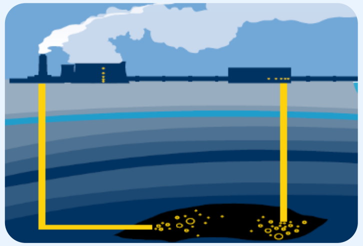

HICP HUMBER INDUSTRIAL CLUSTER PLAN

Humber Industrial Cluster Plan

Net-Zero Emissions Pathways in the Humber

UK Research and Innovation

HEY Hull and East Yorkshire Local Enterprise Partnership

CATCH

November 2022

ERM

elementenergy an ERM Group company

E4tech an ERM Group company

wood.

cambridge econometrics clarity from complexity

Authors & Acknowledgements

This report has been prepared by Element Energy, an ERM Group company.

Element Energy is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. The team of over 100 specialists provides consultancy services across a wide range of sectors, including the built environment, carbon capture and storage, industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon transport. Element Energy provides insights on both technical and strategic issues, believing that the technical and engineering understanding of the real world challenges support the strategic work. In June 2021, Element Energy joined the ERM Group, the largest independent sustainability consultancy, with a global footprint and over 7,000 employees worldwide.

Interpretation of economic impacts has been provided by Cambridge Econometrics.

Cambridge Econometrics is an economics consultancy that works globally from offices in Cambridge (UK), Brussels, Budapest and Northampton, Massachusetts. We specialise in economic research and the application of economic modelling and data analysis techniques for policy assessment and scenario planning. We have particular expertise in the application of whole-economy macro-sectoral models, notably our global E3ME model.

This work was commissioned by the **Humber Industrial Cluster Plan** (HICP). Whilst every effort has been made to ensure the accuracy of this report, neither the commissioners nor Element Energy or any other subcontractors warrant its accuracy or will, regardless of its or their negligence, assume liability for any foreseeable or unforeseeable use made of this report which liability is hereby excluded.

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Drax	Singleton Birch	Lincolnshire County Council
National Grid	PX Group	

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We would also like to acknowledge the wider team that has contributed to the development of the N-ZIP Humber model that was core to this work.

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- University of Sheffield
- University of Hull
- Mike Muskett

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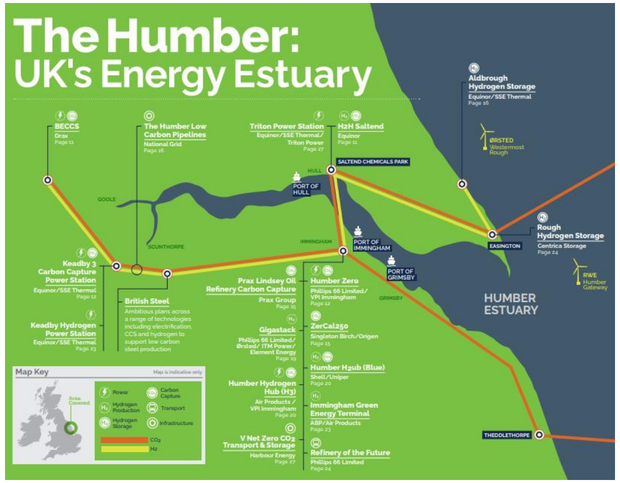
Appendix

Understanding the interplay between over 50 industrials is key for achieving net-zero across the Humber Cluster by 2040

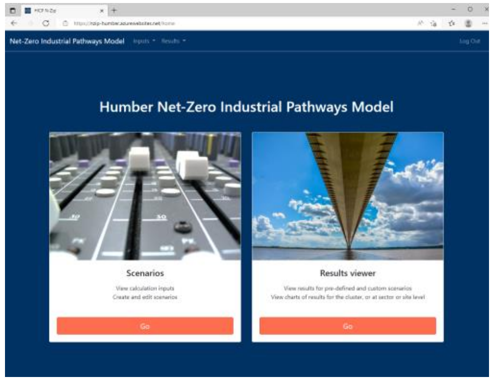
Overview of the Humber Industrial Cluster Plan

