KIND OF BLUE

The real climate impact of Blue Hydrogen and Gas-CCS

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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 June 2024.

Cover Image: Generated with ChatGPT and DALL-E with the prompt: A highly contrasted image of an LNG import terminal, depicted in vibrant shades of blue. The terminal includes large storage tanks, pipelines, and smokestacks.

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Key Findings

Our previous report, "Curb your Enthusiasm", revealed critical flaws in the UK's £20 billion Carbon Capture, Utilisation, and Storage (CCUS) strategy[1]. We found that it is based on outdated assumptions and disproportionately targets high-risk, non-futureproof sectors. We urged the British Government to revise its strategy decreasing CCUS investments in high-risk sectors, such as power and hydrogen.

Despite this, the British Government is still considering subsidies for these sectors. This report evaluates whether or not gas-based CCUS technologies could have a positive climate impact, assuming the technology would work as claimed by the CCUS industry. We focus on CCUS-based hydrogen – '*blue hydrogen*' – and gas-fired power plants with CCS – '*gas-CCS*'.

- **Blue hydrogen and gas-CCS projects are not inherently low-carbon**: These projects can be considered low-carbon only if, on top of achieving high-carbon capture rates, they can guarantee to utilise natural gas with low upstream emissions.
- **New gas demand from CCUS will increase emissions**: If all the gas-based CCUS projects proposed by the UK's Net Zero strategy are built, by 2035, new gas demand could double domestic production requiring an inevitable reliance on high-emission LNG imports.
- **Underestimated carbon intensity of blue hydrogen**: Current estimates are too low. Blue hydrogen from imported LNG could emit over twice the expected amount, exceeding the UK's low-carbon hydrogen standard by 80% to 170%.
- **Overstated carbon savings from gas-CCS**: The reported climate benefits of gas-CCS ignore or underestimate upstream emissions. Actual emissions reductions could be 30% to 60% lower than claimed.
- **Flawed environmental assessment frameworks**: The UK's reporting framework does not adequately account for future upstream emissions. If all gas-based CCUS projects in the Net Zero strategy are built by 2035, they could consume 22%-63% of the UK's Sixth Carbon Budget over their lifetimes. This oversight threatens to derail the UK's Net Zero strategy.

[1] CTI 2024 – Curb your Enthusiasm: Bridging the gap between the UK's CCUS targets and reality (link)

Executive Summary

Carbon Capture, Utilisation and Storage (**CCUS**) technologies **may generate new demand for natural gas via** the production of CCUS-based hydrogen (i.e., **blue hydrogen**) and gas power plants with CCS (i.e., **gas-CCS**). However, this new demand **could have a dramatic climate impact** due to emissions in the natural gas supply chain, especially if gas is imported as liquified natural (LNG).

Despite uncertainties due to its high cost, hydrogen demand is expected to rise as countries seek low-carbon options to decarbonise hard-to-abate sectors. While green hydrogen (from renewable sources) remains expensive and limited in scale, blue hydrogen could help kickstart the hydrogen market in the short term.

Similarly, according to its proponents, gas power plants with CCS can provide a solution for dispatchable and long-duration power generation (or even baseload) without the emissions from the combustion process.

In aggregate, blue hydrogen and gas-CCS could generate new long-term demand for natural gas. It is thus essential to understand the potential **unintended consequences of this additional gas demand** from a climate perspective.

This report calculates the carbon intensity of blue hydrogen and gas-CCS, factoring in upstream emissions from natural gas extraction, processing and transport[2]. This is crucial for the UK and Europe, which are increasingly reliant on imported LNG, particularly from the USA, following the 2022 energy crisis.

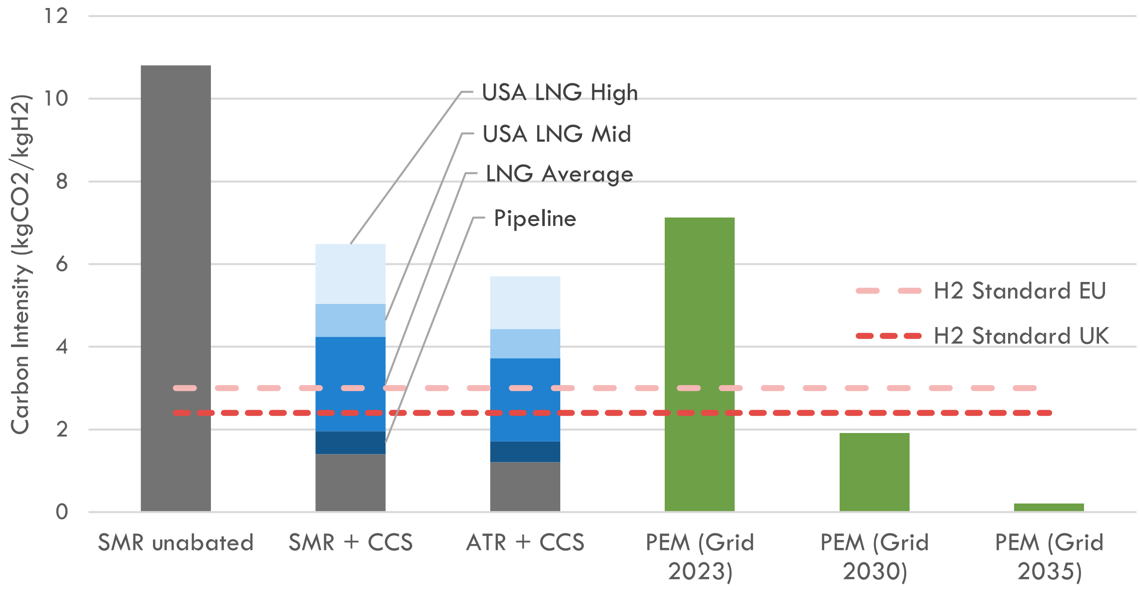
Worryingly, there is great **uncertainty on upstream emissions** that are often **underreported**. For example, independent studies suggest that emissions from LNG from the USA could be 80% to 150% higher than what is reported by the UK's North Sea Transition Authority (NSTA). On average, **LNG imports have a carbon intensity five or more times greater than natural gas from the North Sea**.

However, North Sea gas production is inevitably declining due to depleting reserves and new LNG import capacity is being built. As a result, **increased gas demand from CCUS projects in the UK will lead to higher LNG imports.**

These emissions could more than triple the carbon intensity of blue hydrogen, exceeding UK and EU low-carbon fuel standards. Even with the best technology, blue hydrogen from imported LNG could emit up to 2.5 times more than the UK's low carbon hydrogen standard (LCHS). Green hydrogen, produced from renewable electricity, remains the only truly low-emission pathway.

[2] From here onwards we'll refer to this as upstream emissions including emissions from extraction, processing, transport and distribution of gas.

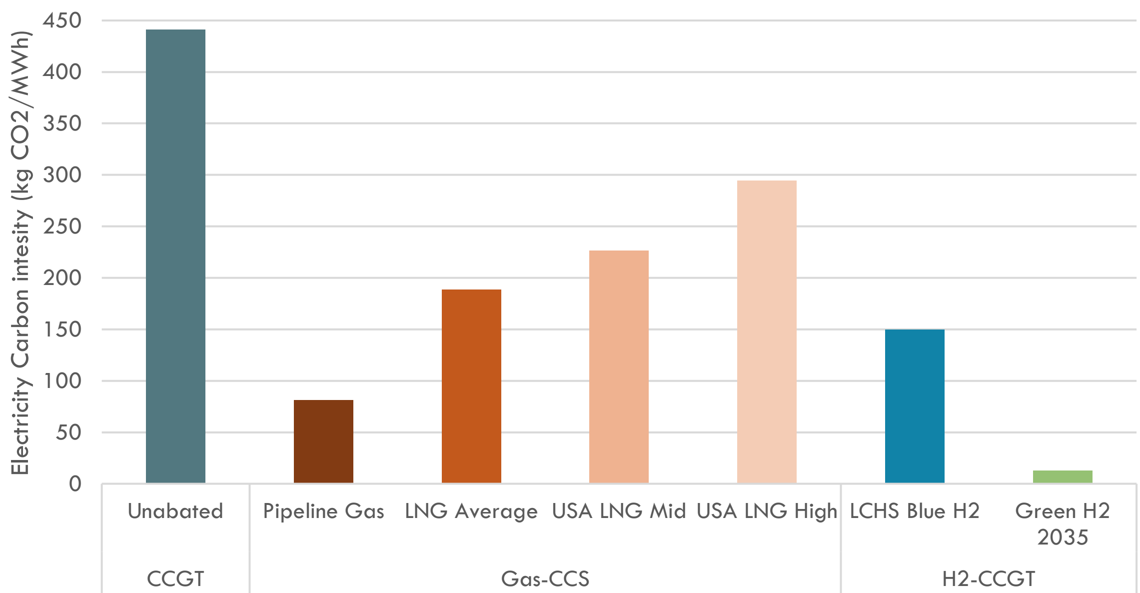
FIG 1: EMISSIONS FROM BLUE HYDROGEN PRODUCED WITH IMPORTED LNG BREACH PAST HYDROGEN'S LOW-CARBON STANDARDS



Source: Carbon Tracker (2024); SMR: Steam Methane Reformer; ATR: Autothermal Reformer; PEM: Proton Exchange Membrane electrolyser – Green hydrogen; details on scenarios in Table 1; Detailed results and assumptions available in Appendix.

Similarly, **upstream emissions can significantly reduce the carbon savings of gas-CCS** power plants. Savings drop from over 80% to only 33% when using LNG from the USA. For hydrogen-fired gas turbines, deep emission reductions are achievable only with blue hydrogen associated with low upstream emissions, or preferably, green hydrogen.

FIG 2: UPSTREAM EMISSIONS SIGNIFICANTLY INCREASE EMISSIONS FROM GAS-CCS AND BLUE HYDROGEN-FIRED TURBINES

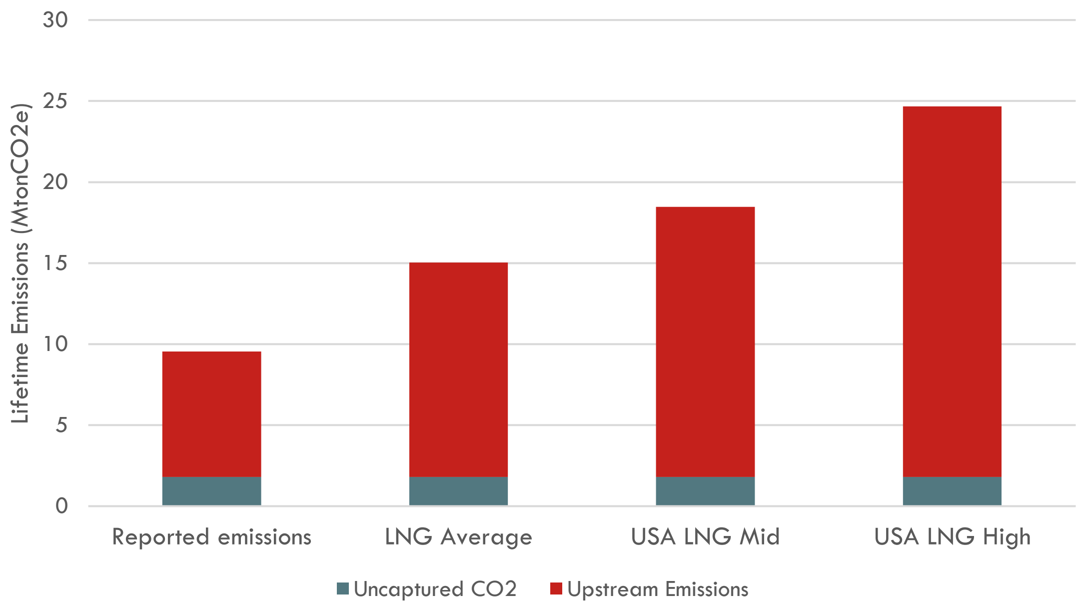


Source: Carbon Tracker (2024); CCGT: Combined Cycle Gas Turbine; LCHS: Low Carbon Hydrogen Standard; Green H2 2035: green hydrogen from average grid electricity mix of 2035; Detailed results and assumptions available in Appendix.

