja. The Renewables.ninja baseline uses historical wind data (we choose 1984), and then uses a future scenario of the distribution of GB wind power across the country to calculate average hourly wind capacity factors for the country as a whole based on the wind speeds in those locations. We then need to recalibrate these hourly capacity factors to get the correct future GB annual capacity factor specified in the generation scenario. In particular this average capacity factor is sensitive to the mix of onshore and offshore wind, because of the significantly higher capacity factor for offshore wind.

generate a set of hypothetical system prices so we can explore risks. Other scenarios are available, and the analysis does not seek to demonstrate which scenarios are better, more likely, or plausible.

In addition to these four main FES scenarios, we also introduce an additional three variants to explore different risk factors:

- **CT-HiPrices**. This scenario doubles the carbon price (to £116/tCO_2) and increases the long-term gas price by two-thirds (to £10/GJ) compared to the CT base.
- **CT-LowInterC**. This scenario reduces the amount of interconnection in the scenario by a third (from 27 GW to 19GW) compared to the CT base, replacing this two-way flexible capacity with an equivalent amount of generation capacity from 1-way flexible biomass generation.
- **ST-LowElectr**. This scenario halves the amount of electrolysis in the system, from 9.8 GW in the ST base case to 4.9 GW.

2.4 Methodology for quantifying investment risk

2.4.1 Calculation of investment risk

The hourly plant-level dispatch and system marginal cost results from the ANTARES model presented in Section 2.2 are subsequently imported into a Microsoft Excel-based discounted cashflow model developed for this analysis. This aims to quantify investment risk by assessing how price formation affects cashflows differently under each of the scenarios. The range of cashflows is represented as a discount-rate impact relating to uncertainty over future price formation processes as represented by the different scenarios. The degree to which different policy options provide revenue stabilisation and a potential reduction in the cost of capital is then assessed.

To assess the risk posed by different decarbonisation pathway scenarios, we treat one of the scenarios (CT-base) as a reference case. We take this reference case as the basis on which financial planning for an investment project in solar or wind is undertaken. We then treat the other decarbonisation pathway scenarios as 'risk' cases against this reference case.

The steps are as follows:

1. The reference scenario (CT-base) is used to determine the expected financial performance of each type of generation, taking account of capture prices and curtailment levels.
2. This expected financial performance is then used to determine the average price premium that each generation type would need to recover over-and-above market prices[3] in order for the investment to break even (i.e. to have a positive NPV under a risk-neutral discount rate).
3. For CfD-style policies, this reference case expectation about the required breakeven premium is used to simulate the strike price that would be achieved in a CfD auction. The auction is assumed to take place before the investor knows which state of the electricity system they will be exposed to. The strike prices vary according to the design of the policy (e.g. 1-sided vs. 2-sided CfDs etc.) because the CfD design affects the expected revenue received, so investors are assumed to adjust their bids accordingly (see Table 2). Energy-only markets are modelled in a simple way by assuming that these price premia would be recovered directly in the market through privately-developed trading arrangements. We use two simple assumptions about the riskiness of these market premia, described in the next section.
4. The cashflow that would be realised in the risk cases are then calculated, keeping the CfD strike prices unchanged from Step 3. This takes account of the phasing of construction costs, the cost

[3] Using system marginal cost as a proxy for market prices

of debt and equity during this period, the timescale of any CfD or other policy support, and the annual market revenue each decarbonisation pathway scenario.

5. The model then converts the differences in cashflow between the decarbonisation scenarios into a 'risk adjusted hurdle rate'. This is the change in project discount rate required to equalise the NPV in the base case scenario with the NPV for the 'risk' decarbonisation scenarios under any given policy option.

2.4.2 Policy Options

As noted above, zero-carbon wholesale electricity markets based on system marginal cost are structurally prone to price cannibalisation, and can lead to varying amounts of curtailment depending on the level of flexibility in the system. In this analysis, we focus attention on various CfD designs as described in Table 2, with further commentary in the Annex.

We also investigate a simplified representation of how the market might try to 'solve' the price cannibalisation problem without direct policy intervention by offering a low-carbon premium above system marginal cost levels. We do not attempt to define how such premium mechanisms could emerge and/or whether they would be delivered through market participants or policies. They are broadly consistent with what would be needed under a 'low carbon obligation' approach to policy (10) but such a premium could also in principle arise directly through market contracts between generators and suppliers. Whether or how such premium payments could or would occur is not the purpose of this analysis; they exist merely so we can represent the risk implications of exposing investors to a price environment based on system marginal price.

