Investable commercial frameworks for Power BECCS

Prepared by Element Energy and Vivid Economics

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Authors

This report has been prepared by Element Energy and Vivid Economics.

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Executive Summary

BECCS' role in contributing to net-zero emissions in the UK

To ensure that the UK can meet its 2050 net zero emissions target, the Climate Change Committee (CCC) clearly states that greenhouse gas removals (GGRs) will be required to balance residual emissions from some of the most difficult to decarbonise sectors, such as agriculture and aviation. The CCC estimate that between 44 and 112 MtCO2e of engineering GGRs could be required annually by 2050 – equivalent to around 20% of current UK emissions. Uncertainty exists around which GGR technologies will be deployed in the coming decades, however Bioenergy with Carbon Capture and Storage (BECCS) is consistently deployed from the late 2020s in current whole systems energy models which achieve net zero by 2050. The UK government's Department for Business, Energy and Industrial Strategy (BEIS) is closely working on policy areas relevant for the deployment of BECCS. In the medium-term, there may be opportunities for deploying BECCS in the UK power sector, but no commercial framework currently exists to facilitate this.

The purpose of this study is to explore commercial frameworks suitable for incentivising the deployment of 'First of a Kind' (FOAK) BECCS in the power sector over the next decade. In this study, "FOAK power BECCS" specifically refers to conventional biomass power generation with post combustion carbon capture and storage (CCS), resulting in both low carbon electricity generation and permanent negative emissions. As these are power-BECCS' two distinct products, this study carefully considered the challenges associated with assigning value to low-carbon electricity versus negative emissions, with the latter viewed as the primary product influencing policy design for power BECCS.

Deployment of power BECCS faces operational and economic challenges

An understanding of the key operational factors and economic risks affecting the investability of FOAK BECCS is crucial to developing a basis for designing future policy support in the UK. This study identified key factors which impact a FOAK power BECCS plant's investability, including important risks and cost uncertainties. Table 1 provides an overview of these operational and economic factors.

Table 1: Key operational and economic factors impacting the investability of FOAK power BECCS

Factor	Considerations	Implications
Biomass Supply Chain Emissions	Many sources and suppliers of woody biomass result in products which are highly variable in their supply chain carbon intensity	Frameworks should consider additional design features or complementary policies which address life-cycle emissions of biomass
CO_2 Transport and Storage Cross-chain Risk	Risks due to failures in other parts of the BECCS project chain, particularly around availability or outages associated with CO_2 transport and storage	These risks fall outside a BECCS developer's control, requiring a commercial framework to address the potential loss in revenue from reduced payments due to the plant's inability to produce negative emissions
Cost Uncertainty	Capital cost differential and uncertainty between new build and retrofit plants, with large ranges provided by studies	There is only one relatively mature BECCS developer in the UK, leading to cost and risk implications during FOAK contract negotiations
Other Market Risks	Electricity prices, biomass prices and carbon prices (if determined by market-based mechanism such as UK ETS)	For example, as the global biomass market grows, uncertainty exists around the future price of feedstocks for BECCS operators

Multi-criteria assessment results in selection of two frameworks for detailed design

To maximise value of policy support, a BECCS commercial framework should be effective, efficient, feasible, and replicable. In this study, a comparative criteria assessment was undertaken to inform the selection of the most promising frameworks for detailed design. Key qualitative criteria were developed which consider the merits of each framework in supporting FOAK power BECCS:

- Effectiveness: incentive strength to stimulate deployment, track record of existing or similar frameworks and economic risk mitigation ability to ensure projects are investable

- Efficiency: ability to promote cost reduction, select for low cost projects and incentivise a plant's net negativity via CO2 reductions (e.g. increasing capture rate or reductions in supply chains emissions)
- Feasibility: ability to distribute cost fairly (e.g. following the 'polluter pays' principle), provide value for money and implement with ease in the 2020s
- Replicability: applicability or adaptability of the framework to other BECCS sectors (e.g. industry, energy from waste) and to NOAK projects

From the assessment, two commercial frameworks were selected by process of exclusion from a longlist (see Section 3 for detailed investigation and design:

- Power Contract for Difference (CfDe) plus Negative Emissions Payment (NEP): A CfDe combined with a NEP to form a single commercial framework. The first component includes a traditional CfD for electricity generation in the UK power market, where the generator is paid the difference between a contractually agreed strike price and market price for electricity (in £/MWh). The second component is a NEP (in £/tCO2), which would be administered as direct subsidies for each unit of CO2 captured.
- Carbon Contract for Difference (CfDc): Standalone CfD mechanism which would provide a subsidy paid above the prevailing carbon price for negative emissions (e.g. UK ETS) up to a contractually agreed strike price on CO2 captured (£/tCO2).

Achieving an investable rate of return for a FOAK BECCS plant with an acceptable distribution of risk is possible but will require substantial payments either through NEPs or through a CfDc. While substantial, these payments are not out of step with carbon prices used for appraisal or expected abatement costs in hard to abate sectors. The base case analysis breaking down each framework's revenue streams against the costs of FOAK BECCS is provided in Figure 1.

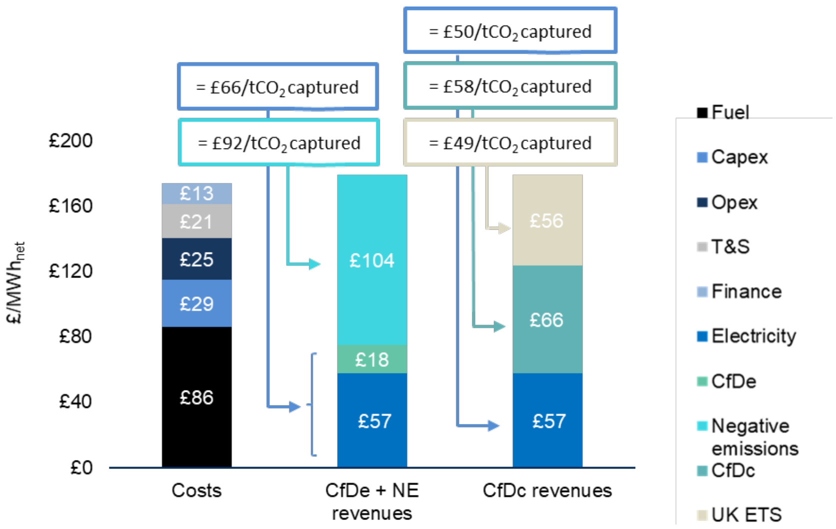

Figure 1: Comparison of the costs for FOAK power BECCS against the revenue sources under the CfDe plus NEP and CfDc frameworks[1]

[1] Evaluated over contract length (T = 15 years) using a weighted average cost of capital of 8.4%. Revenues assume a 75 £/MWh strike price for the CfD_e, 92 £/tCO_2 for the NEP and £107/tCO_2 for the CfD_c. Note that all

The precise level of framework payments to support commercial BECCS will depend on technology development and risk allocation to government and developers. The costs of a FOAK BECCS plant could vary considerably (e.g. biomass fuel costs, capital costs of retrofit versus new build plant). Given the future uncertainty that exists in the exact values of NEPs, strike prices and market prices for negative emissions, the values presented in Figure 1 should be taken as representative only. More precise evaluation of all costs and revenue streams should be considered in the future design of either framework.

Detailed analysis identified important framework design features

Key economic risks, cost uncertainties and biomass sustainability concerns for FOAK BECCS require detailed framework design to ensure BECCS is investable and maximise societal benefits. To mitigate the risk of unintended consequences of FOAK BECCS policy support, this report highlights key areas requiring detailed policy design and suggests policy features that support investability, maximise societal benefit, and mitigate risks. The detailed design features considered fall into three categories, and help to:

1. Reduce risk to developers and financiers to reduce the required rate of return and cost of capital for a FOAK project (as well as NOAK projects). The required internal rate of return (IRR) for privately financed project increases with risk. As shown in Table 2, a higher IRR has substantial impact on the NEP or CfDc in potential FOAK support frameworks. By de-risking projects, the required IRR and hence framework payments can be lowered, reducing the overall cost of BECCS deployment to society. Key de-risking features considered in this report is include, for example, availability payments to address cross-chain risk - a key risk identified by stakeholders.

Table 2: Required NEP and carbon strike price at different IRRs

Required IRR (%)	NEP (£/tCO2)	Carbon strike price (£/tCO2)
13	100	116
11	96	111
9.1	92	107
7	87	103

2. Redistribute costs of the BECCS frameworks across government, emitters, and electricity consumers. The framework payments for FOAK BECCS need not be assumed by

payments are expressed per MWh_{net} not per tonne of gross CO_2 captured. To express revenues and costs in £ per tonne of gross CO_2 captured, please refer to the conversion factors in **Box 2**.

government. For example, current CfDs in the electricity market are levied on electricity consumers. This report considers how different payments may be funded. For example, the report considers how NEP payments could be partially passed on to emitters using offset markets (see Figure 2). Furthermore, the report sets out how different payments could be combined to yield a similar IRR and what the potential distributional implications are. For example, Table 3 sets out how the NEP and CfDe could be combined to provide the same IRR. By funding a CfDe and NEP differently (e.g. a higher CfDe would likely be funded by electricity consumers) this has distributional implications (e.g. a higher CfDe implies electricity consumers pay a larger % of total BECCS costs).

Table 3: Possible combinations of CfDe strike price and NEP for a 9.1% IRR[2]

NEP (£/tCO2)	Strike price (£/MWhnet)
0	179
83	85
87	80
92	75
100	65
105	60

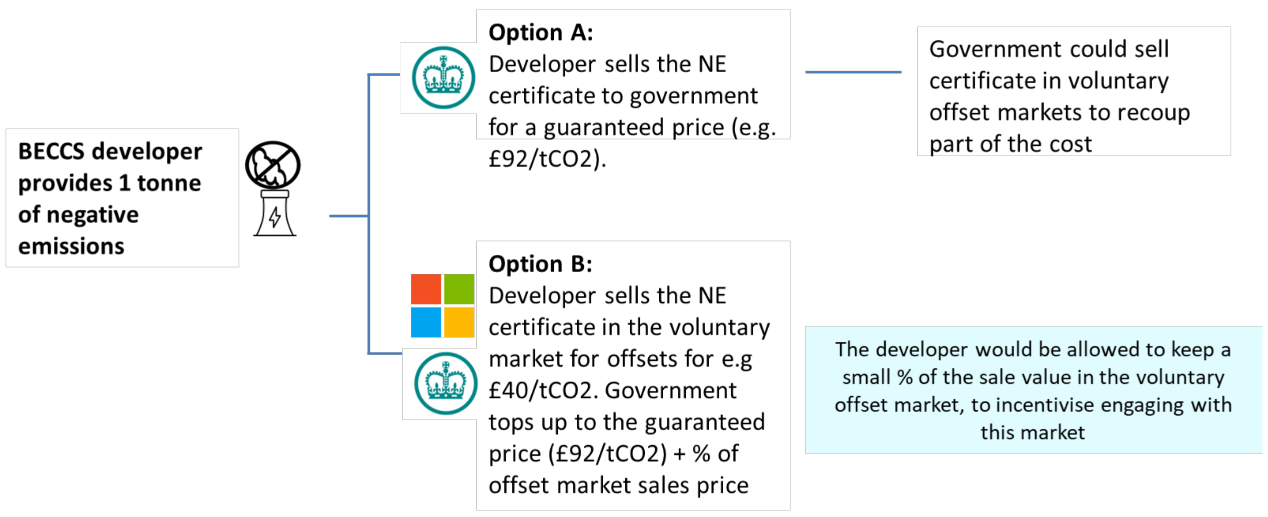

Figure 2: Illustrative offset scheme for the CfDe + NEP framework

[2] Evaluated over contract length (T = 15 years). Assumes a discount rate of 9.1% and electricity price projections from Annex M. Growth assumptions and prices in Updated energy and emissions projections: 2019 (BEIS, 2020).

3. Increase a BECCS plant's net negative emissions and ensure the biomass supply chain is sustainable. Incentives will be necessary to ensure the biomass supply chain is sustainable, and BECCS developers are incentivised to maximize net negative emissions. This report concludes net negative payments (an often citied solution) alone are unlikely to suffice and a broader regulatory approach based on standards and penalties will be necessary.

Findings suggest each framework has potential to support FOAK power BECCS

Both frameworks have the ability to provide the contracted revenue confidence needed to make FOAK power BECCS projects investable. Either are also suitable for application to NOAK power BECCS, offering the potential to reduce payments by transitioning to auction-based mechanisms. To reduce the burden on the exchequer, it is important to consider how the costs of either can be passed onto the market (e.g. through carbon trading). The strengths and weaknesses of each framework are provided in Table 4. Trade-offs exist between the implementation of both frameworks and either may be most suitable depending on the priorities of future policy support.

Table 4: Key differentiating strengths and weaknesses of the CfDe plus NEP and CfDc frameworks

	Strengths	Weaknesses
CfDe + NEP	Values low carbon power and negative emissions separately, allowing separate cost distribution of these externalities Ease of implementation for FOAK: CfDe is well established NEP does not require link to UK ETS	Cost to government can be high without additional link to offset markets or UK ETS, obligation on emitters, etc. Two contracts would require an innovative mechanism to auction jointly for NOAK projects Would require adaptation to apply beyond the power BECCS sector
CfDc	Inherently shifts the costs of BECCS to emitters, adhering to the polluter pays principle Greater potential to be directly used across other BECCS sectors	Does not value low carbon electricity, hence: Developer accepts electricity price risk, which may significantly increase the IRR required Electricity consumer is not subsidising low carbon electricity without design adaptations Risk of delayed implementation or complications arising from integration with UK ETS

There is no clear optimal framework, as which option is preferred depends on government priorities. While this study has not recommended a single commercial model, there are future scenarios in which a favourable policy position exists under the following objectives.

Urgency of FOAK BECCS deployment

If government is looking to reach a final investment decision (FID) in the mid 2020s, The CfDe plus NEP framework may be preferred. This is for two reasons:

- The NEP, unlike the CfDe, does not rely on complex UK ETS adjustments (e.g. changes to ETS cap) allowing it to be implemented quickly.
- The CfDe is a familiar instrument for investors and developers, increasing confidence and shortening the road to reaching FID.

Long term evolution of the market for negative emissions/greenhouse gas removals

If the long term vision for GGR is to maintain a separate market, the CfDe plus NEP is likely preferred as the NEP component could be auctioned and eventually funded through a market mechanism. Conversely, the CfDc framework may be preferable if government's objective is to link all negative emissions technologies to a wider economy-wide carbon market (e.g. linking all hard-to-abate sectors and GGRs into the UK ETS).

Distribution of costs

While a potential scenario exists for the CfDc framework to be implemented for FOAK power BECCS in the 2020s, this would not align with an objective of reducing risks to developers and investors given the higher rate of returns likely required. Moreover, if government views power BECCS should be partly funded via electricity consumers, this further supports adopting the CfDe plus NEP framework. However, if government is willing to take on greater payments for FOAK power BECCS, then the CfDc framework could be favourable if the objective of linking all GGRs to a wider carbon market is also preferred.

To support a decision on a FOAK BECCS commercial framework, further research on existing carbon markets, voluntary offset markets, and funding distribution is recommended. This includes investigating how existing carbon markets can be used to fund BECCS (i.e. adjustments to include negative emissions in the UK ETS or how BECCS could be funded through voluntary offset markets). Additionally, further consideration as to whether negative emissions markets should be linked to the UK ETS would provide clear policy guidance for both FOAK and NOAK BECCS. Lastly, further clarity on the potential funding routes would be of value to policy makers (e.g. obligations on fossil fuel suppliers for negative emissions payments).

1 Introduction

1.1 Background

To ensure that the UK can meet its 2050 net zero emissions target, the Climate Change Committee (CCC) clearly states that greenhouse gas removals (GGRs) will be required to balance residual emissions from some of the most difficult to decarbonise sectors, such as industry, agriculture and aviation. The CCC estimate that between 44 and 112 MtCO2e of engineering GGRs could be required annually by 2050[3] – equivalent to around 20% of current UK emissions. Uncertainty exists around which GGR technologies will be deployed in the coming decades, however Bioenergy with Carbon Capture and Storage (BECCS) is consistently deployed in current whole systems energy models which achieve net zero by 2050.

The UK government's Department for Business, Energy and Industrial Strategy (BEIS) is closely working on policy areas relevant for the deployment of BECCS. Government has been clear on its commitment to position the UK at the forefront of new markets for low carbon technologies and announced up to £100m innovation funding for GGRs, to reduce costs and energy requirements, demonstrate feasibility and better understand the governance. Additionally, government has been working closely on commercial frameworks to support business models for industrial and gas power CCUS, including CO2 transport and storage regulatory models, along with a commitment to deploy two carbon capture clusters by the mid-2020s and a further two clusters by 2030. The government also announced the launch of a cross-government Biomass Strategy. In the medium-term there may be opportunities for BECCS in the power sector, but no commercial framework currently exists.

1.2 Scope

The purpose of this study is therefore to explore what bespoke commercial frameworks may be most suitable for incentivising the deployment of 'First of a Kind' (FOAK) BECCS in the power sector over the next decade. In this study, "FOAK power BECCS" specifically refers to conventional biomass power generation with post combustion carbon capture and storage (CCS), resulting in both low carbon electricity generation and permanent negative emissions. The study's objectives were as follows:

- Review power BECCS performance, risks and costs to understand the basis for policy support
- Understand the range of potential frameworks to support FOAK power BECCS
- Complete a clear and transparent comparative assessment using design criteria developed to evaluate the strengths and weaknesses of framework options

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[3] The Sixth Carbon Budget – Greenhouse Gas Removals (Climate Change Committee, 2020)

- Select promising frameworks and complete more detailed analysis on their design and applicability

Several factors and considerations around designing a robust BECCS commercial framework were left out of scope from this study, however, given their importance, are being considered within other analyses within BEIS. These include detailed processes for monitoring and verifying biomass supply chain emissions, detailed assessment of the distributional impact of where GGR financial support comes from (e.g. cost pass through of emitters paying for the negative emissions) and detailed investigation of biomass sustainability and availability.

1.3 Report structure

The report is structured into the following sections:

- Section 2 – overview of FOAK power BECCS, including operational characteristics, risks and costs
- Section 3 – review of commercial frameworks and assessment criteria, along with the final assessment results which determined the most promising frameworks
- Section 4 – detailed design and analysis of the selected promising frameworks, including consideration of auxiliary design features, framework applicability to other sectors, and final conclusions

2 BECCS Overview

2.1 Current status of BECCS

Globally, the potential for BECCS across the energy sector is supported by the growing ambition to roll-out negative emissions technologies. However, as shown in Figure 3, BECCS deployment to date is limited to only a handful of operating facilities, primarily in the biofuels and power sectors in the US, Europe and Japan.

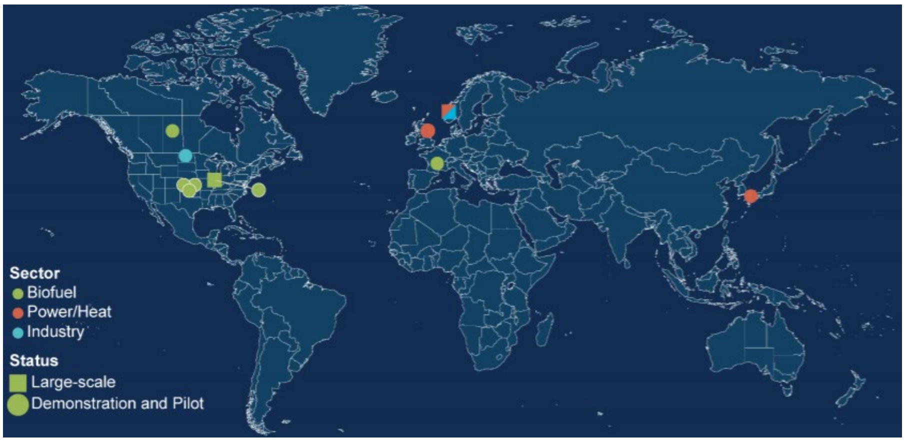

Figure 3: Map of operating BECCS facilities worldwide in 2019[4]

Recent developments in power BECCS demonstration and pilot projects are underway. Running pilot capture facilities since 2009, the demonstration-scale BECCS Mikawa Power Plant (50 MW) in Japan commenced operations in late 2020, now capturing 500 tons of CO2 a day.[5] In the UK, the Drax power plant has been operating a pilot BECCS project with C-Capture since early 2019 and has started a second pilot project with Mitsubishi Heavy Industries in late 2020.

2.2 Power BECCS

2.2.1 Operational considerations

The characteristics of power BECCS plants can vary considerably, depending on technology application (for both biomass combustion and the CCS plant), FOAK versus Nth of a Kind (NOAK) plants, and operational factors including those outside of the BECCS plant’s control (e.g. CO2 transport and storage). Table 5 below summarises some of the key operational factors for power BECCS facilities. These are of particular relevance for not only project developers but also financiers investing in power BECCS plants and governments designing commercial frameworks.

[4] Perspective - Bioenergy and Carbon Capture and Storage (GCCSI, 2019)
[5] Source: Toshiba Starts Operation of Large-Scale Carbon Capture Facility (October 2020).

Table 5: Key operational characteristics of a power BECCS plant

Operational Characteristic	Assumptions (for post combustion CCS)
Capture Rate	FOAK – up to 95%, NOAK – above 95%
Net Efficiency (LHV)	FOAK – 30-32[6] , NOAK – 40%[7]
Lifetime	25 years (FOAK technologies) [6,7]
Load Factor	90% - for baseload power operation ~60% - in first year of operation

Baseload operation maximises the potential for CO2 removal (i.e. negative emissions) from a BECCS plant. For baseload power generation, a load factor of 90% is commonly assumed in literature, with the remaining 10% downtime needed for maintenance or other unforeseen shutdowns.[8] In this study, stakeholder engagement with EPC firms and project developers have expressed agreement that the load factor may be lower in the first year (or even up to 4 years) of operation due to commissioning or unplanned shutdowns. This is highly project dependent and for this study a conservative estimate of 60% has been used.

Efficiency and capture rate are two operational parameters which play a key role in determining the cost and amount of a BECCS plant's negative emissions. A 90% CO2 capture rate is commonly used in literature as a conservative assumption for the operation of a FOAK plant with incumbent CO2 capture technologies (e.g. amine absorption). In practice, capture rates are highly project and technology dependent, ranging from 85-95%.[6,7] Developers may make the engineering choice to operate a high capture rate (e.g. 95%) provided there is sufficient revenue from the negative emissions to warrant the additional upfront capital in capture equipment. While studies suggest capture rates of 95% or greater are possible[9,10], these are more likely in the longer term for NOAK plants or plants utilising more advanced capture technologies (e.g. carbonate looping). Net efficiencies are expected to be around 30-32% for FOAK plants. Lower efficiency plants may offer an opportunity to reduce the costs of negative emissions through reducing capital and operational costs of power generation.[11] With the amount of biomass combustion fixed, lower efficiency plants produce a greater quantity of negative emissions per unit of electricity produced (investigated in section **4.**).

[6] Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology (Wood, 2018)
[7] Analysing the potential of bioenergy with carbon capture in the UK to 2050 (Ricardo, 2020)
[8] Some stakeholders have suggested that the load factor may be lower than 90% in reality for a full BECCS chain. A sensitivity analysis in section 0 highlights a potential load factor variation.
[9] Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass (IEAGHG, 2019)
[10] Special Report on CCUS in Clean Energy Transitions (IEA, 2020)
[11] Inefficient power generation as an optimal route to negative emissions via BECCS? (Mac Dowell et al., 2017)

2.2.2 Biomass characteristics

Currently, biomass used in UK power generation is predominantly sourced from wood pellets imported from the US, Canada or Europe. The presence of several sources and suppliers of woody biomass result in products which are highly variable, not only in their purchase price for biomass generators, but also their emissions intensity upon combustion (i.e. how much CO_2 is emitted per MWh of electricity is produced) and their supply chain carbon intensity (i.e. upstream emissions associated with processing, handling, storage and transport of biomass). Ranges for these biomass feedstock characteristics are provided in Table 6 below.