The **UK's reporting framework fails to account for upstream emissions adequately**, either neglecting them or using outdated average values that do not reflect future scenarios. Upstream emissions constitute more than half of the life cycle emissions for blue hydrogen and gas-CCS projects and thus must not be overlooked. This issue is particularly pressing for **projects likely to run on imported LNG**, such as those **in Teesside, where a new LNG terminal is proposed**. UK regulators currently underestimate this risk by relying on historical data for carbon intensity and ignore the possibility that these plants would run on imported LNG.

For instance, bp's **H2Teesside project could emit two to three times more CO_2 than reported** in its environmental assessment if it relies on imported LNG (see Figure 3). Similarly, Net Zero Teesside **(NZT) Power,** a gas-CCS project developed by a joint venture between bp and Equinor, could see its lifetime emissions increase by 1.7 to 2.6 times if it runs on imported LNG, achieving **emission reductions 50% lower than reported**.

FIG 3: LIFETIME EMISSIONS FROM H2TEESSIDE COULD BE TWO TO THREE TIMES GREATER THAN REPORTED



Source: Carbon Tracker (2024). Reported emissions estimated from H2Teesside Environmental Impact Assessment report.

While we focus on these two case studies, **various similar projects are currently at different development stages:** SSE's Peterhead and Keadby 3 gas-CCS projects, RWE's Stallingborough gas-CCS, EET's blue hydrogen production plant 1 and 2, and Equinor's H2H Saltend blue hydrogen.

We estimate that **if all the gas-based CCUS** projects proposed by the **UK's Net Zero strategy are built**[3]**, by 2035 new gas demand could two times greater than the projected domestic production requiring an inevitable reliance on LNG imports.** Without guarantees on the carbon intensity of natural gas, **these projects could produce two to three times more emissions than reported;**

[3] Here we consider 4 GW of blue hydrogen and 9 GW of gas-CCS plants, see Chapter 5.3 for details.

annual emissions could increase by 8-24 Mton$_{CO2e}$. **Over their 25-year lifetimes,** these projects **could consume 22-63% of the UK's Sixth Carbon Budget** (2033–37).

Contrary to recent decisions by the Secretary of State[4], our findings indicate that **blue hydrogen and gas-CCS projects could hinder the UK's ability to meet national targets and negatively impact the UK Carbon Budgets** unless they use natural gas with low upstream emissions.

In conclusion, blue hydrogen and gas-CCS projects will inevitably produce emissions from uncaptured CO_2 and upstream processes. While mitigation is possible, some emissions are unavoidable. This raises a crucial question for the energy transition: **Under what conditions and thresholds can blue hydrogen and gas-CCS be considered "low-carbon" technologies?**

Thus, if conditions for low-carbon blue hydrogen and gas-CCS cannot be met, **a stronger focus should be placed on green hydrogen** from renewable sources **and alternative flexibility technologies,** such as long-duration energy storage, green hydrogen turbines and pumped hydro.

Additional notes

Our findings on emissions intensities apply similarly to European countries. However, EU pipeline imports generally have higher carbon intensity, thus also resulting in higher carbon intensity for blue hydrogen based on pipeline gas. See Box 1 for more details.

All our estimates are based on an ideal case, assuming CCUS projects perform as developers promise, achieving high capture rates. However, our recent report highlighted that this is often not the case[5]. Additionally, our study excludes factors such as downstream hydrogen leakage, CO_2 leakage, CO_2 infrastructure unavailability and emissions from construction and decommissioning.

Finally, we used a 100-year Global Warming Potential (GWP) to align with the UK Government's methodology. However, climate scientists increasingly recommend adopting a 20-year GWP, which would nearly triple the impact of methane emissions[6].

[4] For example see recent approval of NZT Power (link)
[5] Carbon Tracker 2024 – Curb Your Enthusiasm (link)
[6] Global Warming Potential of methane: GWP 100 years 29.8 – GWP 20 years 82.5

Policy Recommendations

Our analysis highlights a significant regulatory blind spot that risks allowing 'low-carbon' projects to have much higher emissions than reported. Upstream emissions are the largest source of emissions for forthcoming blue hydrogen and gas-CCS projects, yet their importance is underestimated in current regulations and reporting frameworks. This issue is particularly pressing due to Europe's and the UK's increased reliance on imported LNG, which has high upstream emissions.

Given the potential consequences of this regulatory blind spot, the North Sea Transition Authority (NSTA) and the Climate Change Committee need to address this urgently. Furthermore, since this is a cross-cutting policy issue, we recommend that the Department for Energy Security and Net Zero (DESNZ) and the Secretary of State implement regulatory changes in the environmental impact assessment process, as well as commission a study to explore these issues further.

Against this overall background, we strongly recommend policymakers to consider the findings of our research carefully, especially on the following points:

1. **Reporting standards**
   a. We recommend the adoption of strong **Monitoring, Reporting and Verification** (MRV) standards to properly measure upstream emissions. The current self-reporting framework is not working and there is a large gap between reported and measured emissions.
   b. The **NSTA should review its reporting for carbon intensity of imported gas** that we found to be significantly lower than numerous independent sources.
   c. The UK should follow the EU adopting a regulation similar to the recently approved EU Methane Strategy, which introduces **stringent monitoring criteria**, such as the OGMP 2.0 monitoring levels 4 and 5[7].
   d. The UK and Europe should jointly push for **global efforts on methane reduction** – notably, the Global Methane Pledge and the International Methane Emissions Observatory (IMEO) – and introduce stringent **emission limits for imported fuels.**
   e. **Carbon Market.** We strongly recommend that methane emissions are included in the UK ETS market (with the EU ETS including them starting in 2026), and for fossil fuel imports to be subject to the carbon border adjustment mechanism (CBAM) both in the EU and UK[8].
   f. The UK should consider the adoption of a **20-year GWP** (instead of a 100-year GWP) in its climate reporting to reflect the increased short-term climate impact of methane emissions accurately.
2. **Environmental Impact Assessments (EIA)**
   a. **Upstream emissions should be included in the EIA** for CCUS-linked gas projects (e.g., blue hydrogen and gas-CCS).
   b. **Upstream emission factors** used in EIA should **reflect future natural gas supply** scenarios instead of average historical values.

[7] EU Regulation to reduce methane emissions in the energy sector here and here
[8] Currently the list of products included in the UK CBAM Proposal is aluminium, cement, ceramics, fertiliser, glass, hydrogen, iron & steel (link). The EU ETS currently covers cement, iron and steel, aluminium, fertilisers, electricity and hydrogen (link). The EU ETS will start to cover methane emissions from 2026 (link)

- c. Emissions factors used in the calculation for the **Low Carbon Hydrogen Standard (LCHS) should** adopt a similar approach to **reflect the changing gas supply.**
- d. Projects receiving UK Government funding should be required to adopt **maximum criteria for upstream emissions.**
- e. The impact of **downstream leaks** of hydrogen or CO_2 should be included in the EIA.
- f. We recommend that the **EU adopts a more stringent standard for low-carbon hydrogen,** ideally at a similar level of ambition to the UK. The current EU standard, when translated to electricity generation, would deliver an emission reduction of only 58% compared to unabated gas-fired power.

3. **Energy transition strategies**
   - a. The UK's and EU's CCUS strategies should be updated to **only consider projects that would deliver permanent emissions reductions on the whole supply chain,** thus, excluding projects that would produce high upstream emissions.
   - b. Blue hydrogen and gas-CCS projects should not be considered 'low-carbon' unless, in addition to achieving high capture factors, they can guarantee they will not rely on high-upstream-emission supply, such as LNG.
   - c. If conditions for low-carbon blue hydrogen and gas-CCS cannot be met, **a stronger focus should be placed on green hydrogen** from renewable sources **and alternative flexibility technologies,** such as long-duration energy storage, pumped hydro and green hydrogen turbines.

1 Introduction

In our recent report from March 2024 titled "Curb your Enthusiasm", we explored the risk of the UK's CCUS strategy and proposed a set of recommendations to channel the Government's £20 billion worth of funding towards low-risk and high-value sectors for CCUS, such as energy-from-waste and cement[9]. Our report found some limited opportunities for CCUS-based hydrogen, in addition to a high aggregate risk for CCUS in the steel and power sectors.

Nonetheless, the British Government is proceeding with its plan of deploying CCUS-based blue hydrogen and gas-CCS projects, starting with its Track-1 CCUS program.

In this report, we focus on CCUS applications based on natural gas that offer the prospect of extending the utilisation of the fossil fuel in a net zero world, namely: blue hydrogen and gas-power with CCS. While according to their proponents, these technologies offer the opportunity to deliver the benefits of natural gas without the climate impact, we are worried that unless the full lifecycle emissions in the fuel supply chain are properly accounted for, these projects' climate impact could be much worse than what is reported.

We focus our analysis on understanding the climate impact of CCUS-based blue hydrogen and gas power, considering different emission scenarios for natural gas supply sourced from low-carbon pipeline imports, the global LNG market, or LNG from the USA.

1.1 Blue Hydrogen

Today, hydrogen is an important feedstock of the chemical industry and in recent years, it has taken a growing stage in the energy transition discussion as a potential solution to decarbonise hard-to-abate sectors where conventional solutions, such as renewables and electrification, do not apply.

Firstly, low-carbon hydrogen is needed to decarbonise the existing uses of hydrogen. For example, the UK consumes about 0.7 million tonnes (Mton) of hydrogen per year to produce refined oil products and fertilisers. This hydrogen is generally produced on-site using natural gas (without CCUS) and emits an estimated 6 Mton of CO_2 per year.

Furthermore, low-carbon hydrogen and its derivatives, such as ammonia, are expected to play a future role in abating emissions by:

- replacing fossil fuels in industries where high-temperature heat is needed,
- replacing natural gas for long-duration storage and flexibility in the power sector,
- replacing fossil fuels in long-distance shipping and aviation.