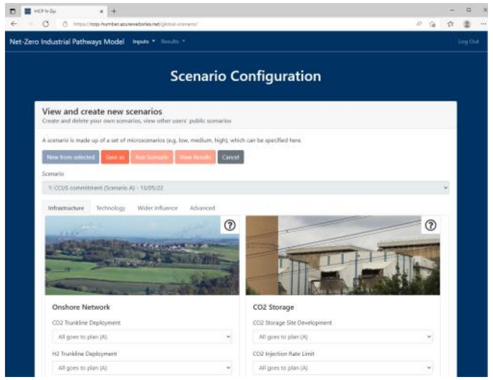
- The Humber is the largest industrial area within the UK, with over 14 $MtCO_2$ emitted annually and employing thousands of people in foundation heavy industries.
- Several industrial decarbonisation projects, exploring carbon capture and storage (CCS) and hydrogen production are emerging in the region, driven by the private sector.
- In 2019 UKRI launched the 2-phase decarbonisation of industrial clusters roadmaps competition. The former Humber Local Enterprise Partnership (LEP), which is now Hull and East Yorkshire (HEY) LEP, and CATCH were initially funded to carry out a Phase 1 feasibility study, and then successfully received Phase 2 funding to develop their decarbonisation roadmap alongside five other competition winners, each taking a share of £8 million in funding from UKRI.
- The phase 2 project to deliver the clusters decarbonisation roadmap is known as the Humber Industrial Cluster Plan (HICP) and is being led by HEY LEP and CATCH, with 8 industrial partners.
- The project aims to develop a regional strategy on how industrial emissions will change over time and provide the region's projects and industry with a well-defined, optimal route to achieving true net-zero in 2040.



Developing the regional strategy must be underpinned by robust analysis

- The Humber cluster required a robust and credible data analysis solution to assess optimum routes to achieving significant carbon reductions by 2030 and net zero by 2040.
- This solution had to provide quantitative evidence for the Humber Industrial Cluster plan and its roadmap to net zero.
- The N-ZIP Humber model determines the optimal decarbonisation pathway for the industrial cluster based on a set of scenario input parameters.
- For each process on each site, the model selects the technology adopted and the year of deployment.
- A net present value (NPV) based cost optimisation is used considering a shadow carbon value to value the benefit of reducing CO_2 emissions.
- The N-ZIP Humber model is an investigative analysis tool, considering different scenarios and not replicating current project and policy plans with fidelity, but helps understand the impact of key decarbonisation decisions within the cluster.





In all four of the core scenarios, deep-decarbonisation is achieved by 2040, with over 96% of emissions abated

Four scenarios are investigated as part of this work

- The core model covers 53 existing industrial & power sites within the Humber area.
- Without decarbonisation, in the Business As Usual (BAU) baseline, emissions of industrial sectors within the cluster are projected to only reduce by 18% due to changes in the markets and national strategy.
- Analysis on the influencing factors informed the selection of four self-consistent, realistic and interesting core scenarios to explore in this report.
- The scenarios varies in terms of assumptions, and consider factors such as costs, level of incentives, the type of hydrogen production routes developed, and the timelines for shared infrastructure development. The variations could be related to commitment to different technology options or policy measures.

In all four of the core scenarios, deep-decarbonisation is achieved by 2040

- A 96% reduction in cluster emissions compared to 2022 levels leaves a remaining level of 0.5-0.7 $MtCO_2$ /year from the cluster that must be removed with greenhouse gas removals.
- The most rapid decarbonisation occurs in the Innovations & Incentives scenario – 80% reduction by 2030 – this is driven by a high carbon value incentive.
- Scenarios with delays to blue hydrogen projects and pipeline network deployment have a more gradual decline – Barriers with Limited Enablers lags the other scenarios with only 31% reduction by 2030.
- CCS is deployed rapidly in Innovations & Incentives reflecting the ambitious roll-out capability in this scenario; however, CCUS Commitment has the greatest uptake of CCS by 2040. The Barriers with Limited Enablers scenario has a delayed uptake of CCS but ultimately adopts the technology heavily.
- Hydrogen fuel switching is adopted reasonably consistently across all scenarios. Higher electricity costs make this a more expensive option in CCUS Commitment which sees more CCS adopted.
- The model chooses to deploy an Electric Arc Furnace at British Steel in all scenarios providing a significant amount of early abatement.