Table 6: Biomass characteristics for a power BECCS plant in the UK

Biomass Characteristic	Assumptions
Cost	15 – 40 £/MWhfuel [7]
Emissions Intensity (Combustion)	1.1 – 1.5 tCO_2/MWhelec (gross) 6,[12]
Supply Chain Carbon Intensity	2 – 50 gCO_2e/MJelec (net) [13] (0.007 – 0.180 tCO_2e/MWhelec (net))

Literature reveals a high range of variability for biomass costs, emissions intensity and supply chain carbon intensity, due to a wide range of feedstocks and suppliers, varying between imports versus domestic production. The cost range in Table 6 is from a recent analysis on the BECCS' potential in the UK, reflecting a similar range expressed by stakeholders in this study. Upon combustion, estimates suggest the emissions intensity of woody biomass can be up to 1.5 tCO_2 per unit of electricity produced. Supply chain emissions are impacted by many factors, primarily from the differences in transport and energy requirements used from harvesting to final delivery of the biomass. In the UK, generators awarded the most recent CfD were subject to meeting a threshold for their supply chain emissions (set at 29 $kgCO_2e$/MWhelec).[14] This threshold is part of the UK's wider sustainability criteria for biomass which also considers biodiversity and carbon stocks.

A BECCS plant's 'net negativity' is heavily influenced by its supply chain emissions intensity of biomass fuel. Net negative emissions for a power BECCS plant is defined in this study by the amount of CO_2 captured and stored minus the lifecycle emissions associated with its biomass supply chain (e.g. due to fuel processing or transport). As the UK approaches net zero, policies and business models for any fuels with high fossil carbon emissions produced in their supply chain will become increasingly unsupportable. This suggests that any commercial framework

[12] Greenhouse gas reporting: conversion factors (BEIS, 2020)
[13] Biomass in a Low-Carbon Economy (Climate Change Committee, 2018)
[14] Contracts for Difference – Generator Guide (Low Carbon Contracts Company, 2019)

for FOAK power BECCS should promote continued improvements to increase the amount of net negative emissions delivered. Principally, this will involve incentivising lifecycle emissions reductions or increasing a plant's CO2 capture rate (assessed under the 'efficiency' criteria in section 0).

2.2.3 Costs

Estimated costs of a FOAK power BECCS plant vary between sources, with fuel and capital costs constituting the two largest cost components. Recent studies suggest that a high level of uncertainty exists for the capital cost of power BECCS, as much as +/- 40%[15],[16]. However, stakeholders and developers suggest this uncertainty would significantly reduce through the front-end engineering and design (FEED) stage of a BECCS project. The cost of biomass fuel is also highly uncertain over the medium-to-long term as the global woody biomass market grows, varying between sources and types of biomass purchased (e.g. wood chips versus wood pellets). In addition to capital and fuel costs, the total levelised cost of electricity (LCOE) for power BECCS also includes fixed and variable operational costs and CO2 transport and storage (T&S) fees. The latter could be a contractually agreed flat fee per tonne of CO2 delivered to a network operator (i.e. in £/tCO2). However, this is yet to be decided and the CO2 T&S fee may have both fixed and variable elements included.

NOAK power BECCS projects have the potential to achieve cost reductions relative to FOAK plants. Studies suggest that the capex and T&S costs of NOAK plants are likely to be 25% lower than FOAK plants, primarily due to technology cost reductions in the CCS elements and economies of scale achieved in T&S infrastructure.[16] This could result in an LCOE for FOAK plants to be as much as 15% higher than those for NOAK plants. Figure 4 below provides estimates for both FOAK and NOAK power BECCS costs. Calculated LCOE values are highly sensitive to fuel cost assumptions, with CO2 T&S fee assumptions adding to this variability. Estimates provided by stakeholders are indicative values taken from a number of conversations held throughout this study with academic and industrial stakeholders in the UK.

[15] Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology (Wood, 2018)
[16] Analysing the potential of bioenergy with carbon capture in the UK to 2050 (Ricardo, 2020)

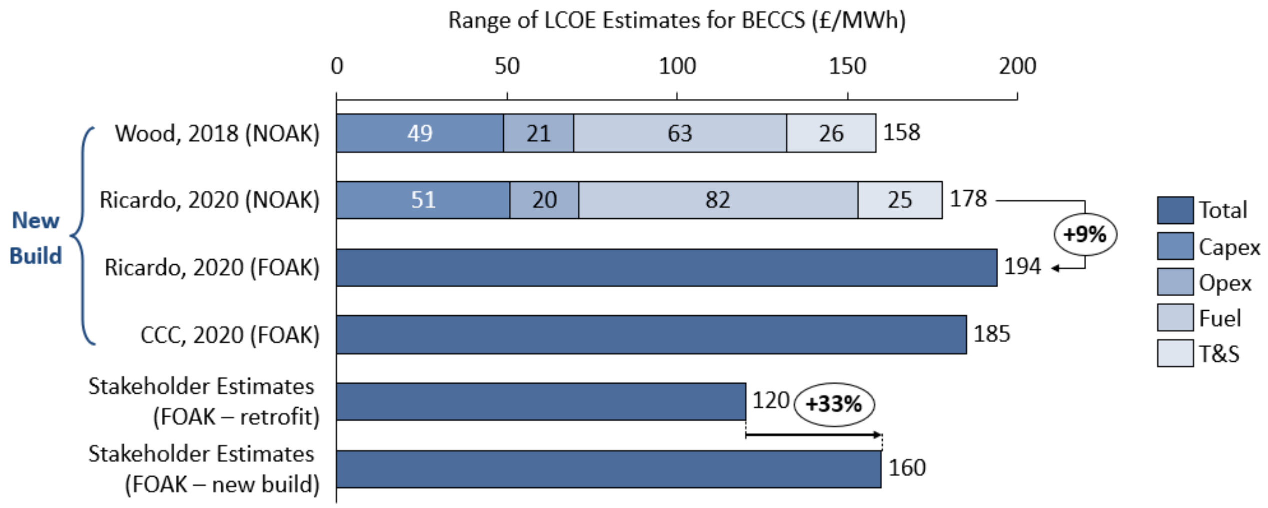

Figure 4: LCOE estimates for power BECCS (broken down by component costs where available)[15],[16],[17]

The capital cost difference between new build and retrofit plants result in an over 30% higher LCOE for a new build plant. Deploying retrofit power BECCS technologies for FOAK plants has the potential to realise significant capital cost savings. This approach can be valuable in promoting the deployment of BECCS technology and securing investor confidence in new plants. Earlier power BECCS adoption via plant retrofits can also lead to greater certainty for the capacities of cluster-based CO2 transport and storage networks. A large-scale BECCS project would provide guarantees of CO2 volumes (i.e. on the order of megatonnes of CO2 per annum) needed for T&S operators to achieve economies of scale in infrastructure build-out. This is commonly referred to as being an 'anchor project' to an industrial cluster pursuing CCUS.

2.2.4 Risks

Power BECCS remains a relatively risky investment compared to well established generation technologies and hence requires a higher rate of return to be attractive for investors. The risk profiles of renewable technologies are changing rapidly as technologies mature. A recent report published on UK-specific hurdle rates for renewable technologies suggest that established renewable technologies such as solar PV and wind now carry less risk than fossil fuel generation projections such as CCGT.[18] Despite these developments, BECCS remains a relatively immature technology and the business model has not yet been demonstrated. As a result, and having been confirmed by various stakeholders, commercial perceptions of BECCS as a risky investment are still pervasive and there is considerable uncertainty that must be addressed through FOAK projects to boost investor confidence in the technology.

FOAK BECCS will face risks common across most large-scale energy projects. Table 7 provides a general overview of the risks that will be considered by potential investors of FOAK

[17] The Sixth Carbon Budget – Electricity generation (CCC, 2020)
[18] Electricity Generation Costs 2020. (BEIS, 2020)

BECCS. Risk of construction delay or force majeure is inherent to any capital-intensive infrastructure project. Likewise, fossil fuel and low-carbon BECCS generation sources are similarly exposed to market risk and policy risk that can undermine investor confidence. For example, both CCGT and BECCS may be exposed to price fluctuations in commodity markets and abrupt changes in policy which could remove financial support or impose new penalties.

Table 7: Typology of risk for FOAK power BECCS

Risks	Definition	Examples
Technology risk	Risks attributable to technological immaturity	Costs (component costs, operations and maintenance costs) associated with the deployment and running of technology are higher than anticipated, including those caused by outages at the BECCS plant
Construction risk	Risks that arise during the construction phase of a power project	Delay in construction leads to higher labour or capital rental costs.
Development risk	The risk of spending significantly on the process to support investment decisions	Risk that sunk costs such as feasibility studies, engineering estimates, business case development and attracting investors could become a flat loss without a positive final investment decision (FID)
Market risk	The risk associated with price changes in inputs and outputs	Electricity prices, biomass prices and carbon prices (if determined by market-based mechanism such as UK ETS)
Policy risk	The risk of policy or regulatory change	Carbon pricing regime, incentives for negative emissions, compliance, or any other policy which affects project costs
Cross-chain risk	Risks due to failures in other parts of the BECCS project chain	Outage or limited capacity in the transport and storage infrastructure; T&S fees increase
Force Majeure risk	Extraordinary and unpredictable risks	A natural disaster which affects the BECCS plant
Social license	Risks originating from public disapproval or negative	Skepticism of negative emissions technologies or perception of adverse environmental consequences delays or interrupts a BECCS project

Risks	Definition	Examples
	perceptions of a project or technology.	

However, some risks are unique to CCS technologies and/or are exacerbated for a FOAK BECCS project. The most frequently cited risk throughout the course of this study include:

1. **Technology risk: Unforeseen costs outside of engineering estimates can occur for any energy project, but this risk is intensified for an energy project involving an emerging technology like CCS**. Large variation between existing estimates indicates the level of uncertainty associated with CCS projects.[19],[20] Additional factors such as unexpected outages originating at the plant could also contribute to higher overhead costs and revenue loss, both which could contribute to a higher risk premium required by investors.

2. **Market risk: Feedstock supply chains and biomass prices were frequently raised as an area of concern from stakeholders in industry and the financial community contacted for this study.** The ability of a developer to secure contracts which guarantee a quantity, price and quality of biomass is less certain given the immaturity of biomass supply chains. Policies will also be necessary to ensure that biomass is sustainably sourced, which may magnify risk for developer that are locked into contracts suppliers with emissions intensive suppliers or suppliers who cannot meet moving thresholds. Of course, not introducing these policies may present new risks around social license for, and public perception of the technology and could compromise the reputation and credibility of investors whose portfolios are increasingly concerned with Environmental, Social, and Corporate Governance (ESG).

3. **Cross-chain risk: Assuming that a BECCS developer will be properly remunerated for negative emissions, perhaps the next most pressing unknown for a BECCS project is the availability and reliability of currently unbuilt T&S infrastructure**. Project value hinges on its ability to provide CO2 removals which is not possible without a T&S network that is a) built on time and b) can function reliably such that the transmission infrastructure has available capacity and CO2 can be safely stored. Aside from oil and gas pipeline infrastructure, investors may not have the experience to properly appraise cross-chain risk associated with FOAK BECCS. The combination of multiple unknowns makes securing a positive FID for FOAK BECCS a relatively precarious financial venture compared to other generation projects.

[19] Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology (Wood, 2018)
[20] Analysing the potential of bioenergy with carbon capture in the UK to 2050 (Ricardo, 2020)

Incentivising investment in FOAK BECCS will require a considerable amount of risk to be mitigated, likely using contracts. The objective of a commercial framework is to allocate the different risks of FOAK BECCS in the most efficient manner possible. Some of these risks naturally sit with the developer. For example, a degree of construction risk and technology risk should be anticipated and prepared for by the developer. Other risks sit beyond direct control of the developer, in which case some form of government involvement may logically therefore be necessary to provide investors with a sufficient degree of revenue certainty (see Figure 5). Assuming CO2 T&S is operated as a regulated asset base to avoid a natural monopoly, the developer should not, for instance, be expected to absorb T&S disruptions that do not originate at the plant itself. The allocation of risks is likely to be decided on a case-by-case basis for FOAK BECCS given the limited number of projects. The use of contracts, which have a proven track record in the UK power sector, may therefore be an effective way of clearly allocating risk and providing legal certainty to the developer. Fundamentally, the contract is designed to provide certainty for the developer established via a legally binding allocation of risk which, if violated, ensures a mode of financial recourse. Ideally the mechanism will be replicable to NOAK projects and create incentives for dynamic efficiency. The CfD framework is an example of a contract system which provides said certainty while also promoting competitive outcomes.

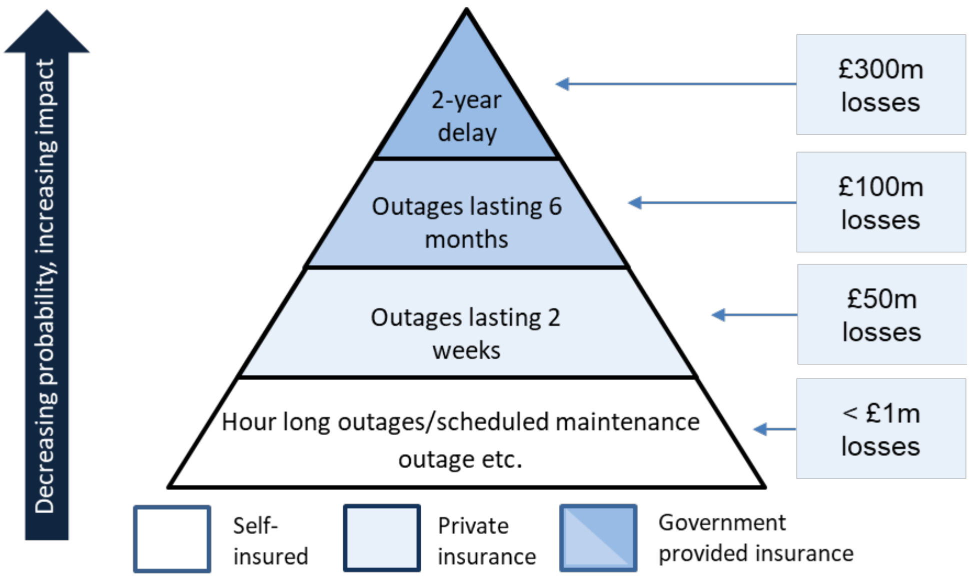

Figure 5: Pyramid of T&S disruptions and risk allocation for FOAK BECCS

Table 8: Summary of key risks identified

Key risk	Key finding
Technology risk	Unforeseen costs outside of engineering estimates can occur for any energy project, but this risk is intensified for an energy project involving an emerging technology like CCS
Market risk	Feedstock supply chains and biomass prices were frequently raised as an area of concern from stakeholders in industry and the financial community contacted for this study.
Cross-chain risk	Assuming that a BECCS developer will be properly remunerated for negative emissions, perhaps the next most pressing unknown for a BECCS project is the availability and reliability of currently unbuilt T&S infrastructure.

3 Initial Review and Evaluation of Power BECCS Frameworks

The following sections covers the steps taken to decide on which power BECCS commercial frameworks were taken forward into detailed design and analysis. The entire process is shown in Figure 6. From a comprehensive list of frameworks identified in literature, nine frameworks were selected for assessment (i.e. the long list). Qualitative criteria derived from literature and stakeholder interviews were developed to assess each framework. The final scoring of the nine frameworks provided insight and rationale for the selection of the most promising frameworks (i.e. the short list).

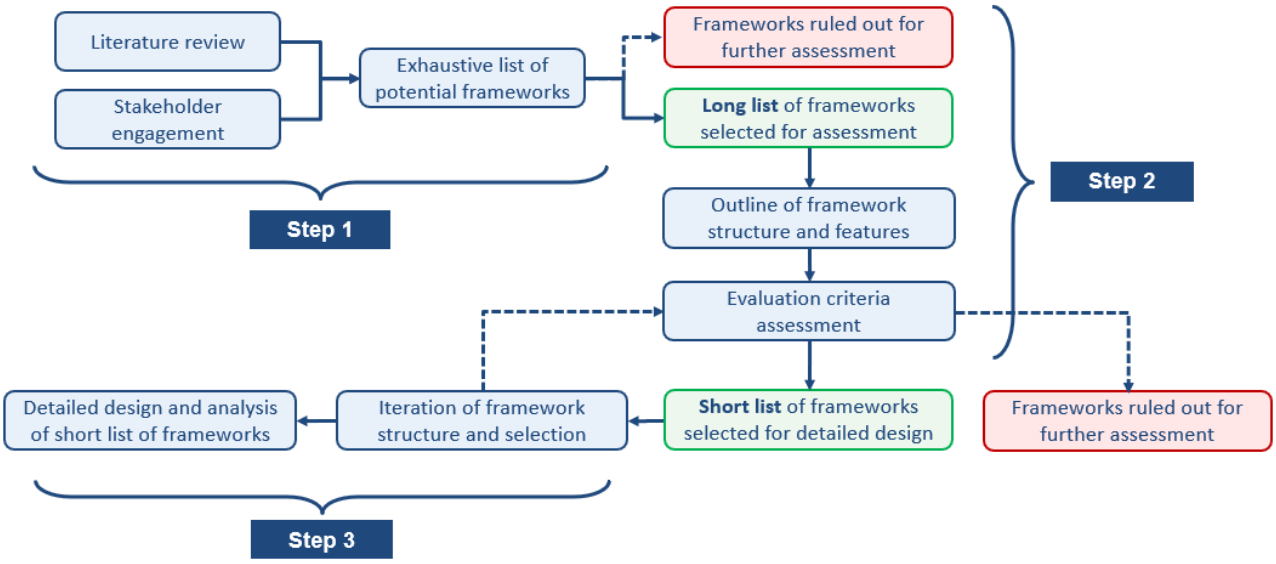

Figure 6: Overview of process for selection and assessment of commercial frameworks

3.1 Categories of commercial frameworks

A number of frameworks have the potential to support power BECCS, varying by their inherent revenue model. Table 9 below outlines categories of frameworks that were identified through an initial literature review. Combinations of incentive structures were also identified as valid frameworks, such as a power CfDe with a negative emissions payment, or the inclusion of negative emissions credits (e.g. UK ETS) as an additional revenue stream. From this initial review, some frameworks were ruled out from the assessment. These frameworks, along with their rationale for exclusion, are outlined in Appendix 0.

Table 9: Literature review of commercial frameworks for FOAK power BECCS

Category	Key revenue model (simplified)
Contract for difference (CfD)	CfDc – subsidy paid above prevailing carbon price up to a strike price on CO_2 removed
	CfDe – traditional power sector CfD on wholesale electricity price
	CfD alternatives – hybrid of the two above or CfDe plus negative emissions payment
Tax credits	Tax relief for operation in £/tCO_2 removed and capital tax credits (traded/non-traded)
Obligation with credits (traded)	Carbon disposal credits, with obligations on emitters (could include fossil fuel companies)
	Carbon disposal credits, with obligations on electricity suppliers
Cost plus subsidy	Direct reimbursement of all properly incurred operational costs
Negative emissions payment	Direct government procurement of BECCS negative emissions via reverse auctions
	Direct subsidy per negative unit of CO_2
	UK ETS inclusion of negative emissions credits
Direct procurement	Direct government procurement of BECCS electricity generation via bilaterally-negotiated service contract
Dispatchable power agreement	Direct availability and variable payments for dispatchable power via consumer subsidy funds
Cap and floor	Top up payments to floor if revenues are below this amount and revenues returned above set cap
Regulated asset base	Regulator would issue a licence to the project developer, outlining the levels of revenue and returns received
Full government ownership	State-owned enterprise takes complete ownership of project construction and operation

3.2 Frameworks considered for FOAK Power BECCS

Nine frameworks were selected as potential candidates to support FOAK power BECCS projects. This page provides a high-level summary of each framework. Greater depth on each framework's key design features, risk considerations and strengths and weaknesses are provided in Appendix 0. All framework attributes were validated and refined from stakeholder and workshop feedback. The nine frameworks were:

1. **Power Contract for Difference (CfDe) – standalone**: Traditional CfD for electricity generation (CfDe) in the UK power market, where the generator is paid the difference between a contractually agreed strike price and market price for electricity (in £/MWh).21
2. **Carbon Contract for Difference (CfDc) – standalone:** CfD mechanism which would provide a subsidy paid above the prevailing carbon price for negative emissions (e.g. UK ETS) up to a contractually agreed strike price on CO2 captured (£/tCO2).21
3. **Negative Emissions Payment – standalone**: Payments (in £/tCO2) administered as direct subsidies for each negative unit of CO2 captured.
4. **CfDe plus Negative Emissions Payment**: A CfDe combined with a negative emissions payment to form a single commercial framework. The financial incentive from the CfDe (£/MWh) could be capped and aligned with an approved level of costs for low-carbon power subsidised by electricity consumers, with the negative emissions payment (£/tCO2) designed to cover remaining costs.
5. **Tradeable Tax Credits**: BECCS operators would receive credits on their tax statements for negative emissions (in £ per tonne of CO2 captured). Value of tax credits could be set for 5-10 year periods, subject to government revision and re-evaluation in successive periods.
6. **Tradeable Carbon Removal Credits with Obligations on Emitters**: A new compliance market would be developed and require certain "emitters"22 to offset their emissions. Market-based emissions price (in £/tCO2 abated) would be driven by supply and demand and the quantity of credits could target specific allocations of negative emissions (e.g. aligned with carbon budgets).
7. **Cost Plus Subsidy**: An open-book contract which includes direct payments from government covering all incurred operational costs of the BECCS plant (fuel costs, CO2 T&S, etc.), plus an agreed margin. Margins on the subsidy would need to be contractually negotiated for bespoke FOAK projects.
8. **Full Government Ownership**: Government, potentially through a state-owned enterprise, takes complete ownership and control of a BECCS project, from plant construction through to long-term operation of the facility. The state-owned enterprise would cover the full range of costs for both low carbon biomass generation and negative emissions.

[21] Conversely, the generator would be liable to refund revenue if the market price exceeds the strike price.
[22] For example, "emitters" could include upstream fossil fuel producers required to dispose of a fixed percentage of the CO_2 contained within their fuel sales or large emitters from other sectors (e.g. aviation, maritime).

9. **Dispatchable Power Agreement (DPA) plus Negative Emissions Payment**: As proposed for the UK's gas CCUS commercial framework, this mechanism would include: availability payments (£/MW)[23] and variable payments (£/MWh) with sufficient incentive to ensure the BECCS plant dispatches ahead of a biomass electricity plant. This structure would be topped up with an additional negative emissions payment (£/tCO_2) for BECCS plants.

These nine frameworks were taken through a scoring assessment against key criteria, which is outlined in the following sections.

3.3 Evaluation criteria

Key criteria were developed to assess each of the potential frameworks on their relative merits in supporting FOAK power BECCS. The criteria in Table 10 were developed through review of literature, engagement with stakeholders and discussions within the wider project team on the key requirements and success factors for a BECCS framework for the public and private sector. The assessment outcomes were assigned based on the strengths and weaknesses highlighted in literature and through engagement, and were validated with the wider steering group for the project.

Table 10: Criteria used for scoring assessment of FOAK power BECCS commercial frameworks

Category	Criteria	Defining Question
Effectiveness 	Incentive strength	Is the financial incentive strong enough to stimulate deployment of BECCS (sufficient revenue or threat of penalties)?
	Track record	Has a similar framework been successfully used previously?
	Risk mitigation	Can the framework mitigate the key economic risks associated with FOAK power BECCS for the private sector to ensure projects are investable for financiers and developers?
Efficiency 	Cost reduction promotion	Can the mechanism select for lowest cost projects and promote operational cost reductions over time?
	CO_2 reduction promotion	Does the framework promote continued CO_2 reductions (e.g. increasing CO_2 capture rate, reducing supply chain emissions)?

[23] Payments decoupled from plant dispatching to reflect the availability of generation and capture.

Category	Criteria	Defining Question
Feasibility	Fair cost distribution	Can the framework provide value for money (e.g. reduced costs for government) and does it follow the 'polluter pays' principle?
	Implementation in 2020s	Is the framework feasible to implement in the late 2020s (i.e. administrative complexity)?
Replicability	Applicability across sectors	Could the framework be applicable or adapted to wider BECCS sectors (e.g. EfW, industry)?
	Suitability to NOAK	Is the framework already suitable or could be adapted for NOAK projects with greater competition?

Commercial frameworks were first evaluated on their effectiveness in stimulating BECCS deployment and promoting investor confidence in a FOAK project.

- Broadly, a framework's incentive strength was assessed on whether the framework is capable of providing a revenue stream that outweighs the additional costs of BECCS and covers all additional costs over revenue received from the market. For example, CfDs would ensure a high incentive for deployment provided that the strike price is set sufficiently high to cover the additional costs of operating the BECCS facility.
- Track record was defined more broadly to include other sectors or countries and did not imply mechanisms must have been previously used within the UK or the power sector to receive a medium-to-high rating. However, more weight would be given for successful frameworks used in similar context (e.g. CfDe in UK electricity market).
- Lastly, frameworks were evaluated on their risk mitigation ability, which closely considered how effectively a framework mitigates key risks faced by the developer (e.g. feedstock prices, CO2 market prices, electricity prices).[24]

Efficiency criteria were also used to evaluate the cost and CO2 reductions that each framework could enable for power BECCS.