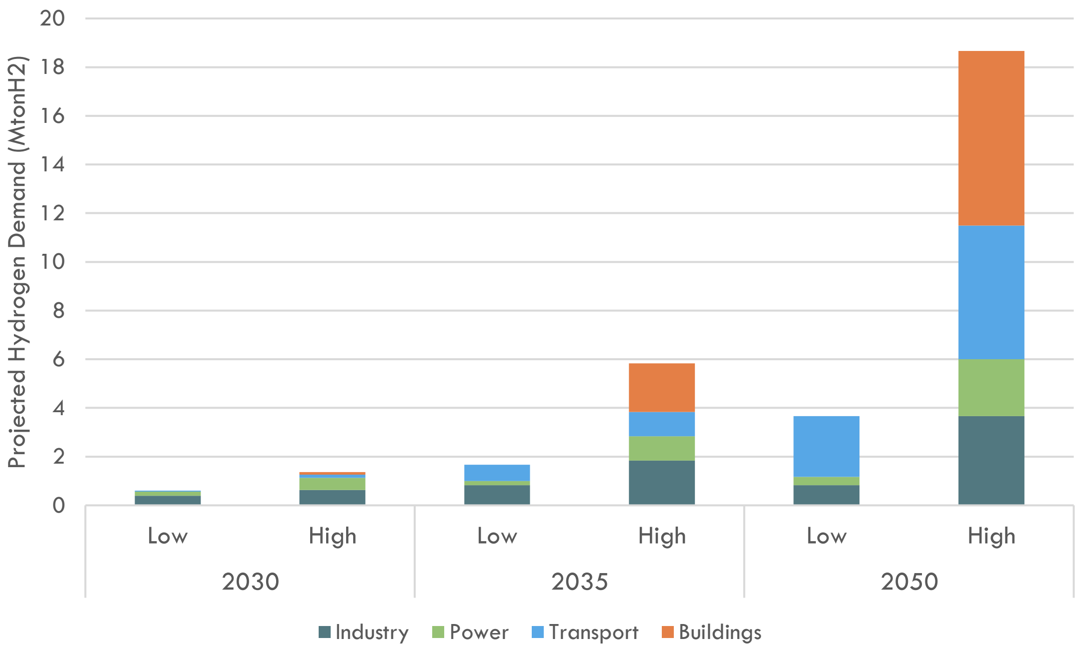
While initially, a wave of hydrogen enthusiasts proposed adopting hydrogen for a very broad array of sectors including domestic heating and road transport where electrification is a much better

[9] CTI 2024 – Curb your Enthusiasm: Bridging the gap between the UK's CCUS targets and reality (link)

option, current estimates have downsized these outlooks and increasingly focus on the use of hydrogen for high-value, hard-to-abate sectors[10].

There is still significant uncertainty on the future demand outlook for hydrogen. For example, official estimates for the UK range between 4 and 18 $Mton_{H2}$ by 2050. Recent news suggests that hydrogen will be officially abandoned for the heating sector and prospects for hydrogen use in road transport are increasingly dwindling. Thus, we expect future hydrogen demand to be much closer to the low-end estimates.

FIG 4: LARGE UNCERTAINTY ON FUTURE HYDROGEN DEMAND



Source: Carbon Tracker (2024) Extrapolated from DESNZ 2021 Hydrogen Analytical Annex.

Nonetheless, there are still major questions about whether or not green hydrogen could satisfy all future demand, especially at what cost. The UK has adopted a twin-track approach developing blue and green hydrogen projects in parallel. For 2030, the UK has set a target of 10 GW of hydrogen production capacity (equivalent to around 1.8$Mton_{H2}$) to be split between 4 GW of CCUS-enable hydrogen and 6 GW of green hydrogen[11].

The EU has an even more aspiring ambition of producing 10 $Mton_{H2}$ and importing another 10 $Mton_{H2}$ of renewable hydrogen by 2030, with the definition including CCUS-based hydrogen compliant with a greenhouse gas emissions saving of at least 70%[12].

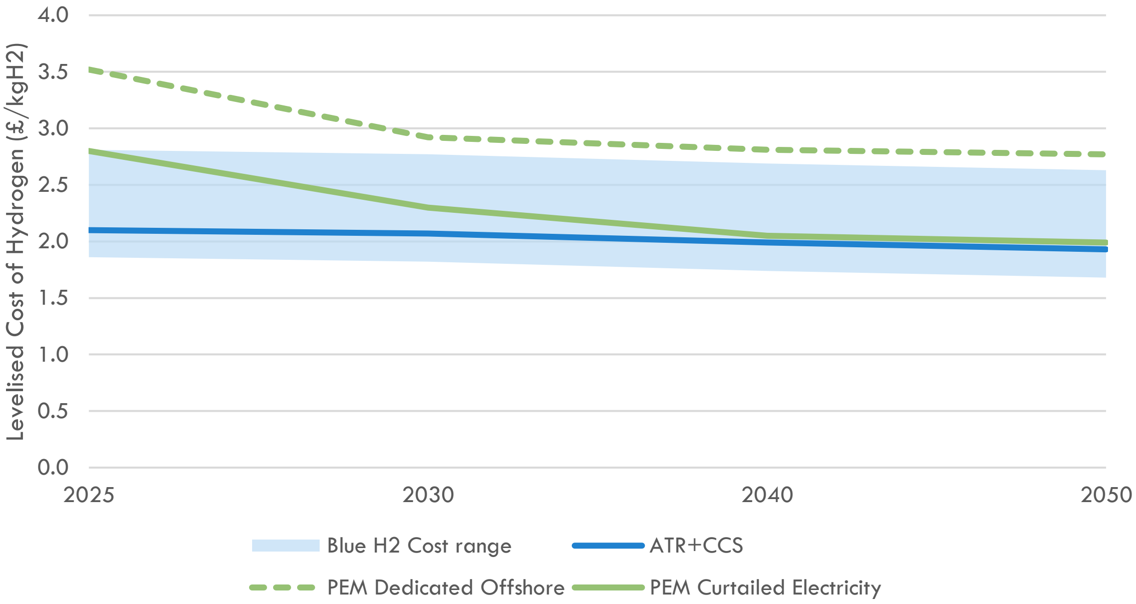
In some regions characterised by high penetration of renewables and low electricity prices, such as the Nordics or Iberia, green hydrogen could soon compete with blue. Our estimates suggest that

[10] Examples: UK cancelling hydrogen village pilot (link); Hydrogen Insight 2023 - A total of 54 independent studies now say there will be no significant role for hydrogen in heating (link); Hydrogen Insight 2024 - Getting to net zero will need nearly a quarter less clean hydrogen than we initially predicted (link)
[11] DESNZ 2023 - Hydrogen Production Delivery Roadmap (link)
[12] EU Hydrogen Strategy (link)

blue hydrogen might still be competitive in the 2030s, even compared to green hydrogen from curtailed electricity, see Figure 5.

Thus, we expect that blue hydrogen could play an important role in the nascent hydrogen market until green hydrogen can scale up at a competitive cost.

FIG 5: BLUE HYDROGEN MIGHT STILL COMPETE WITH GREEN HYDROGEN IN THE LATE 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.

How is hydrogen produced?

Today, hydrogen is mostly produced via two processes: from natural gas via steam methane reforming (SMR), or from coal via gasification. Steam methane reforming is the most common process globally, while coal-based hydrogen is mostly used in China due to the abundance and lower price of coal. Low-carbon hydrogen production remains extremely marginal, with CCUS-based production accounting for 0.6% and electrolytic hydrogen for only 0.1% of the total[13].

Steam methane reforming is a chemical process where methane reacts at high temperatures with steam to produce a gas mixture of hydrogen and carbon dioxide. Next, CO_2 is separated from the gas mixture and is generally vented into the atmosphere. The unabated process emits between 10 and 12 kg of CO_2 per kg of hydrogen.

SMR is a mature technology widely adopted in the industry. In a few applications, SMRs have been coupled with carbon capture technology to reduce emissions and/or produce a CO_2 stream that can be sold for enhanced oil recovery. Currently, only seven large-scale commercial projects are in operation using CCUS to capture emissions from the hydrogen production process.

[13] IEA 2023 – Global Energy Review (link)

However, both in the UK and Europe, there is a potentially large wave of upcoming projects that aim to use CCUS to produce blue hydrogen. The UK's CCUS Track-1 program selected three blue hydrogen projects for a potential combined hydrogen production in excess of 750,000 tonnes by 2030[14], while numerous other projects are currently under development.

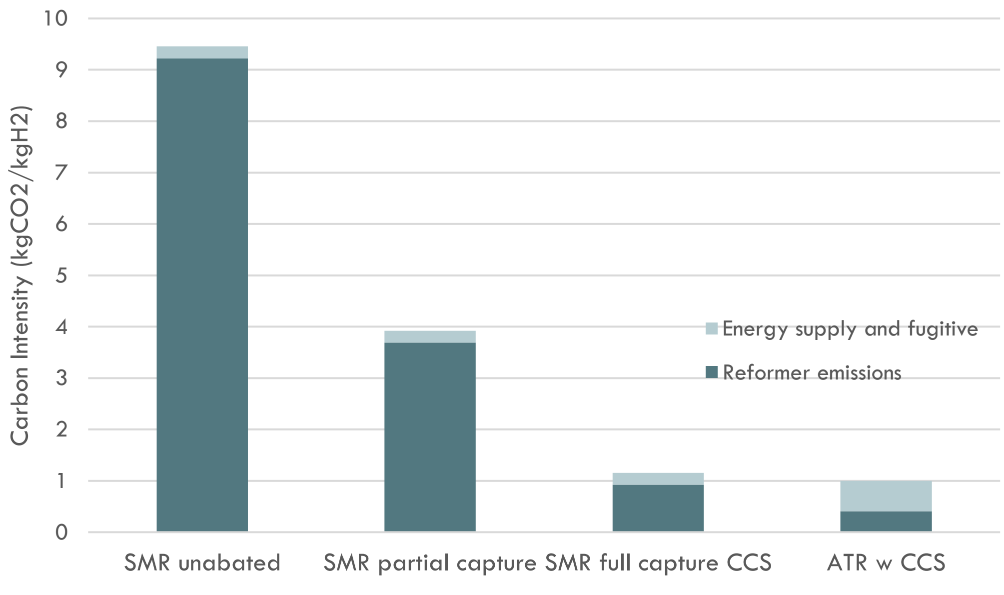
New CCUS-based hydrogen projects are mostly based on two technological pathways:

- Steam Methane Reforming with CCS
- Autothermal reforming (ATR) with CCS

The main difference between the two is the heat requirement. SMRs require external heat that is generally produced via natural gas combustion, so carbon dioxide has to be extracted from both the gas mixture exiting the reformer and the flue gases of the furnace that provides heat to the process. On the contrary, in the ATR process, the reaction takes part in a single chamber without the need for external heat, so CO_2 only needs to be removed from one source. For this reason, despite the ATR process being more expensive, it is becoming the standard solution for blue hydrogen projects, as it reduces the complexity and costs of carbon capture.

Today, most of the SMR+CCS projects in operation capture CO_2 only from the gases exiting the reformer, ignoring about one-quarter of the total emissions. As a result, partial capture reduces emissions by only 60% while full capture can reach 90%, see Figure 6.

FIG 6: COMPARISON OF PROCESS EMISSIONS FOR NATURAL GAS-BASED HYDROGEN PRODUCTION PATHWAYS



Source: Carbon Tracker (2024); SMR: Steam Methane Reformer; ATR: Autothermal Reformer; Partial capture rate:60%.

Process emissions are the most important source of carbon dioxide for the unabated process. However, in abated pathways, upstream emissions (i.e., related to the extraction, processing and

[14] Estimated including H2Tesside phase 1+2, EET Hydrogen HPP1+2 and BOC Teesside Hydrogen see Table 13 in Appendix

transport of natural gas) become an essential factor in determining the carbon intensity of blue hydrogen, see Chapter 3.

1.2 Gas-CCS

Today, one-third of the UK's and one-sixth of the EU's electricity supply comes from unabated, gas-fired plants. As we highlighted in our recent paper, "Curb your Enthusiasm," these plants, which were originally designed for baseload generation, are increasingly being used flexibly to fill the gaps in renewables generation.

As the UK and the EU progress on their decarbonisation of the power sector, gas plants face the existential challenge of either retiring early or reducing their emissions. The two most promising options today for abating emissions are carbon capture and storage, or fuel switching with low-carbon hydrogen. (One role could be played by biomethane, however, limited to its availability and high cost).