In all cases the policies we present are simplified and illustrative. A range of variants can be envisaged, and alternative policies could deliver a similar outcome. For example a 1-sided CfD might be expected to have similar characteristics to a market-wide floor price, the fixed premium might or might not be a feed in tariff, the negative price rule could be applied selectively and the analysis does not take account of opportunities to value stack, for example in providing ancillary services.

Table 2 – Market and policy design options tested

Policy option	Characteristics assumed	CfD strike price / floor Price		
		Offshore Wind	Onshore Wind	Solar
2-sided CfD	15-year contract pays the difference between an agreed strike price (set at auction) and the wholesale market price.	52.4	47.1	49.8
2-sided CfD (extended)	As above, but with 25 year contract	43.3	38.7	35.3
2-sided CfD with negative price rule	As above, but does not pay out if prices go negative (as per current design of the CfD).	58.5	54.0	53.9
1-sided CfD (price floor)	If wholesale power prices fall below the floor, payments are made to the recipient up to the floor. Generators receive all upside payments.	45.5	38.0	41.7
1-sided CfD with clawback	As above, but where wholesale power prices rise above the floor, generators do not receive the positive difference until the gross value of payments	52.4	47.1	41.7

	received under the CfD have been reimbursed.			
Cap and Floor	This sets a minimum and maximum, with prices determined by the market when they are within this range.	47.8	40.6	44.8
Wholesale price + fixed premium	Wholesale price plus fixed price top-up set at a level to	N/A	N/A	N/A
Wholesale price + floating premium	Wholesale price with multiplier	N/A	N/A	N/A

The CfD strike prices shown in Table 2 reflect the different expected revenues under each policy design under the reference decarbonisation scenario.[4] Although the bid prices are different for each CfD design, they all result in the same expected average annual revenue under the reference scenario.[5] This revenue is exactly sufficient to recoup all project costs within the contract period covered by the CfD. Strike prices are therefore not a guide to overall system cost-effectiveness or cost to consumers.

These strike prices can be compared to an LCOE under our model assumptions of £43.3 / MWh We make the following observations on these strike prices:

- **2-sided CfD**. The strike price is substantially above the LCOE reflecting the 15 year contract period over which investment is assumed to be recouped.
- **2-sided CfD (extended)**. The longer duration of the CfD to match the technical lifetime of the project brings the strike price to the same level as the LCOE.
- **2-way CfD with negative price rule.** The strike price is higher than the standard 2-way CfD option due to the expected reduction in payments under this option.
- **1-sided CfD** is substantially **lower** than the strike price under the 2-sided CfD, because investors will expect to capture the upside when prices are above this floor.
- **1-sided CfD with clawback** has the same strike price as the simple 2-sided CfD option because the expected revenues are the same in the reference scenario. This reflects the fact that the clawback mechanism effectively prevents investors from benefiting from upside revenues given the capture prices remain below market prices on average in the reference scenario due to price cannibalisation under the conditions assumed in this study.
- **Cap and floor.** The floor price lies between the 1-way CfD floor price and the 2-way CfD strike price. This is because investors will see some upside when prices are above the floor, but this is upside is constrained by the price cap.

These CfD auctions determine the revenues that generators realise in the high- and low-price decarbonisation scenarios. The differences in revenue represent generators' exposure to price

[4] At this point in the analysis, by assuming that investors base their decisions on expected annual revenue, we assume bidders are risk-neutral i.e. they value expected upside as much as downside. This allows us to later to value the potential risk premium associated with down-side risk relative to this expectation.
[5] However, revenues differ in the 'stress test' scenarios.

formation risk, and are expressed as a change in project discount rate and compared across CfD design options, as presented in the next section.

3 Results

3.1 How do physical system differences translate into revenue risk?

The electricity system model described in Section 2.2 is used to assess how different electricity system configurations would affect electricity revenue risk for different renewable generation sources. Revenue risk has two components: price risk (due to wholesale price cannibalisation), and volume risk (due to curtailment when the system is oversupplied). Figure 1 shows how price risk (positive y-axis) and volume risk (negative y-axis) vary for solar PV, onshore wind and offshore wind under different electricity system scenarios.