- The cost reduction promotion criteria assesses whether frameworks enable low-cost project selection[25] (regardless of who is paying) and whether they have an inherent financial incentive to reduce operational costs over time (i.e. any model with fixed payments as developer returns are greater if operating costs reduce).
- To evaluate CO2 reduction promotion, frameworks which place greater value on quantities of CO2 stored would score highly.

[24] The risk mitigation criteria was not used at the assessment stage to evaluate policy risk, construction risk or cross-chain risks - closer consideration of these risks was undertaken in the detailed design phase.
[25] This criteria considered cost reduction due to competition between projects, however given the unlikelihood of competition for FOAK deployment, no frameworks scored highly on this criteria. Further consideration of promoting competition falls under the 'replicability to NOAK' criteria.

The feasibility of frameworks were assessed as a means to evaluate whether costs represented a fair distribution and the framework could be readily implemented in the next decade.

- The fair cost distribution criteria involved evaluation of two key elements: (1) value for money[26] and the (2) polluter pays principle[27]. Frameworks which scored a higher rating were deemed fairer in the sense that those who receive benefits or contribute to emissions are paying. This involved consideration of two benefits for BECCS, low-carbon electricity production and carbon reductions via negative emissions, benefitting electricity consumers and society or emitters, respectively.
- The second criteria under the feasibility category was implementation in the 2020s, which took into consideration how frameworks differ in their administrative burden in initial setup. For example, a cost plus subsidy would likely be more straightforward to setup within the next few years, whereas market-based mechanisms take greater time to establish initially. Additionally, those with existing or similar structures in place (e.g. CfDs) would be easier to implement in a short-to-medium timeframe.

Two additional criteria were used to assess the replicability of the framework in other BECCS sectors and for NOAK projects.

- For example, applicability across sectors closely considered power-based frameworks which included payments in £/MWh. Such a payment structure would not be easily transferable to support industrial BECCS projects (e.g. cement sector) but could be applicable to energy-from waste plants which sell electricity.
- To evaluate suitability to NOAK, frameworks scored poorly if they were deemed unlikely to be desirable for NOAK projects as they do not reduce costs for government, incentivise competition through a market-based mechanism, and are administratively complex to deliver (e.g. such as cost plus subsidies). Conversely, a CfD could be more readily adapted by adjusting the level of the strike price (£/MWh or £/tCO2), transferring to a competitive allocation process for NOAK projects, and passing costs to the market through a rising carbon price (i.e. CfDc).

3.4 Assessment results

The results of the criteria assessment are shown in Figure 7 on the next page. A full set of rating notes and rationale for each score is provided in the Appendix. Two frameworks performed best out of all considered. Based on these results, they were taken forward for detailed design and analysis. The key rationale for each is provided below:

[26] Value for money defines policies which are cost-efficient, minimising costs for government, taxpayers and consumers, and providing a risk-adjusted fair return to investors.
[27] The ‘polluter pays’ principle suggests placing the burden of societal costs for emissions reductions on fossil fuel producers / consumers and emitters.

- Carbon CfDc - Performs well on most criteria, placing value on CO2 removal, and could be applied to a wide range of sectors or NOAK projects. Subsidy value is likely to reduce over time as the market price for negative emissions increases (e.g. in the UK ETS), thereby reducing subsidy value over time. The strike price could be negotiated with a long-term contract for FOAK projects, providing revenue confidence for investors and developers.
- Power CfDe plus negative emissions payment - Performs reasonably well on all criteria, enabling both low carbon electricity and negative emissions to be valued appropriately, with a long-term contract providing revenue confidence for investors and developers.

Despite its unlikely ability to promote value for money or applicability for NOAK projects, the cost plus subsidy framework was also selected to be analysed at a high-level as a single model run. This was to demonstrate a contrasting option for a FOAK project which could achieve lower financing costs against the two promising frameworks. Additional detailed design elements of cost plus were not explored.

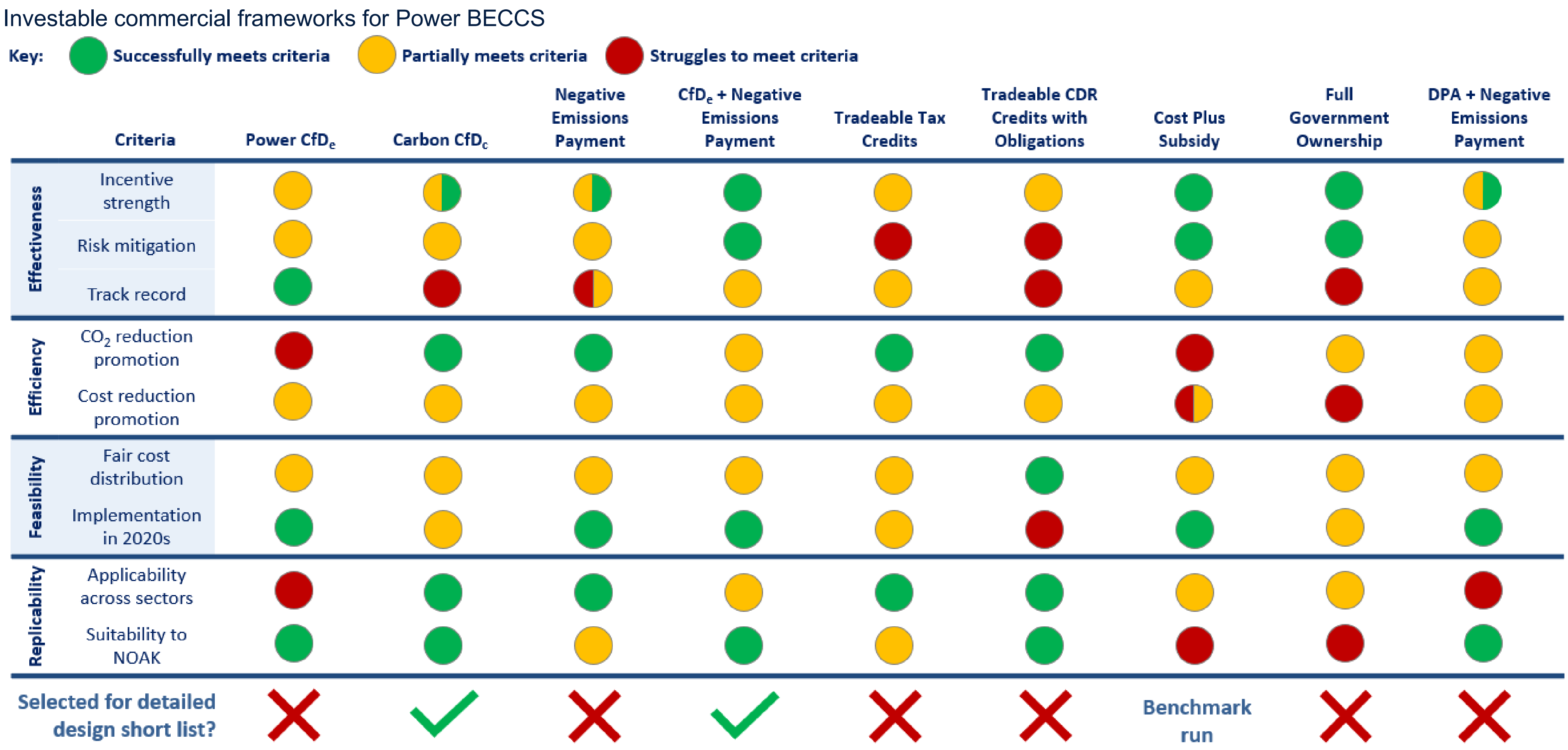

Figure 7: Overview of scoring results from the commercial framework criteria assessment [28]

[28] CDR = carbon dioxide removal, DPA = dispatchable power agreement

The criteria ratings in Figure 7 provided guidance to the selection of which frameworks were selected as most promising for implementation. This selection was not strictly based on the rating outcomes (e.g. by selecting the top 3 frameworks given the most green or least red scores). Table 11 provides a qualitative rationale for the inclusion or exclusion of the shortlisted frameworks analysed in detail in this study. As for the frameworks which were not selected, each typically had at least a couple low ratings or few successful ratings which either limited their ability to provide revenue certainty, mitigate against key risks, or have atypical and limited track records in the UK.

Table 11: Rationales for the inclusion or exclusion of frameworks taken forward into detailed design

Framework	Decision	Rationale
Power CfD_e	No	Eliminated because of its similarity with the dual payment option (CfD_e plus negative emissions payment), with the drawback of not providing a value for negative emissions and higher costs for electricity consumers.
Carbon CfD_c	Yes	Performs well on most criteria, placing value on CO_2 removal and could be applied to a wide range of sectors or NOAK projects. Subsidy value is likely to reduce over time as the market price for negative emissions increases (e.g. in the UK ETS).
Negative Emissions Payment	No	Eliminated because of its similarity with the dual payment option (CfD_e plus negative emissions payment) but does not inherently have a mechanism in place to transfer costs to the market/polluters and does not minimise costs to government.
CfD_e plus Negative Emissions Payment	Yes	Performs reasonably well on all criteria, enabling both low carbon electricity and negative emissions to be valued appropriately, with a long-term contract providing revenue confidence for investors and developers.
Tradeable Tax Credits	No	Assuming tax credits are not contracted or set over the long term, they do not provide sufficient revenue certainty to mitigate against economic risks faced by investors/developers.
Tradeable Carbon Removal Credits with Obligations	No	Eliminated because it does not provide sufficient certainty for the private sector, who end up taking on all risks. Unlikely to be applicable for FOAK projects, however, elements from this framework could be considered in the longer term.
Cost Plus Subsidy	Benchmark run	Struggles to meet the efficiency criteria, however, mitigates against key risks for FOAK projects and has the strength of reducing financing costs. Shortlisted as a contrasting option for the detailed design phase. Additional design elements were not explored.

Framework	Decision	Rationale
Full Government Ownership	No	Limited track record in the UK and unlikely to drive cost or CO_2 reduction efficiencies. Unlikely to be desirable for NOAK projects or other sectors.
DPA plus Negative Emissions Payment	No	Eliminated as revenue certainty is not as strong when compared to the other dual payment option (CfD_e plus negative emissions payment), given the DPA's framework design to reward plant flexibility. Places more value on electricity and unlikely applicable to other GGR or BECCS sectors.

4 Detailed Assessments of Promising Frameworks

The detailed assessment illustrates how the shortlisted frameworks might be designed to incentivise FOAK BECCS deployment given the current state of the technology. As described in Section 0, there are several key risks which may inhibit the mobilisation of capital needed for FOAK BECCS. This section covers the design features that may be required to offset these risks and provide sufficient certainty for investors and developers of FOAK BECCS to make a project investable. There are three central questions to framework design, namely:

- What is the minimum level of payments needed to incentivise investment in FOAK BECCS?
- What are the key risks and uncertainties which may inhibit investment in FOAK BECCS?
- What additional design features could help make FOAK BECCS more investable beyond the primary design features of each commercial framework?

Box 1. Reporting of commercial framework payments for power BECCS – net or gross?

Given the key service provided by a BECCS plant is mitigating climate change, any support for BECCS needs to incentivise net negativity. That is, the sum of BECCS plant's scope 1, 2 and 3 emissions needs to be strongly negative. As highlighted in Section 2, this is typically the case. Nevertheless, incentive structures should be such that BECCS plants minimize the emissions associated with biomass production and transport to the plant.

This requires incentives for BECCS to be structured such that biomass supply chain emissions are minimized, ensuring net negativity is maximized. There are various ways net negative can be incentivised including setting upstream emission standards and the imposition of penalties if these are exceeded and/or linking framework payments to net CO2 captured at a BECCS plant.

For simplicity, payments in a commercial framework for power BECCS are presented throughout this report in units of £ per tonne of gross CO2 captured. This assumes the plant is paid the full value of its emissions captured at the plant, without netting off any emissions associated with the supply chain.

Section 0 provides a deeper discussion on how net negativity can be incentivised.

In line with these central questions, the detailed assessment is structured as follows:

- Section 0 4.1 Primary design features reports the payments required for each framework to be investable and discusses the main features of each framework.
- Section 0 4.2 Sensitivity analysis measures the impact of key risks and uncertainties to BECCS developers and investors as sensitivities. Discussion focusses on the effects of

each sensitivity on project economics, considering both framework-specific and framework-agnostic sensitivities.
- Section 0 Additional design features. Considers additional design features for risk reduction, costs redistribution and reduction, and operational performance.

The focus of the analysis is on how incentives are provided to BECCS developers, rather than how any payments may be funded. The results in this assessment are quantified using a cashflow model (described below) developed specifically for FOAK BECCS, an overview of which is provided in **Box 2**. To understand their impact on the internal rate of return (IRR) — the expected annual growth rate of an investment— the primary design features (Section 0) and sensitivities (Section 0) are modelled using the cashflow model. The cashflow model also allows us to sum the revenue streams to a BECCS plant (from the electricity market, UK ETS, commercial framework, etc.). The term 'framework payments' is used throughout the report to describe all the payments received by the developer that are not earned in markets including the UK ETS. Unless otherwise specified, all framework payments are discounted at a rate of 9.1%. Section 0 qualitatively describes various ways the framework payments could be funded. However, distributional impacts have not been quantitatively modelled.

4.1 Primary design features

Section 4.1 reports on the primary design features of each framework which can incentivise investment in FOAK BECCS. The distinguishing incentives within each framework are discussed in detail for FOAK BECCS retrofit and new build. Where relevant, alternative distributions of payments across incentives are also covered. The design features for the two frameworks are discussed in turn, namely:

- The Power CfD + Negative Emissions Payment (CfDe + NEP) framework
- The Carbon CfD (CfDc) framework

Box 2. Description of the BECCS cashflow model

Detailed assessment of commercial frameworks is carried out by modelling the cashflows for the BECCS developer. A BECCS cashflow model was developed by Vivid Economics to provide illustrative but plausible parameters for the design features of each framework. The primary objective of the model is to find the minimum balance payments to achieve a prespecified IRR. Sensitivities and – wherever possible – design features are modelled by altering any variable that has a direct impact on the cashflows of a BECCS developer, holding constant all other variables.

The cashflow model estimates annual flows of revenues and costs under a set of economic and policy conditions chosen by the user. Key revenue streams include electricity revenues, negative emissions or carbon payment revenues and the UK ETS, which are determined by the commercial framework chosen and projections for electricity and carbon prices. Key costs include capex, fuel costs, fixed and variable opex, T&S fees and finance costs, which all depend on the size, type and utilisation of the plant, as well as the technological specifications (e.g. efficiency), market factors (e.g. feedstock prices) and policy regime chosen (e.g. whether the plant pays for uncaptured CO2 or supply chain emissions). Once a set of economic and policy conditions has been chosen, the model uses goal seek to find the required payment level from a given mechanism while holding all else constant.

To calculate illustrative incentive levels, the cashflow model assumes that a positive financial investment decision (FID) requires an IRR of 9.1%. The IRR of 9.1% is chosen based on a 2018 assessment of investor expectations for different renewable power projects in the UK.B1 An IRR of 9.1% already assumes a substantial amount of risk has been mitigated by the government, including cross-chain risk which is discussed in Sections 0 and 0. A uniform IRR is used to allow for better comparison of frameworks and a levelled assessment of sensitivities, but it should also be acknowledged that the expected rate of return for FOAK BECCS will be determined by the inherent features of the framework chosen. Differentiated risk reduction between frameworks is covered during the discussion of sensitivities for the CfDc framework and explicitly modelled as its own sensitivity in Section 0.

Assumptions and inputs which are based on BEIS' published projections, the most up-to-date literature and input from key industry stakeholders. Key assumptions include:

- Plant size: 498 MWegross

- Capex: £900m and £1,900m for retrofit and new build, respectively

- Opex: £80m/annum

- Fuel costs: £270m/annum

- Utilisation rate: 60% in year 1 and 90% thereafter

- Contract length: 15 years

- Volumetric T&S fee: £18/tCO2

- Emissions intensity of combustion: 1.2tCO2/MWhnet and 1.12tCO2/MWhnet for retrofit and new build, respectively

A full set of inputs and assumptions used for modelling can be found in Section 0 of the Annex. Those inputs for which considerably uncertainty has been previously noted are expressed as a range and explored as sensitivities for each of the shortlisted frameworks.

All figures express costs and revenues per MWhnet throughout this section. Alternatively, all costs and revenues can be expressed in £ per tonne of CO2 captured using the following conversion factors:

- FOAK retrofit: 0.88 MWhnet/tCO2 captured (or 1.14 tCO2/MWhnet)

- FOAK new build: 0.93 MWhnet/tCO2 captured (or 1.07 tCO2/MWhnet)

B1 Electricity Generation Costs 2020. (BEIS, 2020)

4.1.1 CfDe + NEP design features

A strike price of £75 per MWhnet combined with a NEP of £92 (£135) per tonne of CO2 captured is one balance of payments that that provides an 9.1% IRR over the contract length for a FOAK retrofit (new build) plant, though others are feasible.[29] As set out in more detail in Section 0, these estimates are sensitive to assumptions on costs which remain uncertain. Nevertheless, these estimates provide an indication for the level of support required to incentivise a FOAK plant under the framework. The chosen level for the strike price and NEP sits near the mid-point along the two potential ranges of combinations that achieve a 9.1% IRR. As demonstrated below in Table 12, other combinations, which put lesser or greater weight on the NEP, are also feasible.

Difference in the level of support required for FOAK retrofit and FOAK new build is primarily explained by efficiency and capex. FOAK new build is expected to be more efficient and will benefit from additional net export power. For modelling, it is assumed that the FOAK new build is 7% more efficient than its retrofit counterpart and that capex requirements approximately double. The combination of these two factors increase the required NEP by £43/tCO2. This is partially the result of paying off the capex for an asset with a considerably longer useful economic lifetime, a topic which is discussed in more detail in Section 4.2.3 where contract length is explored as a sensitivity. A comparison of the levelised costs and revenues for both plant types are provided in Figure 8.

[29] Please refer to **Box 2** for tCO_2 to MWh_{net} conversion factors. Example calculations: £92 * FOAK retrofit tCO2 to MWh_{net} (1.14) = £104 per MWh_{net}; £135 * FOAK new build tCO2 to MWh_{net} (1.07) = £144 per MWh_{net}.

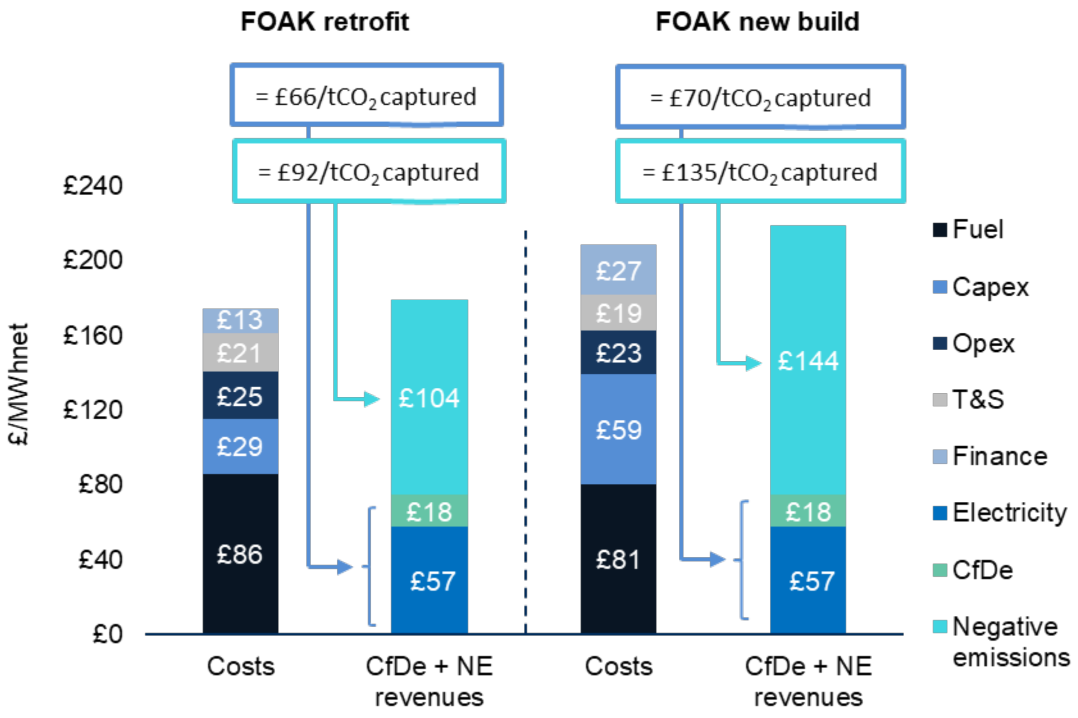

Figure 8: Levelised costs and revenues under the CfDe + NEP framework[30]

The balance of payment mechanisms is a key design feature of the CfDe + NEP framework. Therefore, it requires a value to be set on both the positive externalities of a) firm low carbon power and b) negative emissions. A distinctive characteristic of the CfDe + NEP framework is that it distinguishes between two goods, low-carbon generation and negative emissions, and remunerates the developer for each on a separate basis. This is attractive because the framework can separately value the positive externalities associated with each good, though choices must be made on their respective value. Different balances between the CfDe and NEP can be chosen, our rationale is as follows:

- **Value of firm low carbon generation**: Assuming a CfDe would be structured and funded similarly to those provided for wind, the payments will be levied on electricity consumers. Reliable power which provides inertia to the power system is important. Hence, it is appropriate to set the strike price at a value that reflects the positive externality of firm low carbon generation that is typically associated with conventional biomass generation. The £75/MWhnet strike price is based on a recent support package awarded to the Wylfa Newydd nuclear power plant in Wales. The Wylfa project was chosen on the basis that nuclear power represents a benchmark for firm low-carbon generation in the UK. However, whether nuclear is the appropriate benchmark for FOAK BECCS is an area for further investigation. The potential for different strike prices, reflecting alternative values that could be attributed to BECCS generation, are discussed below and in Table 12.

[30] Evaluated over contract length (T = 15 years) using a weighted average cost of capital of 8.4%. To express revenues and costs in £ per tonne of gross CO_2 captured, please refer to the conversion factors in **Box 2**.

- **Value of negative emissions**: As previously discussed, it is widely agreed that BECCS' system role is primarily to provide negative emissions to balance the residual emissions from the hardest to abate sectors and avoid their mitigation costs. Therefore, abatement costs of hard to abate sectors are a relevant benchmark. However, for FOAK the value of innovation spillovers also need to be considered. Given various possible lines of argument and bottom-up estimation methods, this study estimates the required NEP indirectly as the residual sum of payments needed to incentivise FOAK BECCS after compensating for low carbon generation. An additional £104/MWhnet is required to achieve the 9.1% IRR, which translates into an NEP of £92/tCO2. The NEP is approximately 6 times higher than the proposed price floor for the UK ETS and almost double BEIS' carbon price projections for electricity supply in 2021.[31],[32] However, the NEP is significantly less than the social cost of carbon over the last 9 years of the contract from 2032 to 2040 when compared against the 2018 Greenbook traded carbon values for appraisal.[33] Furthermore, the NEP is considerably lower than abatement options towards the higher end of the UK's marginal abatement cost curve such as fuel switching to ammonia in shipping (abatement cost of £130 to £140/tCO2 in 2035) and decarbonising heat for residential buildings (abatement costs of £135/tCO2 and £230/tCO2 for new and existing homes in 2035, respectively). [34]

The CfDe + NEP framework allows for several possible combinations of payments that achieve an IRR of 9.1%. As shown in Table 12, the framework can accommodate a lower or higher strike price and still maintain a 9.1% IRR if that change is offset by a converse movement in the NEP. In theory, the balance of payments should reflect the relative value of each good as set out above. Framework design might also consider the distributional effects between, for example, the emitter, the taxpayer and the low-carbon electricity consumer, and any potential effects of the chosen NEP on nascent markets for negative emissions or the inclusion of negative emissions in existing carbon markets such as the UK ETS.

Table 12: Possible combinations of CfDe strike price and NEP for a 9.1% IRR[35]

NEP (£/tCO2)	Strike price (£/MWhnet)
0	179
83	85
87	80
92	75
100	65
105	60
107	Market prices

[31] Annex M. Growth assumptions and prices in Updated energy and emissions projections: 2019 (BEIS, 2020).
[32] Please note that new carbon price projections are expected to be published around the same time as this study and are expected to narrow the gap between our illustrative NEP and existing projections.
[33] Carbon prices increase from £98.50 to £160 per tonne (£$_{2019}$). See Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal. Data tables 1 to 19: supporting the toolkit and the guidance. (BEIS, 2018).
[34] The Sixth Carbon Budget (Climate Change Committee, 2020)
[35] Evaluated over contract length (T = 15 years). Assumes a discount rate of 9.1% and electricity price projections from Annex M. Growth assumptions and prices in Updated energy and emissions projections: 2019 (BEIS, 2020).

