Curb your Enthusiasm

Bridging the gap between the UK's CCUS targets and reality

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Carbon Tracker Initiative

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About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's capital markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low-carbon economy.

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Note: The research, data and sources in this report are updated as far as possible to February 2024.

Cover Image: Generated with ChatGPT and DALL-E with the prompt: vivid image with a smoky power plant in the background and a van in the front with a giant vacuum cleaner.

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Key Findings

In this report, we analyse what potential role **Carbon Capture, Utilisation and Storage (CCUS)** could have in supporting the UK's transition towards the legally binding objective of **net zero emissions by 2050**. After reviewing the technology, we found a consistent trend of over-promising and under-delivering worsened by numerous ill-suited business models. CCUS technology features very low levels of modularity and often requires costly custom engineering, which results in a limited level of learning rates and cost reductions. In this context of falling expectations, the UK has set up an ambitious CCUS strategy that is backed by substantial taxpayer funding and claims that it is a sector of opportunity – which it may be, for specific hard to decarbonise heavy industrial sectors. However, we found that the UK is also targeting applications where CCUS could lock consumers into a high-cost and fossil-based future, whereas future-proof solutions could provide lower-cost and zero-emission alternatives.

- The UK's **CCUS targets should be revised** based on updated and more realistic assumptions on the technology's outlook. The government should adopt a more targeted approach towards no-regret, low-risk and future-proof options.
- **CCUS should be prioritised in the cement sector,** which currently has no alternatives to decarbonise. By contrast, it should be avoided in the iron and steel sector, where **hydrogen-based green steel** would be a lower-emission and future-proof solution.
- **CCUS can reduce emissions from existing hydrogen demand** and potentially help to kickstart "new" uses of hydrogen-as-fuel that would require investments in more infrastructure. However, green hydrogen and demand shortfalls could saturate the market and create **stranded asset risks for CCUS-based hydrogen**.
- We found that the window of opportunity for **CCUS** to abate emissions from **gas-fired power plants is limited.** The increased deployment of renewables and storage reduces the need for baseload power generation, while hydrogen turbines could offer a future-proof alternative with lower costs and zero emissions.
- The UK should revisit its strategy towards **negative emissions**, which is **heavily exposed to one single, very large and costly project**. We recommend scaling up removals starting from smaller-scale projects (such as energy from waste) that can demonstrate the technology and avoid locking in very expensive and long-duration subsidy schemes.
- Finally, **the UK must fix its carbon market** to create a long-term price signal above £100 per ton that can provide the right incentive to the market. This is the most important action needed to create a self-sustaining and competitive CCUS sector.

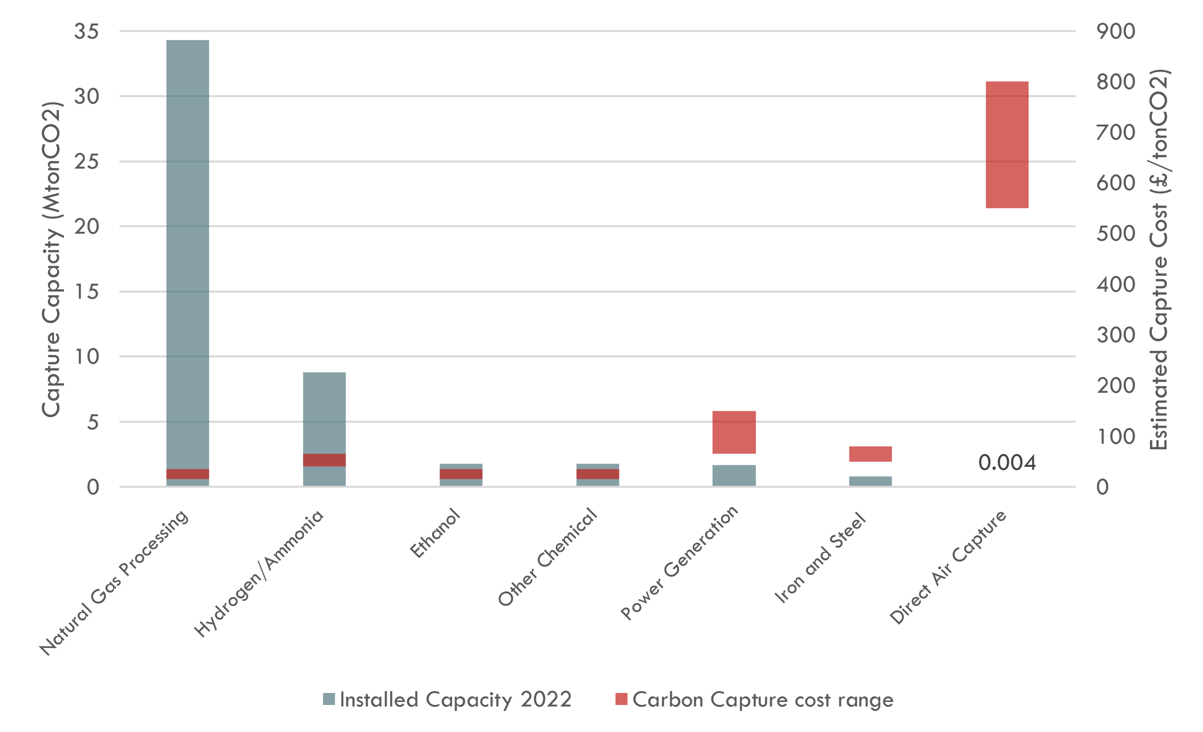
Executive Summary

The UK is increasingly focusing its efforts on creating a self-sustaining CCUS sector that could support its transition to Net Zero by 2050. In this report, we analyse the risks and opportunities related to the UK's CCUS strategy and propose a set of recommendations to align it with the maturity of technologies and the broader net zero plan.

A History of Underperformance

Regardless of a long history of promises and investments, the CCUS industry has still failed to deliver successful projects in many sectors except for some niche applications characterised by low complexity and costs (natural gas processing and refinery/chemical industry).

FIG 1: CCUS PROJECTS TODAY ARE FOCUSED ON LOW-HANGING FRUIT; ONLY A FEW PROJECTS OPERATE WITH DILUTED GAS FLOWS THAT REQUIRE A HIGHER CAPTURE COST



Source: Carbon Tracker (2024) with capacity data from GCCSI 2023 and own estimates for costs.

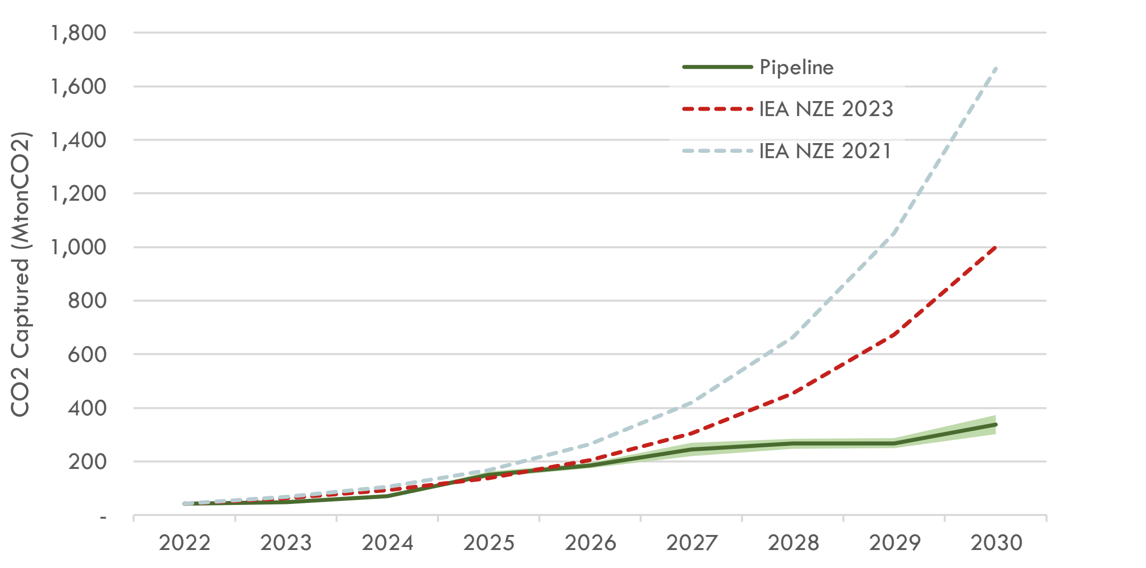
The costs of implementing CCUS in key hard-to-abate applications (such as cement, steel and dispatchable power plants) are still high, and often, the technology has not been proven at scale. As a general rule, capture costs are higher in applications where CO2 must be extracted from flue gases with low concentrations of CO2 and many impurities. Unfortunately, these are the applications where CCUS would be needed the most: cement, steel, power sectors and direct air capture.

Our review of the CCUS projects currently in operation has found a consistent trend of over-promising and under-delivering. Projects are often delivered late and over budget, while the promised high levels of carbon capture rates are regularly not realised. Most projects require tailored engineering and bespoke infrastructure while being characterised by low modularity and scale. As a result, we found very low levels of technology learning and cost reductions in the whole supply chain.

Falling Expectations

Regardless of recent developments such as recent EU proposals relating to the Commission's envisaged new 2040 emissions target and the Net Zero Industry Act, most independent observers are scaling down their expectations on their projected contribution of CCUS towards net zero due to the sector's failure to deliver the scale and cost reductions needed. Most notably, in the last two years, the International Energy Agency (IEA) reduced the expected role of CCUS by 2030 in its net zero scenario by one-third.

FIG 2: REGARDLESS OF REDUCED EXPECTATIONS ON THE CONTRIBUTION OF CCUS TOWARDS NET ZERO BY 2050, THE EXPECTED PIPELINE IS STILL FALLING SHORT



Source: Carbon Tracker (2024), elaborated from IEA and GCSSI own estimates.

Does the UK Really Need CCUS?

Despite this unattractive picture, CCUS remains a key feature of global net zero scenarios because carbon capture and negative emissions can buy time essential to remain below 1.5°C of warming while emissions from the "hardest-to-abate" sectors are phased out.

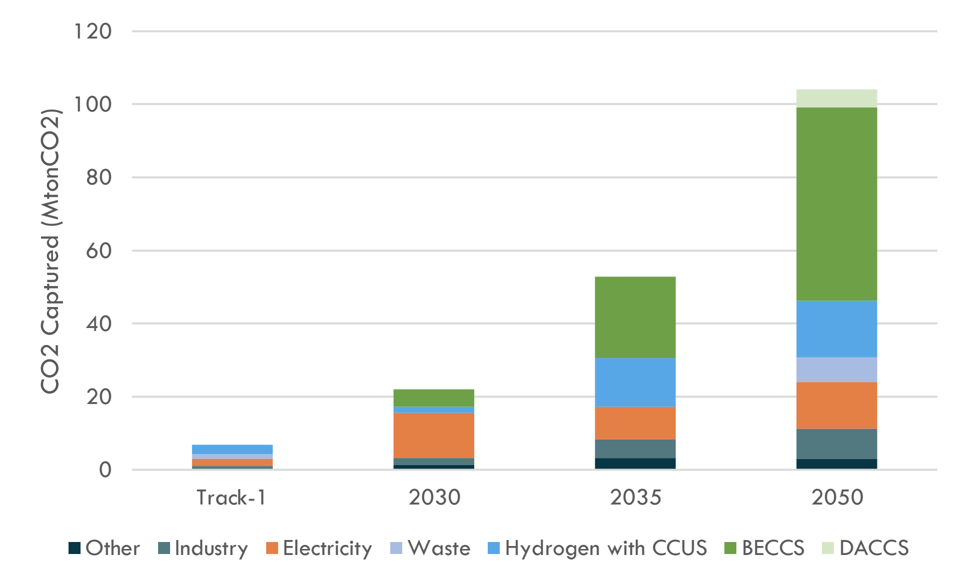
The Intergovernmental Panel on Climate Change (IPCC) range of scenarios shows how CCUS plays an essential role in bringing emissions in line with a pathway aligned with 1.5°C. The IEA's Net Zero by 2050 Scenario still expects that CCUS would contribute to 8% of total emissions reduction, with an important role in abating emissions from some industrial applications, in the nascent hydrogen sector, and a more limited role in the power sector. An important contribution would need to come from emissions removals which unfortunately today are still very expensive and not scalable.

In the UK's Net Zero strategy, CCUS is a key pillar for the decarbonisation of industrial activities, the power sector, and the production of negative emission credits. The Climate Change Committee (CCC) argues in "The Sixth Carbon Budget" (2020) that CCUS is a "necessity not an option to achieve net zero."

The UK's Strategy for CCUS

The British Government has developed a vision for CCUS that is broadly aligned with the CCC's recommendation. The most immediate goal is to achieve a capture capacity between 20–30 million tonne (Mton) of CO_2 per annum by 2030, growing to 50 Mton by 2035, with the aim of creating a self-sustaining CCUS market towards 2050. With these objectives in mind, the government has earmarked £20bn for the sectors and is focusing on de-risking and coordinating the deployment of infrastructure and capture plants in four industrial clusters.

FIG 3: THE CCC RECOMMENDS A RAPID SCALE-UP OF CCUS IN THE UK



Source: Carbon Tracker (2024), elaborated from CCC "The Sixth Carbon Budget" Balanced scenario and own research on Track1 CCUS projects currently shortlisted by the British Government for support.

Risk Assessment

We analysed the risk of deploying CCUS in the UK based on three factors: delivery risk, stranded asset risk and cost premium.

TABLE 1: AGGREGATE RISK OF CAPTURE PROJECTS IN THE UK

	Delivery risk	Stranded Asset risk	Cost Premium	Aggregate Risk
Cement	4	1	3	**2.7**
Iron and Steel	5	4	3	**4.0**
Hydrogen	2	4	2	**2.7**
BECCS	3	4	5	**4.0**
Gas-CCS	3	5	4	**4.0**

Detailed description of scoring criteria in Annex. Risk Level: 1= very low, 3 = medium, 5 = very high

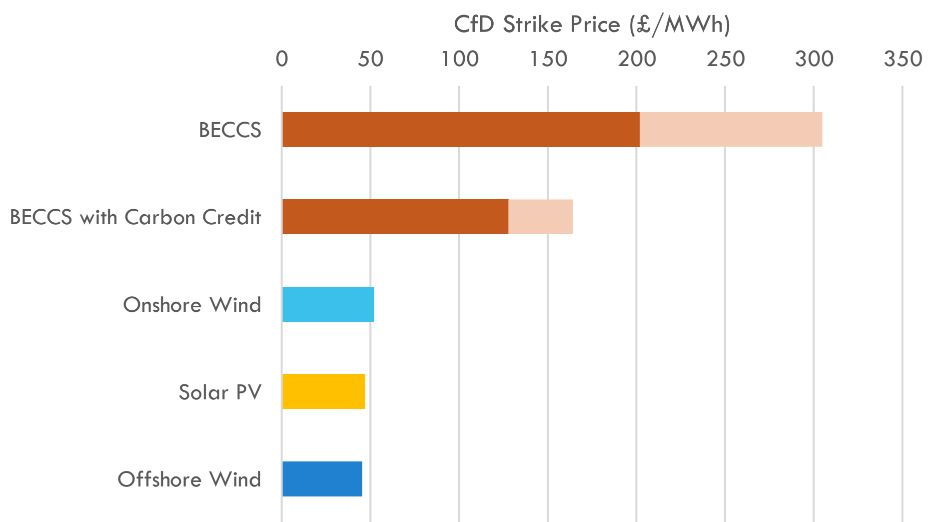
CCUS offers a unique opportunity to decarbonise the British **cement** industry, which has no other alternative for drastically cutting its emissions. While the technology has not yet been deployed at scale in this sector, the first commercial-scale plant is currently under construction in Norway and two projects are at an advanced stage of development in the UK. CCUS in the cement sector would encounter a very low stranded asset risk, while its moderate cost premium could be compensated by carbon pricing. We thus expect a positive outlook for CCUS in this sector and we recommend focusing on delivering first-of-a-kind projects while developing an integrated plan to connect cement industrial clusters with transport and storage (T&S) infrastructure. An important challenge would arise for the transport infrastructure of the few sites away from large industrial clusters.

The **iron and steel** sector faces similar pressure to reduce its emissions, but the situation is much different than for cement: a better alternative exists. Retrofitting CCUS with the ageing steelworks in the UK could be a very risky strategy because the technology, which has not been tested at scale and cannot deliver high emission reductions, could be outcompeted by lower-emission steel produced via hydrogen-based processes at a similar price. For these reasons, we recommend abandoning CCUS for this sector and focusing on a longer-term transition towards hydrogen-based green steel.

We found that **hydrogen** could see some potentially successful deployment of CCUS with a note of caution for a rising stranded asset risk due to probable market saturation. CCUS-based hydrogen, i.e., blue hydrogen, is a rather mature technology that could play an initial role in displacing the existing demand for grey hydrogen, i.e., unabated. Longer-term blue hydrogen can contribute to satisfying the "new" demand for hydrogen-as-fuel from the power sector and heavy industry. However, while in the short term, blue is more competitive than green hydrogen, i.e., renewables-based electrolytic hydrogen, this trend could reverse in the early 2030s. The outlook for hydrogen is extremely uncertain. We expect that future demand will be much lower than current optimistic projections (especially in heating and transportation), and green hydrogen from curtailed electricity (low cost and low carbon) could fulfil the demand and saturate the market.

In the **power sector**, both applications of CCUS – bioenergy with carbon capture (BECCS) and gas-fired power plants with CCUS – face high aggregate risks posing a significant challenge for the full decarbonisation of electricity generation by 2035.

FIG 4: THE COST OF BECCS WOULD BE MULTIPLE TIMES MORE THAN THE COST OF ESTABLISHED RENEWABLE ALTERNATIVES, EVEN WITH CARBON CREDITS

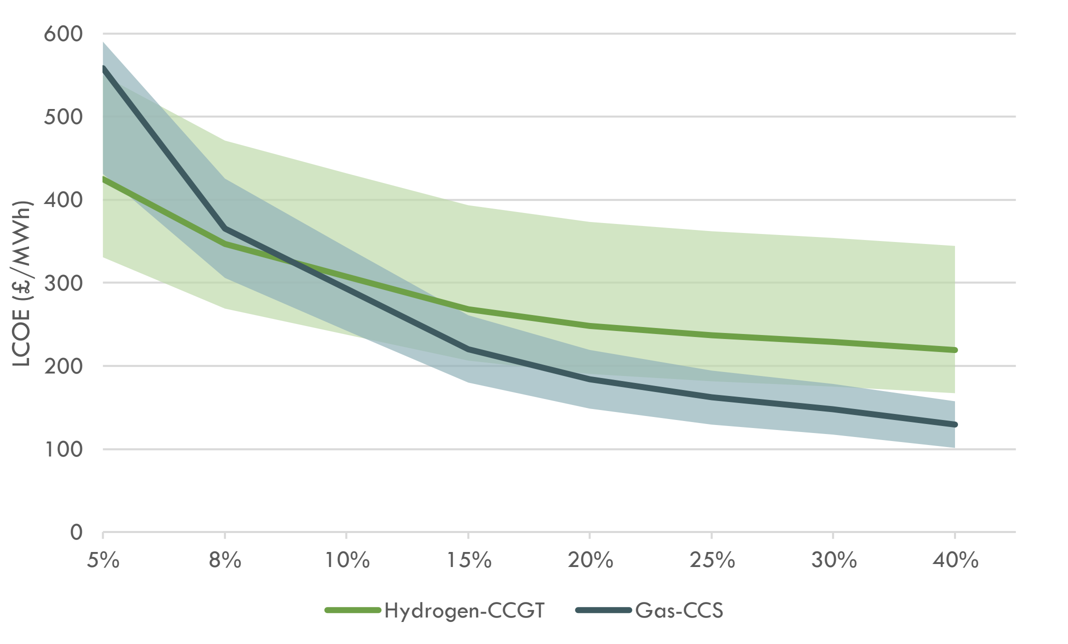


Source: Carbon Tracker (2024), CfD (contracts for difference) strike price based on own modelling for BECCS (with carbon credit of £80/ton for negative emissions) and latest costs from CfD registry for other technologies, accessed January 2024 (here).