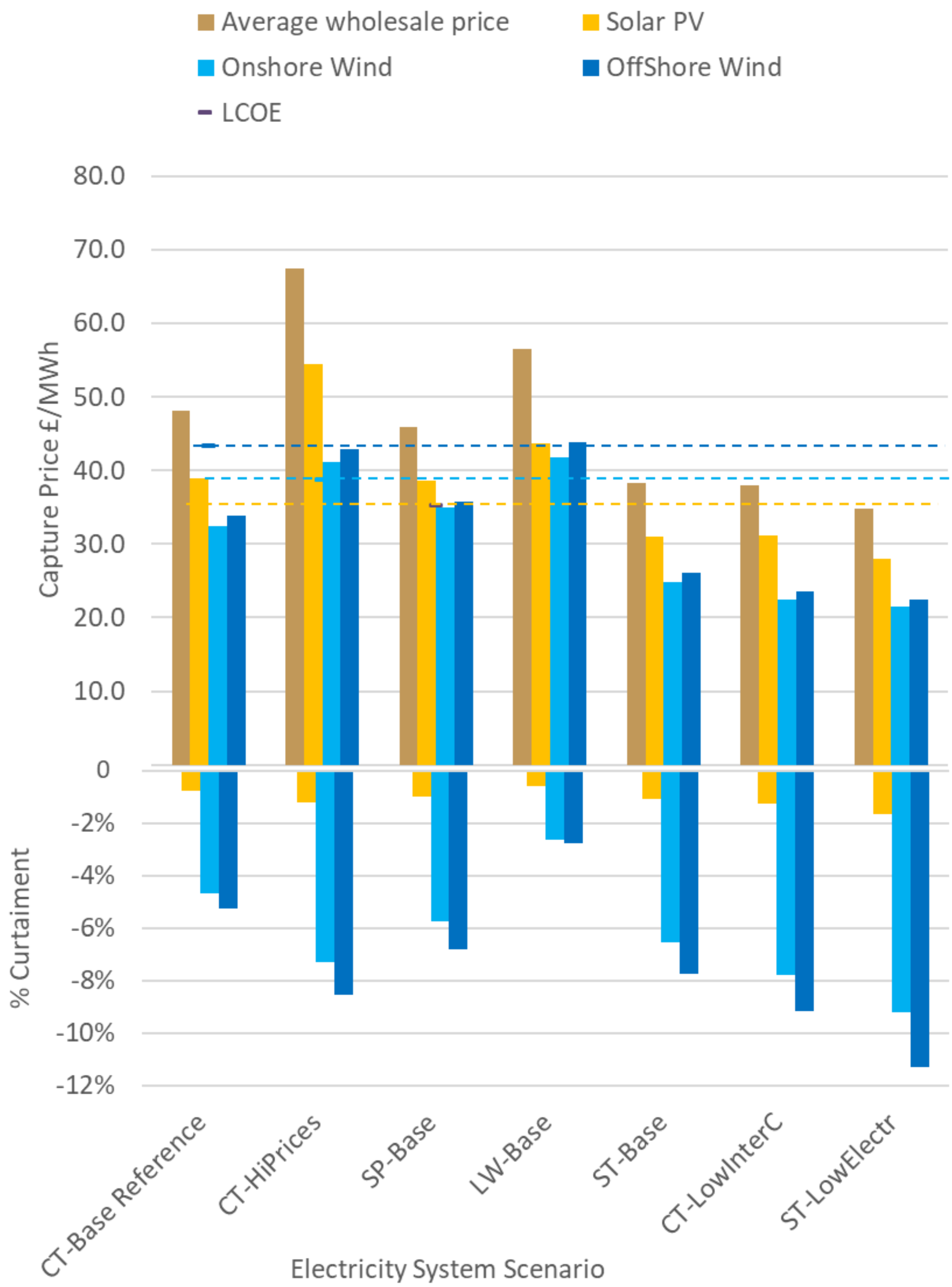

Figure 1. Price cannibalisation and curtailment rates in different decarbonisation pathways

It is striking from these results that curtailment rates for solar remain low (mostly below 1%) across all these scenarios. Capture prices for solar are also less attenuated than wind prices relative to average market prices which has important implications for the financial risk exposure. This is driven by the fact that offshore wind is the largest share of renewable generation in all the FES scenarios considered. This means that output from a specific offshore wind project is more likely to be correlated with average UK generation levels – and therefore with periods of oversupply – than other renewables. Onshore wind is somewhat less correlated with the average than offshore wind, but solar PV is significantly less correlated, leading to much lower levels of exposure to price and volume risk.