4.1.2 CfDc design features

A carbon strike price of £107 (£151) per tonne of CO2 captured provides revenues sufficient to earn a 9.1% return over the contract length for a FOAK retrofit (new build) plant. The CfDc does not distinguish between avoided emissions and negative emissions. The £107-£151/tCO2 is equivalent to the required payments under an isolated NEP (see Table 10), but delivered through a framework with a proven track record in the UK power sector. Differences between payment requirements for FOAK retrofit and FOAK new build are similarly explained by the efficiency and capex assumptions used (see Section 0). A comparison of the levelised costs and revenues for both plant types are provided in Figure 9.

A key feature of the CfDc is that the cost of negative emissions is shared with emitters participating in the UK ETS. Similar to a standard power CfDe, the BECCS developer is paid the difference between the traded price and a negotiated strike price for carbon. The average non-ETS payment made to the developer on top of ETS revenues is £58/tCO2 assuming BEIS 2019 carbon price projections,[36] equivalent to 54% of total framework payments over the contract length. It is assumed here that the CfDc is linked with the UK ETS during the BECCS plant's 1st year of operation. However, an ETS-linked framework for negative emissions accounting may not be likely pre-2030, in which case the full carbon strike price would need to be paid for by public or private entities outside of the UK ETS in the initial years of operation. Furthermore, the consequences of incorporating negative emissions into the ETS should be carefully considered before a formal linkage is established. For example, accommodating an additional 3.6 million tonnes worth of emissions permits per year (assuming the plant operates at 90% utilisation and T&S is available) could have a deflationary effect on permit prices unless the emissions cap is adjusted.

[36] Carbon prices £47 and £53 per tCO_2 in 2030 and 2040, respectively. See Annex M. Growth assumptions and prices in Updated energy and emissions projections: 2019 (BEIS, 2020).

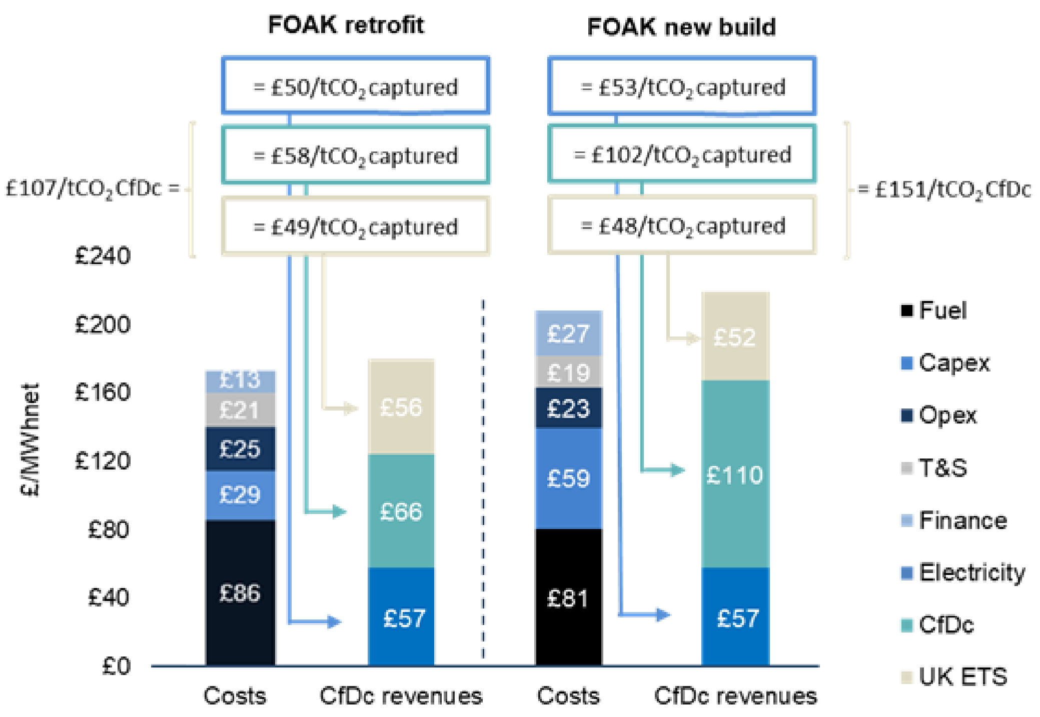

Figure 9: Levelised costs and revenues under the CfDc framework[37]

4.2 Sensitivity analysis

The purpose of the sensitivity analysis is to demonstrate how changes in framework-specific and framework-agnostic variables affect project IRR and the magnitude of payments required to secure a positive FID. The section focusses on the following:

- how revenues and project IRR are highly sensitive to the payments received by the developer via the primary framework mechanisms.
- how the materialisation of key risks and uncertainties can undermine revenue certainty and discourage investment.

Section 4.2 proceeds as follows:

- Section 0 looks specifically at the CfDe + NEP framework and models changes in the strike price and NEP.
- Section 0 looks specifically at the CfDc framework and models change in the carbon strike price and the effects of market risk for wholesale electricity.
- Section 0 models various risks and uncertainties that affect both frameworks.

[37] Evaluated over contract length (T = 15 years) using a weighted average cost of capital of 8.4%. To express revenues and costs in £ per tonne of gross CO_2 captured, please refer to the conversion factors in **Box 2**.

Some additional sensitivities for capex and negative emissions from generation are found in Section 0 of the Annex.

4.2.1 CfDe + NEP specific sensitivities

Negative emissions payments

Mild uncertainty in the NEP will be a major concern for the BECCS developer and investors given its influence on revenues and IRR. The balance of payments will likely lean towards the NEP under the CfDe + NEP framework given the decreasing unit costs of low carbon electricity, which is reflected in recent contracts awarded for wind in the UK. Revenues and IRR are both highly sensitive to any change in the NEP if the CfDe strike price remains constant. The BECCS developer stands to benefit from an additional £21m in revenues from every £ added to the NEP and achieves an IRR of over 12% over a 15 year contract length at an NEP of £100/tCO2, when the strike price is fixed at £75/MWhnet for the purposes of this demonstration.

The certainty of a contract for negative emissions is important to incentivise investment in FOAK BECCS. However, this level of certainty may not be possible within a purely market-based NEP mechanism, especially in the short-to medium-term, as the market does not yet exist and would likely remain immature for some time once established. Therefore, a contract which guarantees a minimum NEP might therefore be required under the CfDe + NEP framework due to potentially large fluctuations in revenue from marginal changes in the NEP. A flat payment established over the length of the contract is assumed for the baseline results in Section 0, but a price floor of CfD may also be effective if the NEP is linked with the UK ETS or other carbon markets in the future.

Table 13: IRR at different NEPs

NE payment (£/tCO2)	IRR at £75 strike price (%)
80	2.9
85	5.9
92	9.1
95	10.7
100	12.8

Strike price

IRR is less sensitive to the strike price received under the CfDe + NEP framework. A lower sensitivity is intuitive given the balance of payments chosen. That said, the strike price is still an important revenue stream at £75/MWhnet, providing an additional £18 per MWhnet of generation to the developer on top of wholesale revenues. Every £1 added to the strike price contributes an additional 0.4% to project IRR and revenues (payments) of £19m. The effect of the strike price on project IRR is shown in Table 14, assuming a fixed NEP of £92/tCO2.

Table 14: IRR at different strike prices[38]

Strike price (£/MWhnet)	IRR at £92 NEP (%)
65	4.6
70	7.0
75	9.1
80	11.1
85	13.0

4.2.2 CfDc specific sensitivities

Carbon strike price

Sensitivity to the carbon strike price under the CfDc framework is analogous to the NEP under the CfDe + NEP framework. Every £ added to the carbon strike price provides the developer with an additional £21m in revenues over the length of the contract. IRR and framework payments at different carbon strike prices are shown below in Table 15.

Table 15: IRR at different carbon strike prices[39]

Carbon strike price (£/tCO2)	IRR (%)
90	-1
100	5.7
107	9.1
110	10.4
120	13.8

Electricity prices

Unlike when in the CfDe + NEP framework, a BECCS developer would be vulnerable to changes in the price of electricity under the CfDc framework. This form of market risk is unique to the CfDc among the frameworks shortlisted for detailed assessment and is perhaps its most significant drawback. As shown in Table 16, project IRR drops to 5.4% under BEIS low wholesale price projections. The carbon strike price under these conditions would need to increase to £114/tCO2 for the developer to maintain a return of 9.1%. Conversely, a scenario

[38] Evaluated over contract length (T = 15 years) at a discount rate of 9.1%.
[39] Evaluated over contract length (T = 15 years) at a discount rate of 9.1%.

of unexpectedly high electricity prices would have the opposite effect: increasing IRR to 12.1% or bringing down payment to £100/tCO2.

An IRR greater than 9.1% may be required under the CfDc, given the additional risk involved. Investors are familiar with the CfDe and will likely expect some form of revenue certainty in the wholesale market for generation. According to the stakeholders contacted in this study, an additional premium may be required in lieu of said certainty. If this were the case, a carbon strike price higher than £107/tCO2 would be needed to offset additional financing costs and secure a positive FID (as discussed in Section 4.3.10 and Box 4).

Table 16: IRR and required payments under different wholesale electricity price projections[40]

Price scenario	IRR at £107/tCO2 carbon strike price (%)	Carbon strike price required for 9.1% IRR (£/tCO2)
BEIS low price projections	5.4	114
BEIS reference scenario projections	9.1	107
BEIS high price projections	12.1	100

4.2.3 Framework-agnostic sensitivities

Fuel costs

A combination of new policy, key demand levers and land constraints could put upward pressure on biomass prices in the future. The value of biomass is expected to change as the social cost of carbon/value of carbon reduction increases.[41] Decarbonisation of heavy industry, greater uptake of biofuels in non-road transport and the deployment of BECCS will very likely increase global demand for biomass in the coming years, putting upwards pressure on prices if land available for modern biomass is limited by natural constraints and/or by the necessary policies to ensure that biomass is sustainably sourced. For example, the Climate Change Committee estimates that 2050 carbon values would increase the value of biomass by £10-33/GJ, equivalent to an increase of approximately 100-500% from today's prices for wood pellets (£6-8/GJ).[42] This is supported by integrated assessment model outputs published by the Network of Central Banks and Supervisors for Greening the Financial System (NGFS), which project an increase in EU biomass prices of approximately 200-300% by 2050 in some scenarios where global warming is limited to 2 degrees Celsius.[43]

40 Evaluated over contract length (T = 15 years) at a discount rate of 9.1%.
41 Analysing the potential of bioenergy with carbon capture in the UK to 2050 (Ricardo, 2020)
42 Biomass in a Low-Carbon Economy (Climate Change Committee, 2018)
43 IIASA NGFS Climate Scenarios Database (n.d.). Accessed on 19/04/2021 via: https://data.ene.iiasa.ac.at/ixmp-explorer-sandbox/#/downloads

A FOAK BECCS project could fail to make any returns under a sustained increase to feedstock prices. Fuel is the largest component of costs for FOAK BECCS at the central feedstock price estimate of £25/MWhfuel.[44] Results from cashflow modelling suggest that a £1/MWhfuel increase in the price of feedstock could increase costs by £64m and decrease IRR by 2.4%. Moreover, the project makes no return over the contract length under the baseline payments (see Table 17) if wood pellets increase by 20% to £30/MWhfuel. The NEP and carbon strike price would need to increase by £11-15/tCO2 to still maintain a 9.1% under a scenario where feedstock prices increase by 15-20% and all other revenue streams are fixed. Under Ricardo's high fuel cost scenario of £40/MWhfuel, the developer suffers losses of approximately £80m per annum and would require a £45/tCO2 increase in the NEP or carbon strike price to maintain a 9.1% return.

Given the considerable risk biomass prices pose, some risk reduction may be necessary to avoid increasing the required IRR and overall cost of FOAK BECCS. A contract between the developer and supplier(s) which guarantees a particular volume, quality and price of feedstock over the contract length is the most desirable outcome for investors. In the absence of these guarantees, the risk of feedstock price volatility will be factored in to investor expectations and will require a higher IRR. As explained above, this will necessarily require greater framework payments, most likely through the NEP.

Table 17: IRR and required payments for a 9.1% IRR under different feedstock prices[45]

Fuel costs (£/MWhfuel)	IRR under baseline payments (%)	NEP required for 9.1% IRR (£/tCO2)	Carbon strike price required for 9.1% IRR (£/tCO2)
15	21	61	77
21	14	80	96
25	9.1	92	107
29	3	103	118
30	0	107	122
40	-13	137	152

T&S outages

Cross-chain risk is frequently cited as the greatest uncertainty for FOAK BECCS among developers and investors. The two most likely instances of cross-chain risk that could have a significant effect on revenues and revenue certainty for FOAK BECCS are 1) a mismatch in the timing of FOAK BECCS and T&S network construction (such that the BECCS plant can

[44] Analysing the potential of bioenergy with carbon capture in the UK to 2050 (Ricardo, 2020)
[45] Evaluated over contract length (T = 15 years) at a discount rate of 9.1%. £25/MWh_{fuel} and £15/MWh_{fuel} values adopted from Analysing the potential of bioenergy with carbon capture in the UK to 2050 (Ricardo, 2020).

provide negative emissions but the network is not available) and 2) unexpected T&S outages during operations. Assuming that the BECCS plant continues to run unabated during a T&S outage, a BECCS developer could lose its largest revenue stream unless it is insured against these disruptions irrespective of the commercial framework chosen.

In extreme cases, the BECCS developer could lose hundreds of millions if the BECCS plant continues to run unabated and is uninsured against cross-chain risk. Damages and impact on project IRR of different T&S disruptions for both frameworks are shown in

Table 20. The results show that a 1 to 2 week annual outage in the T&S infrastructure would cause damages in the tens of millions for the BECCS developer in either framework. Damages increase to over £100m if T&S construction is delayed by 1 year in the 1st year of operations and approximately £300m if the T&S is delayed by 2 years in the first 2 years of operations. The effects of cross-chain risk on revenues and IRR are more severe under the CfDc framework for every type of T&S disruption. This can be explained by the fact that all revenues, excluding the sale of wholesale electricity, are dependent on the capture and storage of CO2 under the CfDc, whereas the balance of payments is distributed between generation and negative emissions under the CfDe + NEP framework.

Investors may require a significantly higher IRR if there is any chance of cross-chain risk materialising while the BECCS developer is uninsured. The T&S network carries considerable uncertainty and risk is difficult to quantify for FOAK. Discussions with stakeholders indicate that an IRR significantly greater than 9.1% would be expected if this risk sits solely with the developer. The illustrative disruptions reported in Table 18 give a sense of how the framework payments would need to compensate for cross-chain risk of the developer is uninsured. Every week of outages adds £1.2/tCO2 to the require NEP and £1.8/tCO2 to the required carbon strike price. Given the significant losses involved, the prospect of a long-term delay in the T&S infrastructure might lead to a significantly higher NEP or carbon strike price to incentivise investment. Potential policy solutions to address cross-chain risk are discussed in Section 0.

Table 18: Damages, IRR and required payments for different T&S disruptions[46]

T&S disruption	Present value of lost revenues (£bn)	IRR (%)	NEP or carbon strike price required for 9.1% IRR (£/tCO2)
CfDe + NEP			
1-week annual outage	19	8.6	93
2-week annual outage	38	8	94
1-year construction delay in	121	6	100

[46] Evaluated over contract length (T = 15 years) at a discount rate of 9.1%. Assumes that net export power increases when T&S infrastructure is down and T&S volumetric fee is void during disruption.

T&S disruption	Present value of lost revenues (£bn)	IRR (%)	NEP or carbon strike price required for 9.1% IRR (£/tCO2)
year 1			
2-year construction delay in years 1-2	286	2.5	114
CfDc			
1-week annual outage	29	8.3	109
2-week annual outage	58	7.4	111
1-year construction delay in year 1	147	5.5	117
2-year construction delay in years 1-2	348	1.5	134

Utilisation rate

Although it is typically assumed that FOAK BECCS will run baseload, the plant could also run at a reduced utilisation rate to compliment intermittent generation. Baseload generation is understood as the natural place for BECCS in the merit order given its primary function to provide GGRs. This is supported by a range of stakeholders across who similarly view a high utilisation factor as being the most likely outcome for FOAK BECCS in the UK. However, a potential benefit of BECCS in addition to low carbon generation and negative emissions is its ability to provide flexible power. Whether running dispatch would be its most valuable use, it is possible that the FOAK plant could run higher in the merit order to compliment an increasing share of generation from wind and solar. This might be seasonally determined for instance, where the plant runs baseload during the colder months and dispatch in the warmer months.

The utilisation rate of FOAK BECCS is highly significant for framework design. Running at a lower utilisation rate implies that the developer must pay off the same amount of capex while providing a lower quantity of goods. Accordingly, the developer will need to be compensated more per unit of negative emissions delivered in a similar way to how it receives higher electricity prices during peak hours.

The BECCS developer cannot afford to run at a low utilisation rate at under a £92/tCO2 NEP or a £107/tCO2 carbon strike price. Decreasing the utilisation rate significantly increases the average cost per tonne of negative emissions. As shown in Table 19, the average cost per tonne of CO2 captured and stored increases from £159 at 90% utilisation to £245 at 35% utilisation. Measured by framework payments per unit of negative emissions delivered, value for money is significantly diminished. An NEP of £182/tCO2 and a carbon strike price of

£190/tCO2 are required to attain a 9.1% IRR for the CfDe + NEP framework and the CfDc framework, respectively.

Table 19: Abatement costs and payments required for a 9.1% IRR at baseload and reduced utilisation

Utilisation rate	Average annual electricity price (p/kWh)	Negative emissions cost (£/tCO2gross)	NEP required for 9.1% IRR (£/tCO2gross)	Carbon strike price required for 9.1% IRR (£/tCO2gross)
Baseload (90% utilisation factor)	4.9	159	92	107
BEIS illustrative modelling (36% utilisation factor)	7.2	245	182	190

Contract length

The design features and sensitivities covered throughout this report all assume that the investor requires a return of 9.1% only over a 15-year contract, after which point the plant continues to operate without government support or shuts down. Given the uncertainty of long-term markets, it is assumed the BECCS plant requires a 9.1% IRR over the contract length. At the end of the contract, the plant may shut down if there is little economic value remaining, a subsequent contract could be negotiated, or it may be possible by the end of the contract for the BECCS plant to operate on a commercial basis given the development of negative emissions markets.

A contract length of 15 years is the standard in the UK electricity market and proposed CCUS business models. The 15-year length contract was chosen to remain consistent with the standard CfD contract length in the UK electricity market and the proposed contract length in BEIS' industrial carbon capture business model. The benefits of a 15-year contract length are that a) the investment community and developers are familiar with planning around a 15-year time horizon and b) the 15 year contract implies a contract end date by which time it is plausible the market for negative emissions is sufficiently mature to support a BECCS plant without support.

Longer or shorter contract are possible for FOAK BECCS; the ideal contract length depends on expectations for the development of market for GGR. Increasing/decreasing the contract length extends/reduces the period over which the developer can recoup the initial investment while operating in the relatively low risk environment provided by contracts with HMG. As shown in

Table 20, this has the effect of decreasing/increasing the NEP or carbon strike price required to achieve a 9.1% IRR. Every 5 years added to the contract increases undiscounted lifetime costs by over £1bn for the CfDe + NEP framework. Extending contract length by the same amount leads to a lower increase under the CfDc framework, from £0.5bn to £0.7bn, due to cost sharing with the UK ETS. A shorter contract is feasible under an accelerated capex repayment schedule but would likely lead to a subsequent contract given a) the long lifetime of the asset and b) the high value of negative emissions, particularly for FOAK new build. On the other hand, a 20-year contract runs the risk of committing the Government to unnecessary payments after a viable GGR market has been established at some point in the future. For these reasons, a 15-year contract may be an appropriate length for FOAK BECCS, after which point the developer receives remuneration via a commercial market.

Table 20: NEP and payments required for contracts of different length

Contract length	Payments required for 9.1% IRR for the CfDe + NEP		Payments required for 9.1% IRR for the CfDc	
	£/tCO2	Total undiscounted framework payments (£bn)	£/tCO2	Total undiscounted framework payments (£bn)
10	101	4	120	2.3
15	92	5.6	107	3
20	81	6.7	102	3.6
25	75	7.9	99	4.1

4.3 Additional design features

A BECCS commercial framework will include design features in addition to the primary payment mechanisms which define the CfDe + NEP and CfDc frameworks. This section sets out additional design features across 3 categories:

1. Features which help reduce risk to developers and financiers, focussing on the most significant risks identified in the sensitivity analysis.
2. Features which help reduce or redistribute costs of the BECCS frameworks
3. Features which could help avoid unintended consequences such as concerns around the sustainability of biomass production and sourcing, or inefficient electricity generation.

4.3.1 Risk reduction

In general, the greater the risk left with the private sector, the higher the return demanded as compensation. A balance needs to be struck in the design of a BECCS framework. More risk can be left with the developers and financiers, in return for greater reward, or vice versa. Leaving risk with the private sector can help incentivise efficiency, but does raise the cost of capital. While the exact distribution of risks and rewards will be the outcome of negotiation, the following provides some general guidelines on which risks may be helpful to reduce, and why.

The contracts for difference set out above are a key tool to help reduce risk for developers, but key risks are still left with developers. Contracts are enforceable, and hence not subject to policy changes, reducing political risk. Furthermore, the contracts provide substantial certainty over revenues through a strike price, or simply a guaranteed payment level for negative emissions (NEPs). This is critical for BECCS, a technology who's main purpose is producing negative emissions, which are currently not valued (or valued at a price far below that necessary for BECCS if considering the price of forestry offsets). However, even with CfDs, substantial risks still sit with the developer, as set out in Table 21.

Table 21: Distribution of key risks across the public and private sector

Risks	Government (or other obligated/levied party)	BECCS plant owners and financiers
Technology risk e.g. plant performance and costs		Technology risk should primarily sit with plant owners, to incentivize efficient operation
Construction risk e.g. costs and timetable		Construction risk should primarily sit with plant owners, to incentivize efficient deployment
Development risk e.g. project failure post-FEED		Development risk typically sits with plant owners, but could be mitigated through e.g. grants for FEED studies
Market risk e.g. feedstock or electricity price volatility	General inflation risk sits with government by indexing contracts Carbon price risk sits with government under the CfDc Electricity price risk sits with Government under the CfDe	Feedstock price risk sits with BECCS plants owners unless addressed in contracts Electricity price risk sits with plant owners under the CfDc

Risks	Government (or other obligated/levied party)	BECCS plant owners and financiers
Policy risk e.g. carbon price volatility	By providing contracts, government effectively eliminates this risk to BECCS plant owners and assumes this risk itself (or passes it own to obligated/levied parties)	
Cross-chain risk e.g. T&S assets not available		This sits with BECCS plants unless specifically addressed in contracts. Given the size of the risks, government support is likely needed

To achieve an IRR around 9.1% (as assumed in the cashflow modelling), government will have to help developers shoulder some of the risks associated with FOAK BECCS. In principle, risks which incentivise efficiency and cost reduction should be left with the developer as much as possible. However, risks which are either too large to (self) insure or are simply beyond the control of the BECCS developer will need to be at least partly assumed by government. The following considers:

- Measures to address cross-chain risk. Cross-chain risk is beyond the control of the BECCS developer and as set-out above can be substantial. It is likely any framework will require measures to address this risk.
- Measures to address market risk. Market risk to a large degree is already addressed with CfDs. However, these do not capture all market risk. In particular feedstock price risk can be substantial. While it can be addressed by developers, some form of limited risk sharing could be desirable if this can substantially lower the required returns by developers.
- Measures to help reduce risks to financiers. These are not targeted to address any specific risk, but can help reduce the cost of capital of a BECCS project by reducing the risks to finance providers.

Cross chain risk

Any FOAK BECCS framework will require a mechanism to address cross chain risk, to make the project investable. Cross chain risk is primarily beyond the BECCS developers' control and can plausibly reduce the IRR to near zero (or lower) as set out in Section 0. Consequently, there is little incentive to invest in BECCS if developers assume most of the cross-chain risk. Furthermore, there is limited economic rationale to assign BECCS developers the cross-chain risk, given they have little to no ability to take action to reduce the risk (i.e. there is no potential efficiency gain from BECCS developers facing this risk).