While renewables, battery storage and flexibility are decreasing the future need for dispatchable power generation, most transition scenarios agree that some form of long-duration and flexible power will be needed in a decarbonised power system to ensure the security of supply, especially during prolonged periods of low renewables generation. This is the niche where gas-CCS or hydrogen turbines could play a role in the long term.

However, both technologies have not yet been deployed at commercial scale. Gas-CCS has only been tested in two small-scale pilot projects[15]. Similarly, 100%-hydrogen turbines have only been tested at small scale, while most utility-scale turbine manufacturers are working on commercialising 100% hydrogen-ready solutions[16]. The main difference between the two technologies is the size of the modifications needed. Gas-CCS requires the addition of a new large-scale component to scrub CO_2 from the flue gases, whereas hydrogen turbines would only need limited modifications to the combustor and fuel supply components. Consequently, the capital cost of a gas-CCS plant is estimated to be around two to three times greater than an equivalent hydrogen turbine[17].

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[18]. In addition, we found three more projects in the UK, for a total capacity of almost 4 GW, that are at an advanced stage of deploying gas-CCS plants[19]. An additional 6 GW of new projects are considering the technology, but are at an earlier development stage.
Gas-CCS projects promise to capture up to 95% of the CO_2 emissions in the flue gases at the cost of losing around 10% of the power plant efficiency[20].

[15] Entropy Glacier CCS (here) and Tata Chemical (here).
[16] 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)
[17] DESNZ Electricity Generation Costs 2021 and 2023 (link)
[18] Net Zero Teesside 2023 (link)
[19] Net Zero Teesside, Keadby 3, Peterhead and Stallingborough
[20] CTI estimates based on technology review

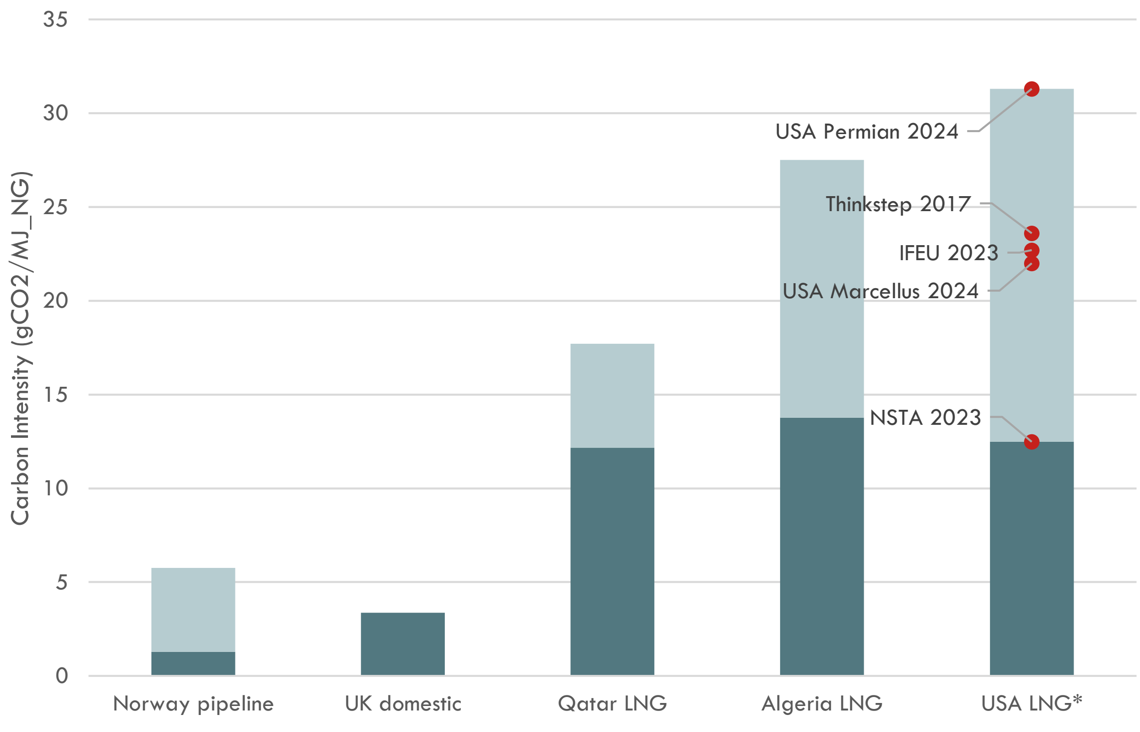
2 Upstream Emissions of Natural Gas

Upstream emissions in the natural gas supply chain are generally neglected for unabated technologies because they are largely outweighed by the emissions generated from the combustion process. However, when dealing with abated technologies the importance of upstream emissions becomes much more prominent and should be closely scrutinised.

Upstream emissions vary widely depending on the origin of natural gas, due to different extraction processes (conventional, fracking), transportation (pipeline, LNG shipping) and the leakages in the full supply chain.

Figure 7 compares the carbon intensity of natural gas imported into the UK depending on the source. Natural gas from Norway features the lowest carbon intensity due to the high emission standards adopted by the country. Liquefied natural gas (LNG) is significantly more carbon intensive than pipeline gas due to the higher emissions incurred during liquefaction, shipping and regasification processes. Additionally, the comparison between Qatar and the USA shows the additional impact from upstream emissions, fracking generates significantly higher emissions than conventional gas extraction (i.e., Qatar).

FIG 7: NATURAL GAS UPSTREAM EMISSIONS VARY WIDELY DEPENDING ON THE ORIGIN COUNTRY AND TRANSPORT ROUTE



Source: Carbon Tracker (2024); based on multiple sources available in Appendix Table 5.

The Norwegian oil and gas industry is a global leader in dealing with upstream emissions having adopted stringent environmental regulations that led to the adoption of emission reduction technologies such as more efficient extraction and processing technology, electrification of offshore platforms and CCS to sequestering the by-product CO_2 flows[21].

Figure 7 shows a wide range of estimates for the carbon intensity of imported LNG, especially from the USA. We compared emissions from a different mix of academic and independent sources and found a large discrepancy in the results[22].

For example, the North Sea Transition Authority (NTSA)[23] reports a carbon intensity of 13 gCO2 per MJ of gas for LNG from the USA, while the external independent sources that we reviewed report an average value of 23 gCO2/MJ. Moreover, one source suggests that LNG imported to the UK from the Permian Basin in the USA could reach 31 gCO2/MJ, 2.5 times higher than the value used by the NSTA[24]. Curiously, a previous version of the NSTA emission monitoring report contained a value for the carbon intensity of US LNG emissions almost double the current one at 24 gCO2/MJ[25]. We found a similar trend with the values used by the NSTA for the carbon intensity of Qatari and Algerian LNG.

This inconsistency is very worrying and should be further investigated as it appears that, in various instances, the values adopted by the regulator are significantly lower than reports from independent research.

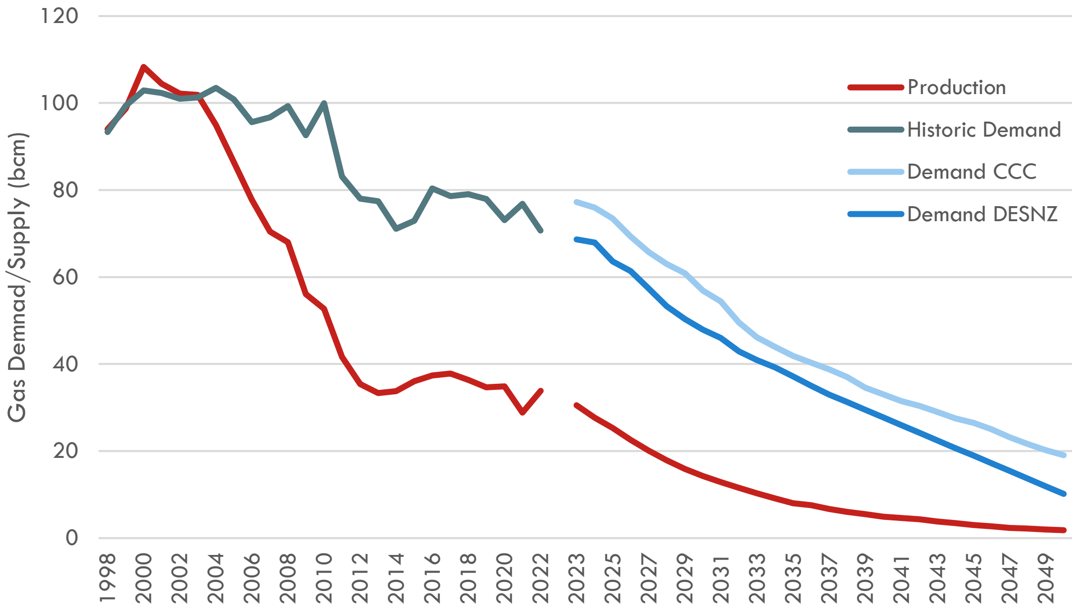
Numerous independent reports have pointed out that there is still a large gap between the emissions self-reported by major fossil fuel companies and emissions estimated via satellites or remote sensing[26]. In particular, the IEA reports that most of the self-reporting is today based on reference values instead of measured emissions and that the difference between the two approaches could be massive.

2.1 UK's Natural Gas Outlook

Natural gas production in the UK has been in steep decline since the 2000s and, in the last ten years, it stabilised around half of the national supply with the rest being imported via pipeline (mostly from Norway) or LNG, see Figure 8. Domestic production is expected to drop further in the coming decades while pipeline imports from Norway are also expected to decrease, though more slowly[27]. The North Sea basin is very mature and most of the reserves have already been extracted, especially on the UK's continental shelf where new investments would not materially change this trend.

[21] Oxford Institute for Energy Studies 2020 - Net Zero Targets and GHG Emission Reduction in the UK and Norwegian Upstream Oil and Gas Industry: A Comparative Assessment (link)
[22] See Table 5 in Appendix for more details and sources.
[23] NSTA – Emissions Monitoring Report 2023, based on data from Rystad Energy (link)
[24] Zhu et al - Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains (link)
[25] The previous version of this publication (the original document is not available online anymore, but its values are quoted here) quoted a 2017 report from Thinkstep - GHG Intensity of Natural Gas Transport (link)
[26] IEA – Global Methane Tracker 2024 (link); IEEFA 2023 (link); Tibrewal et al (2024) Nature (link); RMI 2024 (link); Global Registry of Fossil Fuels 2024 (link); Howarth 2024 (link)
[27] DESNZ 2023 - Role of gas storage and other forms of flexibility in security of supply (link); Norsk Petroleum 2024 - Norway forecast for gas production is stable for 2024-2028 (link)

FIG 8: DECLINE IN DOMESTIC GAS PRODUCTION WITHOUT A DECREASE IN DEMAND COULD LEAD TO INCREASED RELIANCE ON IMPORTED LNG



Source: Carbon Tracker (2024); based on NSTA: March 2024 Production and expenditure projections.

Thus, there is a risk of a growing reliance on LNG imports. This risk is further corroborated by the fact that the UK is currently planning an important expansion of its LNG importing facilities including the ongoing expansion of the Isle of Grain and South Hook LNG terminals and a new import terminal in Teesside[28].