From Figure 1 we draw the following conclusions taking each of the scenarios in turn:

- **CT-base** (**reference case).** Only solar PV has a high enough capture price to recover it's LCOE, whilst wind plant would capture prices below their LCOE. Curtailment levels are modest, at around 5% for wind and below 1% for solar.
- **CT-HiPrices**. The increase in gas and carbon prices drive up average capture prices relative to the reference. The benefits of these higher prices are somewhat offset by the increased levels of curtailment which arise because the higher cost of fossil fuels drives up prices in Europe making the interconnectors more constrained than in the reference scenario.
- **SP-base**, the higher share of unabated gas remaining in the system (43GW compared to 13GW in the reference case) leads to slightly raised average capture prices. However, curtailment levels are also slightly increased relative to the reference, due to lower levels of flexible plant (particularly flexible demand, electrolysis and interconnectors) compared to the reference case.
- **LW-base**. Despite having less than 1GW of gas remaining in the system, this scenario sees higher average prices and reduced curtailment rates mainly due to greater levels of hydrogen generation (7.2GW vs. 4.7GW) and electrolysis (24GW vs. 13GW) compared to the reference case.
- **ST-base**. This scenario has greater levels of nuclear (14GW vs. 10GW), gas + CCS (9GW vs. zero) and hydrogen (12GW vs. 5GW) compared to the reference case, but significantly reduced levels of two-way system flexibility, including flexible demand (9GW vs. 19GW), interconnectors (20GW vs. 27GW) and electrolysis (10GW vs. 13GW). Overall, this reduced level of system flexibility leads to lower average capture prices and increased levels of curtailment relative to the reference case.
- **CT-LowInterC** assumes a reduced level of interconnectors (19GW vs 27 GW), reducing system flexibility, leading to lower average capture prices and increased levels of curtailment.
- **ST-LowElectr** sees similar consequences of reduced system flexibility due to a further reduction in electrolysis capacity compared to the ST-base scenario (10GW vs. 13GW).

3.2 How do different policies affect exposure to revenue risks?

In this step, we look at how the variations in capture prices and curtailment rates presented in Section 3.1 translate into investment risk, and the degree to which different policy options may reduce exposure to these risks.

We assess how each electricity system scenario would affect a project's returns compared to the Consumer Transformation (CT-base) reference scenario, expressing this difference as a discount rate impact. The discount rate impact is calculated as the change in the discount rate required to achieve the same expected net present value for the project as for the reference scenario. The downside risks help give an indication of the extent to which investors will need to be compensated for this risk in their returns, although the cost of capital impact may be lower than the discount rate impact because different types of investor will value risk differently and some will also take into account the upside risk.

Figure 2 shows how the different policy design options (listed on the vertical axis) affect risk exposure (measured on the x-axis) to different decarbonisation pathways (indicated by the different coloured bars). The righthand side of Figure 2 indicates how downside risks vary relative to the CT reference scenario depending on the policy option.