Availability payments provide a potential avenue to addressing cross-chain risk. An illustrative availability payment is shown in Figure 10. In Table 18, which shows the potential damages of T&S outages, it is assumed that the BECCS plant is not remunerated for the potential negative emissions it can provide. Here, the opposite is true: the BECCS plant is effectively paid for their availability to capture CO2 even if the T&S network is not available to store it. From the perspective of the developer, returns during an outage are unchanged when the plant is generating electricity and the T&S network is offline or online – assuming the T&S disruption does not originate at the plant. In other words, the developer is protected from any uninsured damaged shown in Table 18. This assumes that the BECCS plant continues to operate at baseload generation as a low carbon energy source. If this is not the case (e.g. this could be an inefficient use of biomass if sufficient baseload/flexibility is available on the system) the payment would need to be adjusted to account for further loss of revenues. Total framework payments to the developer to the plant are less during a T&S outage under the CfDe + NEP framework, assuming that the plant benefits from an increase in net export power when the CCS unit is inactive. Specifically, framework payments are £122/MWhnet when the T&S is operational and £88/MWhnet when the T&S is down. On the other hand, a T&S outage increases framework payments assuming that UK ETS participants are not liable for purchasing negative emissions which are not provided by the developer. Accordingly, framework payments increase from £66/MWhnet when the T&S is operational to £88/MWhnet when the T&S is down.

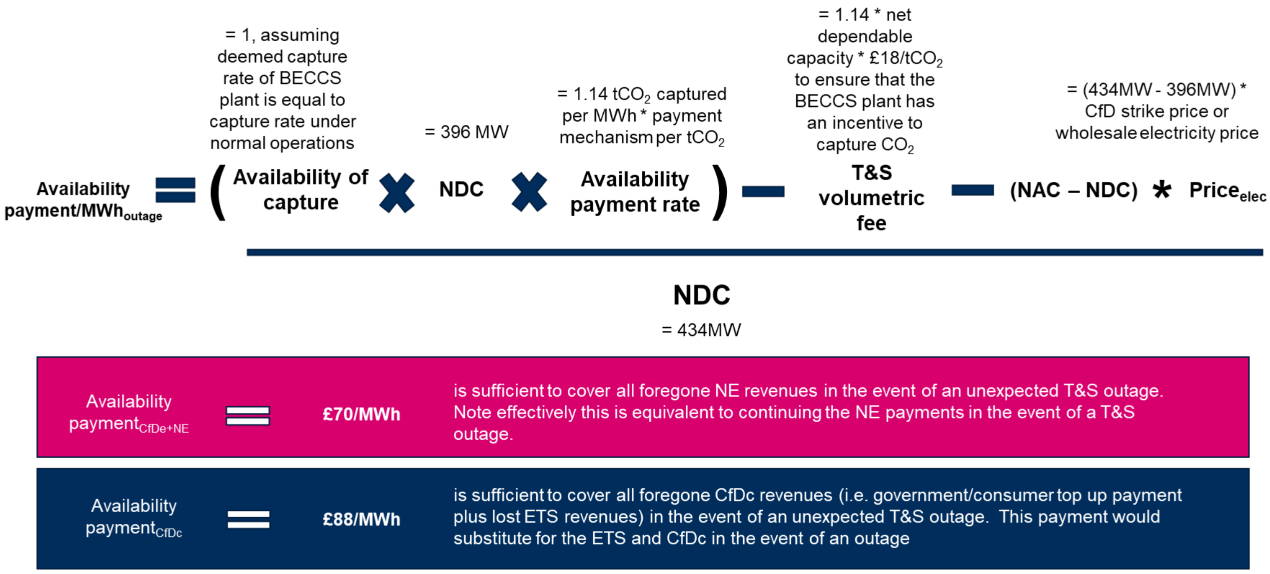

Figure 10: Illustrative availability payment formula for FOAK BECCS[47]

Feedstock price risk

Because the biomass market is immature and risks are substantial, there may be instances where government assuming some risk could substantially reduce the return required by developers. It is unlikely BECCS developers can lock in a price for 15 years, leaving them

[47] Net dependable capacity (NDC) is the plant's capacity for net export during regular operations; net available capacity (NAC) is the plant's capacity for net export during any outage event. Formula adapted from Annex C of BEIS (2020) CCUS business models report. Assumes that a T&S capacity payment is not paid by the BECCS generator. Volumetric fee is originally included in the variable payment, not the availability payment, according to Annex C of BEIS (2020)

exposed to long term price changes. As set out in Section 0, the biomass price can have a large impact on IRR. Developers will require a higher rate of return when fully exposed to this risk. Risk sharing mechanisms like a biomass price ceiling (above which government co-pays for biomass) or agreed links between biomass prices and negative emissions payments could potentially be suitable. Given the immaturity of the biomass market, a possibility is to allow for some adjustments in the framework payments (through strike price adjustments or adjustments to the NEP) after a defined time period (e.g. year 5 and year 10), to reflect changes in the global biomass market.

Unlike cross-chain risk, BECCS developers can take action to mitigate biomass price risk or self-insure against price rises. As a result, feedstock price risk is materially different from cross-chain risk. It is not a necessary condition for government to assume biomass price risk. From an economic point of view, BECCS developers should be exposed to biomass price where possible to create an incentive for the development of low cost and stable supply chains. For example, companies could vertically integrate and take ownership of their own supply chain. Furthermore, similar to practises for purchasing e.g. natural gas, or aviation fuel, long term contracts with biomass suppliers could be set-up to provide certainty over the fuel price. Lastly, a BECCS plant could hedge against biomass price rises.

General risk reduction

Aside from addressing specific risks for BECCS developers, government could help insulate financiers from some of the risks associated with BECCS, to lower the cost of capital. By, for example, providing guarantees, government can reduce the risk to debt providers, lowering the cost of capital. There are various financial instruments that could be considered, potentially in cooperation with the UK infrastructure bank.

Lowering the cost of capital can substantially reduce the framework payments required. As shown in Table 22, the required NEP and carbon strike price decrease to £87 and £103/tCO2, respectively, at a 7% IRR. At a required return equal to BEIS' published hurdle rates[48] for solar PV projects i.e., 5%, required payments decrease even further to £83/tCO2 for the NEP and £99/tCO2 for the carbon strike price.

Other framework designs could help reduce risks further. This report considers two frameworks in detail (their relative merits against a longer list of policies are set out in Section 4). It should be noted, however, that there are other possible frameworks or combinations of frameworks that could help reduce risks to developers further. To illustrate, Box 3. highlights the potential savings due to cost of capital reductions of a 'Cost Plus' framework and Box 4. discusses how combining the CfDe with the CfDc could reduce downside sensitivity to electricity prices discussed in Section 0 for the CfDc framework.

Table 22: Required NEP and carbon strike price at different IRRs

Required IRR (%)	NEP (£/tCO2)	Carbon strike price (£/tCO2)
13	100	116

[48] Electricity Generation Costs 2020. (BEIS, 2020)

Required IRR (%)	NEP (£/tCO2)	Carbon strike price (£/tCO2)
11	96	111
9.1	92	107
7	87	103
5	83	99

Box 3 The Cost Plus framework

The Cost Plus framework demonstrates how risk reduction can lower project costs. Under the framework, government provides full revenue certainty by guaranteeing repayment of operational expenses plus some agreed margin. The framework therefore provides risk mitigation beyond what either the CfDe + NEP or CfDc framework can provide and a lower IRR is required as a result.

A £320m annual subsidy would be sufficient to achieve an IRR of 5% for FOAK BECCS. Figure B1 shows the levelised costs and revenues of FOAK BECCS retrofit using illustrative financing assumptions of a 5% required return on equity (the hurdle rate of solar PV)B2 and a 3.5% required return on debt (the social discount rate from HM Treasury's Greenbook).B3 Intuitively, financing costs decrease significantly and bring the LCOE down to approximately £160/MWhnet. Furthermore, payments are £97 per tonne of gross CO_2 captured and stored, which is £10 per tonne cheaper than the CfDe + NEP framework as well as the CfDc framework if UK ETS payments are included.

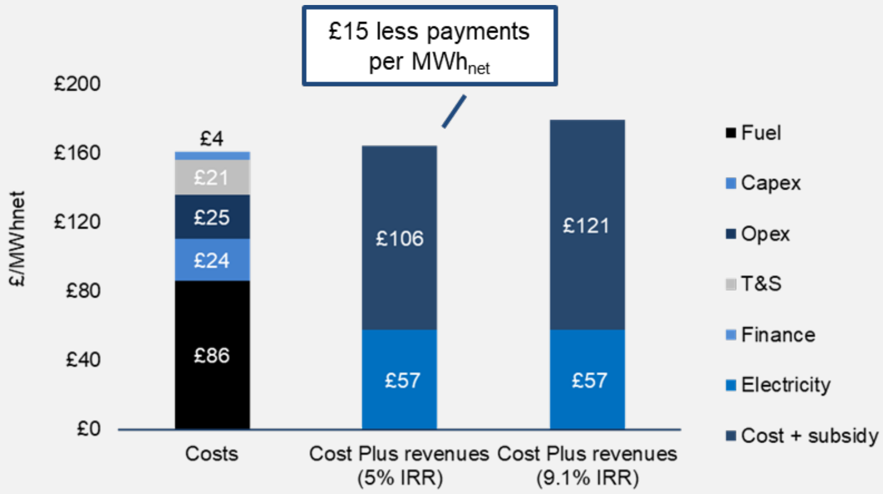

Figure B1: Levelised costs and revenues under a Cost Plus frameworkB4

B2 Electricity Generation Costs 2020. (BEIS, 2020)

B3 Green Book Review 2020: Finds and response. (HM Treasury, 2020).

B4 Evaluated over contract length (T = 15 years) using a weighted average cost of capital of 8.4%. To express revenues and costs in £ per tonne of gross CO2 captured, please refer to the conversion factors in Box 1.

Box 4 The CfDe + CfDc framework

Linking the CfDc with the CfDe provides additional revenue certainty but at the expense of more complexity. The additional premium required by investors under the baseline CfDc framework is no longer justifiable once the framework reduces sensitivity to electricity prices. Under this framework, a carbon strike price equal to the NEP (£92/tCO2) would, in theory, prevent the carbon strike price from increasing to levels shown in Table 15. However, this add-on implies the developer navigates four different revenue streams and the government is responsible for administering and monitoring three in order implement the framework. This could have downsides beyond the associated administrative overhead and could inhibit timely implementation of an already complex policy.

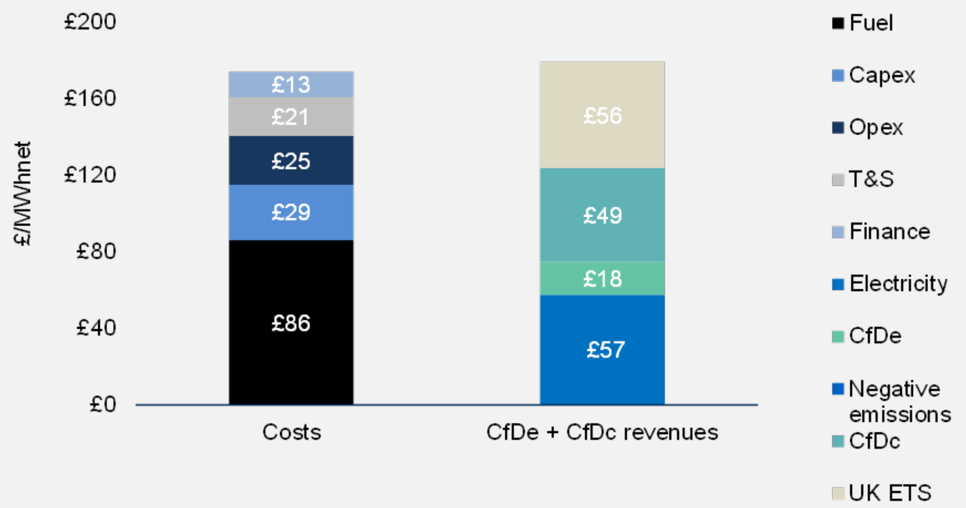

Figure B2: Levelised costs and revenues for the CfDe + CfDc frameworkB5

B5 Evaluated over contract length (T = 15 years) using a weighted average cost of capital of 8.4%. To express revenues and costs in £ per tonne of gross CO2 captured, please refer to the conversion factors in Box 1.

4.3.2 Cost redistribution and reduction

The cost to government, electricity consumers, and emitters of a FOAK BECCS plant will depend both on the total cost of the project, and how these costs are distributed.

- *Reducing project costs.* Commercial frameworks for BECCS should be designed to incentivise cost reductions and minimize the total cost to society. For FOAK BECCS, key considerations include the allocation of risk to BECCS developers to incentivise risk and cost reduction where possible, and reducing the cost of capital. As discussed in Section 4.3.2, these two objectives can conflict, and need to be balanced. In the long run, a key consideration for commercial frameworks for BECCS will be how to foster competition between providers, to incentivise further innovation and cost reductions.

- *Distributing costs.* Key to determining how the two frameworks affect government (and hence tax payers), electricity consumers, and emitters is how the costs of the frameworks are distributed. This is not the focus of this report, nevertheless, the cost distribution is clearly linked to decisions around linking a framework to e.g. the UK ETS and hence is discussed at a high level here.

Fundamentally, the CfD_e + NEP and CfD_c frameworks need not imply different costs to government, consumers, or emitters. Government can choose to levy emitters to pay for the NEP payments for example. Or similarly, levy emitters to pay for the CfD_c payments, or levy a proportion of the CfD_c costs (judged to represent the fair value of firm low carbon electricity) on electricity consumers. There are however practical as well as economic considerations as to why and how the CfD_e + NEP and CfD_c frameworks might in practise differ. The following sets out some of these considerations.

Within the CfDe + NEP and CfDc framework design, some distributional elements are implicit within the frameworks:

- *In a CfD_e + NEP framework, a CfD_e is funded by electricity consumers*. This would follow the model of existing CfDs for offshore wind, where the costs incurred by the low carbon contracts company (LCCC) are levied on consumers. A key implication of this is that *if* a CfD_e strike price is set at a very high level (or at least above the level justified by the positive externality of firm low carbon electricity in the electricity market), then electricity consumers are effectively cross-subsidizing negative emissions for society.
- *In a CfD_c framework, some of the cost is funded by emitters.* Up to the UK ETS carbon price is paid for by emitters (see **Box 3**). Assuming the ETS cap is reduced by the amount of negative emissions produced by BECCS, this implies that the tCO_2 captured x UK ETS price are funded by emitters. A drawback of the CfD_c framework is that emitters (and government) are effectively cross-subsidizing electricity consumers through their payments for negative emissions (unless part of the CfD_c cost is levied on electricity consumers). A potential way to avoid is to combine the two frameworks into a CfD_e + CfD_c (see Box 4).

Taking the above distributional elements as given, framework payments are considerably greater under a CfDe + NEP without a linkage to the UK ETS. Total framework payments, composed of the difference above wholesale prices up to the strike price and the NEP, amount to £2.3bn under the CfD_e + NEP framework for a 498 MWe gross plant over a 15-year contract (with costs discounted at a rate of 9.1%). Under the CfD_c, framework payments are limited to the difference between the traded carbon price in the UK ETS and the carbon strike price. Accordingly, framework payments are reduced by 45% relative to the CfDe + NEP framework as the UK ETS shares the burden of cost. As shown in Table 23, this amounts to a difference of over £1bn over the length of the contract. In undiscounted equivalency, payments for the two programmes are approximately £5.6bn and

Table 23: Framework payments for the CfDe + NEP and CfDc frameworks[49]

Framework	Total discounted framework payments (£bn)	Total undiscounted framework payments (£bn)
CfDe + NEP	2.3	5.6
CfDc	1.2	3

The magnitude and distribution of payments across market and non-market entities are subject to change when payment mechanisms across frameworks are combined. Two framework combinations are feasible, namely:

- The CfDe + NEP + UK ETS, as the name suggests, is a variation on the CfDe + NEP where negative emissions are similarly traded in the UK ETS. The NEP is still assumed to be a flat payment over the contract length, calculated based on projected permit prices within the UK ETS.
- The CfDe + CfDc, which, as described in Box 4, is simply the CfDc combined with a power CfDe.

As shown in Figure 11, combining the CfDe + NEP framework with the UK ETS results in framework payments equivalent to the CfDc as costs are shifted onto the UK ETS. The difference between the two frameworks is that £18/MWhnet of payments that take place through the CfDe mechanism in the CfDe + NEP + UK ETS framework are instead remunerated through the CfDc strike price. The CfDe + NEP + UK ETS and the CfDe + CfDc frameworks are even more similar. In particular, the distribution of payments is essentially identical; the only substantive difference between the two being that the remuneration for negative emissions occur through two different mechanisms i.e. a flat NEP in the CfDe + NEP + UK ETS framework and a carbon strike price in the CfDe + CfDc framework. This all being said, some key distributional differences of the different frameworks do arise under high carbon pricing scenarios, which is discussed in Box 3.

49 Evaluated over contract length (T = 15 years) using a discount rate of 9.1%.

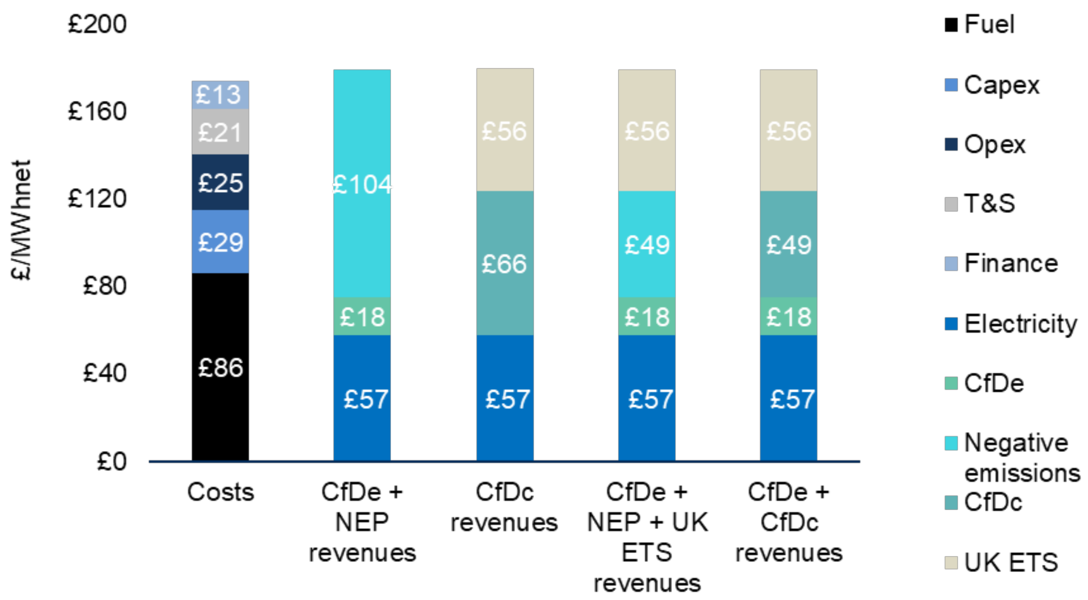

Figure 11: Levelised costs and revenues for the CfDe + NEP, the CfDc and additional framework combinations[50]

Beyond the magnitude of payments and how payments are distributed across payment mechanisms, there are outstanding questions for how the NEP and CfDc are funded which, given the size of the potential payments, need to be carefully considered.

- How are the NEPs funded? It is possible for government to fund NEPs through general taxation. This may be attractive for FOAK BECCS, because of its simplicity, allowing BECCS to be deployed swiftly. Government could choose to use levies or other mechanisms to shift the cost to other parties. An alternative possibility is obligating fossil fuel suppliers (or other emitters) to purchase negative emission certificates and fund the NEPs through these payments.[51] Funding FOAK BECCS in this way could provide a route to building a larger negative emissions market and given the comparative value of the fossil fuel market, and required BECCS framework payments, would have minimal impacts on fossil fuel prices.
- How is the CfDc funded? As set out in Section 0, the CfDc still implies large scale subsidies for FOAK BECCS given the expected difference between the UK ETS price and the strike price. As with the NEPs, this could be funded by government. Alternatively, the cost of the CfDc could be levied on e.g. fossil fuel suppliers (and ultimately fossil fuel consumers), analogous to how the CfDe costs are levied on electricity consumers.

[50] Evaluated over contract length (T = 15 years) using a weighted average cost of capital of 8.4%. To express revenues and costs in £ per tonne of gross CO_2 captured, please refer to the conversion factors in **Box 2**.
[51] Greenhouse Gas Removal (GGR) policy options – Final Report. (Vivid Economics, 2019).

Box 3 Carbon prices and the distribution of payments

The distribution of costs is largely determined by the evolution of carbon prices for any framework that is linked with the UK ETS. A scenario with lower carbon prices will shift the burden of costs onto government, consumers or whichever entity is obligated to pay for the framework outside of the ETS. On the other hand, higher carbon price projections can dramatically reduce non-ETS payments.

However, consumers and government are the recipients of transfers from the UK ETS when carbon prices are high, but only if payments are made through a carbon strike price. As shown in Table B1, framework payments are reduced to £0.1bn under carbon pricing scenarios consistent with BEIS central traded carbon prices for appraisal. The key difference between the CfDc and the CfDe + CfDc on the one hand, and the CfDe + NEP + UK ETS on the other, arises when carbon prices are high. By design, the developer pays back any additional carbon revenues over and above the agreed strike price, resulting in potentially large savings for non-ETS entities in a framework which uses the CfDc. On the other hand, payments under the CfDe + NEP + UK ETS have a lower bound of zero, implying that the developer receives more revenues than is necessary to achieve a 9.1% IRR if carbon permits are traded above £92 per tonne. For example, project IRR increases to 25% when the NEP is set to zero and traded carbon prices follow BEIS' high price projections.

The implication of this being that a CfDc-based mechanism has inherent distributional qualities that are more in-line with the 'polluter pays' principle. This quality is only relevant if the traded price of carbon permits in the UK ETS exceeds the carbon strike price at some point during the 15-year contract. If permits consistently trade at a price lower than the strike price, then the magnitude and distribution of framework payments across the three frameworks will be identical.

Table B1: IRR, additional top-up and framework payments under different carbon prices[B5]

Carbon pricing scenario	Payment per NE (£/tCO2)				Total discounted framework payments (£bn)			
	CfDe + NEP	CfDc	CfDe + CfDc	CfDe + NEP + UK ETS	CfDe + NEP	CfDc	CfDe + CfDc	CfDe + NEP + UK ETS
BEIS 2019 electricity supply sector carbon prices (£47 and £53 per tCO2 in 2030 and 2040, respectively)	92	60	60	43	2.3	1.2	1.2	1.2

Carbon pricing scenario	Payment per NE (£/tCO2)				Total discounted framework payments (£bn)			
BEIS 2018 traded carbon prices for appraisal – low (£41 and £80 per tCO2in 2030 and 2040, respectively)	92	58	58	41	2.3	1.2	1.2	1.2
BEIS 2018 traded carbon prices for appraisal – central (£83 and £160 per tCO2in 2030 and 2040, respectively)	92	4	4	0	2.3	0.1	0.1	0.1
BEIS 2018 traded carbon prices for appraisal – high (£124 and £240 per tCO2in 2030 and 2040, respectively)	92	-51	-51	0	2.3	-1	-1	0

B5: Evaluated over contract length (T = 15 years) at a discount rate of 9.1%. Carbon prices available from Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal. Data tables 1 to 19: supporting the toolkit and the guidance. (BEIS, 2018); Annex M. Growth assumptions and prices in Updated energy and emissions projections: 2019 (BEIS, 2020).

A frequently discussed option to help fund BECCS is the use of voluntary offset markets. This would not be possible in the CfD_c framework, since the emissions would already be accounted for in the ETS or carbon removal market. However, in the CfD_e + negative emissions framework, mechanisms could be designed for BECCS to sell offsets in the voluntary market. The mechanism could be thought of as similar to a CfD_c, but in the offset market rather than the UK ETS. An illustrative example is summarized in Figure 12 below. Linkages to offset markets were not explicitly modelled due to significant uncertainty in future demand and the evolution of offset markets. However, potential cost savings for different prices are analogous to the change in payments for the CfD_e + NEP + UK ETS under different carbon pricing scenarios, as discussed in **Box 3**. Note, this presupposes a particular mechanism in which the BECCS developer sells certificates. Alternative schemes could be considered, including for example a scheme where government directly sells certificates into the voluntary offset market.