BECCS is a critical step for the UK to reach its carbon removal target of 5 Mton by 2030. However, its success is based on the transformation of the large Drax power station to BECCS. This project relies on a technology that has not yet delivered on its promises, especially at this scale. Additionally, it would require a complex subsidy scheme together with a government-provided bridging mechanism that could lock taxpayers' money in a long and costly contract. The cost of electricity generated from BECCS would be several times more expensive than other renewable sources and would require generous carbon credits. Focusing on the delivery of smaller-scale projects would demonstrate the technology while minimising delivery and stranded asset risks.

Gas-CCS could play an important role in providing long-duration and flexible power during prolonged periods of low renewable generation. However, we found a high-aggregate risk and a potentially more competitive future-proof alternative: hydrogen-fired combined cycles (Hydrogen-CCGT). There is a risk that the industry could repeat the mistakes of its troubled history with CCUS in coal power plants. UK companies are planning to rapidly scale up gas-CCS to commercial projects with a potential pipeline of 4–10 GW, although the technology has been tested only at a small scale. The future power system will need gas-CCS plants to operate flexibly and with short operating hours, rather than as baseload. Under these conditions, hydrogen-CCGTs could outcompete them already by 2030 (see Figure 5). The high capital costs of gas-CCS plants risk becoming stranded assets on companies' balance sheets (or on the Government's finances) by the mid-2030s if hydrogen costs come down as expected. In conclusion, we expect that gas-CCS could play only a limited role in parallel to a growing fleet of hydrogen powered plants.

FIG 5: HYDROGEN TURBINES WOULD ALREADY OUTCOMPETE GAS-CCS AT LOW-CAPACITY FACTORS BY 2030



Source: Carbon Tracker (2024) based on technology cost assumptions from DESNZ in 2030 and own fuel cost projections. Natural gas cost: £20-40/MW – Central: Gas-CCS FOAK 2030 at £25/MWh; Hydrogen cost £2.5-5/kg_H2 (i.e., £75-150/MWh)-Central: Hydrogen-CCGT FOAK 2030 at £3/kg_H2; all costs are inflated to GBP 2022; see Annex for details.

Regarding other sectors, we found a potential role for CCUS in the **waste** treatment industry to abate emissions from energy-from-waste plants while creating carbon credits, in parallel with a stronger emphasis on waste reduction and recycling strategies. While costs for engineered **Greenhouse Gas Removals** (GGR), especially Direct Air Capture (DACCS), are still prohibitive and the technology maturity is limited, we recommend continued efforts in research and innovation projects.

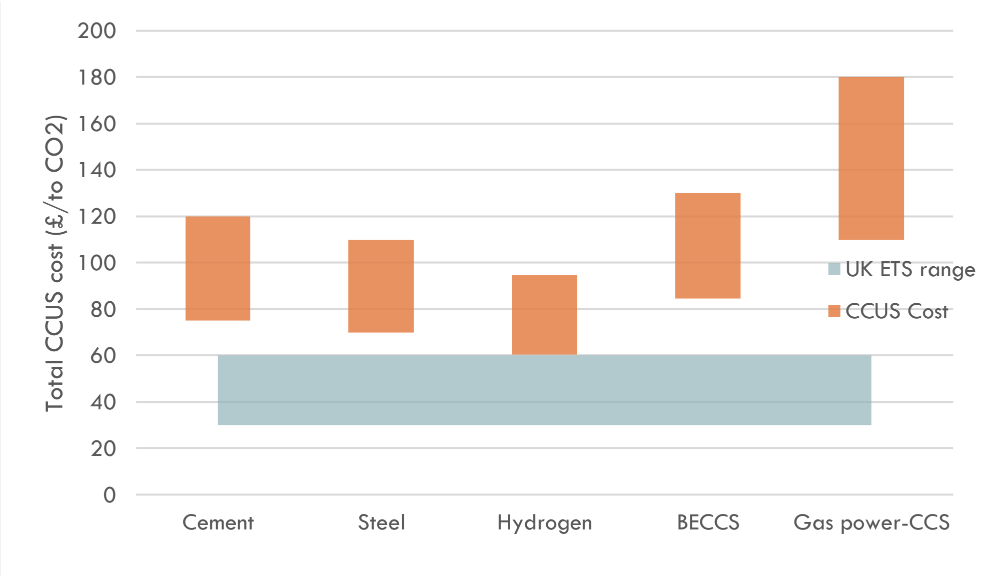
The British Government is focusing on de-risking and, above all, coordinating investments in **transport and storage infrastructure**. Due to long lead times and the uncertainties related to geological surveys, we recommend considering backup storage sites early in the planning stage. Finally, non-pipeline transport should be considered as a last resort for high-value sectors, such as cement and potentially carbon removals, due to higher costs and complexity.

What Price for CO2

Our analysis found that, with a carbon price above £100/ton, most applications could compete on a merchant basis, while higher prices of £120/ton or above would be needed for the power sector.

The main issue we found here is that the current UK carbon market (UK ETS) is extremely volatile with prices dropping to almost £30/ton in the past six months. This market instrument, which in the past has been a strong decarbonisation driver, is now struggling to deliver a long-term price signal. We strongly recommend the Government fix the market by preferably linking it back to its EU counterpart. In our view, **a strong and stable carbon price is the single most important action** needed to deliver the objective detailed in the UK's CCUS vision of creating a self-sustaining and competitive CCUS sector.

FIG 6: TOTAL CCUS COST PER SECTOR (INCLUDING TRANSPORT AND STORAGE) VS UK ETS PRICE RANGE IN THE LAST SIX MONTHS



Source: Carbon Tracker (2024); UK ETS range based on value over the past nine months.

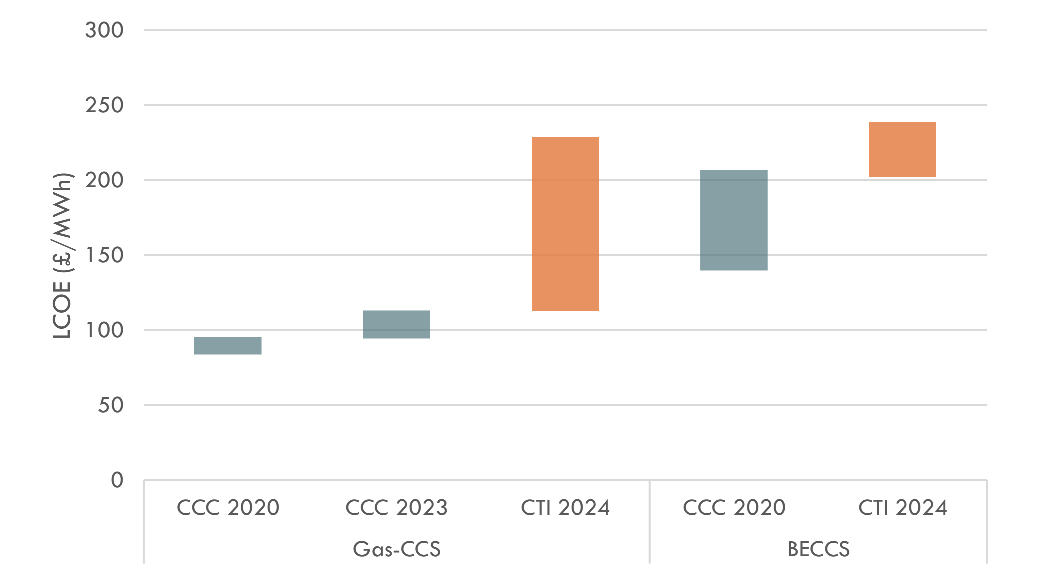
The Need for New Targets

We have found that the model that informs **the Government's CCUS target is based on optimistic techno-economic assumptions that are now outdated** and unrealistic.

We found that the current cost estimates for CCUS could be more than twice the values used in the report that informed the Government's target, "The Sixth Carbon Budget" developed by the CCC. While those cost assumptions were reasonable when the report was published in 2020, they are now out of date. The findings of a 2023 report from the CCC suggest that the need for carbon capture in the electricity sector could be one-third of what was recommended in "The Sixth Carbon Budget." Similarly, we found that the cost for carbon removals (BECCS and DACCS) could be much higher than what was initially assumed.

We thus recommend **an urgent update of the model**, and we believe that it could lead to a downscaled ambition for CCUS. As a result, we recommend that the Government revises its ambition towards adopting a more targeted strategy that could allow it to demonstrate and scale the technology in the sectors where it is needed the most.

FIG 7: THE COST ASSUMPTIONS USED IN "THE SIXTH CARBON" BUDGET SHOULD BE REVISED UPWARDS



Source: Carbon Tracker (2024) elaborated from CCC and own analysis; T&S: transport and storage. CCC 2020: "The Sixth Carbon Budget", CCC 2023: Delivering a reliable decarbonised power system. Gas-CCS CTI based on DESNZ FOAK 2030 with fuel cost of £25/MWh and capacity factor between 15-50%. BECCS cost estimated based on methodology above. Costs are annualised to GBP 2022.

Recommendations

Our analysis shows that the UK's CCUS strategy is at risk of failing to deliver on its targets as a result of targeting sectors where other, better alternatives could provide greater emission reductions at a comparable cost. There is the risk that part of the £20 billion budget allocated to this mission is allocated to non-future-proof solutions with high stranded asset risks. We strongly recommend a more targeted approach focused on no-regret applications and sectors with low-cost premiums and high-future value.

Following our analysis, we advise policymakers on the following high-level recommendations (A more detailed list is available in Chapter 8):

1. Scale back CCUS targets based on an updated transition model informed by updated and more realistic assumptions on CCUS.
2. Develop a plan for deploying CCUS in the cement industry that focuses on industrial clusters, as no mature alternatives exist for this sector.

3. Leverage industry experience to decarbonise the existing demand for grey hydrogen and kickstart “new” uses of hydrogen-as-fuel. Longer term, identify trade-offs between blue and green hydrogen while avoiding overinvestment and demand saturation.
4. Focus on delivering carbon removals via multiple smaller-scale projects, e.g., energy-from-waste, rather than relying on one single very risky power plant conversion. In addition, continue research in other carbon removal technologies.
5. Reconsider options for low-carbon dispatchable generation, due to its high costs gas-CCS could have only a limited complementary to a growing deployment of hydrogen power. Prioritise techno-economic demonstration of the first-of-a-kind gas-CCS project.
6. Fix the carbon markets by creating a clear long-term price signal well above £100/ton.

1 Introduction

This report's objective is to analyse the role of Carbon Capture, Utilisation and Storage (CCUS) in the UK's pathways towards net zero. The country has committed to a vision of establishing a competitive CCUS market in the 2030s and has allocated a total funding of £20 billion to deliver on its ambition. In this analysis, we assess the UK's CCUS strategy against the real status of the technology in order to identify its main challenges and opportunities.

The main goal of this report is to inform and influence policymakers and investors on setting their visions for CCUS by presenting the key challenges that the UK could face in implementing and recommending the applications that should be prioritised.

Carbon Tracker research has traditionally analysed CCUS from the point of view of oil companies; in this report, we move our focus mostly towards the "capture" side of the sector. The UK strategy is focused on deploying CCUS in industrial clusters where various industrial capture sites will share the same transport and storage infrastructure. For this reason, we mostly focus on the challenges of implementing carbon capture in key hard-to-abate sectors, and then we integrate the analysis into the whole system. We assess the risk of deploying CCUS in each sector based on delivery risk, stranded asset risk and cost premium. Finally, we consider the role of carbon markets and present the case for updating the UK's CCUS targets. The report is introduced by a section that analyses the global history of CCUS and its track record.

In a blog post from 2022, we argued against the idea proposed by major oil companies that CCUS would offer the opportunity for them to continue their business-as-usual extraction plans[1]. In that blog, we presented how the deployment of CCUS is still many orders of magnitude lower than required, questioned the feasibility of its future plans and called for strict standards for accounting for negative emission credits.

In the report, "Navigating Peak Demand" from November 2023, we presented the concept of a hierarchy for CCUS that envisages CCUS being reserved for applications with the highest value, such as carbon dioxide removals and hard-to-abate sectors[2]. Ultimately, we recommended that CCUS should not be used to legitimise the development of new oil and gas production.

In this report, we dive into more detail on the sectors where CCUS is expected to play a role with a lens on UK-specific applications: heavy industry (cement, iron and steel), the nascent hydrogen market, the power sector and carbon dioxide removals.

[1] Carbon Tracker Initiative (CTI) 2022 - A magical CCUS unicorn will not save the oil industry (link)
[2] CTI 2023 – Navigating Peak Demand (link)

2 CCUS History and Applications

Carbon Capture Storage and Utilisation (CCUS)[1] is a technology with a long history, born out of necessity from the oil and gas industry to separate carbon dioxide and other impurities from raw extracted fossil fuel. The world's first CCUS project was built more than 50 years ago and was driven by economics, rather than environmental concerns. Occidental, the owner of the Terrell Natural Gas Processing plant in Texas, discovered that instead of venting high-pressure flows of carbon dioxide directly into the atmosphere, they could inject them into oil wells instead and increase oil extraction by more than 30% in a process called Enhanced Oil Recovery (EOR)[3].

For many years, oil and gas companies have been touting CCS as a one-stop solution to abate emissions from fossil fuel extraction and utilisation. However, regardless of the estimated $83 billion in investments poured into the technology since the early 90's, carbon capture has failed to deliver results at a significant scale[4].

Currently, there are about 40 operating CCUS projects in the world featuring a carbon capture potential of little less than 50 MtonCO2 per year, which is about 0.1% of global CO2 emissions[5]. A 2021 study estimates that almost 80% of the large-scale CCUS projects have either been cancelled or put on hold[6]. But the fate of almost 80% of the CO2 that is captured today is used for EOR, effectively cancelling most of the climate benefit. Only around one-third of the CO2 used for EOR is permanently sequestered underground[7].

About half of the CCUS projects in operation are concentrated in the USA (21 Mton), followed by Brazil with 11 Mton, then Canada, China and Australia with 4 Mton each. The remaining capacity is distributed in the Saudi peninsula and Norway.

Before moving to the sector-level analysis, it's important to make a high-level distinction between the two main categories for carbon capture:

- **Pre-combustion** capture represents 94% of the installed global capacity and comprises of projects where CO2 is removed before combustion. In general, these applications operate with gas streams with high CO2 concentration and high pressure, achieving capture costs as low as £20-40 per ton of CO2 (excluding transport and storage).
- **Post-combustion** capture, as the term suggests, refers to capturing CO2 from flue gases produced by the combustion of fossil fuels (or biomass). In this case, carbon capture is more complex as flue gases are more difficult to handle and contain lower concentrations of CO2 and more impurities. As a result, the cost range for post-combustion CO2 capture ranges from £50 to more than £150 per captured ton of CO2.

In the next section, we will analyse the current state of CCUS, focusing on the sectors where carbon capture has been deployed at scale.

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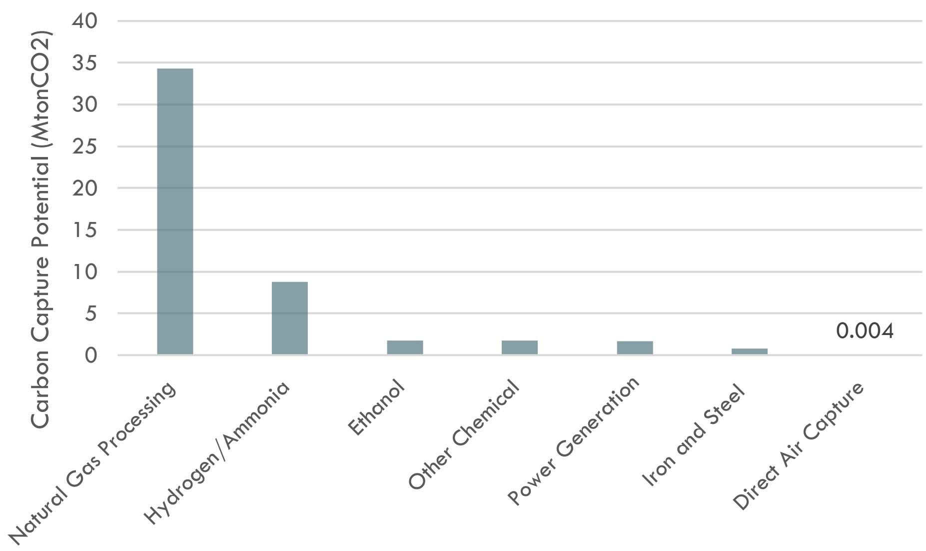
[3] Loria, Bright 2021 – The Electricity Journal (link)
[4] Bloomberg 2023 - Big Oil's Climate Fix Is Running Out of Time to Prove Itself (link)
[5] Global CCS Institute (GCCSI) 2023 - Global Status of CCS 2023 (link)
[6] Wang et al 2021 – Energy Policy Journal (link)
[7] Clean Air Taskforce (link)

FIG 8: CCUS INSTALLED CAPACITY BY SECTOR IN 2023



Source: Elaborated from GCSSI – Global Status of CCS 2023.

2.1.1 Natural Gas Processing

To date, 70% of the global CCUS capacity is used for **natural gas processing**. The four largest CCS plants in operation today – which represent more than half of the global capacity – are all linked to natural gas processing facilities.

At the point of extraction, natural gas is found in a mix of gases containing a variable concentration of CO2 among other impurities (e.g., sulphites, water vapour, nitrogen). These impurities need to be removed to produce a marketable product that complies with market standards. Depending on the nature of the specific geological deposit, the concentration of CO2 can range from a few percentage points to more than 70%. Most of the CCUS applications in the natural gas processing industry operate with high concentrations of CO2. Notably, Petrobras's Santos Basin (the world's largest) operates with concentrations above 20%, and ExxonMobil's Shute Creek (the second largest) with concentrations above 60%[8]. CO2 concentration and gas pressure are the most important drivers for carbon capture costs; the lower the concentration, the higher the costs (See Table 2). Other important factors that drive up costs are the number of points of emissions, the scale of the project, the level of impurities and the cost of energy[9].

CCUS applications in natural gas processing plants are attractive because of a few key factors:

- CO2 must be separated from hydrocarbons (generally methane) to produce marketable products,
- CO2 is found in gas flows at high pressure and high concentration (usually above 20%),
- CO2 often can be sold to be re-injected in oil wells for EOR.

[8] Petrobras 2023 (link); Parker et al 2011 – Energy Procedia (link)
[9] IEA 2023 - CCUS Policies and Business Models (link); GCCSI 2021 – Technology readiness and costs of CCS (link)

The application of CCUS at natural gas processing plants is often driven by strong regulation (e.g., Norway) and/or subsidies for capturing CO2 (e.g., USA).

Nonetheless, even in this sector, CCUS deployment is characterised by a history of over-promising and under-delivering. One notable example is Chevron's Gorgon project in Australia, the fourth largest in the world, which, after an investment of $2.1 billion and seven years of operation, is still failing to reach its promised capture targets. Bloomberg reports that to date, the plant managed to store less than half of its promised target of four million tons of CO2 due to issues with the underground storage site[10]. More recently, Occidental sold its Century CCUS plant in Texas (the third largest) for a fraction of the construction cost. An analysis by Data Desk found that from 2018 to 2022, Century captured less than 10% of the plant's capacity. This is believed to be due to the economics of the plants, which relied on an assumption of high natural gas prices[11].

TABLE 2: CO2 CONCENTRATION IS ONE OF THE KEY DRIVERS OF CCUS COSTS; THE LOWER THE CONCENTRATION, THE HIGHER THE COST

Process	CO2 concentration (%)	Carbon Capture Cost Range (£/tonCO2)
Ethanol/Chemical industry	>95	15-35
Natural Gas processing	4-70 (generally >20)	15-35
Steel Production	20-27	50-80
Ammonia/Hydrogen production	15-20	40-65
Cement process	14-33	55-90
Coal/Biomass-fired boilers	12-14	65-100
Gas-fired turbine	3-4	90-150
Direct Air Capture	0.04	550-800

Source: Carbon Tracker (2024)[12].