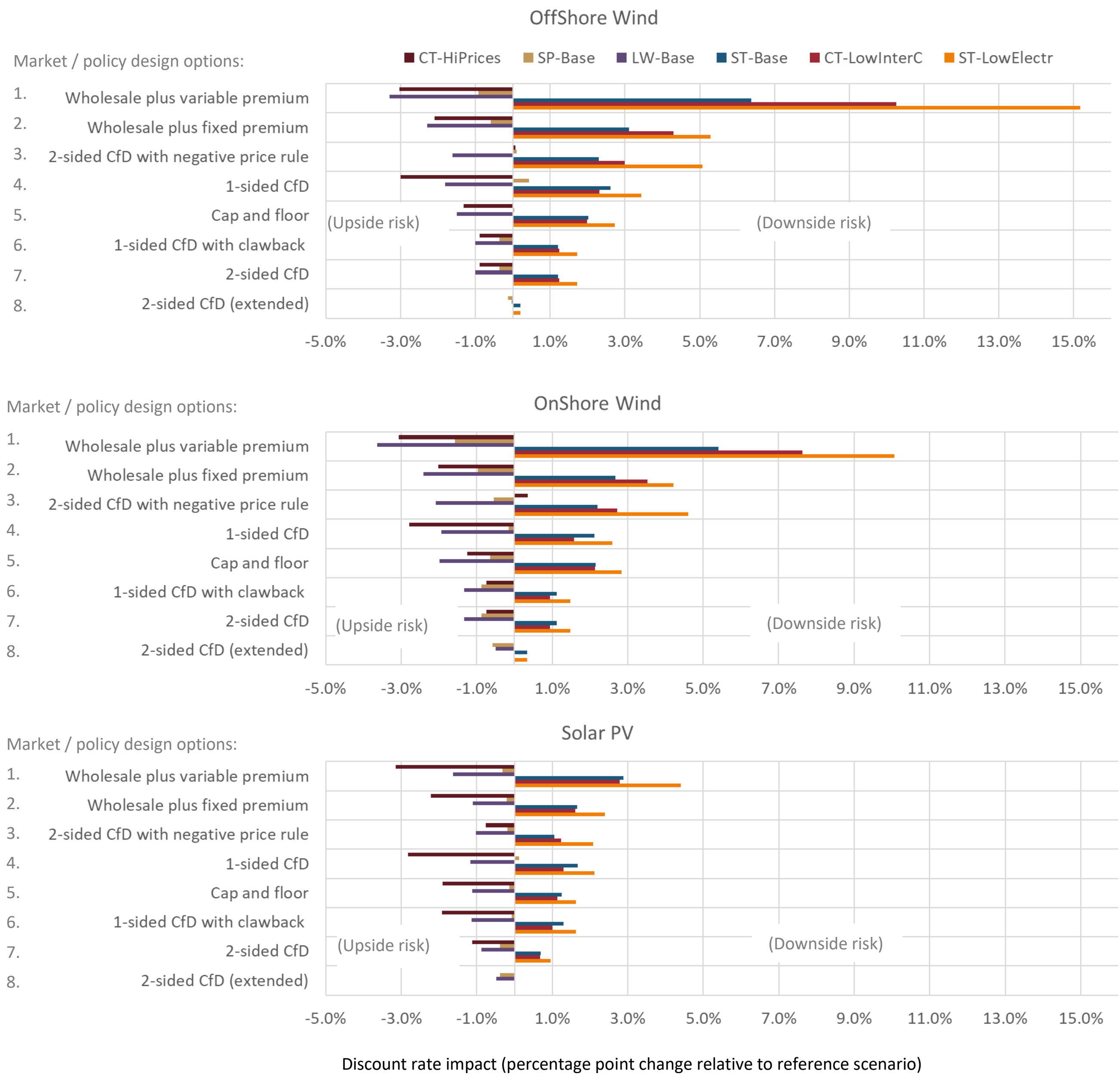

Figure 2. Exposure of renewable generation projects to uncertainty in decarbonisation pathway under different policy and market regimes.

The first key conclusion is that different policy designs have a significant impact on risk exposure. The following commentary focuses on the offshore case, being the most risk-exposed and therefore with the most pronounced differences between the policy support cases. Taking the policy design options in the order shown in the figure, the key messages are:

- Both **wholesale market design options** show the greatest level of exposure to downside risk which can considerably exceed 5 %-points, and extending as high as 10-15 %-points under some cases. This financial exposure particularly reflects the risk of lack of investment in major flexibility infrastructure (such as flexible electrolysis demand and/or interconnectors) in the different decarbonisation scenarios.
- **CfD with negative price rule** reduces upside risk, but leaves projects exposed to quite considerable levels of downside risk (up to 3-5%) driven by uncertainty over the degree of curtailment they might face in future decarbonised markets.
- **1-sided CfD** substantially reduces downside risk compared to the market options, although upside risk is still high. This asymmetrical allocation of risk between investors and consumers (i.e. allowing upside risk to accrue to investors whilst protecting them from downside risk) may be considered a disadvantage in the light of recent market price trends.
- **Cap and floor** constrains both upside and downside risks. These results depend on the spread between the cap and floor; as the cap is increased, the results would approach the same distribution of risks as the 1-sided CfD.
- **1-sided CfD with clawback.** Whilst in principle this allows some upside risk to accrue to investors, in practice under the assumptions used in this work, the degree of cannibalisation is such that investors would not receive any upside, making this option identical in terms of revenues to the standard 2-sided CfD.
- **2-sided CfD** provides a high degree of de-risking of the options assessed, with downside risks (which only arise after the 15-year contract period has elapsed) limited to around a 1% impact on the discount rate.
- **2-sided CfD (extended)**. This option almost entirely eliminates revenue risk because the 25-year contract period matches the assumed technical lifetime of the project.