Allowing BECCS to sell certificates into the voluntary offset market would require careful design to avoid unintended consequences. Key considerations include:

- *Avoiding 'exporting' negative emissions.* While the purpose of BECCS is to provide negative emissions and reduce global emissions, an important secondary goal is its contribution to the UK's domestic net zero target. To ensure this is achieved, BECCS certificates should not be sold to oversees buyers. In other words, BECCS certificates could only be sold to domestic emitters.
- *Avoiding crowding out other forms of GGR.* Since BECCS is heavily subsidized in a FOAK framework, it could crowd out other GGRs from the voluntary market. In practise, most offsets are provided through forestry. Government would need to impose a minimum price on BECCS certificates above the price of forestry offsets to avoid crowding out unsubsidized forestry offsets. Put differently, voluntary buyers of BECCS offsets will need to pay a premium substantially above the price for forestry offsets. There may be demand for this given the benefits a provider of BECCS certificates could provide (e.g. long term certainty over negative emissions provision, high volume, permanence).

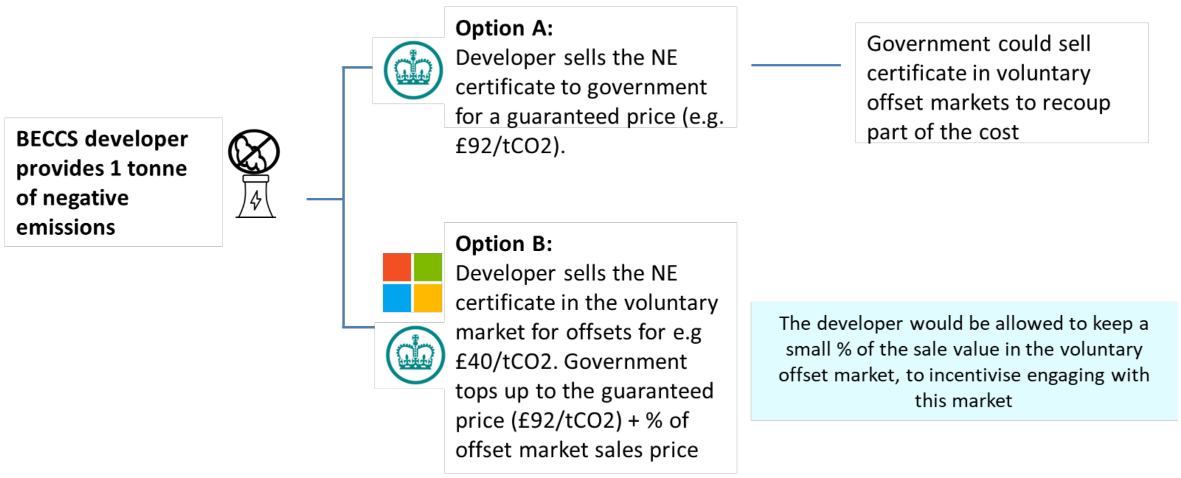

Figure 12: Illustrative offset scheme for the CfD$_e$ + NEP framework

How costs are distributed for FOAK BECCS needs to be considered within the context of a substantial expected scale-up of BECCS and GGR more broadly. Domestic BECCS is expected to reach around 45-95 $MtCO_2$/year by 2050.[52] This implies a need to start scaling up BECCS by the late 2020s and highlights how the market for negative emissions (and BECCS) will scale up substantially in subsequent decades. This wider context raises two points:

1. <u>Timeframes are a material issue.</u> It may be that for this reason government decides to fund some of the framework payments itself, rather than set up new levies or obligations.
2. <u>The future path of wider GGR policy is relevant to what funding route may be preferred now.</u> For instance, NEPs funded through an obligation or linking to the offset market can provide a useful springboard for the creation of a wider market for negative emissions

52 The Sixth Carbon Budget – Greenhouse Gas Removals (Climate Change Committee, 2020)

(distinct from the ETS). If however the long term aim is to include negative emissions in the ETS, the CfD_c framework could provide a useful stepping stone for this instead.

4.3.3 Avoiding unintended consequences

Incentivising sustainable & low-carbon biomass supply

BECCS will use biomass at large scale, and incentivising use of sustainable biomass is critical for its effectiveness as a negative emissions technology. A 1 GW BECCS plant would require the equivalent of around 10% of the UK's current biomass use.[53] Ensuring this is sourced sustainably is crucial, especially if the framework is rolled out for additional BECCS plants. There are many forms of biomass and as set out by the Climate Change Committee, different plausible mixes of biomass sources (UK forestry, UK crops, UK residues, UK biogenic waste, imports) are possible in the long term, with imports ranging from near 0 to several 100 TWhs.[54] Incentives should be designed in such a way that BECCS developers are incentivised to source from more sustainable sources, rather than the cheapest source that meets the minimum requirements .

Providing framework payments based on net emissions could be used to help incentivise upstream emission reductions. The NEP and CfD_c payments as set out in Section 0 are defined on gross emissions captured (see Box 1). Although some challenges would have to be overcome (see Box 6), the benefit of moving to a net negative emissions accounting method is that it provides the developer with a clear monetary incentive to reduce scope 3 emissions i.e. emissions up and down its value chains. As set out in Table 24 cashflow modelling highlights two implications of switching from gross to net payments per tCO_2.

- £/tCO_{2net} is greater than £/tCO_{2gross}. This is for the simple reason that a BECCS plant will require the same payment to achieve an investable IRR, but the net negative emissions are smaller than the gross negative emissions. Overall framework payments would not change.
- The difference in payments for £/tCO_{2net} and £/tCO_{2gross} is modest. In other words, the incentive to reduce upstream emissions (at typical current estimates of supply chain emissions) is modest. At the current thresholds for upstream emissions in biomass supply chains (0.029 tCO_2/MWh_{net}, see Section 0), it is at most £2/tCO_2 if upstream emissions are reduced to 0.

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[53] Assuming the plant runs baseload at a 90% load factor

[54] See Figure 4.7 in the Committee on Climate Change's report on Biomass in a Low Carbon Economy (2018).

Table 24: IRR and required payments under different supply chain emissions intensities[55]

Supply chain carbon intensity (tCO_2/MWh_{net})	Net negative emissions (tCO_{2net}/MWh_{net})	NEP required for 9.1% IRR (£/tCO_{2gross})	Carbon strike price required for 9.1% IRR (£/tCO_{2gross})
0	1.14	92	107
0.029	1.11	94	109
0.05	1.09	95	111
0.1	1.04	99	115
0.15	0.99	103	120

Box 6 Challenges of payments for net negative emissions

Attributing supply chain emissions to the developer may lead to carbon accounting issues and create an unlevel playing field in the power sector. Consistent with international practice, emissions from the supply of feedstock for BECCS are attributed at-source in the agriculture and land use sector (AFOLU). Introducing a net negative emissions measure could therefore lead to double counting emissions from the supply of feedstock – once in the AFOLU sector (perhaps in another country) and a second time in the UK power sector. Net negative emissions payments must hence not be linked directly to accounting practises for national GHG accounts. Furthermore, the net supply chains approach could potentially create an unlevel playing field between BECCS plants and other more carbon-intensive generation sources such as gas fired power plants, which, under the UK ETS, are not mandated to internalise the costs of upstream emissions. Ideally, incentives to reduce scope 3 emissions would be applied across the sector in a manner that does not disadvantage low-carbon generation sources.

£/tCO2net payments are unlikely to be sufficient to incentivise a sustainable supply chain and are not a substitute for frameworks to manage the risks around the sustainability of bioenergy feedstocks based on standards and penalties**.** While net payments create some monetary incentive to decarbonize, it does not capture other externalities such as biodiversity, water quality, social benefits of forests, etc. Regulatory standards like thresholds on emissions and environmental standards will continue to be required. The UK already has a sustainability framework for managing risks around bioenergy feedstocks, which includes requirements to minimise harm to ecosystems and a specific requirement to ensure biodiversity is maintained.[56] A net negative emissions payment might complement this, creating a profit incentive for BECCS developers to minimize their upstream emissions. However, it cannot substitute for it. Furthermore, given the potential scale of biomass demand from UK BECCS,

[55] Evaluated over contract length (T = 15 years) at a discount rate of 9.1%.
[56] See Box 3.2 in Biomass in a Low Carbon Economy (Climate Change Committee, 2018).

there are areas where the framework to manage sustainability of feedstocks could be strengthened. The Committee on Climate Change has set out an extensive list of recommendations for this.[57]

Standards and penalties when standards are breached can incentivise supply chain emissions reductions effectively. The attraction of a threshold is that, combined with a strong financial penalty, a high £/tCO_2 penalty can be attached to upstream emissions, which could reflect externalities beyond just CO_2 emissions. This would provide a substantially stronger incentive than net negative payments. However, there are potential downsides to this approach, namely:

1. This approach does not provide incentives for continuous emission reductions beyond the threshold.
2. Deciding what level to initially set the threshold will require thorough knowledge of current and potential supply chains for FOAK BECCS to find a proper benchmark.
3. Given 1., informed adjustment of the threshold over time may be problematic if government does not have evidence of how much further abatement suppliers/developers can feasibly accomplish.

An effective approach may be to use a combination of mechanisms. For example, the policy could set a maximum supply chain emissions intensity and still net supply chain emissions from the NEP or carbon strike price below that point. This way, a high standard of sustainably sourced biomass could be created while also encouraging incremental improvements. Given for a FOAK plant the incentive from net negative payments are small, it may be practical to use standards and penalties as the primary mechanisms to safeguard sustainability.

Incentivising efficient electricity generation

Given negative emissions are the primary good produced by BECCS, the incentive structure can incentivise inefficient electricity generation to prioritise negative emissions generation over electricity generation and save costs on capital equipment. This is particularly true for the CfD_c framework, where the negative emissions revenues are relatively more important compared to the CfD_e + NEP framework. Contracts awarded to FOAK BECCS could include a minimum generation efficiency requirement, to mitigate this risk.

4.4 Applicability to other sectors

Negative emissions technologies are at various stages of development, with a wide range of abatement costs depending on site scales, locations and technology requirements. Table 25 provides a representative sample of costs along with estimates for the TRL and availability of FOAK technologies across each sector. The sectors are categorised as follows:

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[57] See Section 2.1 and 2.2 in Chapter 3 of Biomass in a Low Carbon Economy (Climate Change Committee, 2018)

- Energy from Waste (EfW) – facilities which incinerate waste (e.g. municipal solid waste) and produce electricity. With CCS applied, EfW plants have the potential for BECCS due to the biogenic portions of waste in their feedstock.
- Industry – includes any industrial subsectors for which biomass feedstocks are used as a low-carbon fuel (e.g. cement, pulp and paper, etc.) and for which CCS is a potential abatement option.
- Hydrogen – low-carbon hydrogen production via waste or biomass gasification technologies, with the potential to apply CCS to the flue gas to achieve BECCS.
- Greenhouse gas removals (GGRs) – other non-BECCS options to remove CO_2 from the atmosphere. These could be land-based solutions (e.g. afforestation, biochar, etc.) or engineered removals (e.g. direct air capture).

Of all negative emissions technologies, power BECCS is likely the lowest cost BECCS option (at least in the near-term). While some land based GGRs are lower cost, these have very different characteristics to power BECCS (co-benefits, trade-offs, permanence, scale, etc.).

Table 25: Abatement costs, TRL and FOAK technology availability across negative emissions sectors.

Sector	Abatement Costs[58]	Estimated TRL and Technology Availability (FOAK)
Power	£70/tCO_2[59]	**TRL 6-7**: First large-scale plant now operational in Japan (2020). Drax planning for commercial scale deployment in UK by 2027.
Energy from Waste	£140-260/tCO_2[60]	**TRL 6-7**: Norway's Northern Lights project aims to have a full-scale CCS equipped EfW plant by 2024. Only a few operational plants worldwide (e.g. Japan) with several under development in the Netherlands.[61] Commercial scale deployment in mid/late 2020s in the UK with the right support incentives in place.
Industry	£100-275/tCO_2[59]	**TRL 5-7**: Norway's Northern Lights project aims to have a CCS equipped cement plant by 2024. Commercial scale deployment in mid/late 2020s in the UK with the right support incentives in place.
H_2 Production	£110/tCO_2[59]	**TRL 4-5**: Commercial scale deployment in the UK by 2023-2025 (modular hydrogen production units without

[58] Costs estimates in this table are for the mid-2030s. BECCS abatement costs are taken from the CCC based on the cost of BECCS relative to counterfactuals: (£/MWh_{BECCS} - £/$MWh_{counterfactual}$) / (tCO_2/$MWh_{counterfactual}$ - tCO_2/MWh_{BECCS})
Counterfactuals: Power = wholesale grid electricity without BECCS, Energy from Waste = plants without CCS, Industry = plants without CCS (including some plants which fuel switch to biomass), Hydrogen = natural gas reforming with CCS
[59] The Sixth Carbon Budget - Greenhouse gas removals (Climate Change Committee, 2020) .Costs for Power/Industry assume retrofit/domestic biomass and Gasification assumes imported biomass. Lower end of GGR costs for peat restoration and higher end for DAC.
[60] The Sixth Carbon Budget – Waste (Climate Change Committee, 2020)
[61] Technical Report – CCS on Waste to Energy (IEAGHG, 2020)

– Bio/Waste Gasification		CCS). Greater uncertainty with timescales for CCS retrofits. Late 2020s/early 2030s could be possible with the combined incentives for carbon removals and low-carbon hydrogen.
GGRs (non-BECCS)	£5-400/tCO_2[59]	**TRL 1-9** (wide range depending on technology): Commercial scale deployment is already occurring for more mature GGRs (e.g. afforestation) or still under RD&D for others (e.g. DAC, TRL 4-6).

Differences across BECCS sectors' revenue streams and existing policy support play an important role in the applicability of future BECCS commercial frameworks. Careful consideration will need to be given to existing policies, as shown in Table 26, which support low-carbon electricity, hydrogen or other manufactured goods. In particular, further assessment is still needed to determine how these can be combined with or adapted to a BECCS policy mechanism. Additionally, key risks will need to managed within each sector, such as carbon leakage in industry, public acceptability (i.e. air pollution) in energy from waste or hydrogen transport and storage availability. Challenges are also likely to exist with adapting frameworks, such as amending contracts for different technologies. Nonetheless, opportunities to modify frameworks towards market-based mechanisms or auctions could drive efficiencies in delivering subsidies and enable greater value for money for consumers and taxpayers.

Table 26: Comparison of revenue streams, risks and policy support across BECCS sectors.

	Power	**Energy from Waste**	**Industry**	**Hydrogen**[62]
Product	Electricity	Electricity	Manufactured goods	Hydrogen
Revenue (or similar)	• Electricity market	• Electricity market • Gate fees[63]	• Commodity markets • Avoidance of UK ETS prices or selling allowances	• New low-carbon fuel demand markets • Gate fees[63] • Avoidance of UK ETS prices or selling allowances[64]

[62] Referring to gasification of biomass or waste to produce low-carbon hydrogen.
[63] A gate fee is the charge levied upon a given quantity of waste received at a waste processing facility (e.g. in £ per tonne waste).
[64] For the portion of emissions derived from non-bio waste feedstocks.

	Power	Energy from Waste	Industry	Hydrogen[62]
Key Risks[65]	• Biomass prices, availability and variability • Uncertain plant dispatch • Electricity revenue	• Feedstock availability and variability • Public acceptability (e.g. air pollution)	• Carbon leakage • Difficulty financing / short payback periods required	• Hydrogen market demand and sale price • H_2 T&S availability • Feedstock availability/price
Existing / Planned Policy Support	Power CfD$_e$ (for biomass generators without CCS)	Power CfD$_e$ (for EfW plants without CCS[66])	Carbon CfD[67] (for any industrial carbon capture, e.g. cement)	H_2 commercial models under development by BEIS[67]

With some modifications, both of the proposed frameworks for power BECCS could be applicable to other sectors offering negative emissions potential. Figure 13 and Figure 14 summarise the key considerations surrounding applicability of the CfD$_c$ and CfD$_e$ plus NEP frameworks, respectively. For the CfD$_c$, the carbon removal market price is yet to be determined, with potential options including ETS inclusion of negative emissions or other sectoral-specific markets (e.g. GGRs). This factor alone will play an important role in its applicability to each sector or similar design/structure with existing policies (e.g. industrial CfD$_c$). For the CfD$_e$ plus NEP framework, this could have the CfD$_e$ set to zero in sectors which do not produce electricity, resulting in a standalone NEP. However, this may be unfavourable compared to the CfD$_c$ which enables costs reductions over time to government as the negative emissions market price increases. For other GGRs which could be able to compete under a CfD$_c$ or NEP type mechanism, additional co-benefits (e.g. ecological restoration) and CO_2 sequestration permanence are important considerations that should be included in the detailed design of any framework selected.

[65] All sectors are exposed to key risks associated with CO_2 T&S availability, CCS costs for dispersed sites, and the high capital costs / immature technology deployment of carbon capture.
[66] BEIS is currently reviewing the application of the industrial CCUS business model (i.e. carbon CfD) for EfW plants.
[67] An update on business models for CCUS (BEIS, 2020). For low-carbon hydrogen production, previous work suggested contractual producer subsidies: Business Models for Low Carbon Hydrogen Production (Frontier Economics, 2020).

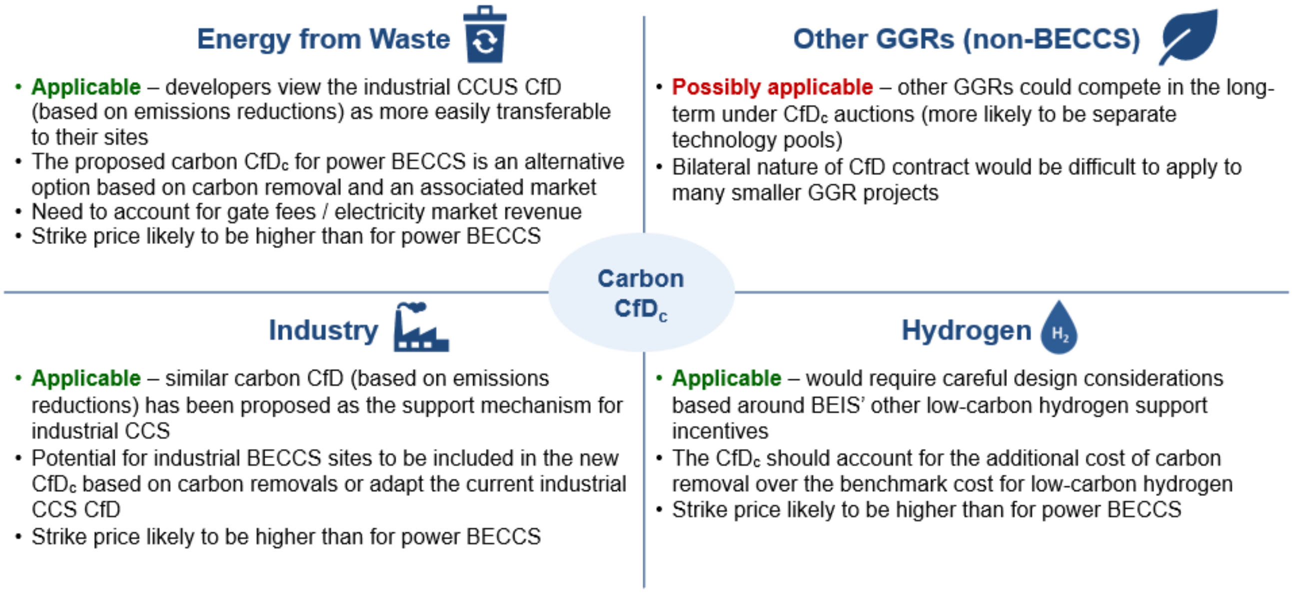


Figure 13: Applicability of the CfD$_c$ framework across other negative emissions sectors

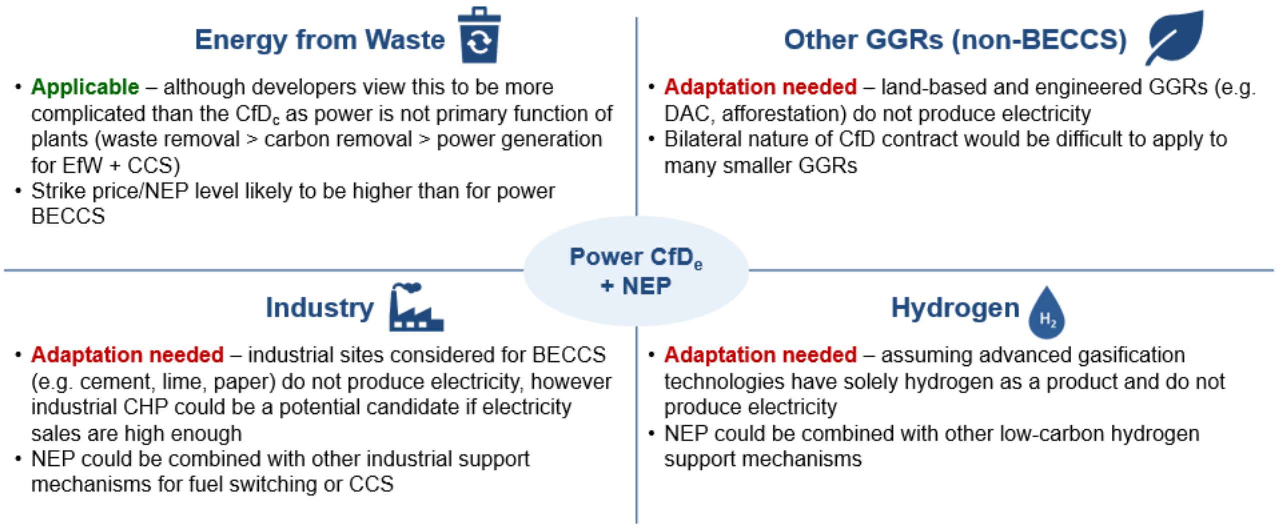


Figure 14: Applicability of the CfD$_e$ plus NEP framework across other negative emissions sectors

An NEP or CfD$_c$ (in £ per tonne of CO_2 captured) has the potential to be combined with or 'top-up' other support mechanisms across sectors. For example, an existing subsidy for the production of low-carbon hydrogen with a CCS-equipped biomass/waste gasification plant could have a subsidy added for the £/tCO_2 of negative emissions. Conversely, if low-carbon hydrogen was supported by a CfD-type mechanism based on CO_2 abated relative to the counterfactual, then a top-up negative emissions payment would not be needed (as long as any negative emissions were accounted for as additional abatement through the mechanism). Similar arguments hold for industrial and EfW BECCS, with the need to ensure negative emissions subsidies are only providing a subsidy above any current or proposed support mechanisms for low-carbon electricity or manufactured goods.

In the long-term, the ability to compete on a £/tCO_2 basis may be possible as costs for NOAK technologies are driven down by innovation and demonstration. For a FOAK BECCS policy mechanism, different technologies are likely to struggle to directly compete in a competitive auction (e.g. for a CfD or negative emissions payment) or would need higher strike prices/payments to be awarded. However, for NOAK technologies, if products are valued separately and correctly (i.e. negative emissions versus co-products), then different sectors may be able to compete for a subsidy (e.g. NEP or CfD) on £ per tonne of carbon removed. For example, the Netherlands' SDE++ mechanism groups technology options into distinct tender rounds based on their expected subsidy level requirements (in € per tonne of CO_2 avoided).[68] This approach could lead to some sectors ultimately being the most cost-effective choice in achieving negative emissions targets. However, there are key co-benefits and trade-offs that could alter this cost optimal choice (e.g. ecological benefits or damages, job growth, etc.). In the future, it is likely that EfW and land-based GGRs will need separate technology pools in any auction-based mechanisms. This is because EfW plants operate to serve a distinct primary function (i.e. waste removal for society) and land-based GGRs have very different characteristics in their costs, trade-offs, and co-benefits. There may also be other supporting policies and regulation needed, including those to avoid unintended consequences (e.g. to avoid more waste being created enabling EfW plants to increase profits). Overall, while competition in the long-term is likely to deliver cost reduction benefits, this requires all co-products to be valued appropriately and the mechanism to consider allocating funding appropriately across sectors or pools.

In the future, while policy mechanisms can play a crucial role in stimulating technology adoption, the wider deployment of BECCS and GGR technologies will also depend on technology availability, costs, and site locations. As mentioned at the start of this section, it is likely that lowest cost options will be deployed first. As technologies and markets evolve, this may lead to other BECCS or GGR options reaching higher TRLs and lower deployment costs. However, whether all options will or should be deployed is highly uncertain. If competitive frameworks for carbon removals develop, this may only result in the most cost-effective technologies deployed. Another key factor will be the location of sites, particularly around BECCS and GGR options which require CO_2 transport and storage. The build-out of infrastructure in and around clusters will directly influence which sites and sectors can permanently sequester CO_2 at scale and cost-effectively. An additional challenge surrounding deployment timing is the competing needs for BECCS sectors. For example, EfW plants are likely to continue to service the needs of waste disposal for the foreseeable future. While the EfW sector may have a higher abatement cost for BECCS, it may be deemed suitable for CCS retrofits instead of building out new plants in other sectors to achieve negative emissions.