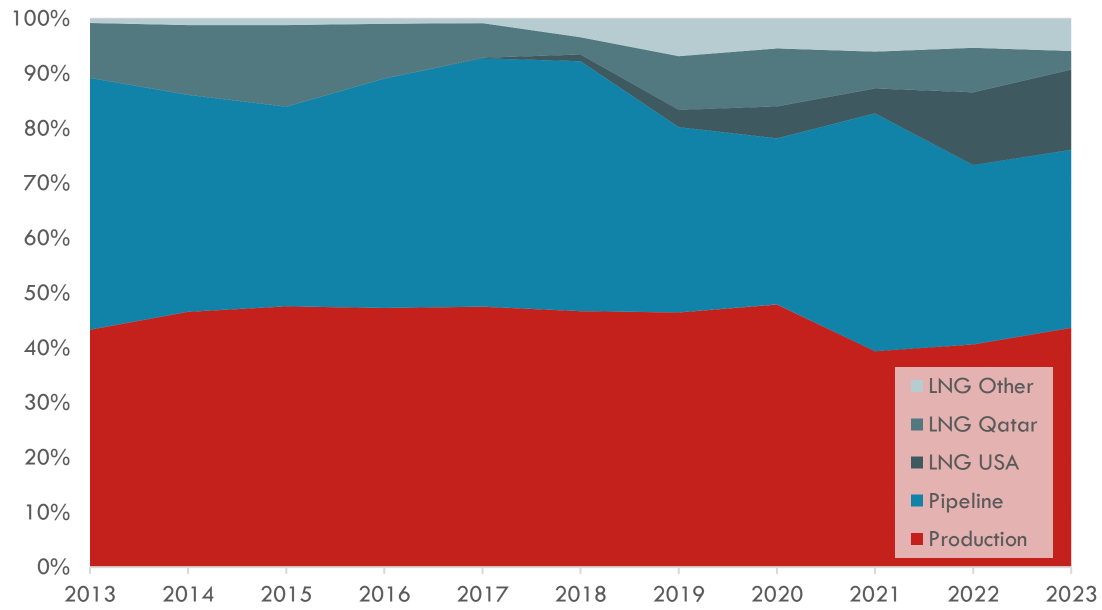
According to projections from DESNZ, the "*UK's import dependence for both LNG and interconnector gas supply is projected to rise from a predicted 13% in 2023 to around 32% by 2030 […], peaking at around 58% in 2045*" – based on DESNZ Statistics from March 2024, we estimate that in 2023 LNG accounted already for 24% of the UK's total gas supply[29]. According to a 2023 study from Energy and Climate Intelligence Unit gas dependency could grow to 60% already by 2035[30]. As LNG is projected to make up a significant proportion of future gas imports, DESNZ has recognised the risk that this could increase emissions and suggested for further studies[31].

We believe that more urgency is needed on this front as the NSTA seems to be underestimating the amount of upstream emissions and the recent growth of LNG from the USA could further exacerbate this issue. Furthermore, the looming risk of new gas demand from blue hydrogen or gas-CCS projects will determine a further increase in supply from the marginal supplier, LNG, and thus an increase in global CO_2 emissions.

[28] Montel News 2024 – LNG hub plans expansion to boost UK energy flexibility (link); South Hook 2024 - Incremental Capacity Project (link); WaveCrest Energy 2024 (link)
[29] DESNZ March 2024: UK Gas Statistics (link)
[30] ECIU 2023 - Rising Gas Imports and the UK's Balance of Trade (link)
[31] DESNZ 2023 - Role of gas storage and other forms of flexibility in security of supply (link)

However, as we will show below, we have found that the UK's reporting frameworks do not properly account for this risk and upstream carbon intensity is either ignored or considered to remain unvaried in the future.

FIG 9: LNG, ESPECIALLY FROM THE USA, IS QUICKLY GROWING IN THE UK'S SUPPLY MIX



Source: Carbon Tracker (2024); Elaborated from DESNZ March 2024: UK Gas Statistics.

In the following section, we will consider the impact of upstream emissions based on the scenarios presented below in Table 1.

TABLE 1: NATURAL GAS UPSTREAM EMISSIONS BASED ON SUPPLY SCENARIO

Source	Upstream emissions (gCO2/MJ natural gas)	Notes
Pipeline Gas	2.3	Average of Norwegian and domestic gas
UK Average 2022	6.8	Average emission of UK's gas consumption in 2022
Average LNG (excl. USA)	17.5	Average of Qatar, Peru, Nigeria, Algeria
USA LNG Mid	22.4	Average of USA estimates
USA LNG High	31.3	LNG from the Permian Basin

Note: these values exclude grid transmission losses and venting which we estimate at 1.5 gCO2e/MJ, see Appendix for sources Table 5-7.

Box 1: Upstream emissions for the EU

The European Union has recently approved a regulation to reduce methane emissions from fossil fuels produced in the EU and imported from abroad. The new regulation obliges the fossil gas, oil and coal industries in Europe to measure, monitor, report and verify their methane emissions and to take action to reduce them. The regulation bans routine venting and flaring and importantly introduces the ambition to introduce a maximum emission standard for importers[32].

In the past three years, as a response to the Russian invasion of Ukraine, the EU saw a sharp rise in LNG imports from 15% in Q1 2021 to 33% in Q1 2024. The share of LNG imported from the USA in the same period skyrocketed from 5% to 21%[33].

The main difference with the UK is that the previous main source of pipeline import for the EU was associated with very high upstream emissions: Russia's pipeline imports of natural gas were estimated to have a carbon intensity of around 29gCO2/MJ compared to only 9 gCO2/MJ for Norway.

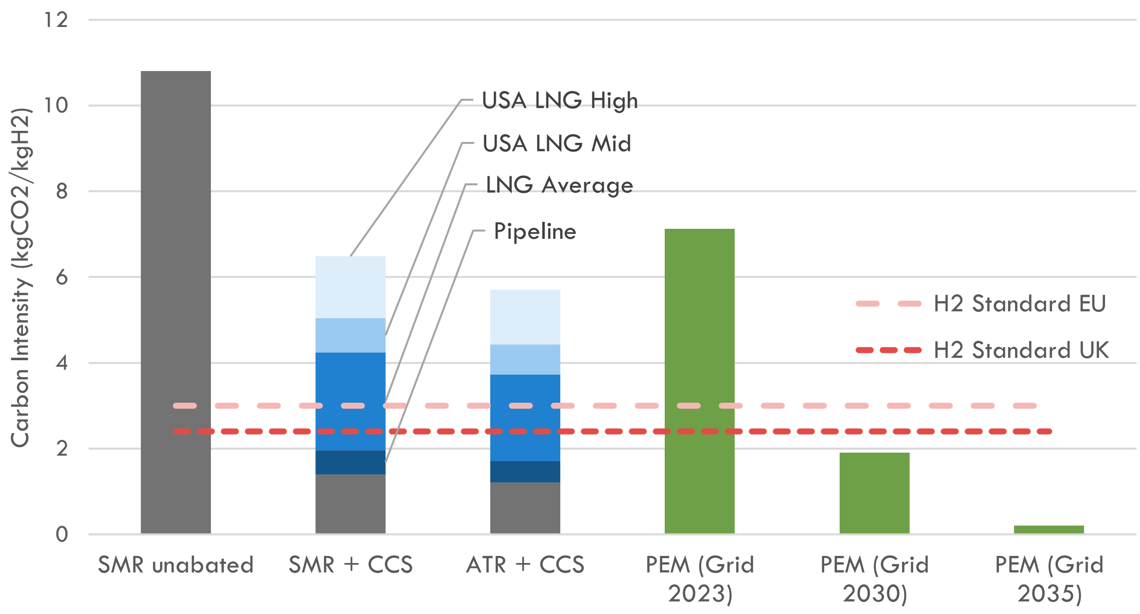
Similarly, other sources of pipeline gas for Europe are also associated with high upstream emissions: Algeria 19 gCO2/MJ, Libya 21 gCO2/MJ and Azerbaijan 16 gCO2/MJ[34].
Thus, the problem of upstream emissions should be an even greater concern for European policymakers.

32 EU Methane Regulation – May 2024 - here and here
33 Bruegel 2024 – based on ENTSOG, GIE and Bloomberg link
34 Norway, Russia, Algeria and Libya values extracted from (EU DG Energy 2015 link) and Azerbaijan based on own estimate from SOCAR's 2021 Sustainable Development report (link)

3 Carbon Intensity of Blue Hydrogen

Bringing together modelling from the process emissions of hydrogen production and the upstream emissions of natural gas, we can estimate the carbon intensity of blue hydrogen based on different scenarios for the natural gas supply, see Figure 10.

FIG 10: COMPARISON OF THE CARBON INTENSITY OF HYDROGEN PRODUCTION PATHWAYS CONSIDERING VARIOUS NATURAL GAS SUPPLY SCENARIOS.



Source: Carbon Tracker (2024); SMR: Steam Methane Reformer; ATR: Autothermal Reformer; PEM: Proton Exchange Membrane electrolyser – Green hydrogen; For details on scenarios Table 1; Detailed results and assumptions available in Appendix Table 8.

Blue hydrogen produced with domestic natural gas or pipeline imports from Norway would comply with the UK's low carbon hydrogen standard (LCHS) of 2.4 kgCO2 per kg of hydrogen (or the EU's limit of 3 kgCO2/kgH2)[35]. The carbon intensity of blue hydrogen based on the average natural gas consumed in the UK in 2022 is also in the ballpark of the low carbon hydrogen standard reaching between 2.2 kgCO2/kgH2 for ATR and 2.5 kgCO2/kgH2 for SMR (see Table 3 in Appendix for detailed results).

Our model clearly shows that blue hydrogen produced with 100% imported LNG would not comply with both emission standards. Blue hydrogen based on average LNG imports would have a carbon intensity of 3.7–4.2 kgCO2/kgH2. American LNG would range between 4.4–5 kgCO2/kgH2 for the central scenario and up to 5.7–6.5 kgCO2/kgH2 for LNG from the Permian Basin. In the central scenario, the average emissions of blue hydrogen produced with American LNG is around double the UK's emission limit.

On the other hand, green hydrogen from grid-sourced electricity could already comply with the low-carbon standards starting from 2030 (based on the modelled UK's average carbon intensity of

[35] UK Low carbon hydrogen standard (LCHS) (link) and EU renewable fuels of non-biological origin (RFNBO) criteria (link)

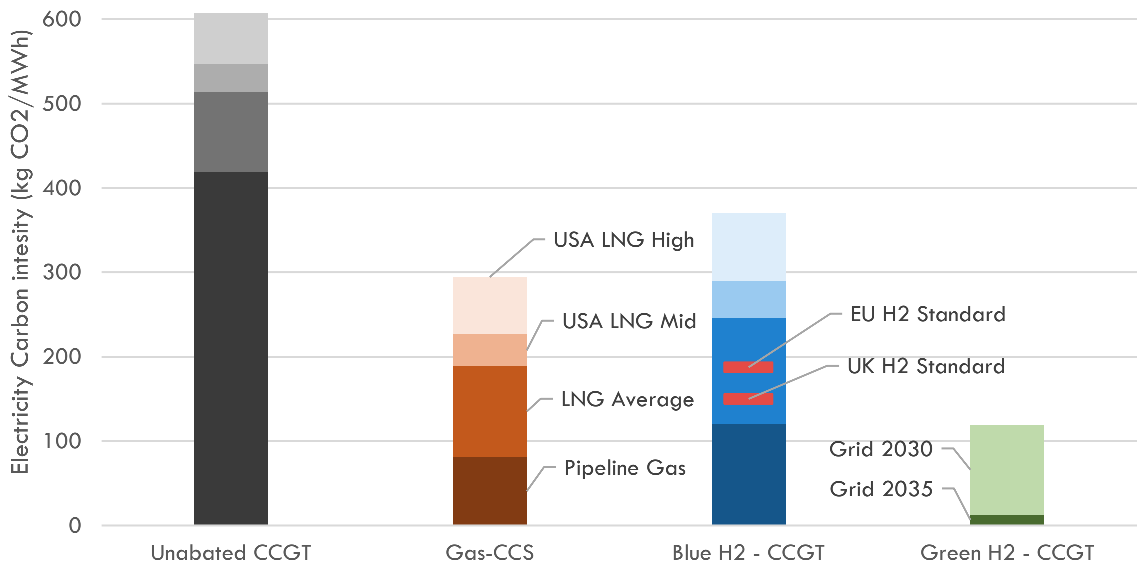
electricity)[36]. Green hydrogen produced from dedicated renewable plants or curtailed electricity would comply already today.