The second conclusion from Figure 2 is that of the three technologies, offshore wind has the widest distribution of discount rate impacts from the different transition scenarios – and in particular the greatest degree of downside risk. This reflects the relatively higher degree of correlation between individual offshore wind projects and the overall GB wind fleet, making them more susceptible to price cannibalisation. By comparison with offshore wind, the transition risks for onshore wind are marginally lower, whereas for solar PV they are significantly reduced. This reflects the reduced volume and price risks, particularly for solar PV, due to the lower levels of correlation with periods of low pricing and/or oversupply which tend to be driven by offshore wind as discussed in Section 3.1.

Solar also has a different response to some of the policy design options compared to offshore wind. For example, solar benefits from upside under the 1-way CfD even when there is a clawback provision because the degree of cannibalisation and curtailment is so much lower for solar than for wind, so that the degree of clawback is reduced.

Although the focus of this analysis is mainly on downside risk, upside risks also have important policy implications. The Steady Progression pathway, which fails to decarbonise, presents an upside risk to wind investors (i.e. delivers higher capture prices than in the reference scenario), particularly for policy cases 1-3 where projects are more exposed to market price risk[6]. The effect is more

[6] A related issue affects price setting by interconnectors with Europe. Under the assumptions modelled here, Europe has still not fully decarbonised, so prices received through interconnection are elevated by the presence of a carbon price. This is why the 'Lead the Way' scenario, which is highly interconnected to Europe, also looks attractive in these results. Different assumptions about decarbonisation rates in Europe would change this result.

pronounced with the higher carbon and gas price variant of the CT scenario, which also has residual gas generation. This is a concern as it could lead to a disincentive to fully decarbonise unless strong additional policy measures are in place.

Interestingly, the Leading the Way (LT-base) scenario also shows considerable upside, even though this is a fully decarbonised scenario for the GB system. This reflects the considerably greater degree of interconnection under this scenario compared to the other decarbonisation scenarios. In the assumptions used for this work, the European system still has considerable degree of fossil fuel use, which tends to keep capture prices elevated for interconnected wind plant in the GB system. This is an assumption that needs to be tested through more analysis of different European-level decarbonisation scenarios.

3.3 Implications for the cost of delivering renewable generation

The final step is to calculate the impact of these risk premiums on the cost of delivering the total stock of renewable expected in our base case scenario. The risk premium for a project is just one of many factors that will impact cost of capital. In practice financing costs will be affected by a range of project specific factors, including the debt leverage that can be achieved by different investors, and financial markets' risk appetite. In this analysis, we have not attempted to address these more complex aspects of project financing, but make the observation that although cost of capital will vary for different investor types, the calculated discount rate impacts are illustrative of the scale of impact of different policy options on cost of capital across the market.

Table 3 firstly presents the average of the downside risk scenarios shown in Figure 2 for each policy instrument, measured in terms of a %-point increase in the discount rate. This discount rate impact is then used to calculate the resulting increase in levelised cost for each technology. Finally, the resulting impact on total system annualised cost in £bn/yr is calculated based on the volume of production that is projected in 2035 for each technology under our reference scenario (i.e. the FES CT-base scenario). These amount to 285 TWh, 105 TWh and 41 TWh for offshore wind, onshore wind and solar PV respectively.

As noted previously, the risk characteristics for renewable investments in a market-only scenario are quite uncertain which is why we show the lower and higher risk cases in Figure 2. In Table 3, we also show an average of the high and low market as a comparator for the policy.