4.5 Conclusion

The analysis from this section allows us to draw several conclusions:

[68] For more information on the SDE++ mechanism: https://english.rvo.nl/subsidies-programmes/sde

1. **A new commercial framework for FOAK BECCS is required**. While a CfDe is a useful tool, on its own it cannot provide an IRR that would be attractive for investment at a reasonable strike price (£/MWh).

2. **Achieving an investable IRR for a FOAK BECCS plant, with an acceptable distribution of risk is possible** but will require substantial payments for negative emissions either through NEPs (around £92/tCO2 for a retrofit) or through a CfDc (with a strike price of around £107/tCO2 for a retrofit).

3. **Payments for negative emissions are substantial, but not out of step with carbon prices used for appraisal or expected abatement costs in hard to abate sectors**. While the required payments for negative emissions are high (in £/tCO2) compared to today's carbon prices, they are lower than the abatement cost of hard to abate sectors. Furthermore, over the length of the contract the £/tCO2 payments for BECCS are lower than carbon prices for appraisal.

4. **Key risks associated with BECCS will need to be clearly distributed across the public and private sectors**. Cross chain risk, in particular, is critical to clearly assign, and BECCS developers will need to be insulated from this risk to a substantial degree. Availability payments, adapted from those proposed in the CCUS power business models, provide a potential solution.

The CfD_e + NEP and CfD_c frameworks have different strengths and weaknesses, and which one is preferred will depend on the broader context. Both frameworks could make BECCS investable and the contracted nature of both allows for risks to be clearly allocated across parties. Furthermore, the frameworks could be designed so that costs are spread appropriately across government, developers, electricity consumers and emitters. Table 27 summarizes key strengths and weaknesses of the frameworks. These imply several trade-offs, and potential situations where one framework is preferred over the other.

- *Long term evolution of ETS and negative emissions markets.* Whether negative emissions markets are integrated within the UK ETS or not will have implications on what the preferred BECCS framework is. If integration between markets for offsets/negative emissions and the ETS is a long term aim, a CfD_c may be preferred. If a separate negative emission market is the preferred long term view, a NEP may be preferred as auctioning of NEP contracts could provide a useful stepping stone to growing a negative emissions market.
- *Urgency of FOAK BECCS deployment.* A CfD_c for negative emissions is only viable in the short term if the UK ETS is adjusted to allow for the inclusion of negative emissions. Amongst other things, this will require changes to the ETS cap. Given the complexity, this is likely to take time, and could delay the deployment of BECCS, unless the CfD_c strike price can be paid in full prior to integration. While the administrative body in charge of providing the CfD_c (e.g. Low Carbon Contracts Company) could potentially design the contract as such, full subsidy payments up to the strike price are unlikely to be the favoured approach for government.
- *Distribution of costs*: While a potential scenario exists for the CfD_c framework to be implemented for FOAK power BECCS in the 2020s, this would not align with an

objective of reducing risks to developers and investors given the higher rate of returns likely required. Moreover, if government views power BECCS should be partly funded via electricity consumers, this further supports adopting the CfD_e plus NEP framework. However, if government is willing to take on greater payments for FOAK power BECCS, then the CfD_c framework could be favourable if the objective of linking all GGRs to a wider carbon market is also preferred.

Table 27: Key differentiating strengths and weaknesses between the CfD_e + NEP and CfD_c frameworks

	Strengths	Weaknesses
CfD_e + NEP	• Values low carbon power and negative emissions separately, allowing separate cost distribution of these externalities • Ease of implementation for FOAK: – CfD_e is well established – NEP does not require link to UK ETS	• Cost to government can be high without additional link to offset markets or UK ETS, obligation on emitters, etc. • Two contracts would require an innovative mechanism to auction jointly for NOAK projects • Would require adaptation to apply beyond power BECCS
CfD_c	• Inherently shifts the costs of BECCS to emitters, adhering to the polluter pays principle • Greater potential to be directly used across other BECCS sectors	• Does not value low carbon electricity, hence: – Developer accepts electricity price risk, which may significantly increase the IRR required – Electricity consumer is not subsidising low carbon electricity without design adaptations • Risk of delayed implementation or complications arising from integration with UK ETS
	Common strengths: • Contracted revenue certainty likely to make FOAK projects investible • Track record of CfD • Could be applied to NOAK projects	**Common weaknesses:** • Relies on bilateral negotiations to award initial contracts, creating a risk of private sector rents • Complex contractual structure (bilateral) with significant resource to implement and run • Potential for high financial burden on exchequer as not all costs are passed to market (additional design features / market linkages could reduce burden)

There are several key areas of further research that would help support a decision on FOAK BECCS commercial frameworks:

- Detailed research on how the existing carbon market can be used to fund BECCS. This includes detailed work on how the UK ETS would need to be adjusted, and similarly how

BECCS could be funded through the offset market, including detailed work on the likely future price of offsets in the voluntary offset market.

- Detailed research on whether negative emissions markets (including voluntary offset markets) should be linked to the UK ETS. There are various levels of linking that are possible, and pros and cons to each. A clear policy preference on this would help assess which BECCS policy (FOAK, but especially NOAK) is most suitable.
- Detailed research into the distributional impacts, and regulatory needs of funding the commercial frameworks through different routes. This report provides a strong basis for this research by quantifying potential costs of commercial frameworks. While we provide a high level description of how costs could be distributed, more research is needed into the detail of how e.g. an obligation on fossil fuel suppliers to pay for negative emissions can be implemented in practise.
- Consideration for how FOAK BECCS affects the economics of a wider site which often contains several generation units, which are unlikely to be converted to BECCS simultaneously.

5 Appendix

5.1 Frameworks ruled out from assessment

UK ETS Inclusion of Negative Emissions (stand-alone)

Description: This framework considered inclusion of negative emission allowances (NEAs) in the UK ETS, which would allow permit participants to offset unabated emissions with NEAs, thereby remunerating negative emissions technologies such as BECCS.

Rationale for exclusion:

- From discussions within BEIS, there still exists significant administrative and political effort to include NEAs in the UK ETS, making it unlikely to support BECCS deployment before 2030.
- Moreover, the instability and uncertainty of the ETS pricing would lead to lack of confidence from project developers and investors, making it an unlikely mechanism to provide sufficient revenue certainty for FOAK BECCS deployment.

Direct Procurement of BECCS Electricity Generation

Description: This framework proposed government to directly procure BECCS plants for electricity generation (in £/MWh). Operators selling electricity from BECCS facilities would be guaranteed a price above the average market price, negotiated bilaterally for a FOAK project.

Rationale for exclusion:

- Atypical mechanism for the electricity market and would add significant complexity to merit-order generation dispatch.
- Costs are likely to be high and borne solely by government (i.e. taxpayers).
- This mechanism was deemed to provide no significant benefit in comparison to a CfD_e, which shares a similar payment structure, but reduces costs to government over time and has a strong track record of success in the UK electricity market.

Cap and Floor

Description: A cap and floor mechanism would include:

- A floor setting the minimum amount of revenue a project could earn (topped up if revenue is below)
- A cap setting the maximum amount of revenue for the project (any excess revenue returned)

Rationale for exclusion:

- Very limited track record, primarily used as a regulated approach by Ofgem to support interconnectors in the UK electricity market with a minimum level of availability required.
- Does not provide any incentivisation structure for a BECCS plant to reduce inefficiencies or decrease supply chain emissions intensity.

- In this case, BECCS requires a subsidy, so the floor would be used to provide revenue directly, like a CfD. This is captured in the CfD models explored, with cap and floor having no distinct benefits.

Regulated Asset Base

Description: A regulator would be established that provides a licence to a BECCS plant outlining the agreed levels of revenue it may receive, with tariffs set for consumers. Investors would receive returns before the project operations commence.

Rationale for exclusion:

- Likely high tariffs and unfair cost distribution on electricity consumers due to difficultly in assessing the asset's worth, which is a particularly acute challenge for valuing negative emissions for a FOAK BECCS plant, all before project construction completed.
- Complex administratively and requires higher initial costs to set up the regulatory body.
- Fairly atypical for financing power stations in the UK and more typical for monopoly markets.
- No competitive market would exist, with the framework unlikely to incentivise cost reductions or CO_2 reductions.
- Unlikely to be used for a larger number of NOAK BECCS projects and no 'consumers' for other GGR sectors.

Tradeable Carbon Removal Credits with Obligations on Electricity Suppliers

Description: Obligations are set on electricity suppliers to procure a set percentage of electricity from BECCS power stations, accounted for with credits on CO_2 stored. Levels could be low initially and increased over time, similar to the previous Renewables Obligation scheme in the UK.

Rationale for exclusion:

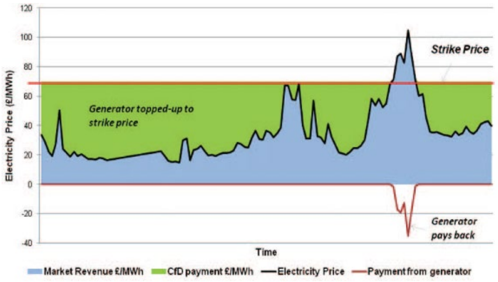
- Compared to the proposed mechanism for obligations on "emitters", this mechanism does not follow the 'polluter pays' principle as it places the costs and risks entirely on electricity suppliers (which are likely to be passed on to electricity consumers).
- Very unlikely for the mechanism to be flexibly adapted to other BECCS sectors in the long-term, as this would place the burden of costs on the power sector for negative emissions in other sectors.

Analysis of the nine frameworks assessed in this study

Stand-alone Power Contract for Difference (CfD_e) [69]

Key Design Features

- Traditional CfDs for electricity generation (CfD_e) in the UK power market, where the generator is paid the difference between a contractually agreed strike price and market price for electricity (or generator refunds revenue if market price exceeds strike price)
- Currently, the CfD_e sets a maximum limit to the supply chain emissions intensity of fuel for a biomass electricity plant, a similar threshold could be transferred to future variations for BECCS



Strengths

- Existing track record for low carbon electricity generation in the UK power market, reduces administrative complexity of mechanism implementation and familiarity helps with investor confidence
- Fixed strike price and long-term contract provides revenue certainty to project developers and financiers
- Straightforward to adjust for NOAK projects with lower strike prices and/or auctions

Weaknesses

- Standalone CfD_e passes costs for negative emissions onto the electricity consumer, which may be politically unfavourable
- No financial incentive for reducing supply chain emissions or increasing capture rate

Risk Considerations

- Government bears risks on electricity market price
- Generator bears risks on generation costs (e.g. biomass fuel price, CO_2 T&S, capex, opex)
- Government risk in overpaying due to uncertainty in determining the appropriate level of the strike price for a FOAK BECCS plant

Stand-alone Carbon Contract for Difference (CfD_c) [69]

Key Design Features

- Carbon CfDs (CfD_c) would provide a subsidy paid above the prevailing carbon price (e.g. UK ETS*) up to a contractually agreed strike price on CO_2 captured (£/tCO_2)
- A similar CfD_c is the UK government's proposed business model for industrial CCUS, with contractually agreed strike prices assumed to cover operational capture costs (including fuel), capex investment and CO_2 T&S costs
- For BECCS, the CfD_c could cover the additional costs of the CCS plant and wider integration costs (e.g. for CO_2 transport)

Strengths

- Contract similarities with CfD_e financing and proposed CfD_c for industry provides familiarity for investors and is likely to reduce administrative complexity of mechanism implementation
- Fixed strike price and long-term contract provides revenue certainty to project developers and financiers
- Linkage with carbon price likely to result in reduced costs borne by government over the project's lifetime
- Subsidy is paid on net CO_2 removed, incentivising reductions in supply chain emissions or increasing capture rates

Weaknesses

- *Uncertainty on whether a prevailing market price for negative emissions (e.g. UK ETS) would be available for FOAK projects, resulting in delayed implementation or a fixed top-up payment

Risk Considerations

- Government bears risks on carbon market price, both its volatility and implementation timeline
- Generator bears risks on power generation costs (e.g. biomass fuel price,

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[69] Figure sources for CfD_e (LINK) and for CfD_c (LINK).

CO_2 T&S, capex, opex)

Stand-alone Negative Emissions Payments

Key Design Features

- Negative emissions payments (in £/tCO_2) could be administered under two variations:
  - Direct subsidies for each negative unit of CO_2 stored
  - Procurement via reverse auctions
- This stand-alone framework for negative emissions payments assumes contracts for FOAK BECCS plants are bilaterally negotiated for at least medium-to-long term timeframes (e.g. up to 15 years)
- In the long-term, procurement could be managed through reverse auctions with bids submitted for new projects
- Negative emissions payments are subject to revision over time and assumed to decrease for renewed contracts / NOAK projects as other markets develop (e.g. UK ETS credits)
- Negative emissions payments would apply to BECCS plants only for FOAK investment support, with potential to expand to other greenhouse gas removal options over time

Strengths

- Procurement mechanisms allows for a tighter control on the exact volumes of CO_2 removed from the atmosphere
- Long-term procurement contracts provide revenue certainty to project developers and financiers

Weaknesses

- Initially, subsidy costs to incentivise FOAK BECCS projects will likely be high and borne entirely by government
- Variations on subsidies which are not a flat rate over time would provide uncertainty to project developers and financiers

Risk Considerations

- Generator bears risks associated with electricity market revenue, tied to the uncertainty of operating the plant as baseload which is desired to maximise revenue from negative emissions payments
- Generator bears risks on generation costs (e.g. biomass fuel price, CO_2 T&S, capex, opex)

Power CfD_e plus Negative Emissions Payments

Key Design Features

- A CfD_e could be combined with negative emissions payments to form a single commercial framework
- The combined contract would likely be awarded through bilateral negotiations for FOAK BECCS, potentially awarded through reverse auctions in the longer term to drive further competition
- The financial incentive from the CfD_e (£/MWh) would be capped and aligned with an approved level of costs subsidised by electricity consumers, with the negative emissions payment (£/tCO_2) covering remaining costs
- Potential for the LCCC to negotiate both contracts simultaneously

Strengths

- Combining the two options spreads the costs across the two services which the plant provides:
  - Electricity consumers fund the low carbon power generation costs
  - Government (initially) funds the negative emissions
- Procurement-based negative emissions payment still allows for a tighter control on the exact volumes of CO_2 removed from the atmosphere
- Long-term payment contracts provide revenue certainty to project developers and financiers

Risk Considerations

- For the BECCS plant operator to maximise profits and mitigate against revenue uncertainty, both the CfD_e and negative emissions payment are contingent on a BECCS plant's baseload operation throughout the length of the contracts
- Generator bears risks on generation costs (e.g. biomass fuel price, CO_2 T&S, capex, opex)

Weaknesses

- More complex to design compared to standalone CfDs
- Greater administrative requirements compared to standalone CfD_e or negative emissions payments mechanisms (although likely mitigated if administered through single entity)
- Uncertain ability to incorporate future market value of negative emissions e.g. in the UK ETS; therefore unlikely to minimise cost to government

Tradeable Tax Credits [70]

Key Design Features

- Tax credits would allow BECCS operators to receive credits on their tax statements for negative emissions (in £ per tonne of CO_2 stored)
- Value of tax credits could be set for 5-10 year periods, subject to government revision and reevaluation in successive periods
- Credits could be traded to allow for firms with smaller tax liabilities to take advantage of the mechanism, i.e. tax credit purchased by any other large tax paying entity
- Incentives could also be provided for the initial capital investment in the CCS plant

Overview of USA's 45Q Tax Credit for CCUS

TYPE OF CO_2 STORAGE/USE	MINIMUM SIZE OF ELIGIBLE CARBON CAPTURE PLANT BY SIZE ($KtCO_2$/YR)			RELEVANT LEVEL OF TAX CREDIT GIVEN IN OPERATIONAL YEAR (USD/tCO_2)						
	POWER PLANT	OTHER INDUSTRIAL FACILITY	DIRECT AIR CAPTURE	2018	2019	2020	2021	2022	2023	2024
DEDICATED GEOLOGICAL STORAGE	500	100	100	28	31	34	36	39	42	45
STORAGE VIA EOR	500	100	100	17	19	22	24	26	28	31
OTHER UTILISATION PROCESSES*	25	25	25	17	19	22	24	26	28	31

Strengths

- Tax credits covering both operational and capital costs may provide a strong incentive for project developers
- Successful track record in developed markets (e.g. 45Q tax credit)
- Minimal administrative burden compared to other mechanisms, as tax credits do not require a direct funding stream from government

Weaknesses

- As a long-term consideration for NOAK projects, there is no inherent way to adjust tax credits to pass costs on to consumers
- Lack of incentivisation for competition between new projects, so risk of overcompensating some projects

Risk Considerations

- Uncertainty with long-term support of tax credits which could change with different ruling parties in power and preclude investors from financing FOAK BECCS plants
- Generator bears risks on generation costs (e.g. fuel price, CO_2 T&S, opex) and electricity market revenues

Tradeable Carbon Removal Credits with Obligations

Key Design Features

- Obligations to purchase carbon removal credits within a compliance market which would require certain "emitters" to offset their emissions:
  - upstream fossil fuel producers to dispose of a fixed percentage of the CO_2 contained within their fuel sales
  - large emitters from other sectors (e.g. aviation, maritime)
- Market-based emissions price (£/tCO_2 abated) would be driven by supply and demand
- The quantity of credits could target specific allocations of negative emissions which could be aligned with carbon budgets
- Initial entrants selling credits are likely to be engineered removals (e.g. BECCS, DAC) or land-based options (e.g. afforestation, habitat restoration) which have reliable accounting methods for the amount of CO_2 removed
- Over time, the market liquidity could increase with the inclusion of other GGR options

Strengths

- Supports fairer cost distribution since costs are borne by emitters (following the 'polluter pays' principle) and the mechanism would be revenue-neutral for government
- Incentivises competition between GGR options
- Similar successful track record in the UK electricity market for deploying low-carbon generation (i.e. Renewables Obligation)

Weaknesses

- Early market would not have sufficient liquidity, thus unlikely to provide sufficient revenue and long-term revenue certainty as a standalone mechanism for a FOAK BECCS plant
- High administrative barrier to setup a new market, may lead to delays of deployment for a FOAK BECCS plant

Risk Considerations

- Private sector bears all risks, largely due to the uncertainty over the stability of the price of obligations credits over time and market liquidity in earlier years

[70] Figure source [LINK].

Cost Plus Subsidy

Key Design Features

- Cost plus subsidy would involve an open-book contract which includes direct payments from the government covering all incurred operational costs of the BECCS plant (fuel costs, CO_2 T&S, etc.), plus an agreed margin
- BECCS developers would need to submit project proposals outlining their volumes of CO_2 captured and delivery timeframes
- Margins on the subsidy would need to be contractually negotiated for bespoke FOAK projects

Risk Considerations

- Government bears the majority of the operational risks of costs attributed to the CCS plant and any overall increases in project costs (e.g. due to plant-wide integration)
- Risk management could include build-in of pain-gain sharing mechanisms to incentivise improvements - enabling the contractor to share in the benefits of cost savings, but also to bear some of the cost when there are cost overruns

Strengths

- Guaranteed payments and long-term contracts provide revenue certainty to project developers and financiers, reducing financing costs.
- Protects FOAK BECCS plant from market uncertainties
- Targeted control of project development could allow for government to select projects with maximum co-benefits

Weaknesses

- Politically unfavourable cost distribution as all costs and risks are borne by government, with significant annual subsidies required
- Does not incentivise a BECCS plant to operate as baseload and optimise negative emissions potential
- Has not been widely used in energy investments
- Difficult transition to a market-based mechanism for NOAK projects
- Administratively complex, making the mechanism unfavourable for NOAK projects or application to wider sectors

Full Government Ownership

Key Design Features

- Government, potentially through a state-owned enterprise, takes complete ownership and control of a BECCS project, from plant construction through to long-term operation of the facility
- The government would effectively subsidise the deployment of a FOAK BECCS project with taxpayer funds directed towards the state-owned enterprise to cover the full range of costs for both low carbon biomass generation and negative emissions
- Government would still be paid for the power generation at wholesale market price, reducing the taxpayer burden

Risk Considerations

- Government bears all project risks, including the operational risks of costs attributed to the entire CCS plant and any overall increases in project construction costs (e.g. due to plant-wide integration)
- Government bears risks on generation costs (e.g. biomass fuel price, CO_2 T&S, capex, opex) and electricity market revenues.

Strengths

- Targeted control of project development could allow government to maximise negative emissions potential from BECCS and select projects with maximum co-benefits
- Successful track record in several developed markets, e.g. Norway's state-owned enterprise (Gassnova) coordinating the Longship CCS project
- Relatively quick to implement as the project would not be subject to investment consortia delays and does not require development of new markets or market mechanisms
- Lower financing costs may reduce overall project cost

Weaknesses

- Not easily scalable to NOAK projects or other sectors without requiring significant government resourcing and spending
- Has not been supported by any studies or reports on financing mechanisms for CCUS/BECCS plants
- Politically unfavourable cost distribution as all costs and risks are borne by government; no successful track record in the UK
- Administratively complex to operate a state-owned enterprise
- Administratively complex, making the mechanism unfavourable for NOAK projects or application to wider sectors

DPA plus Negative Emissions Payment

Key Design Features

- As proposed for the UK's gas CCUS commercial framework, this mechanism would include:
  - Availability payments (£/MW) decoupled from plant dispatching to reflect the availability of generation and capture
  - Variable payments (£/MWh) with sufficient incentive to ensure the BECCS plant dispatches ahead of a biomass electricity plant by considering the increased costs due to capture (opex, fuel, T&S)
  - Additional negative emissions payment (£/tCO_2) for BECCS plants
- A BECCS plant would still be able to secure other revenue sources in the electricity market (i.e. balancing market or ancillary services)

Risk Considerations

- For a FOAK BECCS plant, uncertainty with operating as dispatchable/mid-merit could be riskier for investors to have revenue confidence
- Generator bears risks on generation costs (e.g. biomass fuel price, CO_2 T&S, capex, opex)

Strengths

- Transferrable to NOAK BECCS plants, applying lessons learned from gas CCUS and FOAK BECCS to reduce subsidies required from government
- Combining the two options spreads the costs across the two services which the plant provides:
  - Electricity consumers fund the low carbon power generation costs (the availability payment could potentially be adapted to be government-funded)
  - Government (initially) funds the negative emissions

Weaknesses

- Availability/variable payments incentivise dispatchable operation, competing with negative emissions payments which incentivise baseload operation – this is unlikely to maximise a BECCS plant's negative emissions potential, which is likely the more important service to society (versus power)
- Limited track record as this has only been recently proposed for dispatchable gas CCUS plants in the UK
- Unable to be transferred to other BECCS/GGR sectors
- Uncertain ability to incorporate future market value of negative emissions e.g. in the UK ETS; therefore unlikely to minimise cost to government

5.3 Rationales for criteria scoring

Table 28: Rating notes for the Stand-alone Power Contract for Difference (CfD_e) framework

Criteria	Rating	Rating Notes
Incentive strength	Amber	At a high enough strike price, the CfD_e would be able to incentivise deployment. However, a medium rating reflects the uncertainty with implementing a stand-alone CfD_e that provides a sufficiently high incentive, which would need to be considerably higher in value than other CfDs.
Risk mitigation	Amber	Generator manages the risks associated with biomass price, CO_2 T&S fee, capex and opex costs, and CO_2 emissions price (if one were to exist on biomass/carbon removals in the future). The CfD_e's strike price under a long term contract could provide sufficient revenue confidence for financiers and developers.
Track record	Green	Successful track record in the UK electricity market for incentivising low carbon power generation.
CO_2 reduction promotion	Red	No financial incentive for reducing supply chain emissions or increasing capture rate. However, standards could be enforced in contracting, such as the current threshold for supply chain emissions intensity within CfDs.
Cost reduction promotion	Amber	BECCS operator does have an incentive to reduce operational costs over time (e.g. through innovation) to increase profits. There could be a competitive auction process to select lowest-cost projects, however, medium rating reflects how this is unlikely for FOAK projects.
Fair cost distribution	Amber	While electricity consumers would be fairly paying for the low carbon generation from BECCS, they would also be subsidising the negative emissions which benefit society more broadly and fossil fuel consumers in particular.
Implementation in 2020s	Green	Able to setup new contracts for BECCS and build upon existing CfD_e frameworks/structure.
Applicability across sectors	Red	Difficult to be replicated to other BECCS sectors, except for waste to energy plants which also participate in the electricity market.
Suitability to NOAK	Green	Could be readily adapted by adjusting the level of the strike price or transferred to a competitive allocation process for NOAK projects.