4 Carbon Intensity of Gas-CCS and Hydrogen-Based Power

In the next section, we estimate the carbon intensity of electricity production based on either gas-CCS or hydrogen-based turbines highlighting different scenarios for the gas supply mix.

First, we calculate the emission intensity of unabated and CCS-based gas-fired generation. Then, we consider the option of hydrogen-fired turbines fuelled by blue or green hydrogen. We differentiate the results to highlight the impact of upstream emissions.

FIG 11: CARBON INTENSITY OF ELECTRICITY GENERATION WITH GAS-CCS AND HYDROGEN CONSIDERING THE IMPACT OF VARIOUS NATURAL GAS SUPPLY SCENARIOS



Source Carbon Tracker (2024); CCGT: Combined Cycle Gas Turbine; details on scenarios in Table 1; Modelling assumptions available in Appendix in Table 10.

Figure 11 shows that accounting for upstream emissions significantly affects the carbon intensity of a gas turbine. Even for unabated combined cycle plants, the emission intensity can increase by 45% when upstream emissions are considered.

By ignoring upstream emissions, the carbon emissions of gas-CCS could be up to 90% lower than the unabated case. However, already by accounting for the upstream emotions of today's gas grid the carbon intensity increases to 107 kgCO2/MWh, only a 76% reduction compared to an unabated gas turbine operating with the same mix (440 kgCO2/MWh)[37]. Furthermore, emissions

[36] See Appendix for details

[37] In the following examples we consider this value as the reference case for unabated CCGT emissions

increase to 189 $kgCO_2/MWh$ for 100% LNG scenario and to 226–294 $kgCO_2/MWh$ for American LNG (see Table 4 in Appendix for detailed results).

Thus, the carbon savings of gas-CCS compared to unabated gas plants could drop to 57% for imported LNG, 50% for American LNG and only 33% for American LNG from the Permian Basin.

The results are similar for blue hydrogen-fired gas turbines. Also in this case, LNG-based blue hydrogen would deliver limited emission savings. Worryingly, even blue hydrogen compliant with the UK's low carbon hydrogen standard (LCHS) of 2.4 $kgCO_2/kgH_2$ would reduce emissions by 66% while the EU's limit of 3 $kgCO_2/kgH_2$ would result in an emission reduction of only 58%.

Green hydrogen-fired turbines offer the only technological pathway that can deliver consistent emission reductions for long-duration dispatchable electricity generation (except for long duration energy storage technologies). Green hydrogen based on grid electricity could already deliver emission cuts of up to 74% by 2030 and close to 100% by 2035.

5 Considerations for Environmental Impact Assessments

The analysis above shows how upstream emissions can completely change the climate impact of CCUS-based technologies that aim to abate emissions from natural gas-based processes (i.e., blue hydrogen and gas-CCS). Positive climate impacts would be delivered only if, on top of achieving high capture rates, these technologies operate with natural gas from low-carbon sources and do not increase demand for LNG imports.

Unfortunately, today, upstream emissions are not properly considered in the impact assessments for these projects. We found these issues in the documentation submitted by various projects that recently submitted or are in the process of submitting Environmental Impact Assessment (EIA) reports for obtaining a Development Consent Order (DCO) from the UK's Planning Inspectorate[38]. In all the cases we analysed, upstream emissions are either neglected or estimated using reference emission factors based on the current gas import mix but do not provide scenarios for future changes.

This is particularly problematic for projects with a clear risk of being directly powered with imported LNG. This is the case in the Teesside industrial area where WaveCrest Energy is planning the construction of a new LNG regasification terminal which is currently going through the Planning Inspectorate[39].

Upstream emissions are the largest source of emissions both for blue hydrogen and gas-CCS projects accounting for more than half of the total lifetime emissions. Thus, environmental impact assessments should rely as much as possible on accurate estimates and include scenarios and sensitivity analysis for future supply mix changes. Alternatively, project approval should be conditional on complying with maximum carbon intensity criteria for imported fuel. However, this is not the case today.

Below we present our findings via two case studies and showcase how varying upstream emission levels can impact lifetime emissions:

- Blue Hydrogen: H2Teesside
- Gas-CCS: Teesside Net Zero (TNZ) Power

Both projects will be part of the East Coast Cluster, they are located in the Teesside industrial area and are planned to be connected with the Northern Endurance Partnership's CCUS facilities. Additionally, both projects will likely consume LNG imported from the planned WaveCrest Energy LNG Terminal.

While we focus the report on these two case studies it is important to point out that this is a very pressing issue as numerous similar projects are in a similar development process[40]:

[38] NZT Power, Keadby CCS, H2Teesside, Stallingborough CCGT, Peterhead CCGT (with Scottish Government)
[39] UK Planning Inspectorate - Teesside Flexible Regas Port: Project information (last accessed 6/6/2024) (link); WaveCrest Energy 2024 (link)
[40] The list below is not supposed to provide an exhausting inventory of all the projects under development.

- Keadby 3, 910 MW CCGT with CCS developed by SSE Thermal: received planning consent in December 2022[41].
- Peterhead, 910 MW CCGT with CCS developed by SSE Thermal: applying for planning consent with the Scottish Government[42].
- Stallingborough, 900 MW CCGT with CCS developed by RWE: in pre-application with the UK Planning Inspectorate[43].
- EET Hydrogen HPP1+2, 350 MW (+1000 MW phase 2) blue hydrogen project developed by Essar Energy Transition (formerly known as Vertex Hydrogen): granted planning permissions from local authorities in January 2024[44].
- H2H Saltend, 600 MW blue hydrogen project developed by Equinor: granted planning permissions from local authorities in February 2024[45].

5.1 Blue Hydrogen: H2Teesside

H2 Teesside is a blue hydrogen project under development by bp planned for 2028. The project would feature a production capacity of about 160,000 tonnes of hydrogen per year in Phase 1 which could grow to more than 300,000 in Phase 2 (our calculations are based on Phase 1). The project would install an Autothermal Reformer (ATR) with a capture rate of 95%. H2Teesside is currently in the application process with the UK's Planning Inspectorate for a development consent order (DCO)[46].

We re-assessed the project's lifetime greenhouse gas emissions using different scenarios for upstream emissions and based on the reference information in the project's environmental impact assessment (EIA) report[47]. We focus our assessment on operational emissions (uncaptured CO_2 emissions and upstream emissions) because they would account for 85% of the total annual emissions[48].

We estimate that Phase 1 of the project could capture around 1.4 $Mton_{CO2e}$ per year and emit around 0.07 $Mton_{CO2e}$ per year of non-captured CO_2. Additionally, the project would produce an additional 0.24 $Mton_{CO2e}$ per year from upstream emissions, based on reference values from its IEA report. In aggregate, this would result in a carbon intensity of 1.6 kgCO2/kgH2 (excluding emissions from construction and minor sources[49]) thus compliant with the UK's limit for low-carbon hydrogen.

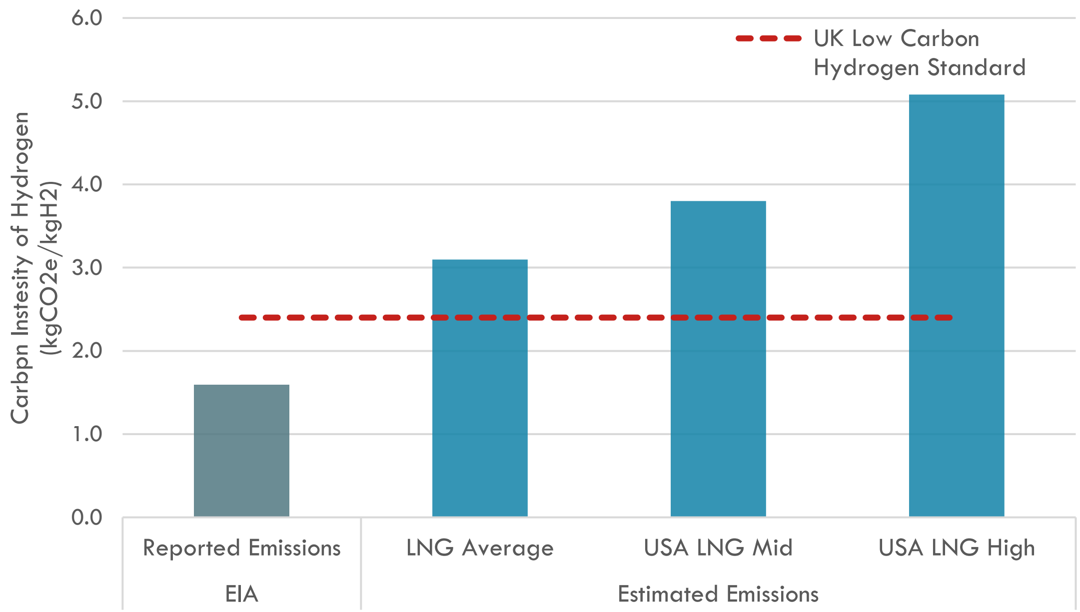
The upstream emission factor used in the EIA report is sourced from DESNZ which reports the well-to-tank emissions of natural gas based on the weighted average of the carbon intensity of the

[41] SSE Thermal 2022 - Landmark Power CCS project in Humber becomes UK's first to gain planning consent (link)
[42] Scottish Government 2024 - The Peterhead Low Carbon CCGT Power Station Project (last accessed 6/6/2024) (link)
[43] UK Planning Inspectorate - Stallingborough Combined Cycle Gas Turbine (CCGT) generating plant and Carbon Capture Plant (CCP) (last accessed 6/6/2024) (link);
[44] Hynet-EET 2024 – Plans for UK's largest hydrogen production hub given green light (link)
[45] Equinor 2024 - Equinor's H2H Saltend project given major boost as planning permission granted (link)
[46] UK Planning Inspectorate - H2Teesside: project information accessed (last Accessed 6/6/24) (link)
[47] Detailed documentation is available in Appendix Table 11
[48] Calculated from EIA report.
[49] Excluded emission sources among others: construction, decommissioning, imported electricity, downstream emissions, H2 flares and vents, workers transport, maintenance and uncaptured emissions during unavailability.

produced and imported natural gas in 2022[50]. However, as discussed above, the project is likely to run entirely or at least partially on imported LNG which is associated with much higher emissions.

We found that the climate impact of H2Teesside would change significantly if the blue hydrogen plant is run with imported LNG, see Figure 12.

FIG 12: H2TEESSIDE ESTIMATED CARBON INTENSITY OF BLUE HYDROGEN BASED ON NATURAL GAS SUPPLY SCENARIOS AND COMPARED AGAINST THE UK'S LOW CARBON HYDROGEN STANDARD.



Source Carbon Tracker (2024); EIA: Environmental Impact Assessment; Estimated emissions based on scenarios from Table 1. Detailed modelling assumptions are available in the Appendix.