Table 3. Impact of risk exposure to the cost of delivering renewable investments by 2035

		2-sided CfD (25 yr)	*2-sided CfD (15 yr)*	*1-sided CfD with clawback*	*Cap and floor*	*1-sided CfD*	*2-sided CfD with negative price rule*	*Average risk mkt scenario*	*Low risk market scenario*	*Higher risk market scenario*
	Average downside risk (%-point d.r. increase)									
Offshore Wind		0.1%	1.4%	1.4%	2.2%	2.8%	3.5%	**7.4%**	*4.2%*	*10.6%*
Onshore Wind		0.2%	1.2%	1.2%	2.4%	2.1%	3.2%	**5.6%**	*3.5%*	*7.7%*
Solar PV		0.0%	0.8%	1.3%	1.4%	1.7%	1.7%	**2.8%**	*2.0%*	*3.6%*
	Levelised cost (£/MWh)									
Offshore Wind		43.6	46.7	46.7	48.9	50.4	52.2	**65.0**	*54.5*	*75.5*
Onshore Wind		39.3	41.9	41.9	45.2	44.4	47.6	**55.5**	*48.5*	*62.6*
Solar PV		35.3	38.0	39.6	39.9	41.0	40.8	**44.9**	*42.0*	*47.8*
	Generation in 2035 (TWh)	Total annualised generation cost by 2035 (£bn/year)								
Offshore Wind	285	12.4	13.3	13.3	13.9	14.4	14.9	**18.5**	*15.5*	*21.5*
Onshore Wind	105	4.1	4.4	4.4	4.8	4.7	5.0	**5.8**	*5.1*	*6.6*
Solar PV	41	1.4	1.5	1.6	1.6	1.7	1.7	**1.8**	*1.7*	*1.9*
Total		**18.0**	**19.3**	**19.3**	**20.3**	**20.7**	**21.6**	**26.2**	*22.3*	*30.1*
reduction relative to average market risk scenario		*-8.2*	*-6.9*	*-6.9*	*-5.9*	*-5.5*	*-4.6*			
		-31%	*-26%*	*-26%*	*-22%*	*-21%*	*-18%*			

4 Conclusions

A very large volume of renewable energy generation investment is key to achieving the transition to a zero-carbon electricity system. For countries, such as the UK, that have ambitious decarbonisation goals a primary function of energy policy is therefore to attract the necessary investment at sufficient speed and scale. The degree of risk that investors face will be key to the feasibility and cost of achieving this.

As well as expanding the volume of low carbon and renewable electricity, decarbonisation scenarios also envisage expanding the use of electricity in transport, heating and industry, replacing direct combustion of fossil fuels. The energy transition presents low carbon projects with both volume and price risks which together affect the cost of capital. Volume risks arise because of uncertainty over the frequency and duration of periods when the system as a whole is over-supplied relative to demand, with the total level of demand also uncertain and dependent on policies to expand the roles of electric vehicles or heat, for example. For individual investors in renewable energy, price risks arise due to uncertainty over fundamental price formation processes in a system with very low levels of fossil fuels, connected to uncertainty over the price behaviour and performance of infrastructure designed to increase system flexibility. We term these risks stemming from the uncertainty over the mix and scale of future demand and supply technologies ‘transition pathway risk’.

In this paper we find that the cost of capital can vary by about a third depending on the extent to which policies expose renewable energy investors to transition pathway risk. In general, the greater the exposure to wholesale market price variations and uncertainties, the greater the risk and cost of capital will be. The primary policy mechanism investigated here for managing this risk is the UK policy of Contracts for Difference (CfD). These substantially reduce investment risk, albeit with considerable variation in risk exposure between different CfD designs.

Our analysis shows that the presence and choice of intervention type has the potential to increase investment risk in a range that goes up to 15% points for offshore wind, around 9% points for onshore wind and around 4% points for solar. This also has substantial implications for annual system costs associated with finance payments, with policy design able to reduce overall costs by around £8bn *per year* compared to average market risk levels, in the UK market context we explore in this paper. Cumulative savings will be much larger, given the large volume of capital addition required to deliver net zero goals. The paper does not seek to compare the UK to other countries, doing so would be a valuable next step, but we would expect risks and cost impacts to reflect the same underlying drivers – share and correlation of renewable outputs, and system flexibility.

The energy price shocks of 2022 have shone a harsh spotlight on costs and risks to consumers. This contrasts with the low-demand, low-price conditions in 2020 during Covid lockdowns where a primary policy concern was with investor risk and price cannibalisation. This emphasises the need for policy to take into account the allocation of both upside and downside risks between generators and consumers. Work by Gross et. al. (37) shows that 2-sided CfDs can also help reduce the extent to which upside price risk is passed through from investors to consumers.