2.1.2 Hydrogen and Industry

CCUS has seen a few successful applications in the chemical industry to abate emissions from **hydrogen** production or remove CO2 from synthetic gas (**syngas**) production.

Hydrogen use in the chemical industry is concentrated in petroleum refineries and ammonia production. Petroleum refineries use hydrogen to break down heavy hydrocarbons into valuable products, such as diesel and jet fuel (hydrocracking and hydrogenation). Hydrogen is the main feedstock for the industrial synthesis of ammonia, which is the key ingredient for fertilizers and many commercial solvents.

Hydrogen for industrial uses is commonly produced with two processes: either steam reforming of methane (and other hydrocarbons), or through gasification (i.e., partial oxidation) of coal, bitumen or biomass. These processes yield a gas mixture containing high concentrations of CO2 that must be removed from the hydrogen flow. In most plants, CO2 is simply vented to the atmosphere, but in some cases (currently, there are seven large-scale projects), it is captured to decrease carbon

[10] Bloomberg 2023 - Big Oil's Climate Fix Is Running Out of Time to Prove Itself (link)
[11] Bloomberg 2023 - An Oil Giant Quietly Ditched the World's Biggest Carbon Capture Plant (link)
[12] CO2 concentration data elaborated from: Wang, Song 2020 (link) and Pace, Sheehan 2021 (link) see the Annex for cost data

emissions, and, when possible, sold to neighbouring oil fields for EOR. In 2022, CCUS-based hydrogen production accounted for only 0.6% of the total[13].

The context is quite similar for syngas purification. Syngas is a synthetic gas mixture containing variable concentrations of hydrogen, methane, carbon monoxide and carbon dioxide. It is generally produced from the gasification of carbon-containing feedstocks, such as coal, biomass or even municipal solid waste. Alternatively, a similar process is applied in the fermentation process required for **ethanol production.** In this process, the CO2 concentration can be higher than 95%[14].

In aggregate, hydrogen and syngas represent 30% of the global installed capacity of CCUS. These applications share many similarities with natural gas processing, as they both use gases with high concentrations of CO2 and high pressure and require CO2 removal to produce marketable products.

2.1.3 Power Sector

The power sector is the only application where post-combustion capture has been tested at a large scale. In this sector, CCUS offered the attractive prospect of continuing to burn coal and gas as long as the resulting emissions were captured and stored. Unfortunately, the technology has proven to be much more complex and expensive than thought, while renewables cost reductions have dramatically changed the landscape.

Today, only two commercial-scale power plants are operating with CCUS capturing CO2 emissions from burning coal[15].

TABLE 3: TECHNICAL SUMMARY OF COAL-POWER CCUS PROJECTS

	Boundary Dam	Petra Nova
Start date	2014	2016
Location	Canada	USA
Status	Operating	Suspended in 2020 and restarted in Sept 2023
Power Generation (MW)	160	240
Capture potential (MtonCO2/year)	1	1.6
Capture rate	target 90% – realised approx. 65%	target 90% – company report 92% contested 65-70%[16]
Fate of Carbon	EOR	EOR
Capital Cost (million $)	780	1,000

Source: Carbon Tracker (2024) based on multiple sources.

Both projects have had troubled histories characterised by consistent underperformance, recurring technical issues and ballooning costs. While these two projects demonstrated the technical feasibility

[13] IEA 2023 - Global Hydrogen Review 2023 (link)
[14] ADM 2023 (link)
[15] Reportedly in June 2023 China Energy Investment Corporation started the operation of a 0.5 MtonCO2 coal-fired CCS plant at the Taizhou thermal coal power plant in China's eastern Jiangsu province (link)
[16] IEEFA 2022 – The ill-fated Petra Nova CCS project: NRG Energy throws in the towel (link)

of carbon capture on coal-fired plants, they also clearly highlighted the associated risks and complexity.

Boundary Dam in Canada is a first-of-a-kind project that retrofitted a coal-fired power unit with CCUS in 2014. The project, which totalled an investment of about $1.2 billion, encountered numerous difficulties on its path and it is estimated that it managed to capture less than 65% of its CO2 emissions, in contrast with an official target of 90%[17]. In its most recent update for Q4-2023, the company reports that the plant achieved an emission intensity of 377 kgCO2/MWh. That is higher than the emissions of a modern gas-fired power plant (around 350 kgCO2/MWh) and much higher than the initial 90% capture target (~130 kgCO2/MWh). In 2023, the plant captured 0.79 Mton of CO2, which was still 20% short of its initial target of 1 Mton[18]. After 10 years of operation, Boundary Dam has still not managed to reach its original annual capture targets once.

Petra Nova faced a worse destiny: the plant started operating in 2016 and after only four years, it shut down for a prolonged period and restarted operations in September 2023[19]. It is reported that NRG Energy sold its 50% stake to JX Nippon for a small fraction of the plant's construction cost[20]. The success of CCS at Petra Nova is highly contested. While the company reported a 92% capture rate, detailed figures were never published, and independent analysis estimated a much lower capture rate of as low as 65%[21].

Another notable example in the power sector is the Kemper CCS power plant in Mississippi, which was supposed to capture CO2 pre-combustion from lignite gasification. The project was scrapped before starting operation, as costs ballooned to $7.5 billion[22]. Experts attribute most of the fault for the delays and budget overruns to the extensive scale-up of the technology from pilot to larger scale[23].

Natural gas-fired power plants with CCS

The cost and complexity of capturing CO2 from the diluted flue gases of gas turbines (3%-4% concentration) is much higher than for coal-fired power plants. Currently, to the best of our knowledge, there are only two operating applications of CCS on natural gas-fired plants: both started operations only in 2022 and feature small capture capacities below 0.05 MtCO2 per year[24].

2.1.4 Other Sectors

Iron and Steel

To date, there is only one large-scale operating application of CCS in the steel sector: the Al Reyadah CCS project operated by Emirates Steel in Abu Dhabi. Commissioned in 2016, the project

17 S&P 2022 - Only still-operating carbon capture project battled technical issues in 2021 (link)
18 SaskPower 2024 - BD3 Status Update: Q4 2023 (link)
19 Reuters 2023 – Carbon capture project back at Texas coal plant after 3-year shutdown (link)
20 Bloomberg 2023 - The World's Largest Carbon Capture Plant Gets a Second Chance in Texas (link)
21 IEEFA 2022 – The ill-fated Petra Nova CCS project: NRG Energy throws in the towel (link)
22 Greentech media 2017 – Carbon Capture Suffers a Huge Setback as Kemper Plant Suspends Work (link)
23 IEA 2017 - We can't let Kemper slow the progress of carbon capture and storage (link)
24 Entropy's Glacier CCS – 0.05 Mton (link); Tata Chemical in Winnington 0.04 Mton (link)

applies CCS to a gas-fired Direct Reduced Iron (DRI) process, featuring a capture capacity of 0.8 Mton per year[25]. Unfortunately, very little information about this project is publicly available.

Cement

At the time of writing, there are no commercial-scale projects employing CCS in the cement industry. However, the world's first cement CCS project is reportedly under construction in Norway: Heidelberg Materials' Brevik CCS project, targeting an operational date of 2024[26].

Greenhouse Gas Removals (GGR)[27]

This refers to technologies that can generate negative emissions by permanently removing carbon dioxide from the atmosphere. Currently, this sector includes a large array of alternatives generally separated into technology-based solutions, such as DACCS and BECCS, as well as nature-based solutions (NBS), including afforestation, habitat restoration, soil sequestration and enhanced rock weathering. For this report, we'll focus on the first group, as NBS are not directly comparable due to longer sequestration timelines, scale, costs and additionality issues[28].

Bioenergy with carbon capture (BECCS) consists of converting biomass into useful energy (usually in a power plant) while sequestering CO2 emissions to be permanently stored. Since burning biomass is considered carbon neutral under stringent sustainability criteria, sequestering CO2 emissions from its combustion generates negative emissions while producing useful products, heat and electricity.

A variation on this is **energy-from-waste**, where non-recyclable solid waste is incinerated and the resulting CO2 emissions are captured and stored. In this case, negative emissions come from the biogenic part of solid waste, which is generally considered around 50% of the total mass. Carbon capture in these applications shares many similarities with BECCS. At present, no large-scale project operates with this technology, while a few small-scale plants are currently running and numerous projects are at an advanced development stage.

Direct air capture and storage (DACCS) is a technology that is based on removing CO2 from atmospheric air via chemical absorption (or adsorption), which is then stored permanently. This process is highly complex and energy intensive due to the very low concentration of CO2 in atmospheric air (422 parts per million, or 0.04 of volumetric concentration)[29]. Currently, there is just one DACCS plant operating at a significant scale: Climeworks in Iceland, with a capacity of 0.004 Mton per year which markets carbon removal credits for around £1,200 per ton[30]. DACCS costs are now estimated between $700–1,000 per ton (i.e., £565–805/ton) of CO2 and are projected to drop to a range between $400–700 per ton in 2030 (i.e., £320–565/ton)[31].

Today, the largest development for DACCS is Occidental Petroleum's investment towards building a direct air capture plant in Texas, USA, with an expected capacity of 0.5 Mton of CO2. The plant

[25] Sheet Piling (UK) ltd (link) and Masdar Institute (link)
[26] Heidelberg Materials 2023 – Brevik CCS (link)
[27] The term is usually replaced with CDR (Carbon Dioxide Removals) outside of the UK
[28] Department for Energy Security and Net Zero (DESNZ) 2023 - Engineered Greenhouse Gas Removals (link)
[29] NASA 2023 (link)
[30] Climeworks website – accessed February 2024 (link)
[31] Bloomberg 2023 - Occidental's Big Buy May Change Course of $150 Billion Market (link)

is planned to come online in mid-2025 and the company is betting on reducing the capture cost to $400-500/ton in the coming years [32].

Due to these high costs and low level of scale, we don't consider that the technology will be able to deliver a significant contribution in the near term, especially in the UK, where high energy prices would create an additional barrier. We thus exclude DACCS from our assessment but recommend continued efforts towards research and innovation in this area. In the words of Exxon's CEO, "We're at the very early stages of the technology" even halving costs would not be enough to make it profitable[33].

2.2 Falling Expectations

The previous section presented a rather bleak picture of the global CCS industry; regardless of large investments, the sector has failed to deliver deployment of CCS at scale for over 30 years. Today, successful applications are mostly focused on "low-hanging fruit," where CO2 must be separated regardless of climate concerns and often rely on revenues from enhanced oil recovery.

In our assessment, we found that structural issues of the technology have not yet been resolved. CCS has achieved very low levels of modularity, remains site-specific and needs custom engineering for both the capture and storage of CO2. Capturing CO2 in low-concentration applications has often proven to be more complex than expected, with numerous projects facing cost overruns and technical difficulties. Finally, CCUS projects show very limited levels of technology learning rates and related cost reduction, raising concerns about future promises of low costs[34].

Notwithstanding recent positive developments such as the EU's proposed new ambition to 50 Mton of storage capacity by 2030[35]. On the global stage, the expectations of CCS's role in decarbonising the energy sector have been declining as the industry failed to scale and deliver on its promises.

We find this trend explicitly in the IEA's models that consistently decreased their expectations on the future role of CCS in the energy transition. In the two years since the first publication of the Net Zero Emissions by 2050 Scenario (NZE), the IEA has lowered CCS's expected utilisation in 2030 by about one-third (see Figure 9). In the 2023 Net Zero report, the reduced CCS deployment is compensated by an increased rollout of renewables and electrification.

At this point, we have to ask the following question:

2.3 Do We Really Need CCUS?

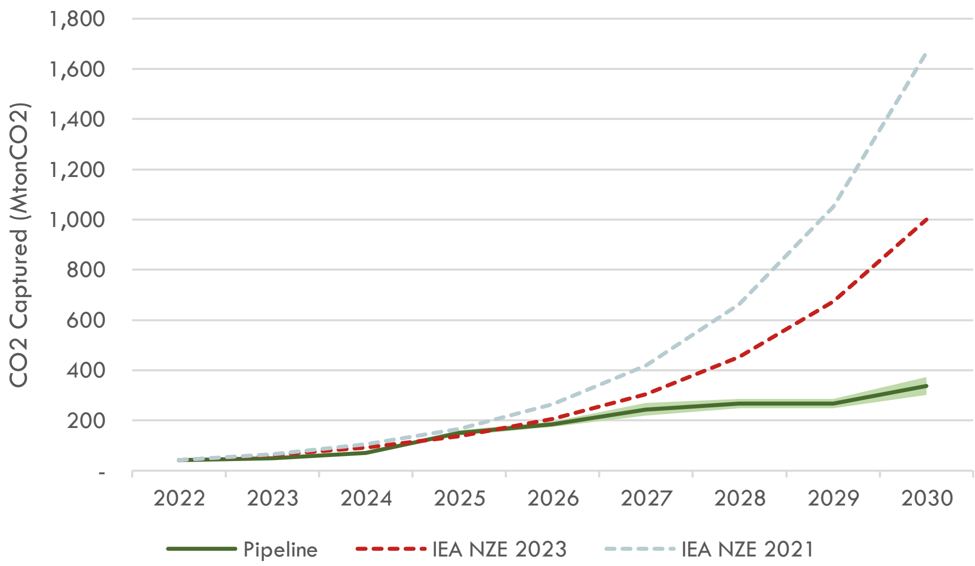
Regardless of its troubled history and high cost, it is still widely asserted that CCUS is critical to achieving net zero emissions. Both the IEA and IPCC recognised the important role that CCUS could play in reducing emissions, especially in the industrial sector.

[32] Oxy 2023 – Occidental Investor Presentation Winter 2023/24 (link)
[33] Transcript of Exxon's 4Q 2023 Earnings Call (link)
[34] Oxford Smith School of Enterprise and the Environment 2023 - Assessing the relative costs of high-CCS and low-CCS pathways to 1.5 degrees (link)
[35] European Commission 2024 – Net-Zero Industry Act (link)

In the IPCC AR6 (Intergovernmental Panel on Climate Change Sixth Assessment Report), CCUS plays a significant role in most scenarios aimed at limiting global warming to below 2C compared to pre-industrial levels[36]. CCUS is considered a key technology for achieving deep emission reductions in heavy industries, hydrogen production and in the power sector to reduce stranded asset costs from coal power plants and support renewables integration. Finally, the IPCC scenarios expect that CCUS would be needed to produce carbon dioxide removals via BECCS and, in a limited volume, DACCS. Generally, the need for CCUS in IPCC scenarios can vary dramatically depending on the type of scenario, technology assumption and whether there is an overshoot or not; but overall, CCUS is expected to play an important role in all the scenarios that limit warming below 2C. However, the IPCC is still sceptical about the costs of CCUS. A group of researchers from Oxford University compared multiple 1.5C aligned transition scenarios and found that the ones that rely more heavily on CCUS would be expensive: a high-CCS route could cost one trillion dollars per year more than a low-CCS scenario[37].

In conclusion, the IPCC states that CCUS may be needed to mitigate emissions from the remaining fossil fuels that cannot be decarbonised, but the economic feasibility of deployment is not yet clear.

FIG 9: GLOBAL CCUS PROJECTION IEA NZE 2021 VS 2021 VS CURRENT PIPELINE



Source: Carbon Tracker (2024), elaborated from IEA NZE data interpolated with percentage growth from 2022-2030. IEA CCUS database 2023 and GCCSI 2023.

In the IEA's Net Zero Emissions by 2050 Scenario, CCUS contributes to 8% of total emissions reductions, mostly to abate emissions from the cement and chemical industries, while contributing to a smaller extent to the steel and power sector. In IEA models, CCUS capacity should reach 1,000 Mton per annum by 2030 (a 20x increase compared to today) and scale to 6,000 Mton by 2050. Unfortunately, today's plans are falling short of even this downsized ambition[38]. If all the announced

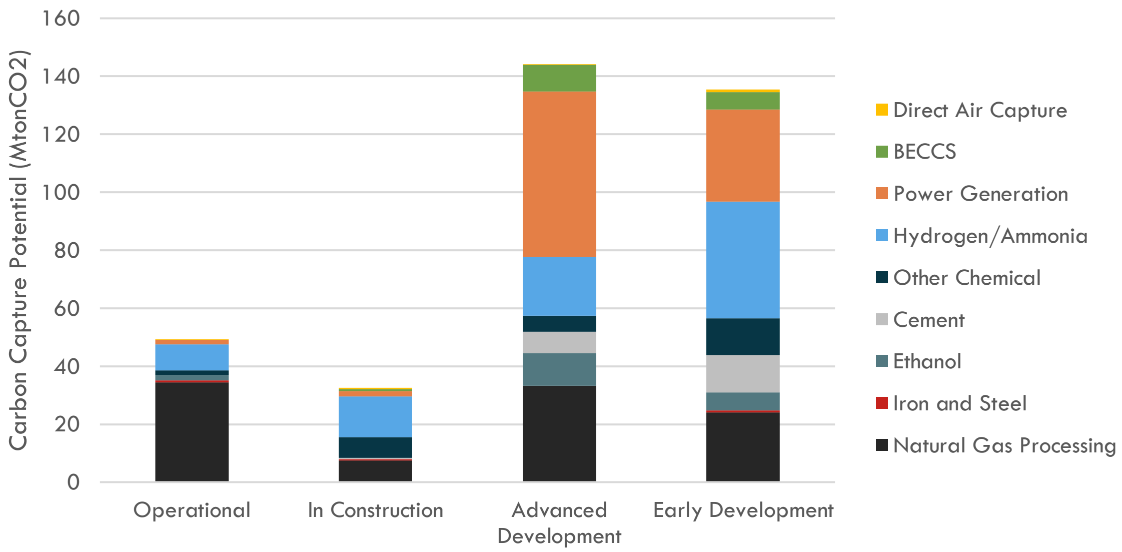
[36] IPCC – Sixth Assessment Report (link)
[37] Oxford Smith School of Enterprise and the Environment 2023 - Assessing the relative costs of high-CCS and low-CCS pathways to 1.5 degrees (link)
[38] IEA 2023 – Net Zero Roadmap (link)

CCUS projects in the world were built by 2030, global capacity would still struggle to reach 400 Mton.

Almost half of the projects announced or under construction – for a total of 135 Mton – are based in the USA and are driven by the new wave of incentives in the Inflation Reduction Act (IRA). The IRA offers support of $85/ton of CO2 captured and permanently stored and up to $180/ton for DACCS. The UK comes second with a potential pipeline of 54 Mton[39].

The projects under development are still largely focused on traditional applications, such as natural gas processing, hydrogen, ethanol and chemicals, accounting for 60% of the new capacity. In non-traditional applications, there is a growing pipeline of projects focusing on the application of CCUS in the power sector (one-third of the total) and the cement industry. Steel production and DACCS continue to represent a very small share of projects under development.

FIG 10: GLOBAL CCUS PIPELINE BY STATUS AND SECTOR



Source: Elaborated from GCSSI 2023.