Blue hydrogen produced utilising imported LNG would breach the UK's low carbon hydrogen standard reaching 3.1 kgCO2/kgH2. The carbon intensity of blue hydrogen could be more than twice the LCHS in the case of LNG from the Permian Basin reaching 5.1 kgCO2/kgH2.

On an annual basis, this would increase the project's emissions by twice in the case of imported LNG and up to three times in the worst case for imported LNG from the USA. In other words, the project could be emitting in the atmosphere up to 0.6 tonnes of CO_2 for every tonne of CO_2 permanently stored underground.

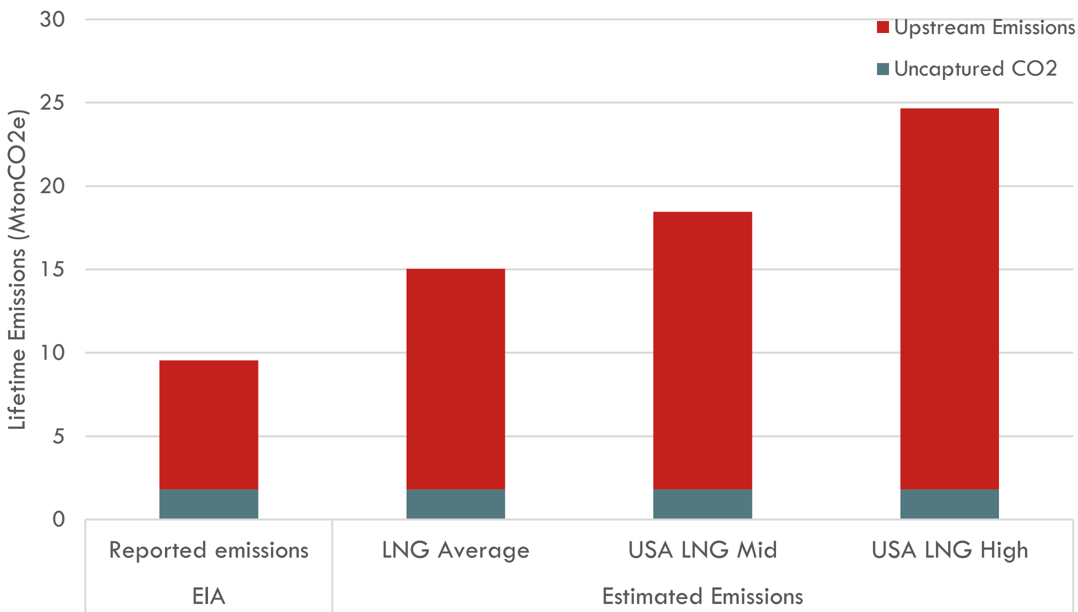
Throughout the lifetime of the project, the implication could be extremely important. The lifetime emissions of H2Teesside could grow from the 8 $Mton_{CO2e}$ derived from the project's EIA to 15 $Mton_{CO2e}$ in the LNG scenario, 19 $Mton_{CO2e}$ in the central USA scenario and up to 25 $Mton_{CO2e}$ in the worst-case scenario, see Figure 13. As a result, the lifetime emissions of this project could be two to three times larger than reported in its EIA.

The full construction of H2Teesside, phase 1 and phase 2, would double the production capacity thus doubling the lifetime emissions which could reach 30 $Mton_{CO2e}$ in the LNG scenario, 38 $Mton_{CO2e}$

[50] DESNZ – Greenhouse gas reporting: conversion factors 2023 (link)

in the central USA scenario and up to 50 Mton$_{CO2e}$ in the case of American LNG sourced from the Permian Basin.

FIG 13: H2TEESSIDE LIFETIME EMISSIONS BASED ON DIFFERENT NATURAL GAS SUPPLY SCENARIOS.



Source Carbon Tracker (2024); EIA: Environmental Impact Assessment; Reported emissions estimated based on values from EIA report; Estimated emissions based on scenarios from Table 1. Detailed modelling assumptions are available in the Appendix.

5.2 Gas-CCS: Net Zero Teesside (NZT) Power

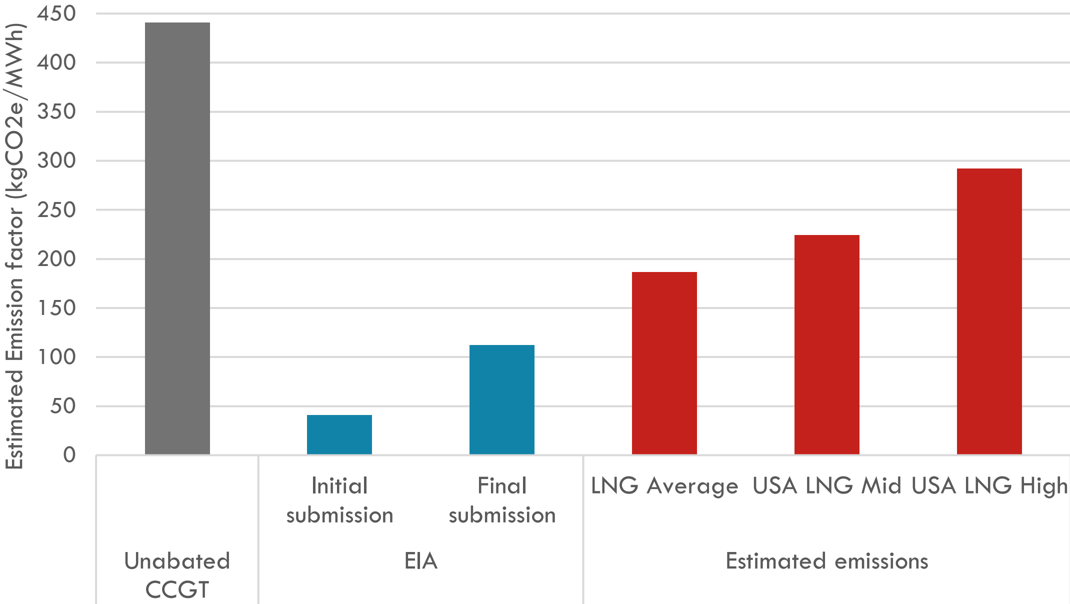
NZT Power is a joint venture between bp and Equinor which is planning to build a gas-CCS power plant to produce flexible and dispatchable low-carbon power to the grid. The plant will consist of a new 860 MW gas-fired turbine coupled with carbon capture to remove emissions from the flue gases. Up to 2 million tonnes of CO_2 per year would be captured, transported and then stored by the North Endurance Partnership in a subsea storage site beneath the North Sea.

The project received the Development Consent Order (DCO) in February 2024[51] and it is aiming to start operation in 2027 (subject to FID in September 2024). The Government DCO decision has been legally challenged by an environmental consultant, Dr Andrew Boswell, who has applied for a judicial review claiming that the application underestimates the lifetime emissions of the project[52].

Similarly to before, we estimate the impact of accounting for upstream emissions on the lifetime of this project. The most important difference in this case is that the initial EIA report for this project did not consider upstream emissions. A subsequent update on the environmental application introduced an emission factor for upstream emissions based on the same approach as H2Teesside, the average emission factor of the gas in the UK's grid in 2022[53].

[51] UK GOV 2024 – Press Release: Net Zero Teesside Project development consent decision announced (link)
[52] The Guardian 2024 – UK 'net zero' project will produce 20m tonnes of carbon pollution, say experts (link)
[53] Detailed documentation is available in Appendix Table 11

FIG 14: NZT POWER EMISSION INTENSITY OF ELECTRICITY GENERATION BASED ON DIFFERENT NATURAL GAS SUPPLY SCENARIOS



Source Carbon Tracker (2024); CCGT: Combined Cycle Gas Turbine; Unabated CCGT based on 53% efficiency and upstream emission from UK average 2022. EIA: Environmental Impact Assessment; Values for Initial Submission and Final Submission estimated based on figures provided in EIA submissions, see Appendix for details and links; Estimated emissions based on scenarios from Table 1. Detailed modelling assumptions are available in the Appendix.

Figure 14 shows this issue clearly, when discounting upstream emissions a gas-CCS project could have emissions as low as 41 kgCO2/MWh of electricity produced (excluding emissions from construction and minor sources[54]), however, they would grow to 112 kgCO2/MWh when including historical gas grid emission factors[55].

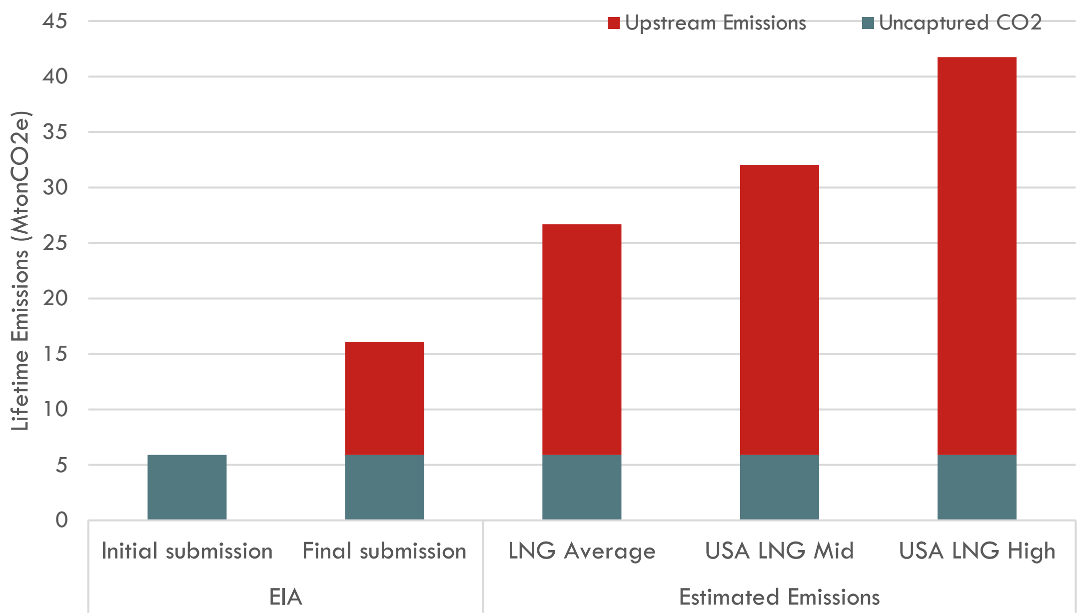
While the updated submission is more reflective of the reality it still fails to account for the possibility of the projects running on LNG, which, as discussed above, we believe to be very likely. In that case, emissions would grow to 187 kgCO2/MWh in the average LNG scenario and between 224-292 kgCO2/MWh for the USA LNG scenarios.

Based on the project's EIA, NZT Power could deliver a carbon reduction of 73% compared to the unabated case (-90% in the initial submission). However, the carbon savings would reduce to 58% in the LNG scenario and down to only 34% in the worst-case scenario.

Our model shows that accounting for upstream emissions increases drastically the potential climate change impact of NZT Power. Lifetime emissions could grow from the 16 $Mton_{CO2e}$ reported in the EIA to 28 $Mton_{CO2e}$ in the LNG scenario, 32 $Mton_{CO2e}$ in the central USA scenario and up to 41 $Mton_{CO2e}$ in the case of LNG from the Permian Basin. We estimate that NZT Power's lifetime emissions could be 1.7 to 2.6 times larger than reported in the EIA report.

[54] Excluded emissions sources among others: construction, decommissioning, waste disposal, materials, worker commute, material transport and electricity consumption.
[55] Calculations are based on the Reference scenario of the DCO which assumes a carbon capture rate of 90% and 8424 operating hours per year.