Table 29: Rating notes for the Stand-alone Carbon Contract for Difference (CfD_c) framework

Criteria	Rating	Rating Notes
Incentive strength	A / G	At a high enough strike price, the CfD_c would be able to incentivise deployment, however, there is uncertainty with implementing a stand-alone CfD_c that provides a sufficiently high incentive above a prevailing carbon price. A medium-high rating reflects that a high enough strike price is more likely to be possible than a CfD_e.
Risk mitigation	Amber	Generator manages the risks associated with biomass price, CO_2 T&S fee, capex and opex costs, and electricity price. The CfD_c's strike price under a long term contract shields from risks associated with uncertainty in market CO_2 prices in future CO_2 credit markets, and gives overall revenue confidence.
Track record	Red	Track record is limited to the proposed CfD_c for industrial CCUS in the UK. In addition, given the immaturity of the UK ETS and its likely candidacy as the prevailing carbon price, there would need to be adjustments to allowances to compensate for the negative emissions introduced in the market.
CO_2 reduction promotion	Green	With subsidy paid on amount of CO_2 captured (i.e. negative emissions), this incentivises a BECCS plant to increase its capture rate.
Cost reduction promotion	Amber	Private sector is incentivised to reduce operational costs over time to increase profits. There could be a competitive auction process to select lowest-cost projects, however, medium rating reflects how this is unlikely for FOAK projects.
Fair cost distribution	Amber	Linkage with carbon price likely to result in reduced costs borne by government over the project's lifetime. Taxpayer funds paying for the subsidy with society bearing the costs and benefitting from negative emissions. However, medium rating reflects how the framework does not follow the 'polluter pays' principle.
Implementation in 2020s	Amber	Uncertainty on whether a prevailing market price for negative emissions (e.g. UK ETS) would be available for FOAK projects, resulting in delayed implementation or a fixed top-up payment.
Applicability	Green	Applicable across all BECCS sectors in theory.

Criteria	Rating	Rating Notes
across sectors		
Suitability to NOAK	Green	Could be readily adapted by adjusting the level of the strike price or transferred to a competitive allocation process for NOAK projects.

Table 30: Rating notes for the Stand-alone Negative Emissions Payments framework

Criteria	Rating		Rating Notes
Incentive strength	A	G	At a sufficiently high value, the negative emissions payment would be able to incentivise deployment, however, there is uncertainty with implementing a stand-alone payment that provides a sufficiently high incentive. A medium-high rating reflects that a high enough payment is more likely to be possible than a CfD_e.
Risk mitigation	Amber		Payments may not be able to provide confidence for investors seeking to mitigate financial risks faced by the developer over the project lifetime (i.e. biomass price, electricity price, CO_2 price, CO_2 T&S fee, capex and opex costs). There is also uncertainty of delivering flat-rate payments over long-term contracts (15+ years).
Track record	R	A	First of its kind government procurement/subsidy directly on quantities of negative emissions.
CO_2 reduction promotion	Green		With subsidy paid on amount of CO_2 captured (i.e. negative emissions), this incentivises a BECCS plant to increase its capture rate.
Cost reduction promotion	Amber		Initial high costs for government to subsidise FOAK BECCS plants, primarily because the mechanism does not address key risks. Private sector is incentivised to reduce operational costs over time to increase revenue.
Fair cost distribution	Amber		The £/tCO_2 has to be higher than 'estimated' to give enough incentive and compensate for risks, reflecting lower value for money for taxpayers. Costs entirely borne by government for services of both low carbon electricity generation (benefits electricity consumers) and negative emissions (benefits society/emitters).
Implementation in 2020s	Green		Straightforward payment and accounting structure to implement.
Applicability	Green		Able to be transferred to negative emissions payments for

Criteria	Rating	Rating Notes
across sectors		other BECCS sectors.
Suitability to NOAK	Amber	Payment value can be reduced for NOAK projects or payments transferred to a competitive procurement process with reverse auctions or a separate negative emissions credit market. However, costs are never passed to market and it is likely some projects will be overcompensated.

Table 31: Rating notes for the CfD_e plus Negative Emissions Payments framework

Criteria	Rating	Rating Notes
Incentive strength	Green	A combined payment structure is likely to provide sufficient financial incentive to ensure developers/financiers meet their required annual revenues, in comparison to a stand-alone CfD_e or negative emissions payment which may not provide high enough incentives.
Risk mitigation	Green	Generator manages the risks associated with biomass price, CO_2 T&S fee, capex and opex costs, and CO_2 emissions price (if one were to exist on biomass/carbon removal in the future). Long term contract with CfD_e and added negative emissions payments should provide sufficient revenue confidence for investors.
Track record	Amber	Combined mechanism has no track record. However, medium rating reflects the CfD_e's successful track record in UK electricity market.
CO_2 reduction promotion	Amber	With negative emissions payments paid on the amount of CO_2 captured, this incentivises a BECCS plant to increase its capture rate. However, medium rating reflects CfD_e's limited incentive to reduce CO_2 emissions and on the relative value of the CfD_e versus negative emissions payment.
Cost reduction promotion	Amber	With both financial incentives, a BECCS operator still has an incentive to reduce operational costs over time (e.g. through innovation) to increase profits. There could be a competitive auction process to select lowest-cost projects, however, medium rating reflects how this is unlikely for FOAK projects.
Fair cost distribution	Amber	Costs are spread across the two services which the BECCS plant provides: (1) Electricity consumers fund the low carbon power generation costs, and (2) Government

Criteria	Rating	Rating Notes
		(i.e. taxpayers) funds the negative emissions benefitting society. Medium rating reflects uncertainty as to whether the subsidy will reduce over time to provide value for money for electricity consumers (depending on the evolution of wholesale electricity market price[71]). In addition, the framework does not follow the 'polluter pays' principle.
Implementation in 2020s	Green	CfD$_e$ would require lower effort (compared to other frameworks) to setup new contracts for BECCS and build upon existing CfD$_e$ frameworks and structure. Negative emissions payments have a straightforward payment and accounting structure.
Applicability across sectors	Amber	Unable to be replicated to other BECCS sectors, except for waste to energy plants which also participate in the electricity market. However, the negative emissions payment can be replicated, along with setting the CfD$_e$ to zero for sectors which do not involve electricity generation.
Suitability to NOAK	Green	Value of the CfD$_e$ could be readily adapted by adjusting the level of the strike price or transferred to a competitive allocation process for NOAK projects. Negative emissions payment value can be reduced for NOAK projects or transferred to a competitive procurement process with reverse auctions.

Table 32: Rating notes for the Tradeable Tax Credits framework

Criteria	Rating	Rating Notes
Incentive strength	Amber	Tax credits covering both operational and capital costs could provide a strong incentive for project developers. Medium rating reflects the uncertainty as to whether the value of the credits would be of sufficiently high value alone, since traded credits would need a liquid enough market to work well.
Risk mitigation	Red	Uncertainty exists with long-term support of tax credits which could change with different ruling parties in power and undermine confidence for investors financing FOAK BECCS plants. Generator manages the risks associated

[71] There is significant uncertainty on the evolution of prices in the wholesale electricity market as increasing volatility and negative pricing becomes more common due to an increasing penetration of variable renewable energy systems.

Criteria	Rating	Rating Notes
		with biomass price, CO_2 T&S fee, capex and opex costs, electricity price and CO_2 emissions price (if one were to exist on biomass/carbon removal in the future).
Track record	Amber	Successful track record in developed markets (e.g. 45Q tax credit in the USA). However, no implementation track record in the UK.
CO_2 reduction promotion	Green	With credit applied to the amount of CO_2 captured, this incentivises a BECCS plant to increase its capture rate.
Cost reduction promotion	Amber	BECCS operator does have an incentive to reduce operational costs over time (e.g. through innovation) to increase profits. Lack of incentivisation for competition between new projects, so risk of overcompensating some projects.
Fair cost distribution	Amber	Partially fair cost distribution as costs are entirely borne by government (i.e. benefit of negative emissions to society). However, mechanism does not follow the polluter pays principle.
Implementation in 2020s	Amber	Tax credits do not require a direct and new funding stream from government. However, political opposition for tax credits may lead to implementation delays.
Applicability across sectors	Green	Credits could apply to all BECCS sectors.
Suitability to NOAK	Amber	As a long-term consideration for NOAK projects, there is no inherent way to adjust tax credits to pass costs on to consumers. However, the value of the tax credit could be reduced over time.

Table 33: Rating notes for the Tradeable Carbon Removal Credits with Obligations framework

Criteria	Rating	Rating Notes
Incentive strength	Amber	Early market unlikely to have sufficient liquidity, thus may be unable to provide sufficient revenue and long-term revenue certainty as a standalone mechanism for a FOAK BECCS plant. However, the incentive strength is dependent on the market value of credits, which is influenced by government through their choice of parties to obligate and at what level.

Criteria	Rating	Rating Notes
Risk mitigation	Red	Private sector bears all risks in project costs (i.e. biomass fuel price, CO_2 T&S fee, capex and opex, electricity price). In addition, generators bear significant revenue risks due to the uncertainty over the stability of the price of obligations credits over time and market liquidity in earlier years.
Track record	Red	Obligations have limited successful track record in the UK electricity market for deploying low-carbon generation (i.e. Renewables Obligation). Carbon removal credits have no track record in the UK.
CO_2 reduction promotion	Green	With credit applied to the amount of CO_2 captured, this incentivises a BECCS plant to increase its capture rate.
Cost reduction promotion	Amber	Market-based mechanism would support operators to offer lower cost credits by reducing operational costs over time. However, a medium rating reflects the uncertainty to which this would be possible for FOAK projects in a market with low liquidity.
Fair cost distribution	Green	Supports a fair cost distribution since costs are borne by 'emitters'[72] (following the 'polluter pays' principle) and the mechanism would be revenue-neutral for government.
Implementation in 2020s	Red	High administrative barrier to setup a new market, may lead to delays of deployment for a FOAK BECCS plant.
Applicability across sectors	Green	All BECCS sectors could participate in the market.
Suitability to NOAK	Green	The market would be favourable for NOAK projects, incentivising competition between greenhouse gas removal options (including BECCS). This is likely to result in lowest-cost options being deployed over time as market liquidity increases.

Table 34: Rating notes for the Cost Plus Subsidy framework

Criteria	Rating	Rating Notes
Incentive strength	Green	Guaranteed payments and long-term contracts provide revenue certainty to project developers and financiers,

[72] Emitters could include upstream fossil fuel producers (i.e. required to dispose of a fixed percentage of the CO_2 contained within their fuel sales) or large emitters from other sectors (e.g. aviation, maritime)

Criteria	Rating		Rating Notes
			reducing financing costs
Risk mitigation	Green		High revenue confidence for investors since government bears most of the operational risks of costs attributed to the CCS plant and any overall increases in project costs (e.g. due to plant-wide integration). Developers are protected from cost/market uncertainties over the project lifetime (i.e. biomass fuel price, CO_2 T&S fee).
Track record	Amber		Framework has not been widely used to support investments in the energy industry, however, has been used for infrastructure and defense projects in the UK.
CO_2 reduction promotion	Red		Subsidy does not inherently incentivise the plant to implement any CO_2 reduction opportunities, but could incorporate an additional built-in mechanism (e.g. margins contingent on supply chain emissions reductions over time).
Cost reduction promotion	R	A	Subsidy does not incentivise the plant to reduce operational costs. However, guaranteed government payments reduce capital financing costs and the framework could include pain-gain sharing mechanisms.
Fair cost distribution	Amber		Value for money is low given the greater payments required from government/taxpayers. Politically unfavourable cost distribution as all costs and risks are borne by government, with significant annual subsidies required. However, society does benefit from the negative emissions.
Implementation in 2020s	Green		Straightforward open-book contract which could be implemented within a relatively short timeframe.
Applicability across sectors	Amber		While the mechanism could be transferred to any of the other BECCS sectors, the medium rating reflects the high administrative complexity of the subsidy to be managed across multiple industries.
Suitability to NOAK	Red		Difficult to transition to a market-based mechanism for NOAK projects. Unlikely to be replicable given the unsustainable financing required from government in the long-term.

Table 35: Rating notes for the Full Government Ownership framework

Criteria	Rating	Rating Notes
Incentive	Green	Ownership by state-owned enterprise would allow for all

Criteria	Rating	Rating Notes
strength		additional costs to be covered by national financial resources.
Risk mitigation	Green	Government bears all of the risks of the project (i.e. biomass price, CO_2 T&S fee, capex, and opex, electricity price), including the operational risks of costs attributed to the entire CCS plant and any overall increases in project construction costs (e.g. due to plant-wide integration).
Track record	Red	Track record limited to a few developed markets (e.g. Canada's purchase of the Trans Mountain pipeline, Norway's state-owned enterprise (Gassnova) coordinating the Longship CCS project). Limited track record in the UK with public-private partnerships (e.g. Thames Tideway Tunnel).
CO_2 reduction promotion	Amber	Targeted control of project development could allow government to maximise net negative emissions potential by reducing supply chain emissions and increasing plant capture rate.
Cost reduction promotion	Red	Unlikely to achieve cost reductions that would be possible in the private sector. However, lower financing costs may reduce overall project cost.
Fair cost distribution	Amber	Low value for money as entire plant would be subsidised by government/taxpayer funding. Politically unfavourable cost distribution as government bears all costs and risks. Does not follow the 'polluter pays' principle. However, society does benefit from the negative emissions.
Implementation in 2020s	Amber	The project would not be subject to investment consortia delays and does not require development of new markets or market mechanisms. However, medium rating reflects the uncertainty on how quickly a state-owned enterprise could mobilise the expertise to deliver a full-scale FOAK BECCS plant.
Applicability across sectors	Amber	Not easily scalable to multiple sectors without requiring significant government resourcing and spending.
Suitability to NOAK	Red	Administratively complex to operate a state-owned enterprise, unlikely to be used for NOAK projects. Also unlikely to be politically favourable as a long-term option for BECCS deployment.

Table 36: Rating notes for the DPA plus Negative Emissions Payment framework

Criteria	Rating		Rating Notes
Incentive strength	Y	G	At a sufficiently high value, the negative emissions payment would be able to incentivise deployment. However, the uncertainty of the values in the availability/variable payments may lead to insufficient financial incentive to ensure developers/financiers meet their required annual revenues.
Risk mitigation	Amber		Generator manages the risks associated with biomass price, CO_2 T&S fee, capex and opex costs, and CO_2 emissions price (if one were to exist on biomass in the future). Long term contract under DPA and added negative emissions payments could provide sufficient revenue confidence for investors, however, medium rating reflects the uncertainty of the operating load factor for a FOAK plant.
Track record	Amber		Combined mechanism has no track record. Medium rating reflects the DPA's proposed detailed design for gas CCS plants in the UK.
CO_2 reduction promotion	Amber		With negative emissions payments paid on the amount of CO_2 captured, this incentivises a BECCS plant to operate baseload and increase its capture rate. However, medium rating reflects DPA's competing incentive to run a dispatchable plant, which may not result in a BECCS operator maximising their negative emissions potential.
Cost reduction promotion	Amber		With both financial incentives, a BECCS operator still has an incentive to reduce operational costs over time (e.g. through innovation) to increase profits. It is assumed that the DPA will be awarded through bilateral negotiation for FOAK BECCS plants. There could be a competitive auction process to select lowest-cost projects, however, medium rating reflects how this is unlikely for FOAK projects.
Fair cost distribution	Amber		Costs are spread across the two services which the BECCS plant provides: (1) Electricity consumers fund the low carbon power generation costs, and (2) Government (i.e. taxpayers) funds the negative emissions benefitting society. In addition, the framework does not follow the 'polluter pays' principle.
Implementation in 2020s	Green		DPA would require relatively low effort to setup new contracts for BECCS and build upon existing DPA

Criteria	Rating	Rating Notes
		structure. Negative emissions payments have a straightforward payment and accounting structure.
Applicability across sectors	Red	Unable to be replicated to other BECCS sectors, except for waste to energy plants which also participate in the electricity market.
Suitability to NOAK	Green	Values of the DPA's availability and variable payments could be readily adapted or transferred to a competitive allocation process for NOAK projects. Negative emissions payment value can be reduced for NOAK projects or transferred to a competitive procurement process with reverse auctions.

5.4 Key assumptions and inputs for cashflow modelling

Table 37: Key inputs and assumptions for cashflow modelling[73,74,75,76,77,78]

Input or assumption	Value	Unit	Sources and rationale
Key policy inputs and assumptions			
CfD contract length	15	Years	Uses assumed length of BEIS 2020 CCUS business models report and previous CfDs awarded to offshore wind.
Debt repayment period	15	Years	Assumption.
Negative emissions and carbon accounting method	Gross	tCO_2/MWh_{net}	Assumes that supply chain emissions are not netted from any negative emissions or carbon payments. Changes in the accounting method are modelled as an additional design feature.

[73] Carbon Capture, Usage and Storage. An Update on business models for Carbon Capture, Usage and Storage. (BEIS, 2020).
[74] 'Budget 2021 sets path for recovery'. (HM Treasury, 2021). Accessed on 19/04/2021 via: https://www.gov.uk/government/news/budget-2021-sets-path-for-recovery
[75] Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology (Wood, 2018)
[76] Analysing the potential of bioenergy with carbon capture in the UK to 2050 (Ricardo, 2020)
[77] Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass (IEAGHG, 2019)
[78] Electricity Generation Costs 2020. (BEIS, 2020)

Input or assumption	Value	Unit	Sources and rationale
Key financial inputs and assumptions			
Debt-to-equity split	40-60	%	Vivid assumption.
Corporate tax rate	25	%	UK budget announcement 2021.
Discount rate and required rate of return on equity	9.1	%	Equal to FOAK BECCS hurdle rate from BEIS' Electricity Generation Costs 2020.
Required rate of return on debt	8	%	Assumption.
Currency base year	2019	£	Input.
Key plant inputs and assumptions			
Plant type	Retrofit (incl. compressi on bar)	n.a	Assumption.
Utilisation rate (t_1,$t_{2 \rightarrow 25}$)	60,90	%	Based on stakeholder consultation and assumptions found in Wood's 2018 report on CCS technologies.
Total gross installed capacity	498	MWe	Wood, 2018; and Ricardo, 2020.
Net export power	396	MWe	Wood, 2018; and Ricardo, 2020.
Net export power with CCS turned off	434	MWe	Wood, 2018.
Capture rate	95	%	IEAGHG, 2019.
Net efficiency	0.29 – 0.31	MWh_{net}/ MWh_{fuel}	Indicative range based on previous reporting and stakeholder input.
Emissions intensity of combustion	0.9 – 1.3	tCO_2/M Wh_{net}	Indicative range based on previous reporting and stakeholder input.
Key cost assumptions			
Capital expenditures	540 –	£m	Indicative range based on previous reporting in Wood, 2018 and Ricardo,

Input or assumption	Value	Unit	Sources and rationale
(retrofit)	1,250		2020, and stakeholder input.
Capital expenditures (new build)	1,200 – 2,700	£m	Indicative range based on previous reporting in Wood, 2018 and Ricardo, 2020, and stakeholder input.
Operating costs (including fuel)	240 - 510	£m/year	Based on fuel costs from Ricardo, 2020 and stakeholder input.
T&S fees	18	£/tCO_2	Based on input from BEIS.
Key price projections			
Electricity prices			Annex M. Growth assumptions and prices in Updated energy and emissions projections: 2019 (BEIS, 2020).
Carbon prices			Central price scenario: Annex M. Growth assumptions and prices in Updated energy and emissions projections: 2019 (BEIS, 2020). Alternative pricing scenarios: Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal. Data tables 1 to 19: supporting the toolkit and the guidance. (BEIS, 2018).
Dispatchable power utilisation rate			BEIS internal modelling

5.5 Additional sensitivities

Dynamic fuel costs

Table 38: Dynamic fuel costs using EU biomass prices from the NGFS climate scenarios database[79]

Cost scenario	NEP required for 9.1% IRR (£/tCO_{2gross})	Carbon strike price required for 9.1% IRR (£/tCO_{2gross})
GCAM 5.2 Immediate 2C	137	122
REMIND-MAgPIE Immediate 2C	155	140

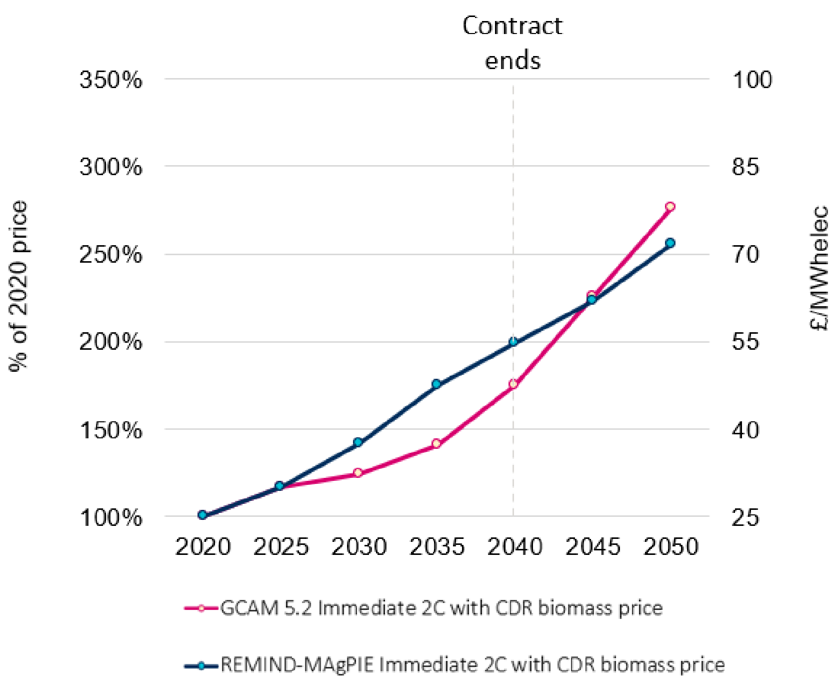

Figure 15: Biomass price index from NGFS applied to central fuel cost (£25/MWh_{fuel})

Capex

Table 39: IRR and required payments for the CfD_e + NEP framework under different capex scenarios[80]

Capex scenario	IRR at £92 NEP (%)	
Retrofit	20	72

[79] Evaluated over contract length (T = 15 years) using a discount rate of 9.1%. Biomass indices from IIASA NGFS Climate Scenarios Database (n.d.). Accessed on 19/04/2021 via: https://data.ene.iiasa.ac.at/ixmp-explorer-sandbox/#/downloads

[80] Evaluated over contract length (T = 15 years) using a discount rate of 9.1%.

Capex scenario	IRR at £92 NEP (%)	
(-40% capex)		
Retrofit	9.1	89
Retrofit (+40% capex)	2.2	105
New build (-40% capex)	4.4	101
New build	-7.2	139
New build (+40% capex)	-15	177

Table 40: IRR and required payments for the CfD$_c$ framework under different capex scenarios[81]

Capex scenario	IRR at £92 NEP (%)	Carbon strike price required for 9.1% IRR (£/tCO_{2gross})
Retrofit (-40% capex)	20	90
Retrofit	9.1	107
Retrofit (+40% capex)	2.2	123
New build (-40% capex)	4.4	121
New build	-7.2	159
New build (+40% capex)	-15	197

[81] Evaluated over contract length (T = 15 years) using a discount rate of 9.1%.

Negative emissions potential from generation

Table 41: IRR and required payments for the CfD_e + NEP framework at different levels of negative emissions potential per MWh of net export[82]

Negative emissions from generation (tCO_2/MWh_{net})	IRR at £92 NEP (%)	NEP required for 9.1% IRR ($£/tCO_{2gross}$)
0.9	0.1	111
1	4.5	102
1.14	9.1	92
1.2	10.9	88
1.3	13.6	83

Table 42: IRR and required payments for the CfD_c framework at different levels of negative emissions potential per MWh of net export[83]

Negative emissions from generation (tCO_2/MWh_{net})	IRR at £92 NEP (%)	NEP required for 9.1% IRR ($£/tCO_{2gross}$)
0.9	-1.7	131
1	3.4	119
1.14	9.1	107
1.2	11.8	102
1.3	14.4	96

[82] Evaluated over contract length (T = 15 years) using a discount rate of 9.1%.
[83] Evaluated over contract length (T = 15 years) using a discount rate of 9.1%.

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