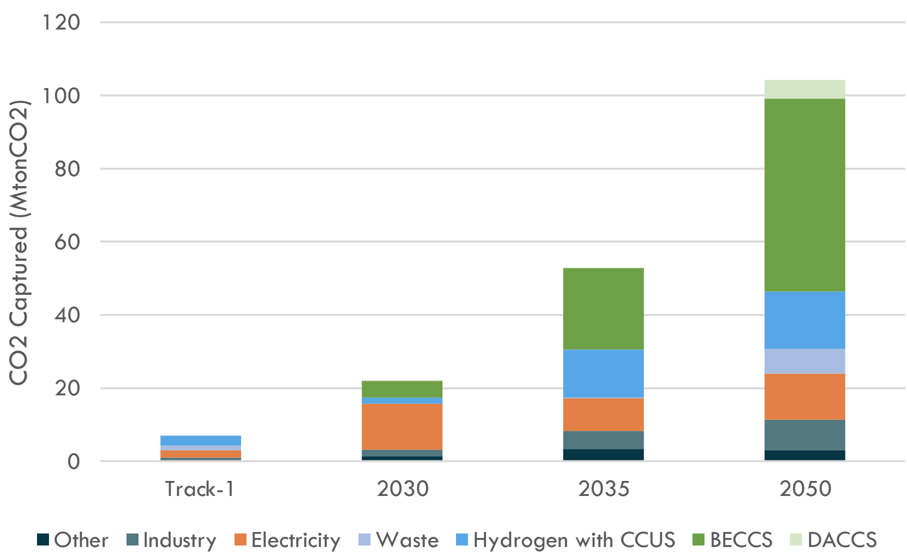
[39] GCCSI 2023 - Global Status of CCS 2023 (link)

3 The UK's Strategy for CCUS

CCUS[40] is an important pillar of the UK's decarbonisation strategy, where it is expected to play a key role in abating emissions from industrial activities, power plants and generating negative emissions with carbon removal. In "The Sixth Carbon Budget," the Climate Change Committee (CCC) argues that CCUS is a "necessity, not an option to achieve net zero" and that pathways without CCUS would be more expensive and would delay net zero[41]. In its central scenario (i.e., Balanced Pathway), the CCC projects that CCUS will need to capture 22 Mton of CO2 by 2030, ramping up to 53 Mton in 2035 and up to 100 Mton in 2050. In CCC's scenario, CCUS is focused on the electricity sector in the short term, while in the longer term, hydrogen and industry take on a bigger role. A key contributor will be carbon removals which are expected to generate more than 50 Mton CO2 of credits by 2050.

As a note of caution, the CCC report is based on research carried out mostly in 2019; since then, the energy landscape has changed significantly and some of the assumptions underlying the report are now outdated (more on this in Chapter 7). The CCC will release its advice for the 7th Carbon Budget in early 2025, and this will likely contain updated targets for CCUS.

FIG 11: CCC RECOMMENDATIONS ON CCUS FROM BALANCED SCENARIO AND ESTIMATED POTENTIAL FROM TRACK-1 PROJECTS



Source: Carbon Tracker (2024), elaborated from CCC 2020 and own research on Track-1projects. (See Table 4)

The UK has a long history with carbon and capture. The first policy programs started back in 2007 with a second competition round launched in 2012. However, both programmes failed to deliver any project with the competitions closing in 2016 due to a lack of government funding. Past UK

[40] Throughout this report we use the term CCUS for consistency with the language used in the UK policy documents while almost all the expected applications will be focused on CCS (without use).
[41] Climate Change Committee (CCC) 2020 – The Sixth Carbon Budget (link)

programs focused on demonstrating and delivering CCUS in the power sector. Notably, the 2012 competition focused on a coal-fired (White Rose) and gas-fired power plant (Peterhead)[42].

Since 2018, the British Government has focused on a cluster-based approach and its ambition was solidified in the 2023 Spring Budget, and later in December 2023 with the publication of its vision for the sector[43]. The Government aims to make the UK a global leader in CCUS, creating a self-sustaining CCUS sector that supports thousands of jobs and reduces emissions to ensure a better environment for future generations. The plan is to develop a commercial and competitive CCUS market in three phases:

1. Market creation – get to 20–30 Mton CO_2 per annum by 2030.
2. Market transition – support the emergence of a commercial and competitive market, with at least 50 Mton by 2035.
3. A self-sustaining CCUS market – meet net zero by 2050.

To achieve this ambitious plan, the Government committed to invest £20 billion in the 2023 Spring Budget to foster the creation of a CCUS industry.

Learning from past experiences, the Government is focused on delivering CCUS in industrial clusters where multiple industrial emitters of CO2 would be connected by one single transport and storage infrastructure. This is potentially a very effective strategy, as it is estimated that almost 70% of the UK's industrial emissions are concentrated in seven industrial clusters[44].

Currently, two clusters (HyNet and the East Coast Cluster) have been selected in the "Track-1" for delivery in the mid-2020s. As part of its "Track-2," the Government is planning to support the construction of Transport and Storage systems in two additional clusters (Acorn and Viking) by 2030. We estimate that the projects shortlisted in "Track-1" could deliver up to 6.9 Mton of capture capacity by 2030, or about one-third of the Government's ambition. The remaining contribution is expected to come from projects in "Track-1 Expansion" and "Track-2" and have not been selected yet. The Government's ambition also includes the consideration of a future reliance on non-pipeline transport for projects outside the four main clusters.

By leading the cluster sequencing, the Government is focusing on the crucial task of coordinating the delivery of capture projects with the essential infrastructure needed to transport and store CO2.

In parallel with allocating funding, the Government is designing a set of business models for the delivery of industrial carbon capture (ICC) in industry and waste management, hydrogen production, power sector with Dispatchable Power Agreements (DPA), bioenergy (BECCS), greenhouse gas removals (GGR), and transport and storage infrastructure. In this way, it aims to attract private finance and remove market barriers providing long-term revenue certainty.

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[42] DESNZ – UK carbon capture, usage and storage (link)
[43] DESNZ 2023 - Carbon capture, usage and storage: a vision to establish a competitive market (link)
[44] National Infrastructure Commission (NIC) 2023 - The Second National Infrastructure Assessment (link)

TABLE 4: LIST OF PROJECTS SHORTLISTED IN CCUS TRACK-1

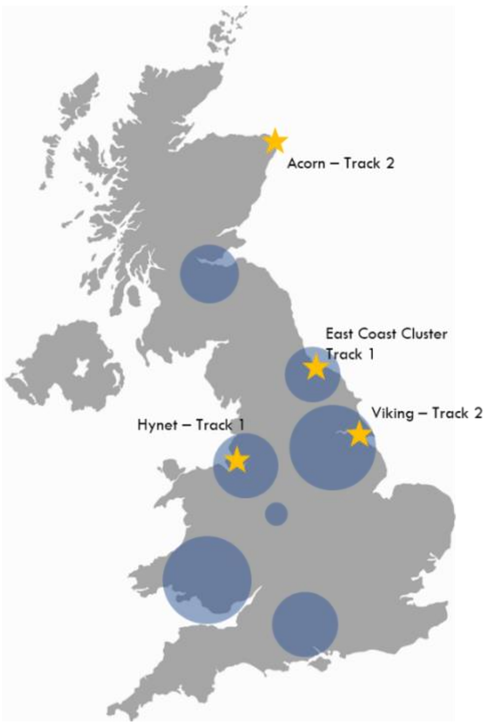
Project Name	Sector	Capture capacity est. (MtonCO2)
East Coast Cluster		
Net Zero Teesside Power	Electricity	2
bpH2Teesside	Hydrogen	2
Teesside Hydrogen CO2 Capture	Hydrogen	0.2
Hynet Cluster		
Hanson Padeswood Cement Works CCS	Industry	0.8
Viridor Runcorn Industrial CCS	Waste	0.9
Protos Energy Recovery Facility	Waste	0.38
Buxton Lime Net Zero	Industry	0.02
HyNet Hydrogen Production Plant 1 (HPP1)	Hydrogen	0.6

Source: Carbon Tracker (2024). Capacities estimated from multiple project-specific sources.

Below is a summary of the UK's Government targets for CCUS[45]:

1. Store 20-30 million tonnes of CO2 per year by 2030 and at least 50 Mton by 2035.
2. Support CCUS in two industrial clusters by the mid-2020s and a further two by 2030.
3. Bring forward at least one power CCUS plant in the 2020s.
4. Deploy up to 1 GW of CCUS-enabled hydrogen in the 2020s and up to 4GW by 2030.
5. Capture up to 6 Mton of industrial CO2 emissions per year by 2030 and 9 Mton by 2035.
6. Remove 5 MtCO2 of greenhouse gas by 2030 (e.g., BECCS and DACCS).

FIG 12: MAP OF UK'S INDUSTRIAL CLUSTERS AND LOCATION OF CCUS CLUSTERS



Carbon Tracker (2024), The size of the bubble represents the annual emission of the cluster based on 2019 emissions from NAEIP

[45] Based on a collection of the latest CCUS documents published by DESNZ

4 Risk Assessment

In the next section, we assess the feasibility and delivery of CCUS in the following sectors:

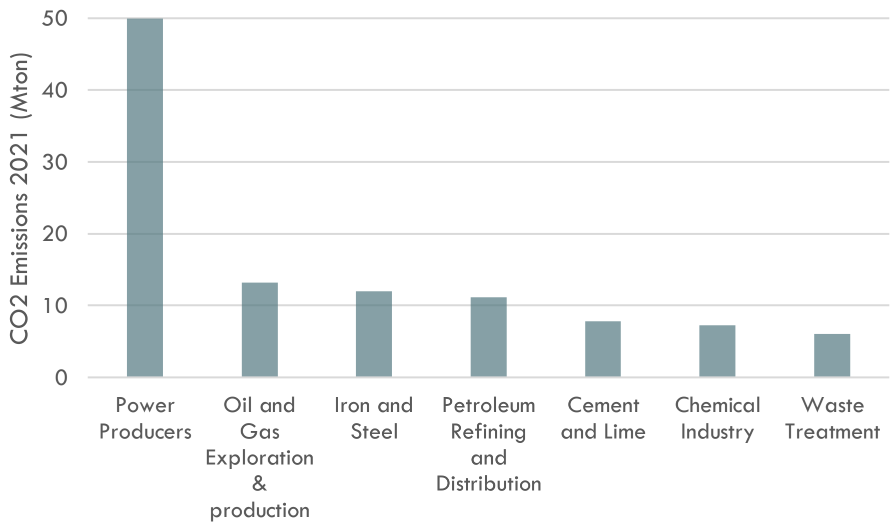
1. Cement
2. Iron and steel
3. Hydrogen production
4. Power generation
    a. Bioenergy CCS (BECCS)
    b. Gas-CCS

We focus our assessment on how these applications perform on three criteria:

1. **Delivery risk** – considers the risk of successfully delivering CCUS at the scale and on the timeline needed for the sector, considering the technical challenges and industry readiness.
2. **Stranded asset risk** – considers the risk that even despite the technology working, it could be outcompeted by cheaper alternatives and as a result, face early retirements and impairment losses.
3. **Cost premium** – estimates the additional cost of carbon capture to the benchmark price of the underlying product.

A detailed description of the scoring criteria is available in the Annex.

FIG 13: UK'S CO2 EMISSIONS OF SELECTED ENERGY AND INDUSTRY SECTORS IN 2021



Source: Elaborated from The National Atmospheric Emission Inventory. (Emissions from large point sources.)

4.1 Cement

The cement sector is an important part of the British economy, with an annual production that averaged above eight million tonnes in the last 10 years. Importantly, the cement industry is a large source of CO_2 emissions in the UK, with an estimated 8Mton of CO_2 emitted by the sector in 2021 (about 2% of the UK's total emissions)[46].

Emissions from cement production cannot be removed with classic approaches, e.g., fuel substitution or electrification, because CO_2 is an unavoidable by-product of the calcination reaction that transforms limestone into CO_2 and calcium oxide, the essential component of cement. In addition, the high temperatures needed to kickstart the reaction are generally achieved by burning fossil fuels, hence producing additional CO_2 emissions.

The UK's cement industry is looking at CCS as a viable solution to decrease its emissions. One cement project has been shortlisted for the Track-1 CCUS clusters, Hynet Padeswood Cement Works, plus one lime plant, Buxton Lime Net Zero.

FIG 14: LOCATION OF UK'S CEMENT SITES

Carbon Tracker (2024)

4.1.1 Delivery Risk: 4/5

We found a high delivery risk for the application of CCS in the cement industry because this technology has not yet been proven at an industrial scale. Technical experience is currently limited for small-scale pilot projects and there are still many open questions on which process will be the most suitable: post-combustion capture or oxy-combustion. A carbon capture plant in a cement furnace would need to withstand flue gases with low concentrations of CO_2 and high levels of impurities.

[46] UK Gov Building materials and components statistics: October 2023 (link) and National Atmospheric Emission Inventory (NAEI) (December 2023 update) (link)

The industry will be looking very closely at Heidelberg's Brevik CCS, the first industrial-scale project under construction in the cement industry that could be commissioned by the end of 2024 with a target to capture 50% of the plant's emissions[47].

From an industry point of view, four companies representing 40% of the UK's cement production are joining efforts under the Peak District Cluster. Their aim is to develop a CO2 transport and storage network with the ambition of cutting over 3 Mton of CO2 starting in 2030. This initiative could reduce the delivery risk of the technology by pooling resources and sharing risk among industries in the same geographical area and sector. One potential advantage for this industry is the low number of actors involved in cement manufacturing; emissions are concentrated in only ten large-scale plants[48]. However, an important challenge for the sector would be connecting the sites distant from the planned CO2 transport and storage infrastructure

Nonetheless, we still rate a high delivery risk for this application due to the technical complexity and lack of expertise in capturing CO2 from the calcination process.

4.1.2 Stranded Asset Risk: 1/5

We have not found any promising alternative technology that can significantly reduce CO2 emissions in the cement production process. Additionally, the UK Emission Trading Scheme would protect domestic CCS-based cement production from imports of cheaper unabated cement through the Carbon Border Adjustment Mechanism (CBAM) that is set to start in 2027[49].

For example, removing emissions from the combustion process with electric kilns can remove the emissions related to the combustion of fuels needed to provide the heat for the calcination reaction. However, this would only reduce emissions by 30%, as it would not tackle the emissions of the calcination process.

Alternatives to the calcination process have only been demonstrated at a laboratory scale, so we do not expect them to pose a stranded asset risk to CCS-retrofitted cement kilns[50].

4.1.3 Cost Premium: 3/5

Based on our carbon capture estimates, we calculate that CCS could add between £33 to £52 per tonne of cement produced, resulting in a cost premium of up to 20% compared to the average 2021 price of British cement.

4.2 Iron and Steel

Steel is another industrial sector that is facing a huge decarbonisation challenge in the UK. The UK produces around 7 million tonnes of steel per year, resulting in annual CO2 emissions of around 12 Mton (equivalent to 3.5% of the total UK emissions). The UK steel industry employs almost 40,000 workers and produces a direct contribution to the economy of almost £3 billion per year[51].

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[47] Heidelberg Materials – Quarterly Statement January to September 2023 (link)
[48] NAEI 2023 (December 2023 update) (link)
[49] DESNZ 2023 - The long-term pathway for the UK Emissions Trading Scheme (link)
[50] IEA 2023 – Cement (July 2023 update) (link)
[51] MakeUK 2023 - UK Steel Key Statistics 2023 (here); NAEI 2023 (December 2023 update) (link)

About 80% of the UK's steel production is primary steel from blast furnaces produced at Tata Port Talbot and British Steel Scunthorpe[52]. Both companies are under pressure to reduce the environmental impact of their operations and are considering CCS among other options to reduce their CO2 emissions[53].

Box 1: Steel production process today
There are two important distinctions when it comes to steelmaking:

1. **Primary steel** is steel produced from mined iron ore via blast furnace (BF) or direct reduced iron (DRI).
2. **Secondary steel** is steel produced by recycling/upgrading scrap iron in an electric arc furnace (EAF).

The blast furnace route is a highly carbon-intensive process, which emits on average 1.9 tons of CO2 per ton of steel[54]. With this process, CO2 emissions are produced at different emissions points; the largest share (~50%) comes from the blast furnace, where coke (a refined form of coal) and iron ore react to produce pig iron.

DRI produces primary steel in a two-step approach. First, iron ore is reduced into iron sponge using a reducing agent, and then the iron sponge is melted and refined into steel in an EAF. The reducing agent is commonly obtained by reforming natural gas to produce syngas with a variable concentration of hydrogen and carbon monoxide. (Few applications adopt coal gasification). Compared to the BF process, gas-fired DRI reduces CO2 emissions between 30% to 60%, depending on the specific plant design. This process is less common than BF and is limited to countries with very low natural gas prices (e.g., Middle East, North America, Russia); it currently accounts for less than 10% of the global primary steel production[55]. Emissions of the gas-DRI route are on average about 30% lower than BF.

Steelmaking from EAF incurs far lower CO2 emissions than BF, at between 0.2 to 0.4 tons of CO2 per ton of steel, depending on the country's electricity mix. Regardless of its lower carbon intensity, primary steel production cannot be entirely replaced by EAF due to its limited capacity. Some 85% of end-of-life steel is already recycled and not all scrap metal can be reused due to quality issues[56].

4.2.1 Delivery Risk: 5/5

We found a very high risk of delivering CCS in the UK's steelmaking plants. The technology is still unproven for blast furnaces – the technology adopted in UK's steelworks – and the industry is moving towards alternative solutions.

Globally, there is no application of CCS for blast furnace-based processes. There is only one CCS-based steel plant in operation (owned by Emirates Steel in the United Arab Emirates); the plant is based on a gas-DRI process and has been fitted with pre-combustion carbon capture. The resulting CO2 is used for enhanced oil recovery. Some observers estimate that the CCS plant captures only

52 MakeUK 2023 - UK Steel Key Statistics 2023 (here)
53 British Steel (link) and Tata Steel (link)
54 JRC 2022 – Technologies to decarbonise the EU steel industry (link)
55 IEA 2023 – Steel (July 2023 update) (link)
56 JRC 2022 – Technologies to decarbonise the EU steel industry (link)

about 25% of the process emissions[57]. We are not aware of any other project in operation, aside from smaller demonstration and pilot projects.

Achieving high levels of CO2 reduction by adopting CCS for blast furnaces is has not yet been tested and would be potentially very challenging due to the multiple points of emissions that would require post-combustion technology on low-concentration flue gases. Retrofitting blast furnaces with CCS would capture between 50–70% of emissions. Further increasing the capture rate would require a significant rebuilding of the process (e.g., via HIsarna process)[58].

Alternatively, a solution would be to transition to gas-fired DRI with CCS. However, this would require a complete reconstruction of the production process, while ignoring a potentially lower-emission and lower-cost alternative, hydrogen-DRI.

Both Tata Steel and British Steel seem to be moving away from plans to install CCS at their UK facilities in favour of a move towards Electric Arc Furnaces. British Steel has recently announced a plan to shut down its Scunthorpe blast furnace and replace it with secondary steel production from EAF[59]. Similarly, Tata Steel is considering shutting down its Port Talbot facility, putting 3,000 jobs directly at risk[60]. Notably, labour unions are pushing for a more substantial green transition towards the adoption of hydrogen DRI-based steelmaking[61].

If these two facilities were to move away from primary steel, the UK would permanently become more dependent on international markets. While a transition to EAF would decrease domestic emissions, it would not make a significant impact on global emissions, as the UK would still need to import primary steel produced from unabated technologies.

Due to the combination of a high technological risk and low industry interest in moving forward with CCUS, we rate the delivery risk of carbon capture in the UK's steel industry as very high.

4.2.2 Stranded Asset Risk: 4/5

CCS-based primary steel produced in the UK would face a high stranded asset risk due to strong competition from lower-cost and lower-emissions alternatives.

First, primary steel based on CCS would face competition from EAF-sourced steel, while still featuring a higher carbon footprint due to the limited abatement potential of CCS in blast furnaces.