Risk management principles dictate that risks should be allocated to those best able to manage them. This work has concentrated on transition risks associated with uncertainty over the future pathway of decarbonisation. In particular, the work shows that there are fundamental risks associated with the degree of flexibility in the electricity system, which in turn is influenced by wider macro-trends such as the degree of hydrogen consumption and electrification of different parts of the economy, the degree of interconnection with other countries and the degree of system flexibility that these might bring. Future whole-system pathways are not within the power of individual power generation investors to manage, and are highly policy- and path-dependent, making associated price behaviour is difficult to predict and hedge. Many of these transition risks and uncertainties will tend to reduce over time as the pathway becomes revealed, and there is greater clarity over the physical and operating characteristics of the system. We have referred to the current stage of the transition the ‘build-phase’ where speed of response is paramount, risks are high, and there is a strong case for socialising these risks with an equitable allocation between investors and consumers. Once the system is closer to being decarbonised, the risk profile will be different. Investment rates will still need to be high, due to growing demand from increased electrification. However, we would expect to see at this point a more ‘steady-state’ phase in terms of the structure of the electricity system, with greater understanding of system operation, price formation and associated risk characteristics. At that point, market hedging structures may become more feasible, making allocation of risk to market participants more efficient than it is during the build phase.

In short, this analysis suggests that for future electricity systems with a high share of renewable generators, 2-way CfDs would offer substantial financial benefits through reduced cost of capital compared to relying solely on carbon pricing, or policies that do not stabilise wholesale market revenues, such as tradeable renewable certificates or green premiums. This reduced cost of capital is a static system efficiency – i.e. it helps to deliver investment in infrastructure at lower cost.

There are other measures of efficiency that we have not attempted to quantify in this work. For example, the various policy mechanisms assessed in this paper will perform differently in terms of dynamic efficiency – i.e. the degree to which they allow for optimising the choice of infrastructure that gets built and how it operates.

In this paper, we do not attempt to quantify the likely relative balance between dynamic and static efficiencies of different policy options. leaving this for future research work. Instead, the value of this research is to provide a reference point against which other analysis of different policy formulations can be compared. The paper demonstrates the large financial impact of wholesale market price risks on the overall cost of the energy transition, particularly during the immediate ‘build phase’ where uncertainties are significant and largely outside the control of individual investors. Two-way CfDs provide investors with a secure investment environment and help to protect consumers against fossil fuel price volatility. Policymakers need to weigh any prospective alternative approaches against these tangible and proven benefits, so that the right mix of signals for efficient power system operation and measures to ensure cost effective investment can be found.

5 Data Availability

The data for this study is accessible from the Energy Data Centre under licence CC-BY 4.0 using this link https://doi.org/10.5286/UKERC.EDC.000964 .

Annex. Commentary on Policy Options Assessed

Policy option	Comments
2-sided CfD	By fixing prices for a number of years, it reduces exposure more than the other policy options considered. This is based on the original form of the CfD which led to reductions in auction prices.
2-sided CfD (extended)	Longer contracts extend the period over which projects recover their investment, lowering strike prices, and reducing tail risks of plant being unable to recover costs in the later part of their technical lifetime. However, they lock-in consumers for a longer duration.
2-sided CfD with negative price rule	This exposes projects to uncertainty over the degree of negative pricing events under different risk scenarios. All else equal, would expect projects to bid higher in auctions compared to Option 1 to compensate for reduced revenues.
1-sided CfD (price floor)	This reduces exposure to downside risk, but projects can benefit from any upside so would be expected to bid lower in the auctions compared to Option 1. Exposure to upside might attract a different type of investor, but transfers significant risk from investor to consumers.
1-sided CfD with clawback	This reduces exposure to downside risk to the same extent as standard price floor, but gives a more even distribution of upside risk between investors and consumers.
Cap and Floor	We assume that the price cap is determined by the regulator (we set it at £70/MWh). We then assume that the floor price would be bid at auction at a level that would be expected to recover costs over the duration of the contract under the reference scenario.
Wholesale price + fixed premium	Representation of a market-based solution. Electricity users pay a premium on top of the short-run system marginal cost to procure electricity from renewables, enabling them to recover capital costs. In this case, we assume a fixed premium negotiated under expected (reference scenario) conditions to recover investment costs.
Wholesale price + floating premium	As above, but here we assume that rather than being fixed, the additional market revenue acts as a multiplier to the electricity revenue, and so is subject to the same degree of risk. The multiplier is set at a level that recovers investment under the reference scenario.

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