FIG 15: NZT POWER LIFETIME EMISSIONS BASED ON DIFFERENT NATURAL GAS SUPPLY SCENARIOS



Source Carbon Tracker (2024); EIA: Environmental Impact Assessment; Values for Initial Submission and Final Submission estimated based on figures provided in EIA submissions, see Appendix for details and links; Estimated emissions based on scenarios from Table 1. Detailed modelling assumptions are available in the Appendix.

5.3 Consequences for the UK's Net Zero Strategy

The British Government has allocated £20 billion of funding to deliver its CCUS strategy, which aims to develop 20–30 Mton$_{CO2}$ of capture capacity by 2030, at least 50 Mton$_{CO2}$ by 2035 and a self-sustaining CCUS market from 2035 onwards.

As part of this strategy, DESNZ has shortlisted eight CCUS projects to be selected for accelerated funding in order to be included in the first two CCUS clusters. Among these projects there are two large-scale blue hydrogen and one gas-CCS projects, see table below[56].

TABLE 2: SUMMARY OF ESTIMATED LIFETIME EMISSIONS OF TRACK-1 CCUS GAS-BASED PROJECTS UNDER DIFFERENT SUPPLY SCENARIOS

Lifetime emissions (MtonCO2e)	Reported emissions	LNG scenario	USA LNG High
NZT Power	16	27	41
H2Teesside	15	30	49
EET Hydrogen (former Vertex) HPP1+2	14	28	46
Total	**45**	**85**	**137**

Source Carbon Tracker (2024)

These three projects would determine a considerable increase in natural gas demand that we estimate at more than 4 bcm per year, this would be equivalent to 9% of the projected 2030 gas

[56] From this assessment we exclude BOC's Teesside Hydrogen due to its limited scale (0.2MtonCO2/year)

demand or almost one-third of the projected domestic production for 2030[57]. This new demand, which could grow even further if more blue hydrogen and gas-CCS projects are developed, would put strong pressure on the natural gas supply outlook and would inevitably result in increased LNG import.

Based on the current reporting framework, which assumes that the gas supply mix will remain unchanged, these four projects' aggregate lifetime emissions would amount to 45 $Mton_{CO2e}$. However, if these plants were operating with imported LNG, total CO_2 emissions could grow to 85 $Mton_{CO2e}$ and up to 137 $Mton_{CO2e}$ in case of imports from the USA. There is thus the risk that projects developed with the aim to abate emissions will result in emissions two to three times larger than reported significantly undercutting their contribution toward reducing global emissions.

In the worst scenario, the lifetime emissions produced by these four projects would account for 14% of the UK's sixth carbon budget (2033–37) or would be equivalent to 40% of the UK's total emissions in 2021.

This issue raises important questions about the **UK's Net Zero strategy reliance on blue hydrogen and gas-CCS**. In particular, the current Net Zero strategy for the power sector recommends for 9GW of gas-CCS plants by 2035 and up to 18 GW by 2050[58]. If these plants were run following the same principles of NZT Power EIA (i.e. baseload operations) they could generate massive amounts of CO_2 emissions that put at risk net zero targets. For example, by 2035, emissions related to the 9 GW of gas-CCS targets could be between 12–19 $Mton_{CO2e}$ for the 'LNG average' and 'USA LNG high' scenarios respectively. Even assuming flexible power plant operations (capacity factor of 40%) emissions could reach 5–8 $Mton_{CO2e}$ per year.

Similarly, the 4 GW of blue hydrogen production capacity targeted for 2030 could result in yearly emissions between 3–5 $Mton_{CO2e}$ under the 'LNG average' and 'USA LNG high' scenarios[59].

We estimate that total new gas demand from this 9GW of gas-CCS and 4 GW of blue hydrogen could reach 18 bcm by 2035, more than twice than 2035 projected domestic production. This confirms our assumption that these projects will run, at least partly, on imported LNG.

In aggregate, the lifetime emissions of 9 GW of gas-CCS and 4 GW of blue hydrogen could total between 210 and 600 $Mton_{CO2e}$ and risk exhausting between 22% and 63% of the UK's Sixth Carbon Budget (2033–37)[60].

This raises the question about the actual contribution of gas-CCS and blue hydrogen projects to the UK's net zero targets and calls for strong regulation on upstream emissions.

If unaddressed, the climate impact of upstream emissions could derail the UK's net zero strategy.

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[57] We assume that H2Teesside and HyNet Hydrogen Production Plant are developed in both phases and that operate with the capacity factors provided in H2Teesside EIA. Demand and production projections based on DESNZ demand outlook and NSTA March 2024 Production and expenditure projections (link)
[58] DESNZ 2023 – Powering Up Britain: Technical Annex (link)
[59] Target 4GW blue hydrogen by 2030 from: DESNZ 2023 - Hydrogen production delivery roadmap (link)
[60] The low lifetime emission range includes flexible gas-CCS operation (capacity factor 40%)

6 Appendix

TABLE 3: DETAILED RESULTS CARBON INTENSITY OF BLUE HYDROGEN

Carbon Intensity (KgCO2e/KgH2)	SMR	ATR
Pipeline Gas	2.0	1.7
UK Average 2022	2.5	2.2
Average LNG (excl. USA)	4.2	3.7
USA Mid	5.0	4.4
USA High	6.5	5.7

TABLE 4: DETAILED RESULTS CARBON INTENSITY OF ELECTRICITY GENERATION

Carbon Intensity (KgCO2e/MWh)	Unabated CCGT	Gas-CCS	Blue H2-CCGT
Pipeline Gas	419	81	120
UK Average 2022	441	107	150
Average LNG (excl. USA)	514	189	246
USA Mid	547	226	290
USA High	608	294	370

TABLE 5: UPSTREAM EMISSIONS OF NATURAL GAS IMPORTED TO THE UK BY COUNTRY OF ORIGIN

Country	Upstream emission range (gCO2/MJ_NG)	Source
Norway Pipeline	1.3 – 5.8	UK NSTA 2024 and EU DG Energy 2015
UK Domestic	3.4	UK NSTA 2024
Qatar LNG	12.2-17.7	UK NSTA 2024 and IFEU 2023
Algeria LNG	13.8-27.8	UK NSTA 2024 and IFEU 2023
Nigeria LNG	10.7-20.8	UK NSTA 2024 and IFEU 2023
USA LNG	12.5 22.0 22.7 23.6 31.3	UK NSTA Marcellus to UK – Zhu et al USA to Germany – IFEU Thinkstep 2017 Permian to UK – Zhu et al

Sources:

- UK NSTA 2024 – Emissions Monitoring Report 2023 (here)
- EU DG Energy 2015 – Study on actual GHG data for diesel, petrol, kerosene and natural gas (here)
- IFEU 2023 - Analysis of the greenhouse gas intensities of LNG imports to Germany (here)
- Zhu et al 2024 – Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains (here)
- Thinkstep 2017 – GHG Intensity of Natural Gas Transport (here)

Natural gas emission factor: 56.7 gCO2/MJ

Hydrogen conversion from MJ to kg = 120.0 MJLHV/kg H2 from DESNZ 2023 link

TABLE 6: NATURAL GAS UPSTREAM EMISSIONS BASED ON SUPPLY SCENARIO

Source	Upstream emissions (gCO_2/MJ natural gas)	Notes
Pipeline Gas	2.3	Average of Norwegian and domestic gas
UK Average 2022	6.8	Average emission of UK's gas consumption in 2022 – calculated with weighted average of imports
Average LNG (excl. USA)	17.5	Average of Qatar, Peru, Nigeria, Algeria
USA Mid	22.4	Average of USA estimates
USA High	31.3	LNG from Permian Basin - Zhu et al

Note: these values exclude grid transmission losses and venting which are presented below.

TABLE 7: TRANSMISSION LOSSES AND VENTING

	Value	Notes
Energy consumption transmission (%)	0.13 %	DESNZ 2023
Venting Losses transmission (%)	0.1 %	DESNZ 2023
Total Transmission losses	1.5 gCO_2/MJ_Gas	Own calculation

- DESNZ 2023 – Data for calculating Greenhouse Gas Emissions under the UK Low Carbon Hydrogen Standard here

TABLE 8: BASIC ASSUMPTIONS FOR THE BLUE H2 MODEL

	SMR	ATR	PEM	notes
Efficiency (%)	74%	84%	79%	DESNZ 2021
Carbon Capture Rate (%)	90%	95%	--	DESNZ 2021
Energy Supply and Fugitive Emissions (gCo2/MJ H2)	1.96	4.93	--	DESNZ 2024

- DESNZ 2021 – Hydrogen production costs 2021 here
- DESNZ 2024 – UK Low Carbon Hydrogen Standard – Hydrogen Emission Calculator here

TABLE 9: AVERAGE ELECTRICITY GRID EMISSION FACTORS

	Value ($kgCO_2$/MWh)	Notes
2023	153	National Grid ESO data
2030	45	CCC "Sixth Carbon Budget" balance scenario
2035	5	Own assumptions*

* Assumption taken for visualisation purposes as average 2035 emissions should be zero

TABLE 10: ASSUMPTIONS FOR GAS-CCS AND HYDROGEN-TURBINE MODEL

	Unabated CCGT	Gas-CCS	Hydrogen CCGT	
Efficiency (%)	53%	47%	48%	DESNZ 2020 & 2023
Carbon Capture Rate (%)	--	90%	--	DESNZ 2020 & 2023

DESNZ 2020 & 2023 – Electricity Generation costs 2020 and 2023 here

TABLE 11: MODELLING ASSUMPTION FOR H2TEESSIDE

	Value	Notes
Hydrogen Capacity (kg/hour)	22175	
Carbon Capture rate	95%	
Process emissions (kgCO2/kg H2)	7.42	Calculated from EIA report
Operating hours	8760	
Lifetime (years)	25	
Upstream emissions (gCO2/MJ_NG)	8.39	Based on the Well-to-tank (Gross CV) emission factor from the same reference used in the EIA report – DESNZ 2023

All figures are based on the documentation provided in the Environmental Impact Assessment (EIA) report here

In detail: Volume 6 Environmental Impact Assessment Information Part 1 – Environmental Statement Chapters – Chapter 19 Climate Change

DESNZ 2023 - Greenhouse gas reporting: conversion factors 2023 link

TABLE 12: MODELLING ASSUMPTION FOR NZT POWER

	Value	Notes
Gross Capacity (MW)	860	
Net Capacity (MW)	684	
Carbon Capture rate	90%	Based on the Reference scenario in EIA report
Operating hours	8424	Based on the Reference scenario in EIA report
Lifetime (years)	25	
Upstream emissions (gCO2/MJ_NG)	9.30	Based on the Well-to-tank (Net CV) emission factor from the same reference used in the EIA report – DESNZ 2023

All figures are based on the documentation provided in the EIA report here

In detail: Volume 6 Environmental Impact Assessment Information Part 1 – Environmental Statement Chapters – Chapter 21 Climate Change

NZT Power **Initial submission EIA** (without upstream emissions) from May 2021 link

NZT Power **Final submission EIA** (including upstream emissions) from 30 May 2023 link

DESNZ 2023 - Greenhouse gas reporting: conversion factors 2023 link

TABLE 13: CCUS TRACK-1 PROJECTS TECHNICAL DATA

	Hydrogen capacity (ton/year)	Gross (MW)	Electricity	Capacity
NZT Power	--	860		
H2Teesside (Phase 1+2)	583’000	--		
BOC Teesside Hydrogen	30’000	--		
Vertex HyNet Hydrogen (Phase 1+2)	360’000	--		

Based on data extrapolated from company reports and EIA when available

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