In the longer term, primary steel production with CCS will face strong competition from hydrogen-DRI. A pilot project is already operating in Sweden (Hybrit), intending to deliver fossil-free steel to the market by 2026[62]. All the major European steelmakers (SSAB, ThyssenKrupp, Salzgitter, ArcelorMittal, Voestalpine) have initiated or announced projects to develop hydrogen-DRI. Similarly, major iron ore miners are aligning with these plans, shifting production towards iron ore suitable for

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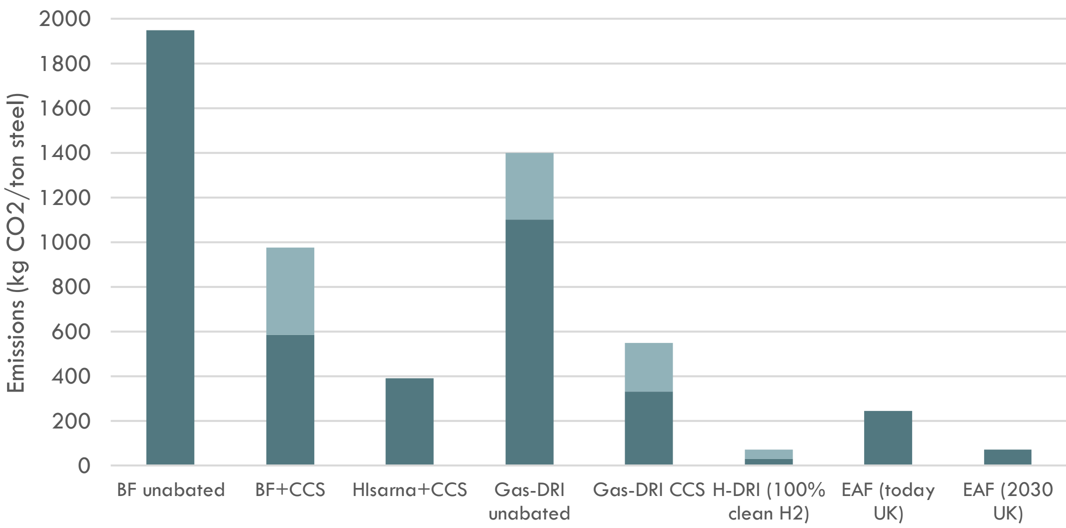
[57] JRC 2022 - Technologies to decarbonise the EU steel industry (link)
[58] MakeUK 2022 - Net Zero Steel A Vision for the Future of UK Steel Production (link)
[59] Sky News 2023 - British Steel to shut down blast furnaces at Scunthorpe plant 'leaving 2,000 jobs at risk' (link)
[60] FT 2023 - Tata Steel pulls announcement on 3,000 job cuts at Welsh factory (link)
[61] The Guardian 2024 - 'A golden opportunity': Port Talbot fights to keep its steelmaking tradition alive
[62] SSAB Annual Report 2022

DRI[63]. Notably, in 2021, Tata renounced a plan to adopt CCS at its Dutch site in favour of H2-DRI after pressures from labour unions and politicians[64]. Following its experience with CCS-based gas-DRI, Emirates Steel is building a new DRI project, this time 100% hydrogen-based [65].

Hydrogen-DRI features numerous advantages compared to a CCS-based blast furnace. First, there is already a mature technology; conventional gas-DRI furnaces can already operate with gas flows containing up to 50% of hydrogen (currently unabated)[66]. They can accept flexible levels of hydrogen, blending (both blue and green hydrogen), and they can achieve very high emissions abatement rates: up to 98% if powered entirely with green hydrogen and decarbonised electricity[67]. While the costs are still very uncertain, preliminary figures suggest a cost premium of around 20-30% compared to unabated steel[68]. At this price, hydrogen-DRI would be in direct competition with CCS-based steel (see Figure 15), even neglecting the carbon cost. CCS-based BF steel will need to pay increasing carbon costs when free allocations of ETS permits are phased out. (Timelines are currently under discussion.)[69] Finally, retrofitting the existing coal-based BF processes with CCS will lock in an ageing infrastructure and maintain a long-term reliance on metallurgical coal imports.

FIG 15: CCS-BASED STEEL WOULD FEATURE HIGHER EMISSIONS THAN ALTERNATIVE TECHNOLOGIES



Source: Carbon Tracker (2024). BF emission 1950kgCO2/ton steel from MakeUK; BF+CCS capture rate 50-70% from JRC; HIsarna+CCS expected 80% reduction from JRC; Gas-DRI emissions 1100kgCO2/ton steel from Midrex data; Gas-DRI+CCS capture rate 50-70%; H-DRI (hydrogen) from JRC; EAF based on MakeUK and grid emissions factors from National Grid ESO.

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[63] IEEFA 2024 – Carbon capture falls even further behind as BHP, Rio and BlueScope collaboration accelerates green steel transition (link)
[64] Reuters 2023 – Tata says Dutch state support needed in drive for 'green' steel (link); Tata Steel 2022 (link)
[65] Hydrogen Insight 2023 – Electrolysers already delivered for UAE's first green hydrogen-based steel project (link)
[66] Midrex (link) – Gas-DRI furnaces operate by reforming methane into a syngas composed of hydrogen and carbon monoxide. The share of hydrogen and carbon monoxide can be varied and pushed up to 100% hydrogen.
[67] JRC 2022 – Technologies to decarbonise the EU steel industry (link)
[68] H2 Green Steel reportedly signed offtake agreements indexed to steel benchmark prices with a 20-30% cost premium adjustment. Hydrogen Insight 2023 (link)
[69] DESNZ 2023 – The long-term pathway for the UK Emissions Trading Scheme (link)

4.2.3 Cost Premium: 3/5

Cost estimates for blast furnace carbon capture are still very uncertain, as there is not any such plant in operation today. Based on existing literature, we estimate that the cost of capturing CO2 could range from £85 to £142 per ton of steel produced. In relative terms, the comparative impact of CCS on the final steel price would be limited between 13% and 31% of the final product cost.

4.3 Hydrogen

Hydrogen is one of the strategic energy sectors that is vital to replace imported fossil fuels with cheaper, cleaner and domestic sources of energy, according to the UK's "Powering Up Britain" plan. Hydrogen is supposed to have applications in many competing sectors with CCUS, where renewables and energy efficiency alone cannot displace fossil fuels. Hydrogen is an energy carrier that can:

- replace fossil fuels in industries where high-temperature heat is needed.
- replace natural gas for long-duration storage and flexibility in the power sector.
- potentially contribute to the decarbonisation of shipping and aviation.

Today, the UK consumes about 0.7 Mton of hydrogen per year to produce refined oil and fertilizers. This hydrogen is generally produced on site using natural gas (without CCUS) and produces an estimated 6 Mton of CO2 per year[70].

Future hydrogen demand is expected to rise sharply as demand scales up in industry and in the power sector. According to the "UK Hydrogen Strategy", demand for hydrogen could grow very quickly in the 2030s from about 1 MtonH2 in 2030 to up to 5 MtonH2 in 2035, potentially reaching 17 Mton in 2050 (See Figure 16). However, the outlook of the fuel is still very uncertain and disputed. In the same strategy, more conservative assumptions project the 2050 hydrogen demand to be below 4 Mton. This uncertainty is mostly due to the potential use of hydrogen for domestic heating and transport.

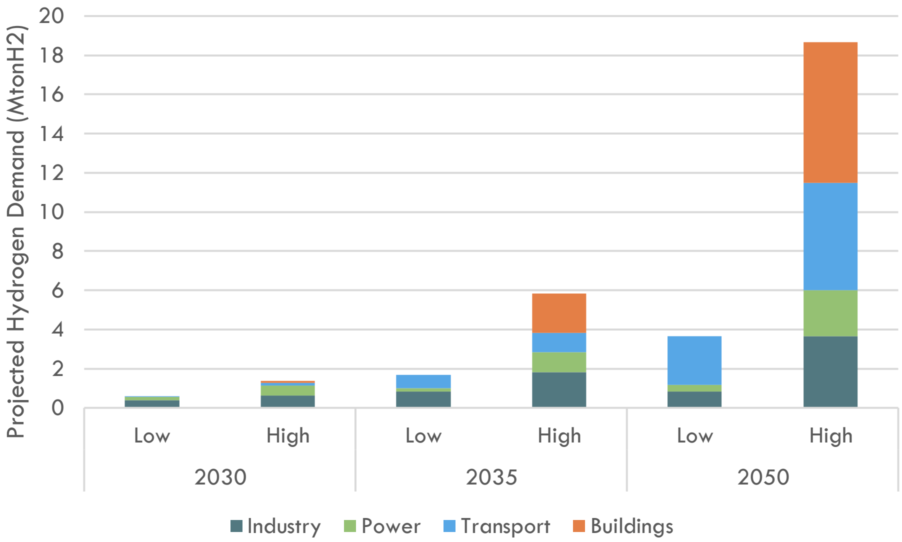
There are three main pathways to produce hydrogen:

- From natural gas - via steam methane reforming (SMR) or autothermal reforming (ATR)
- From coal or biomass - via gasification or pyrolysis
- From electricity - via proton exchange membrane (PEM) electrolysis and alkaline electrolysis.

Globally, today's hydrogen production is dominated by unabated SMRs (62%) with a smaller role provided by coal gasification (21%). Low-carbon hydrogen production is still extremely marginal with CCUS-based production accounting for 0.6% and electrolytic hydrogen only 0.1% of the total[71].

[70] Marsh 2022 - Hydrogen in the UK: Challenges of a clean hydrogen strategy (link)
[71] IEA 2023 – Global Energy Review (link)

FIG 16: THERE IS A VERY LARGE UNCERTAINTY ON THE FUTURE HYDROGEN DEMAND IN THE UK



Source: Extrapolated from DESNZ 2021 Hydrogen Analytical Annex.

In the following section, we refer to hydrogen produced via SMR or ATR abated with CCS as "**blue**" hydrogen and to electrolytic as "**green**" hydrogen.

Currently, the UK has a target of 10 GW of low-carbon hydrogen production capacity by 2030, which is pursued with a "twin track" approach that will include the promotion of both green (6 GW) and blue (4 GW) hydrogen. In total, the UK's hydrogen strategy aims at a production target of around 60 TWh of hydrogen (or 1.8Mton) by 2030[72].

4.3.1 Delivery Risk: 2/5

We found a low delivery risk for CCUS-abated hydrogen production in the UK. The main reasons are the high concentration of CO2 in the flue gases and the maturity of the technology.

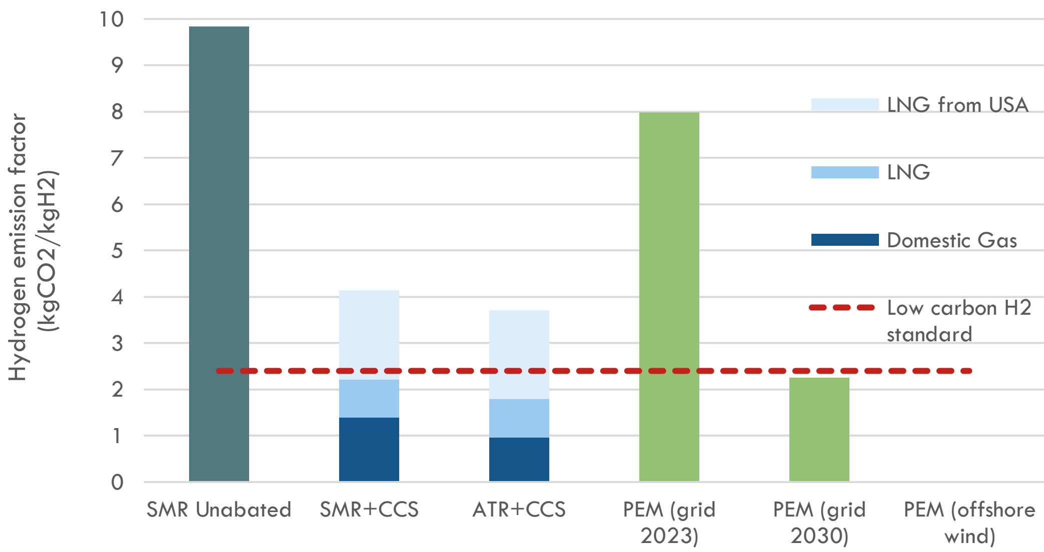
The main benefit of SMR and ATR processes is that the high-pressure gases exiting the reformer contain a high concentration of CO2 (>20%) and very low impurities. For these reasons, the process of separating CO2 from the hydrogen flow is more simple and less expensive. Standard SMRs are slightly more complex with an additional 25% of emissions generated from the combustion of natural gas in a furnace that provides heat to the process[73]. The existing applications of CCUS on SMRs capture only the CO2 generated in the reformer. Thus, to achieve high emission reduction in SMRs, post-combustion technology would be needed, increasing the complexity and cost of the project. However, two of the three projects selected in the Track-1 cluster focus on ATR technology, which avoids this step and promises to deliver capture rates above 95%[74].

Secondly, the hydrogen sector is one of the few sectors that already sees various successful experiences with CCS today with seven large-scale projects (aggregate capacity 8.8Mton of CO2) operating both in coal and gas-based hydrogen production (see Chapter 2.1.2).

[72] DESNZ 2023 - Hydrogen production delivery roadmap (link)
[73] Katebah et al 2022 - Cleaner Engineering and Technology Journal (link)
[74] BP Teesside (link) Vertex Hynet (here)

A potential matter of concern for blue hydrogen production in the UK is the stringent emission intensity limit of 20gCO2e/MJ (equivalent to 2.4 kgCO2e/kgH2) of produced hydrogen set by the Government for hydrogen to be certified as low carbon[75]. The emissions from unabated blue hydrogen production range between 8.5-9.5 kgCO2e/kgH2 (see Figure 17). Compliance with the emission limit, which includes upstream emissions incurred during the extraction and transport of gas, is more challenging for SMR-CCS hydrogen. It also requires high capture rates in the post-combustion side of the plant (the most complex and risky one). For this reason, notwithstanding the higher capital costs, the industry is focusing prevalently on ATR technology for large-scale blue hydrogen projects. Blue hydrogen produced from natural gas with high upstream emissions, e.g., imported LNG, would unlikely comply with the emission standard.

FIG 17: EMISSIONS INTENSITY OF DIFFERENT HYDROGEN PATHWAYS VS EMISSION LIMIT IN UK



Source: Carbon Tracker (2024) SMR: Steam Methane Reforming ATR: Autothermal Reforming PEM: Proton Exchange Membrane electrolyser. SMR unabated emissions 8.47kgCO2/kgH2 + upstream central case; SMR capture rate 90%; ATR capture rate 95%; upstream emissions from UK Low Carbon Hydrogen Standard (default data) best caste, central (LNG), worst case (LNG USA).

The UK's CCUS "Track-1" selected three blue hydrogen projects to move forward, these projects could deliver a combined hydrogen production of up to 2 GW by 2027. Numerous other projects are looking at CCUS-based hydrogen production in the UK, including expansions of the projects included in Track-1.

These technical reasons, in addition to the progress observed from the industries that are going to develop these projects, justify our low delivery risk for this sector[76].

4.3.2 *Stranded Asset Risk: 4/5*

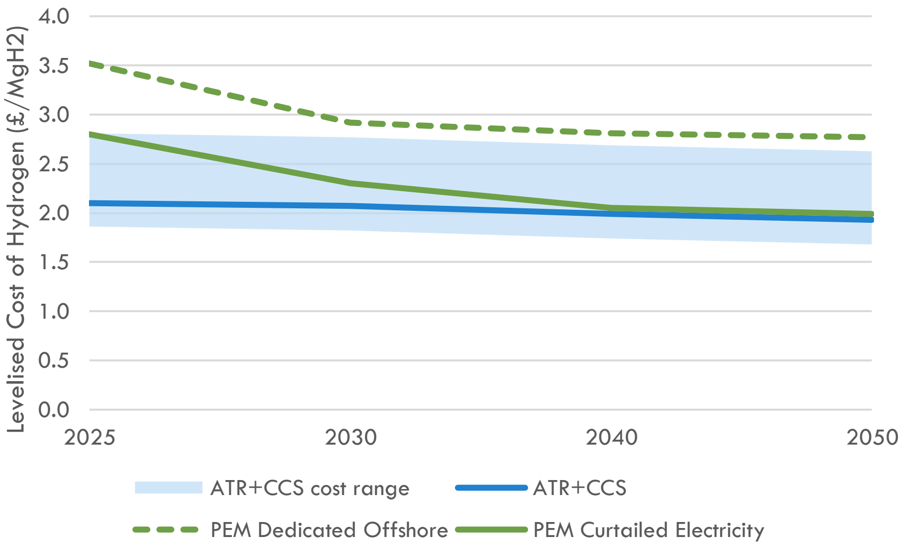
We consider that CCS-based hydrogen production in the UK faces a high risk of stranding due to the competition from green hydrogen and potential demand shortfalls.

[75] DESNZ 2023 - UK Low Carbon Hydrogen Standard (link)
[76] Hynet's Hydrogen Production Plant (HPP1) is moving forward having receive in January 2024 the green light from local councils (link)

Today, blue hydrogen is significantly cheaper than green due to the high electricity costs and the limited availability of surplus generation from renewables. The first Hydrogen Auction Round (HAR1) for green hydrogen production delivered prices of £241/MWh (equivalent to £9.5/kg). In comparison, blue hydrogen costs are estimated at around £2–3/kg today[77].

We modelled that green hydrogen produced with curtailed electricity will be competitive with blue hydrogen starting in the mid-2030s; green hydrogen produced from dedicated offshore wind generation could still be more expensive in 2050. While curtailed electricity is still rather limited today, electricity curtailment is set to grow dramatically by 2030. We estimate that in Scotland, up to 20% of the wind generation risks being wasted due to grid congestion by 2030[78]. As a result, important volumes of low-cost green hydrogen could enter the market.

FIG 18: GREEN HYDROGEN FROM CURTAILED ELECTRICITY COULD BECOME COMPETITIVE IN THE MID-2030S



Source: Carbon Tracker (2024), elaborated from DESNZ Hydrogen Production Costs 2021; ATR: Autothermal Reforming PEM: Proton Exchange Membrane electrolyser. ATR+CCS natural gas cost range £20-40/MWh Central case £25/MWh; PEM dedicated offshore wind costs from DESNZ 2023 electricity generation costs; PEM curtailed electricity at capacity factor 25% and £0/MWh, values in GBP2022.

Blue hydrogen could have an immediate application in replacing the current consumption of unabated hydrogen in the UK's refineries and chemical industries. In the medium term, "new" demand for hydrogen-as-fuel would materialise from heavy industries and the power sector. In these applications, which require large investments in storage and transport infrastructure, blue hydrogen could help to kickstart the adoption in these new sectors as green hydrogen could still be scarce and higher cost.

Nonetheless, two important questions remain for the long-term competitiveness of blue hydrogen.

First, the cost of blue hydrogen is strictly linked to the cost of the underlying commodity, natural gas. The recent energy crisis has clearly shown the high levels of volatility of the international gas markets.

[77] DESNZ 2023 HAR1 results (link); S&P 2023 (link)
[78] CTI 2023 – Gone with the Wind (link)

While costs are now receding to more sustainable levels, there is high uncertainty on the horizon for natural gas. As a result of updated commodities prices, BloombergNEF's latest market outlook estimates an acceleration by 1–3 years on the date when green hydrogen undercuts blue in most markets, which could happen by 2033[79].

Second, there is a significant off-taker risk for the nascent hydrogen sector as future demand could grow slower than the current production targets. This is well depicted in the UK's hydrogen strategy, where the 2050 projection for hydrogen demand ranges between 4 Mton and 17 Mton[80]. We anticipate that future hydrogen demand will trend closer to the lower-end projection, as hydrogen uptake in the heating and transport sector is very unlikely. Numerous independent studies (currently 54) have consistently found that there will be no significant role for hydrogen in the heating sector[81]. Similarly, electrification is clearly becoming the preferred option to decarbonise the transport sector, perhaps with shipping and aviation as exceptions.

Thus, while blue hydrogen could be an effective strategy to accelerate the creation of the hydrogen industry, it faces important stranded asset risks in the late 2030s when green hydrogen and demand shortfalls could lead to market saturation. Particularly, we warn that the operating lifetime of blue hydrogen plants could be shortened significantly in this scenario.

4.3.3 Cost Premium: 2/5

We found a low-cost premium for blue hydrogen due to the low capture cost for this technology. We estimate that carbon capture could increase the cost of producing hydrogen by up to £0.5 per kg compared to unabated SMR, resulting in a cost premium between 6% and 20% depending on the future cost of hydrogen.

Power Sector

Decarbonisation of the power sector is the most urgent and closer-term energy transition target on the road to net zero emissions by 2050. The current UK's policy ambition is for a decarbonised power sector by 2035. In 2021, the power sector was by far the largest source of industrial emissions in the UK with 53 Mton of CO2[82].

In this context, a role has been proposed for carbon capture to abate emissions from flexible power plants – gas-fired combined cycles (Gas-CCS) – and generate negative emission credits through bioenergy with capture and storage (BECCS).

4.4 BECCS

Biomass-based power generation plays an important part in the UK's electricity mix. In 2023, biomass and waste accounted for 6% of the UK's total electricity generation (wind 30%, solar 5%, hydro 1%)[83]. Biomass electricity generation is concentrated in the Drax power station, which with

[79] BNEF - 2023 Hydrogen Levelized Cost Update: Green Beats Gray (link)
[80] DESNZ 2023 - UK Hydrogen strategy (link)
[81] Hydrogen Insight 2023 - 'Unambiguous' | A total of 54 independent studies now say there will be no significant role for hydrogen in heating (link)
[82] Energy and emissions: 2021 to 2040 (May 2023 update) (link)
[83] Elaborated from National Grid ESO data

2,600MW of installed capacity accounts for about 80% of the UK's biomass-based electricity generation.

Bioenergy with capture and storage (BECCS) is a critical technology to achieve the UK's 2035 target of net zero emission in the power sector. Negative emissions from BECCS would offset the emissions generated by the residual unabated gas-fired plants that will still be needed in 2035 for the security of supply. According to National Grid's Future Energy Scenarios, there could be between 1.7 GW and 4.7 GW of BECCS capacity in the system in 2035.

The conversion of the Drax power station to BECCS is the largest carbon capture project in the UK pipeline, with the potential to capture up to 8 Mton CO2 per year (2 units with 4 Mton).

4.4.1 Delivery Risk: 3/5

We allocate a medium-high delivery risk for Drax BECCS because of two main factors. First, for the troubled experiences of CCS in the power sector, and second, for the uncertainty of Drax's financial outlook and the negotiations with the Government. To date, the most advanced applications of BECCS are some small-scale demonstration projects with the largest being Mikawa CCS in Japan, where CCS has been retrofitted to a 50MW biomass power plant to capture around half of the plant's emissions. The capture capacity is around 0.2 Mton per year[84]. In the UK, Drax has been running a small-scale pilot on BECCS since 2019[85].

The CCS experience with coal-fired power plants shares many similarities with how BECCS could work. However, as mentioned in the first chapter, CCS has a poor track record in this sector. The only two commercial applications (Boundary Dam and Petra Nova) have struggled both financially and technically, underdelivering significantly on initial claims.

Installing CCS at Drax will increase the level of complexity and scale compared to those two projects. Firstly, the flue gases of biomass combustion contain a higher level of impurities and pollutants that can interfere with the amine solvent needed to capture CO2[86]. Both the coal-based power CCS plants (Boundary Dam and Petra Nova) experienced issues with solvent management and degradation; biomass combustion could make this problem worse. Secondly, the scale of the project is much larger than the largest power-CCS project in operation (650 MWx2 units Drax vs 240MW for Petra Nova). This project would be a first-of-a-kind – as CCS has never been applied at a large scale on biomass power plants – and simultaneously would likely be the largest BECCS project in the world. Such an ambition relying on unproven technology increases the risk of delivery and cost overruns.

Additionally, while capturing emissions from the combustion of sustainably-sourced biomass generates carbon credits, the emission incurred on the supply chain (i.e., processing, pelletisation and shipping) should be discounted from the overall budget. Supply chain emissions for Drax are around 100 kg_{CO2}/MWh of electricity, one-third of the emissions of a modern gas-fired power plant (~350 kg_{CO2}/MWh), but still ten times higher than wind-based electricity (~10 kg_{CO2}/MWh)[87].

[84] Toshiba 2020 – Toshiba Starts Operation of Large-Scale Carbon Capture Facility (link)
[85] Drax 2019 - Carbon dioxide now being captured in first of its kind BECCS pilot (link)
[86] UK CCS Research Community (UKCCSRC) 2022 – Gibbins and Lucquiaud (link)
[87] Drax – Annual report 2022 (link)

The second critical aspect in the delivery of BECCS at Drax Power Station is the uncertainty around Drax's financial outlook which is heavily dependent on the result of a key negotiation with the Government. The company is set to run out of its most important revenue stream in April 2027 when the existing subsidy for biomass will expire. The company is currently in formal discussions with the UK Government to set up a bridging mechanism between the end of current renewable schemes in 2027 and BECCS[88]. Additionally, the company's debt structure has recently come under scrutiny from investors and the sustainability credentials of burning biomass are being challenged by the UK regulator and environmental groups[89].

Drax announced in its 2023 half-year report that UK BECCS investments are currently paused subject to further clarity on the support mechanisms (i.e., subsidies) at Drax Power Station[90]. In its full-year results for 2023, the company announced that they are now targeting a start date for the first unit of 2030, delayed by three years on the previous target, with a second unit to follow[91].

The negotiations taking place with the Government, which is expected to take a decision by 2025 or 2026, are crucial for the future of the project. We expect that any further delay to the current targeted FID date of 2026 could spell the end for BECCS at Drax.

Failure to find an agreement would likely lead Drax to abandon the plan and focus on developing projects in the US, where the $85 per ton of CO2 incentive, introduced with the Inflation Reduction Act, provides a strong incentive for its BECCS ambitions. Drax has identified two sites for the development of BECCS in the US, with the first site due for a FEED study in 2024.

Nonetheless, we expect that smaller-scale projects could have a higher chance of success due to the lower risks and the overall lower capital requirements. In conclusion, due to both technical and financial challenges, there is a significant risk that BECCS will not be delivered at the scale and speed required by the CCC's "The Sixth Carbon Budget".

4.4.2 Stranded Asset Risk: 4/5

BECCS faces a high level of stranded asset risk in the UK. On one side, BECCS is currently the only credible option for the UK Government to achieve the 2030 removal target (i.e., 5 Mton). On the other hand, the electricity produced by BECCS will be much more expensive than other renewables.

Due to its high cost, the electricity produced from these plants will struggle to compete with lower-cost sources of renewable energy. This is especially important because the plant is planned to operate with a baseload profile due to its design characteristics and the high fixed costs. As periods of zero or negative prices are set to grow enormously in the coming years, BECCS plants will face strong competition to sell their output while they will not be able to maximise value by focusing only on periods of high demand and low renewables. (We estimate that by 2035, almost 50% of the hours will experience surpluses in renewables generation[92].)

[88] DESNZ 2024 – Transitional support mechanism for large-scale biomass electricity generators (link)
[89] Bloomberg 2023 – Drax Under Scrutiny From Short Sellers Over Debt Structure (link); Euractive 2023 - UK sued for counting wood burning with carbon capture as 'negative emissions' (link); FT 2023 - Drax faces probe over sustainable biomass claims (link)
[90] Drax – Half year results for the six months ended 30 June 2023
[91] Drax – Full year results for the twelve months ended 31 December 2023
[92] Internal CTI power sector model

An additional cost risk comes from the biomass pellets needed to power the process. Currently, most of Drax's biomass is imported from North America; in 2023, the supply chain experienced high prices due to inflationary pressure and market volatility. In recent news, Enviva, one of Drax's pellet suppliers and the world's largest pellet producer, saw catastrophic losses in its third quarter and feared to be filing for bankruptcy, posing growing pressure on the global biomass supply chain[93].

BECCS plants would need strong subsidy support – in the form of CfD contracts – to ensure long-term profitability. However, these contracts would be trading at a strong premium compared to other renewable sources, increasing the volume of subsidies needed to keep these plants in operation. Revenues from carbon credits would be critical in determining the profitability of BECCS plants. The Government's preferred option to support BECCS projects is to rely on a Dual-CfD covering both electricity and carbon credits. However, there are still many unknowns regarding carbon credit markets[94]. Identifying the reference price for carbon credits could be challenging. Today, voluntary credit markets are still at a very early stage characterised by low liquidity and low prices. An alternative solution would be to price negative emissions at the same level as UK ETS allowances. However, this would require a significant redesign of the existing rules.

The think tank Ember, which recently increased its projected subsidy cost for Drax BECCS to £1.7 billion per year, estimates that the subsidy scheme for the conversion of Drax risks locking taxpayers' money into a long (15–25 years) and costly (£26–43 billion) contract[95]. In addition the cost of the bridging mechanism between 2027 and 2030 could be in excess of £2 billion[96].

We estimate that BECCS could be by far the most expensive technology in the CfD basket, surpassing even experimental technologies, such as Tidal. Even when considering a generous carbon credit (i.e., £80/tonCO2), BECCS would cost three times more than the latest contracts for offshore wind (see Figure 19).

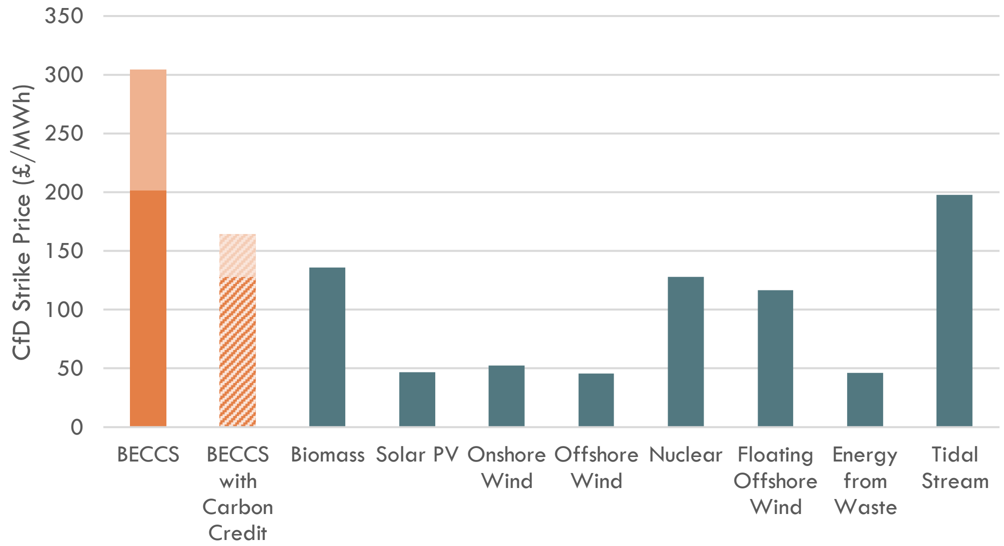
Many factors could challenge the competitiveness of BECCS. However, the proposed Dual-CfD could shield projects from some of these risks by offloading the costs to consumers.

4.4.3 Cost Premium: 5/5

We calculated a very high-cost premium to retrofit biomass-fired power plants with CCS. The additional cost for carbon capture in biomass-fired power plants could be between £65/MWh and £100/MWh. As a result, installing BECCS could come at a cost premium between 55–147% of the future cost of electricity. Even after including a generous payment for the negative emissions, the price of BECCS could see a cost premium of up to 41%.

93 WSJ 2024 - Wood Pellet Maker Enviva Prepares to File for Bankruptcy (link)
94 DESNZ 2023 - Business model for power bioenergy with carbon capture and storage (Power BECCS) (link)
95 Ember 2024 - Drax's BECCS project climbs in cost to the UK public (link)
96 DESNZ 2024 - Biomass power transitional options: impact assessment (link)

FIG 19: BECCS COULD BE THE MOST EXPENSIVE TECHNOLOGY IN THE CFD BASKET



Source: Carbon Tracker (2024). CfD strike price for BECCS based on own modelling (carbon credit of £80/ton for negative emissions) and latest costs from CfD registry for other technologies, accessed January 2024 (here).

4.5 Gas-CCS

The UK's power sector is still highly reliant on unabated gas-fired power plants, which were still the largest source of electricity in the country in 2023, providing one-third of the total generation. Nonetheless, gas's role in the power sector is expected to fall dramatically on the road towards net zero by 2035.

The CCC models that by 2035, the role of unabated gas-fired plants should fall to a marginal 2% of generation (or less) and will is replaced by 12-20 GW of dispatchable low-carbon capacity in the form of hydrogen or gas-CCS. In its "Future Energy Scenarios," National Grid ESO found similar results[97]. Unabated gas plants would be relegated to the role of strategic reserves.

Thus, the 28 GW of combined cycle plants (CCGT) operating today are facing an existential challenge of either retrofitting with CCS (or hydrogen) or becoming stranded assets facing early closures.

4.5.1 Delivery Risk: 3/5

We found a medium delivery risk for the deployment of post-combustion CCS on gas-fired power plants. First, to the best of our knowledge, there is no utility-scale gas-fired power plant in operation that adopts post-combustion CCS. We only found two small-scale pilot projects in operation:

- Glacier CCS in Alberta, which captures CO2 from a small-scale gas-fired reciprocating engine, started operation in 2022. Its capture capacity target is 0.05 [98].
- Tata Chemical in Winnington, which captures part of emissions from a 96 MW gas-fired CHP (combined heat and power) plant, started operation in 2022. The CO2 is used in an

[97] CCC 2023: Delivering a reliable decarbonised power system (link); AFRY 2023: Net Zero Power and Hydrogen: Capacity Requirements for Flexibility (link); National Grid ESO Future Energy Scenario 2023 (link)
[98] Entropy Corporate presentation December 2023 (link)

adjacent chemical plant to produce sodium bicarbonate and it features a capture capacity of 0.04 Mton per year[99].

While these projects are proving some initial progress for the technology, their costs have not been disclosed yet and, more importantly, their scale is much smaller than what is planned for the UK. For example, Net Zero Teesside Power would feature an electrical capacity of 860 MW and a carbon capture target of 2 Mton of CO2, 40 times larger than the two pilot projects in operation.

Scaling up a technology by such a high factor comes with high risks and uncertainties. In this context, it is worth citing the failure of the Kemper CCS project. Experts attribute most of the fault for the delays and budget overruns to the massive scaling up of the technology from pilot to commercial scale[100].

The main technical challenge of deploying CCS in gas power plants stems from the very low concentration of CO2 in the flue gases of gas turbines (3-4%, see Table 2). This factor significantly increases the cost, size and complexity of the equipment needed to capture CO2. Additionally, flexible plant operations – quick starts and fast ramp-up of output – pose another technical challenge for the operation of the carbon capture equipment by increasing NOx emissions (harmful for amine solvents) and requiring larger volumes of solvent[101].

These concerns are heightened by the emission standards required to comply with the UK's Dispatchable Power Agreement, the main subsidy scheme for gas-CCS. Failure to deliver high carbon capture rates (above 70%) could result in a loss of the Governmental subsidy essential to keep the plant profitable[102]. As shown above, all the large-scale post-combustion CCS projects in the power sector have struggled to consistently comply with high capture levels.

The UK's CCUS Track-1 project list includes one gas-CCS project, Net Zero Teesside Power, with a final investment decision expected in 2024 and a potential start date in 2027[103]. In addition, we found three more projects, for a total capacity of almost 4 GW (equivalent to about 8 Mton), that are at an advanced stage of deploying gas-CCS plants[104]. An additional 6 GW (about 12 Mton) of projects are considering the technology but are at an earlier development stage.

Regardless of the strong interest from the power industry, we found that due to the technical challenges, this application has a medium to high delivery risk.

4.5.2 Stranded Asset Risk: 5/5

We found a very high stranded asset risk for gas-CCS because of strong competition from other low-carbon flexible assets and the progressive reduction of utilisation rates.

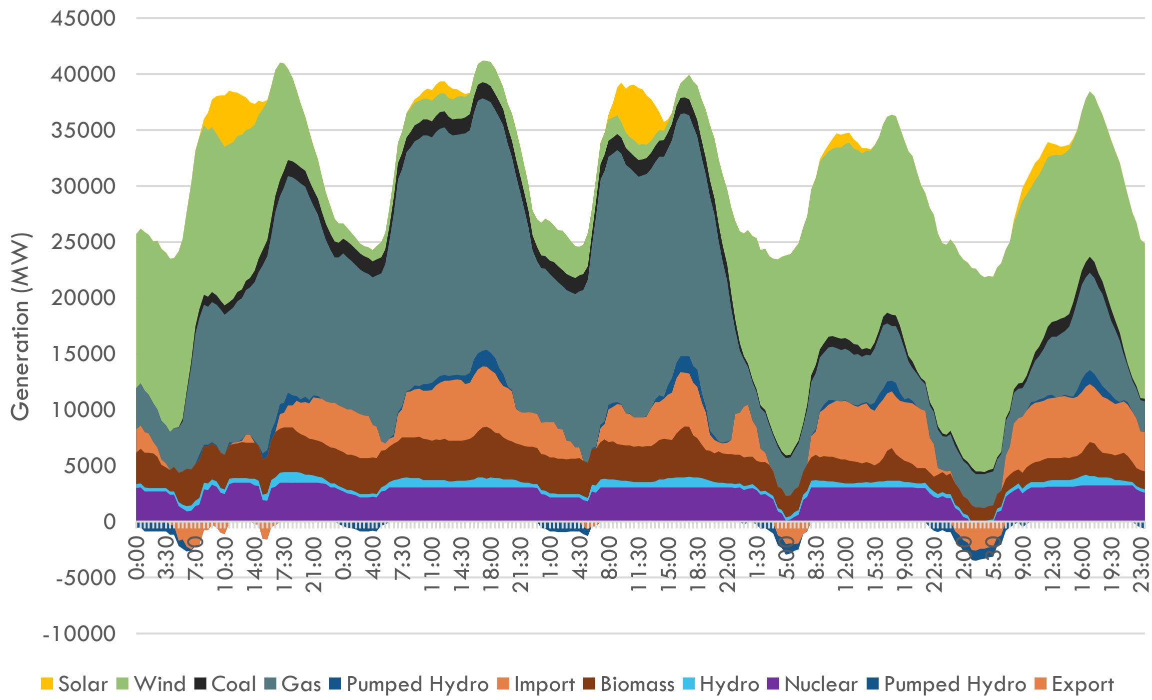
First, we see an important risk of oversupply. In National Grid scenarios, the gas-CCS capacity needed to achieve a net zero power sector by 2035 is between 3-5 GW, compared to as much as

[99] Tata Chemicals – Integrated annual report 2022/23 (link)
[100] IEA 2017 – We can't let Kemper slow the progress of carbon capture and storage (link)
[101] UK CCS Research Community (UKCCSRC) 2022 – Gibbins and Lucquiaud (link)
[102] DESNZ - Dispatchable Power Agreement business model summary, November 2022 (link)
[103] Net Zero Teesside 2023 (link)
[104] Net Zero Teesside, Keadby 3, Peterhead and VPI Immingham

10 GW of projects in the pipeline[105]. The CCC models the range for gas-CCS ranges between 0-5 GW[106].

Secondly, as the penetration of renewables increases, the role of gas-fired plants will move increasingly from baseload operations to flexible peakers, thus, decreasing revenues and increasing costs. We can already spot this trend today; large power plants are increasingly needed to flex their output and are often turned off during periods of high renewable output. The average capacity factor of UK's CCGTs in 2023 was of 35%[107].

FIG 20: EXAMPLE OF FOUR DAYS IN OCTOBER 2023 WITH HIGH FLEXIBLE OPERATION OF GAS POWER PLANTS. THESE EVENTS ARE SET TO BECOME MUCH MORE COMMON AS WIND ENERGY PENETRATION GROWS



Source: Carbon Tracker (2024) data elaborated from Elexon and National Grid ESO from 15-11-2023 to 19-11-2023

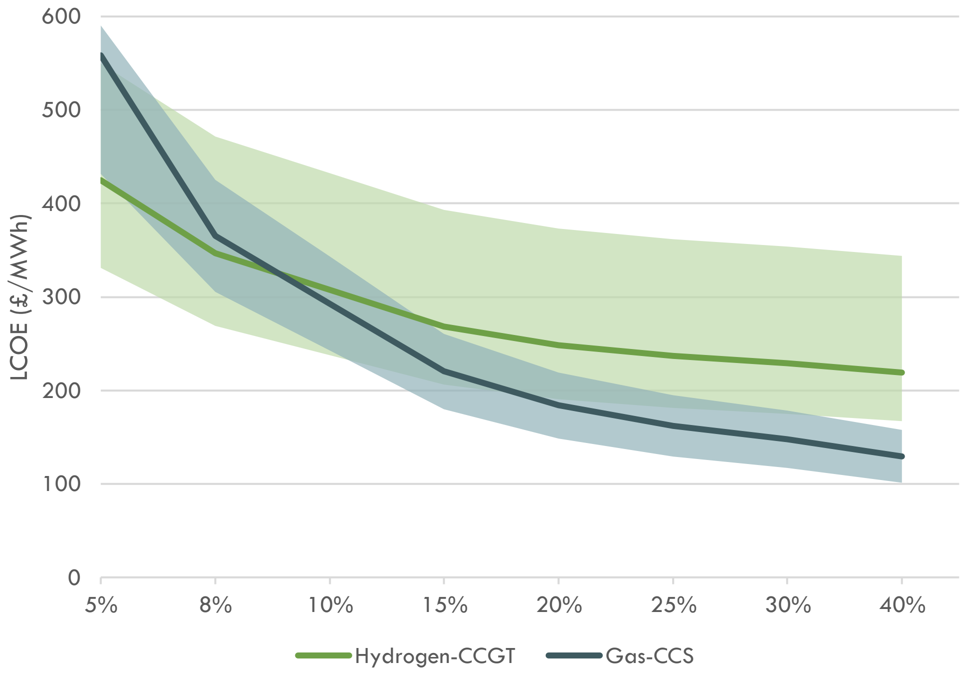
Growing deployment of renewables will decrease the need for baseload power and crowd out gas power plants from the merit order. Battery storage and demand side flexibility will increasingly provide ancillary services and short-duration flexibility, another important source of revenue for gas plants. Reportedly, competition from batteries and flexibility is already increasing the financing costs for CCGT plants in the UK today[108].

Eventually, gas turbines fuelled with hydrogen (green or blue) are the most threatening competitor for gas-CCS, as they could provide the exact same services. In terms of maturity level, hydrogen-CCGTs are currently at a similar level to gas-CCS, with the substantial difference that they require less equipment changes compared to gas-CCS. Retrofitting a gas plant with CCS requires the

[105] National Grid ESO Future Energy Scenario 2023 (link)
[106] CCC 2023: Delivering a reliable decarbonised power system (link)
[107] Internal CTI research based on elexon data
[108] Reuter 2023 - Giant batteries drain economics of gas power plants (link)

addition of large-size new equipment to extract CO2 from flue gases while hydrogen-CCGTs are much more similar to a standard gas turbine and require substantial modifications only on the turbine combustor and the gas-handling equipment[109]. Regarding infrastructures, the amount of extra infrastructure needed for both technologies is comparable, as hydrogen requires both new pipelines and storage sites. However, they can be minimised with the co-location of hydrogen production and power plants.

FIG 21: HYDROGEN TURBINES WOULD OUTCOMPETE GAS-CCS AT LOW-CAPACITY FACTORS ALREADY BY 2030



Source: Carbon Tracker (2024) based on technology cost assumptions from DESNZ in 2030 and own fuel cost projections. Natural gas cost: £20-40/MW – Central: Gas-CCS FOAK 2030 at £25/MWh; Hydrogen cost £2.5-5/kg_H2 (i.e., £75-150/MWh)- Central: Hydrogen-CCGT FOAK 2030 at £3/kg_H2; all costs are inflated to GBP 2022; see Annex for details.

Our cost modelling shows that at low utilisation rates, hydrogen turbines could already be the cheapest alternative in 2030 (see Figure 21). The high capex cost is the greatest weakness for gas-CCS plants; in comparison, hydrogen-fired turbines exhibit significantly lower capital costs, but higher fuel costs (with future potential for cost reductions), which are advantageous at low utilisation rates.

In conclusion, while power-CCS could have a niche role in ensuring the security of supply, most of these plants are not set to come online before 2030 and could experience a high stranded asset risk early in their lifetime due to competition from hydrogen turbines and low-carbon flexibility.

[109] All utility-scale turbine manufacturers already provide turbines that can accommodate a certain degree of hydrogen blending and are developing 100% hydrogen turbines (Siemens Energy, MHI, GE, Ansaldo Energia). Small-scale 100%-hydrogen pilots have been demonstrated, Siemens Energy (link). Kawasaki in 2023 launched on the market a 100% hydrogen turbine (1.8MW) for industrial applications (link)

4.5.3 Cost Premium: 4/5

We calculate a medium- to high-cost premium for gas-CCS. Driven by the high capital cost needed for the carbon capture equipment, the investment cost for a CCS-equipped CCGT unit could be more than double the cost of a standard CCGT[110].

Recently, a FEED study prepared by Bechtel National estimates a capture cost of £92 per ton for a 420 MW gas turbine running for 5000 hours (57% capacity factor). Worryingly, the capture cost would grow dramatically in the case of shorter utilisation and flexible operation of the plant[111].

We estimate that the cost premium for gas-CCS plants could be between £28/MWh and £47/MWh or an increase on the future electricity price between 24% and 67%.

4.6 Aggregated Risk Assessment

We aggregated the scores of the exercise above to highlight the comparative risk of the five applications that we considered. By aggregating the three indicators we can calculate an aggregate risk index.

TABLE 5: AGGREGATE RISK OF CAPTURE PROJECTS IN THE UK

	Delivery risk	Stranded Asset risk	Cost Premium	Aggregate Risk
Cement	4	1	3	**2.7**
Iron and Steel	5	4	3	**4.0**
Hydrogen	2	4	2	**2.7**
BECCS	3	4	5	**4.0**
Gas-CCS	3	5	4	**4.0**

Detailed description of scoring criteria in Annex. Risk Level: 1= very low, 3 = medium, 5 = very high

We found a great opportunity for the deployment of CCUS in the **cement industry**, regardless of the high delivery risk. This sector has no other mature alternative to decarbonise but to invest in carbon capture. The adoption of CCUS could be facilitated by focusing on the key industrial clusters while the sector's competitiveness could be protected by the CBAM mechanism.

We do not consider the **iron and steel** sector as a feasible pathway for the application of CCUS in the UK due to the high delivery risk and stranded asset risk. Both the UK's producers of primary steel are abandoning the idea of retrofitting their plants with CCUS and seem to be moving towards electric arc furnaces. In the longer term, we see potential for a transition towards hydrogen-based steel production, which could yield lower-emission and lower-cost steel compared to CCUS.

We found that **hydrogen** is a promising application for CCUS in the UK due to the unmatched low delivery risks and cost premium. CCUS can remove emissions from the existing hydrogen demand (e.g., oil refineries and fertiliser plants), while operating in highly specialised sectors. Furthermore, CCUS can kickstart adoption of hydrogen in new sectors (e.g., industry and power), however, the

[110] BEIS - Electricity Generation Costs (link)
[111] Bechtel National 2022 - Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (here)

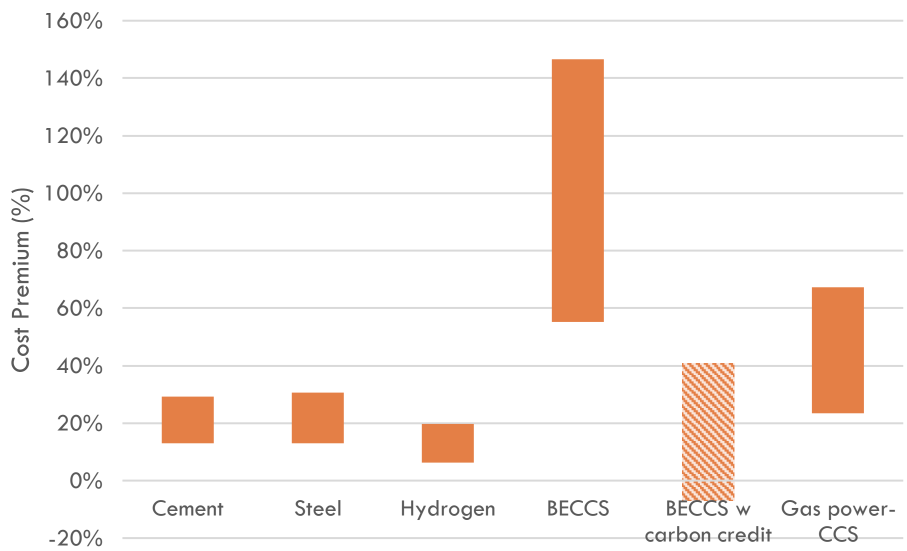
lifetime of these projects could be shortened by the risk of market saturation brought about by green hydrogen and demand shortfalls.

In our assessment, the **power** sector faces the highest challenges for the deployment of CCUS regardless of a strong Government ambition and some projects being already in official negotiations.

For **BECCS**, we found a very high-cost premium; even with the compensation of carbon credits, the technology could still be more expensive than all the other renewable sources and require large subsidies. Additionally, the largest project in the pipeline – Drax power station – is facing numerous challenges both from a financial and technical side, putting the achievement of the Government's greenhouse gas removal target at stake.

Similarly, we found a high aggregate risk for **gas-CCS**, which could provide dispatchable low-carbon flexibility to the grid. However, we see a risk that the industry could repeat the mistakes of its troubled history with CCUS in coal power plants. There are still many uncertainties regarding the actual performance and costs of deploying CCS on large-scale gas-fired combined cycles, especially under flexible operations and reduced running hours. The combination of energy storage and hydrogen-fired turbines can dramatically decrease the window of opportunity for gas-CCS, confining it to the margin of the energy market. The high capital costs needed for this technology risk transforming these investments into stranded assets on companies' balance sheets or on Government finances.

FIG 22: COMPARISON OF COST PREMIUMS FOR CAPTURE PROJECTS IN THE UK



Source: Carbon Tracker (2024).

4.7 Other Sectors

Energy-from-Waste (EfW)

CCUS can be deployed to reduce emissions from waste treatment, especially in plants where non-recyclable waste is incinerated to produce heat and electricity. Currently, two EfW projects have been selected in the "Track-1" shortlist of projects.

While EfW shares many similarities with BECCS from a technological perspective, from an economic point of view, they feature one key advantage: EfW plants are paid to incinerate waste (an effective negative fuel cost) and electricity production is a positive by-product of the process.

Similarly to BECCS, EfW with CCUS can generate emission removals, as around half of the non-recyclable waste is from biogenic sources[112].

For all these reasons, CCUS in the waste sector can provide a promising option to scale up the technology in a smaller sector with fewer decarbonisation alternatives. However, such initiatives should go in parallel with a stronger emphasis on waste reduction and recycling.

Engineered Greenhouse Gas Removals (GGR)

As the CCC's analysis for "The Sixth Carbon Budget" found, CO2 emission reduction alone will not achieve net zero; carbon removals will be needed to compensate for the residual emissions in the hardest-to-abate sectors.

In addition to BECCS and the potential removals from waste, other technologies have the potential to generate negative emissions: afforestation/reforestation, biochar, direct air capture of CO2 with storage (DACCS), enhanced rock weathering and electrochemical ocean carbon removal[113].

These technologies are still at a very early stage and more research and innovation is needed to increase their performance and reduce costs. In the long term, DACCS could offer the most scalable solution for permanent carbon removals. However, the costs and scale of the technology are still prohibitive today. We thus recommend greater efforts towards research and development in DACCS and other promising technologies to bring them to commercial readiness targeting the CCC removals target.

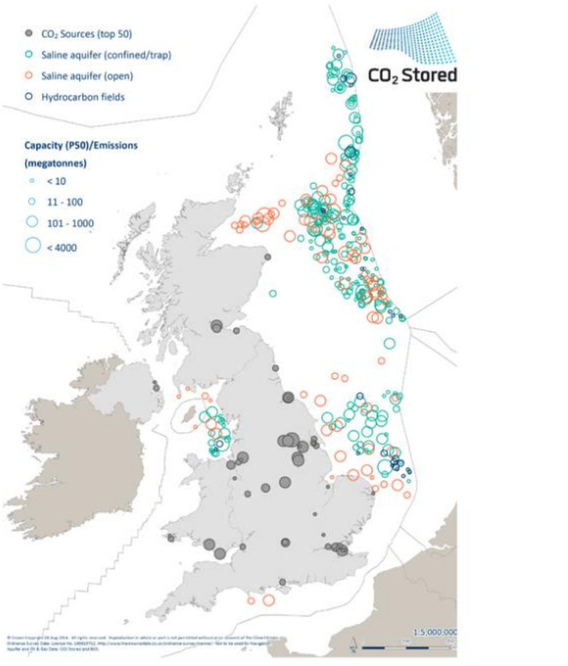
[112] Viridor 2023 - Viridor's Runcorn CCS Project: World leading carbon capture (link)
[113] For more details on rock weathering and ocean removal see Green Alliance 2024 - Does the UK need BECCS to reach net zero? (link)

5 What About Transport and Storage?

In this note, we limited our analyses to the technologies needed to capture emissions. In contrast to the “capture” side of the problem where the Government is adopting a market-based approach, the transport and storage infrastructure will be developed as a regulated sector using the structure of the regulated asset base (RAB) model. However, this does not mean that the downstream sector should not be an area of concern for policymakers.

The UK CCUS clusters are designed to transport the compressed CO2 captured from industrial facilities to offshore underground storage deposits via pipelines. This option is technologically mature and rather low cost. However, outside of industrial clusters, some applications might require relying on non-pipeline transportation (shipping, rail and road), which due to the complexity and inefficiency of the additional conversion steps, could dramatically increase transportation costs.

FIG 23: MAP OF POTENTIAL CARBON STORAGE SITES IN THE UK



Source: British Geological Survey 2023.

The situation is more complex for permanent underground storage. The UK is blessed with excellent potential to store CO2 in underground offshore reserves under the continental shelf. The British Geological Survey estimates this potential above 78,000 Mton (compared to annual emission in 2021 of 343 Mton)[114]. However, as with any activities that involve geological surveys (for example oil and gas exploration), there are many risks and uncertainties with the actual realisation of the projects. The CCS industry is not an exception; the only two existing projects storing carbon offshore (Sleipner and Snøhvit in Norway) faced big challenges related to the unpredictable nature of the underground deposits. In the case of Snøhvit, the initial deposit was expected to have a storage

[114] British Geological Survey 2023 (link)

capacity that would last 18 years. However, the deposit was filled in just three years and CO2 injection was moved to an adjacent deposit[115].

In addition to the uncertainty around the geological deposit, CO2 storage sites have very long lead times for development at around 10 years. Thus, it is essential for backup storage sites to be developed in parallel with the primary sites in order to increase the resiliency of the storage site.

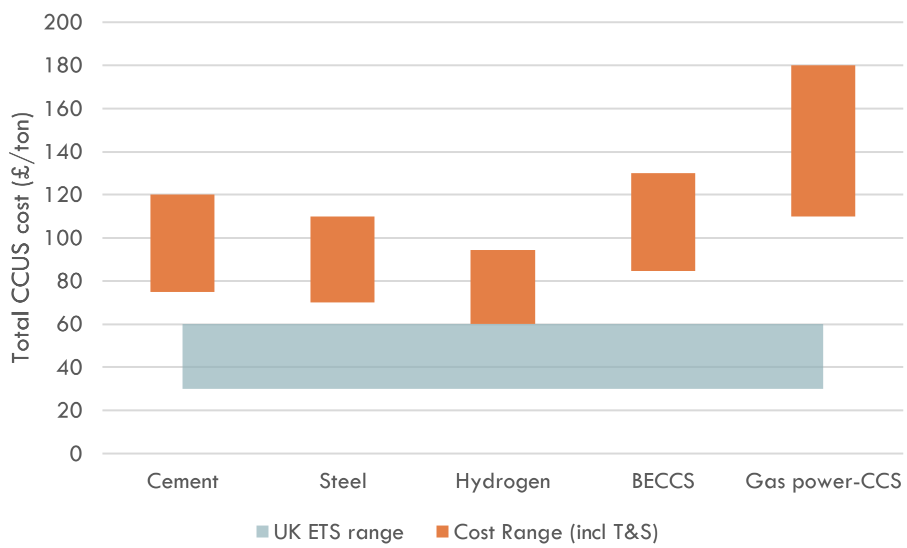
In terms of economics, the extra cost for the transport and storage of CO2 in the UK could range between £20 and £30 per ton of captured CO2 (for pipeline transport)[116].

[115] IEEFA 2023 - Norway's Sleipner and Snøhvit CCS: Industry models or cautionary tales? (link)
[116] Estimated from IEA 2023 CCUS Policies and Business Models: Building a Commercial Market (link)

6 What Price for CO2?

By bringing together CO2 capture cost with transportation and storage costs, we can estimate the range of carbon prices needed to make the CCUS sector profitable under market conditions.

FIG 24: TOTAL ADDITIONAL COST FOR CCUS BY SECTOR COMPARED TO THE UK ETS PRICE RANGE OF THE LAST NINE MONTHS



Source: Carbon Tracker (2024); UK ETS range based on value over the past nine months.

The chart below shows that the carbon price range needed to bring CCUS to market without subsidy support is more than £80/ton CO2; most applications could compete at a price of around £100/ton. Gas-CCS is the only exception that would require prices of at least £120/ton CO2 to justify the cost of CCUS compared to unabated technologies.

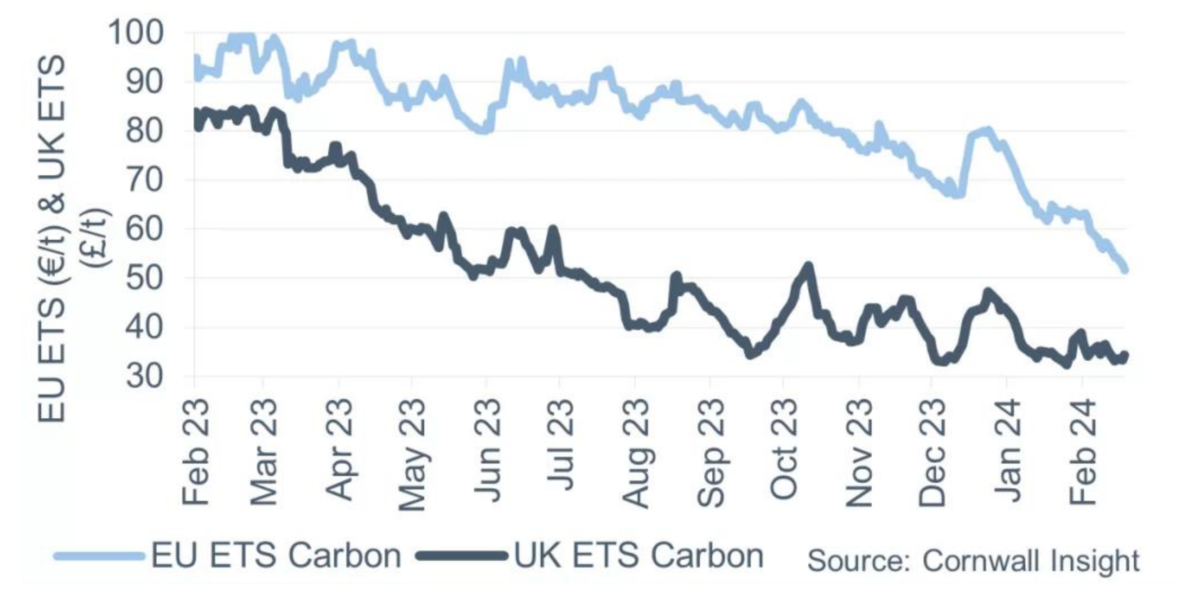
For BECCS, we find that negative emissions should be priced above £80/ton CO2 to compensate for the cost of capture and transport of CO2. However, this still would not cover the higher cost of biomass-based electricity generation compared to other low-carbon alternatives.

These values are in stark contrast with the recent prices of UK ETS, which recently fell to a record low of £31 per ton of CO2[117]. Historically, the UK ETS has been a strong instrument to drive industrial decarbonisation, however, the recent developments have reversed this trend as the market has become "weak and volatile," crashing to historic lows in recent months. The prices of the UK ETS market have been falling sharply in 2023 from around £80/ton in January to around £30/ton in December. The UK ETS prices decoupled further from EU ETS, which fluctuated around £60–80/ton in the same period[118].

[117] FT 2024 - UK carbon price falls to record low (Link)
[118] Team Energy 204 – Energy Wholesale Market Review – 23 February 2024 (link)

What's more, the UK ETS is experiencing increasingly high levels of volatility. We foresee that this trend is set to continue due to the low liquidity of the market since the decoupling from the European market, which occurred due to Brexit.

FIG 25: DIVERGENCE OF CARBON PRICES UK VS EU



Source: Cornwall Insights from Team Energy - Energy Wholesale Market Review – 23 February 2024 (link)

The Government recently announced its willingness to extend the UK ETS beyond 2030 (and at least to 2050) and to align it with the country's net zero targets. In addition, the Government declared its intention to extend the scope of the scheme to more sectors (upstream oil and gas, maritime, waste) in order to review the free allowances and to introduce a carbon border adjustment mechanism (CBAM)[119].

All these measures can send positive long-term signals to investors in the CCUS industry; however, we do not consider them strong enough to determine investment decisions on new CCUS projects. The carbon market is still too volatile and illiquid, and there is too much uncertainty on the long-term price outlook.

We strongly recommend an overhaul of the UK ETS price with a vision to provide clear long-term price signals. Potential measures could be setting a rising price floor or considering linking the UK ETS with the EU scheme. As Energy UK points out, if the UK-EU carbon pricing dynamics remain the same, British companies will have to pay over half a billion pounds per year to the EU simply to export to Europe[120]. It is in the UK's interest to link with the EU carbon market as it could bring higher revenues for the UK exchequer and enable a stronger signal for low carbon and CCUS.

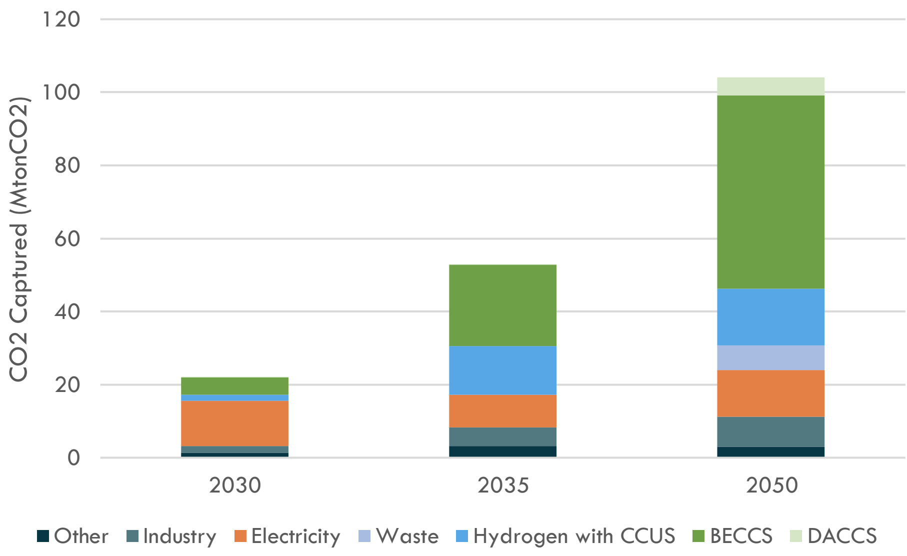
In our view, this is the single most important action needed to deliver the UK's CCUS vision of a self-sustaining and competitive CCUS sector.

[119] DESNZ 2023 - The long-term pathway for the UK Emissions Trading Scheme (link)
[120] Energy UK 2023 - Without linking emissions trading systems, UK companies face higher bills and red tape (link)

7 The Need for New Targets

As we mentioned above, the UK's CCUS strategy is aligned with the recommendations contained in "The Sixth Carbon Budget" published by the Climate Change Committee (CCC), an independent body that advises the UK Government on emission targets and greenhouse gas reductions. "The Sixth Carbon Budget" covers the period from 2033 to 2037 and sets out the level of greenhouse gas emissions the UK can emit during this time while staying on track to meet its long-term climate goals (particularly its legally binding target of achieving net-zero emissions by 2050). Overall, "The Sixth Carbon Budget" provides a comprehensive roadmap for the UK to achieve its climate targets.

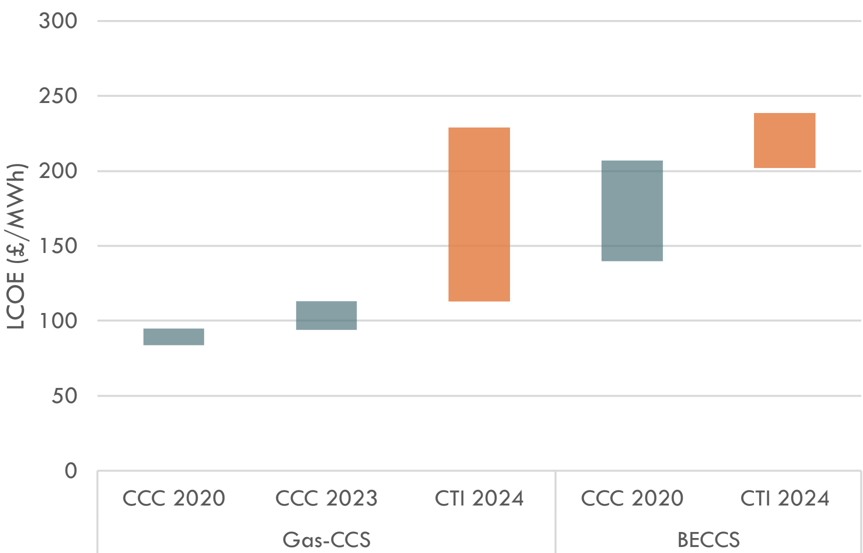
FIG 26: CARBON CAPTURE BY TARGET FROM THE CCC BALANCED SCENARIO



Source: Carbon Tracker (2024), elaborated from the CCC's "The Sixth Carbon Budget" Balanced scenario.

As part of "The Sixth Carbon Budget" modelling work, the CCC estimated the amount of carbon capture needed to comply with the carbon budget. However, we argue that these estimates are based on techno-economic assumptions that are now outdated and should be revised. The CCC found that the power sector and BECCS would play a major role, however, below we show how these results are based on outdated assumptions.

FIG 27: COST COMPARISON OF CCC ASSUMPTIONS VS CURRENT VALUES



Source: Carbon Tracker (2024), elaborated from CCC and own analysis; T&S: transport and storage. CCC 2020: "The Sixth Carbon Budget", CCC 2023: Delivering a reliable decarbonised power system. Gas-CCS CTI based on DESNZ FOAK 2030 with fuel cost of £25/MWh and capacity factor between 15-50%. BECCS cost estimated based on methodology above. Costs are annualised to GBP 2022.

Our estimate of the Levelized Costs of Energy (LCOE) of gas-CCS is more than twice the original figure used to model "The Sixth Carbon Budget." Regardless of us relying primarily on official sources, the main difference we introduced is to model a more realistic capacity factor. The estimate used by the CCC is based on the assumption that these plants would operate with a baseload profit, hence with a capacity factor of 80% or higher. In reality, it is widely recognised that the utilisation of these plants will be much lower, limited to hours with low renewables output. In 2023, the CCC published a report that looked at the power sector in detail and found that gas-CCS plants would indeed operate with a capacity factor of around 40%; National Grid models [121]. Our internal models suggest that even this figure could be optimistic, and their capacity factor could be as low as 15% by 2035.

Interestingly, the 2023 CCC report found that hydrogen-fired plants are more cost effective than gas-CCS due to their improved competitiveness at low utilisation. Out of the 17GW of dispatchable lower-carbon capacity needed by 2035, gas-CCS would provide only 2 GW, while hydrogen-fired plants would make up the rest. We estimate that this alone could cut the captured emission in the power sector from 9 Mton to around 2.5 Mton by 2035.

Similarly, we found that the cost assumptions for carbon removals BECCS and DACCS are more optimistic than the cost range that we estimated based on recent market data. For BECCS, our cost estimates are around 25% higher than the values used for "The Sixth Carbon Budget" model. For DACCS, the discrepancy is even larger; the cost range used by CCC for DACCS (£200-300 per ton of CO2) is very optimistic. Currently, global DACCS costs are estimated at around £560–800 per ton ($700–1,000 USD), while costs are projected to fall between £320-500 by 2030. The current best estimate is from Occidental Petroleum, which aims for its Texas plants to reach £320 per ton

[121] CCC 2023: Delivering a reliable decarbonised power system (link); AFRY 2023: Net Zero Power and Hydrogen: Capacity Requirements for Flexibility (link); National Grid ESO Future Energy Scenario 2023 (link)

by around 2030 ($400 USD)[122]. In the UK, where energy prices are one order of magnitude higher than what Occidental can get in Texas, such cost ranges are extremely unlikely. (Note that DACCS costs are heavily linked to energy prices.)

Additionally, due to their capital-intensive nature, CCUS projects would be affected by the recent surge in interest rates and raw material costs that have caused troubles for the European wind industry. On the other hand, battery storage and solar are consistently delivering cost reductions that exceed expectations[123].

Bringing all these factors together suggests that the CCUS targets outlined in "The Sixth Carbon Budget" could be significantly overestimated and that an updated model would feature a much lower role for CCUS and higher reliance on renewables, electrification and storage.

The CCC is currently updating its research in view of the publication of the 7th Carbon Budget recommendations planned for early 2025. We strongly recommend that the Committee update its techno-economic assumptions and as a result, we would expect a downscaled and more targeted contribution from CCUS. We advise that the UK's CCUS targets should be revised accordingly.

[122] See Chapter 2.1.4
[123] BNEF LCOE update 2H 2023 (link)

8 Recommendations

The UK has all the right credentials to develop a CCS industry: a high ambition, the right geology, funding resources, a supportive industry and the right technical skills. However, we found that there is still a high risk that the CCUS sector will fail to deliver on the Government's ambition due to both technical and economic challenges. Furthermore, we found that the current targets are based on outdated techno-economic assumptions overly optimistic towards CCUS.

We advocate for policymakers to take a cautious approach towards a technology that, on a global scale, has consistently failed to deliver results, despite the large resourcing that has been channelled into this sector. The CCUS supply chain does not show evidence of developing technology learning rates that could lead to substantial cost reductions. This is because of thermodynamic limitations, engineering challenges, low modularity, geology risks and the need for bespoke engineering.

For these reasons, we urge the Government to prioritise the demonstration of CCUS in no-regret sectors while focusing on the delivery of first-of-a-kind technologies. Applications in sectors with no alternatives and low-cost premiums should be prioritised due to their opportunity to be more resilient to the risk of cost overruns and competition from other technologies. On the other hand, applications that would unnecessarily extend the lock-in on fossil fuels should be avoided and minimized. Finally, a transition plan with lower reliance on CCUS should be developed.

1. Firstly, we urge the Government to **revise its CCUS targets** based on updated and more realistic assumptions on the technology's outlook. A more targeted approach towards CCUS would allow for focusing the Government's resources on high-value and low-risk applications, while potentially developing the technology needed for other sectors.
2. For the **industrial sector**, we strongly recommend focusing on delivering CCUS in the **cement** industry. This sector, which is strategic for the British economy, has no other alternative to decarbonise and faces a rather low-cost premium that could be shielded by the planned introduction of a CBAM. Some cement sites away from major industrial clusters could require custom-built transport infrastructure.
3. In the **steel sector**, we found that CCUS could be inferior to hydrogen, which could deliver greater emission reductions at a comparable price. For this sector, we recommend abandoning CCUS and focusing on a longer-term transition towards hydrogen-based green steel.
4. We found a medium to low risk for CCUS in the **hydrogen** sector. The technology is the most mature and has already been successfully deployed at scale in the chemical industry.
    a. Initially, the deployment should focus on the petrochemical and fertiliser industry to replace the existing demand for unabated hydrogen with the added advantage of operating in highly skilled industries.
    b. In the medium term, blue hydrogen could play a role in kickstarting "new" uses of hydrogen for the industry and power sector.
    c. However, from the mid-2030s, we see an increasing risk of stranding and market saturation due to rising green hydrogen production and demand shortfalls. The long-term outlook is still very uncertain, but we expect that the window of opportunity for blue hydrogen will be determined by green hydrogen's ability to scale up production and bring down costs.
    d. Finally, as the energy system transitions away from natural gas, blue hydrogen's dependency on the fuel risks locking in continued dependency on fossil fuels.

5. We found a high aggregate risk in the **power sector**, where renewables, battery storage and new flexible technologies pose a great competitive risk against CCUS.
    a. **BECCS** is the only realistic option for the Government to reach its carbon removal target of 5 Mton of CO2 by 2030. However, we found a high risk linked with this pathway. Most of the BECCS potential will come from one single site that is still very uncertain due to both technical and financial challenges.
        i. We consider it unlikely that BECCS will be able to deliver on the current targets and timelines.
        ii. There is a risk of locking taxpayers into an expensive and long-term subsidy scheme with large BECCS projects.
        iii. We recommend the Government focus on smaller projects that can demonstrate the technology with a smaller delivery and stranded asset risk.
        iv. In the case of under-delivery, we encourage that more focus be placed on accelerating renewables, efficiency and electrification, rather than turning to other types of large-scale baseload power plants and/or very expensive carbon removal technologies.
    b. We found a high risk for **Gas-CCS** in all the categories despite its functional role in delivering a net zero power sector by 2035. There is a high risk of successfully scaling up gas-CCS to the size of the projects under development. In addition to the high-cost premium, this application is faced with a strong stranded asset risk due to competition from other low-carbon flexibility options, especially hydrogen turbines.
        i. We recommend prioritising first-of-a-kind projects as soon as possible to demonstrate the technology.
        ii. Further investments should be subject to technology demonstration in order to minimise stranded asset risk and subsidy costs for taxpayers.
        iii. Meanwhile, investment in hydrogen turbines should be accelerated as a potentially more competitive option to deliver long-duration flexibility.
        iv. We envisage that due to its high capital cost and limited operating hours, gas-CCS will play only a limited role in providing low-carbon dispatchable power in parallel with a growing deployment of hydrogen power.
6. **Waste-from-energy** with CCS should be pursued to build expertise and abate emissions from non-recyclable waste management in parallel with advancing waste reduction and recycling efforts.
7. **Direct air capture** (DACCS) and other carbon removal technologies are still at a low level of technological maturity. We recommend that research and innovation be focused on these areas, aiming towards cost reductions and scalability.
8. The UK Government should focus on ensuring the coordination between capture projects and **transport and storage** infrastructure.
    a. Back-up storage sites should be considered in parallel to primary sites due to the high uncertainty of geological site development.
    b. Due to the higher costs, non-pipeline transport should only be considered for sectors with no decarbonisation alternatives.
9. We urge a deeper reform of the UK's **carbon market** (UK ETS) that could deliver a stronger long-term price signal above £100 per ton CO2 in the 2030s to achieve the Government's goal of creating a self-sustaining and competitive CCUS sector.
    a. Our preferred option is to consider linking the UK ETS market with the continental European market.

9 Annex

Currency conversions based on 2022 rates:

Exchange rate	
USD -> GBP	0.81
EUR -> GBP	0.96

Consumer price inflation (CPI) index (2015=100) from Office of National Statistics (ONS):

	2018	2019	2020	2021	2022
CPI Index	105.9	107.8	108.7	111.6	121.7

Assumptions used for carbon capture cost (excluding transport):

	Capture Cost Range (2022GBP/ton_CO2)	
Cement	55	90
Iron and Steel	50	80
Hydrogen	40	65
BECCS	65	100
Gas-CCS	90	150

Carbon Capture costs have been collated by a review of published scientific literature, technical studies, and company reports including international organisations such as the IEA, BNEF and the National Petroleum Council.

Process emissions:

	Process emissions		
Cement	650	kg_CO2/ton_cement	Credit Suisse 2021
Iron and Steel	1950	kg_CO2/ton_steel	MakeUK 2023
Hydrogen	8.5	kg_CO2/kg_H2	Katebah et al 2022
BECCS	1140	kg_CO2/MWh_electricity	Internal modelling based on pellet fuel emission factor and biomass power plant efficiency
Gas-CCS	350	kg_CO2/MWh_electricity	Internal modelling based on natural gas emission factor and CCGT class-H efficiency

Description of risk-scoring criteria:

Delivery Risk		
1	Very low	High level of technological maturity, there are already successful examples of commercial-scale deployments. High interest from the industry with projects in the pipeline and under construction.
3	Medium	The technology has seen some commercial-scale deployment with mixed results. Additionally, there is a significant pipeline of projects under development.
5	Very high	Low technological maturity, the technology has been tested only at a very small scale and without successful case studies. Low interest from the industry in investing in this application.
Stranded Asset Risk		
1	Very low	There are no mature alternative technologies to decarbonise the product/service, while future demand is not supposed to change.
3	Medium	There are some potential alternative technologies, however their maturity, competitiveness or emission reduction is still lower. Future demand is uncertain.
5	Very high	Various mature technologies could provide the same product/service, at a competitive (or lower) cost and produce similar (or lower) emissions. Additionally, demand for the product/service could decrease or change significantly.
Cost Premium		
1	Very low	<5%
2	Low	5%<x<15%
3	Medium	15%<x<30%
4	High	30%<x<60%
5	Very high	x>60%

Benchmark Values for Cost Premium

The benchmark value used for the cost premium is based on an estimate of the future market price of the final product (e.g., cement, steel, electricity). For cement and steel, we based our projection on the price range experienced pre energy crisis.

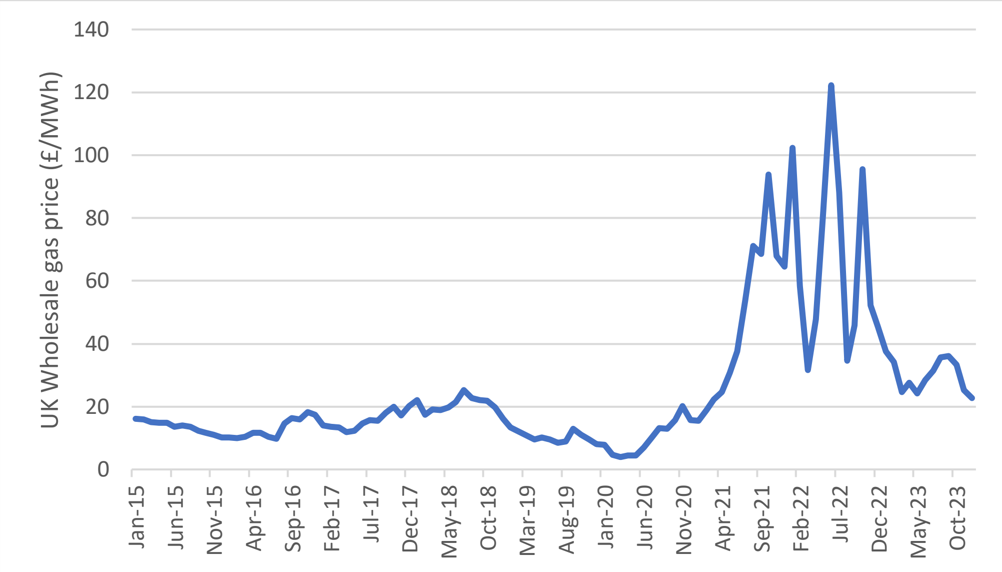
Electricity price ranges are aligned with the official projections of the UK's Government reference scenario.

For the cost of hydrogen, we used a benchmark price based on the projected cost of hydrogen by 2030. This is because hydrogen is not a standard traded product today, so it is not possible to create a relevant benchmark price based on today's market conditions. To build our prediction, we used a wide range that represents the current spread of analysts' forecasts on the cost of hydrogen in the UK by 2030. The upper-end estimate includes a cost surcharge of £0.5/kg for pipeline transport and salt cavern storage (link).

Benchmark cost range		
Cement (£/ton)	180-250	link
Steel (£/ton)	450-675	link
Hydrogen (£/kg)	2.5-5	own estimate
Electricity (£/MWh)	70-120	link

Natural Gas Cost Assumptions

In all our calculations (including future gas prices), we adopted a cost range between £20-40/MWh with a central case of £25/MWh aligned with the UK's Government reference scenario (link).



CfD Strike Price for BECCS

The CfD strike price for BECCS is estimated by adding the CCS premium to the CfD strike price of Drax unit 1. This is a first order simplification as the final strike price would need to consider many more parameters, including contract length and detailed project finance modelling for the whole plant.

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