Overview of the scenarios modelled

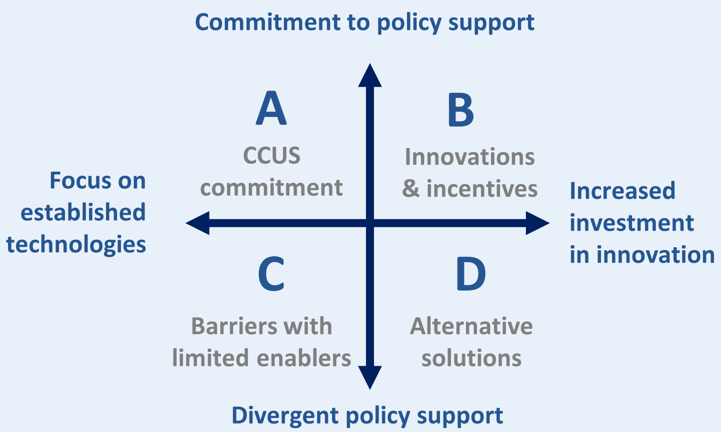


Chart E.1 Technology uptake (2040)

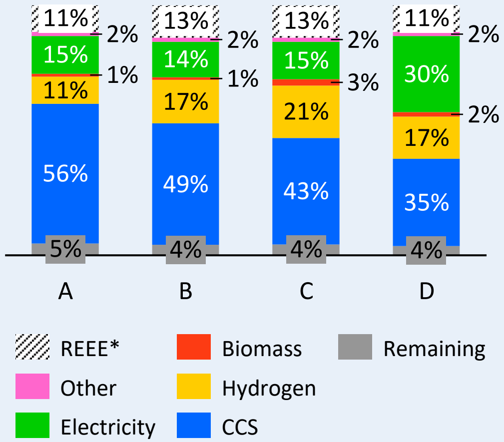
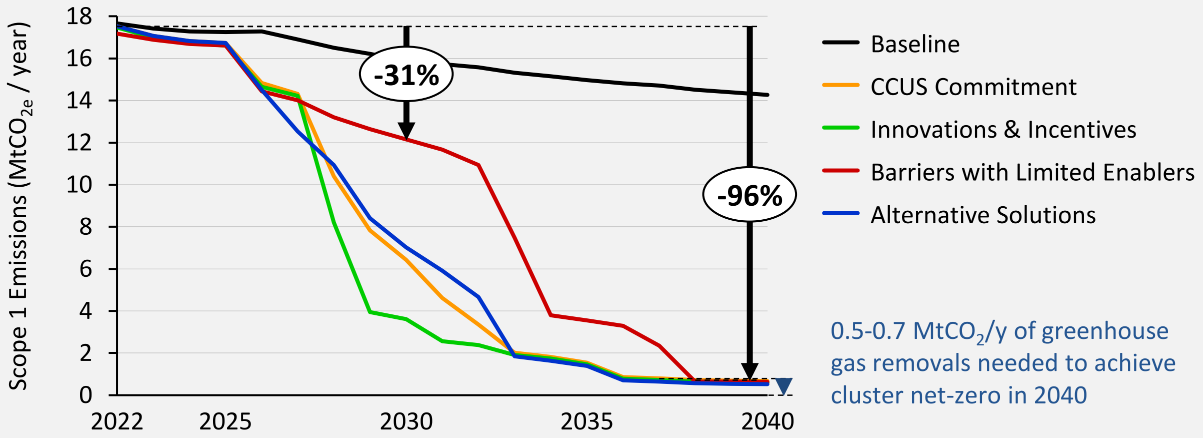


Chart E.2 Total Scope 1 emissions over time (cluster)



**REEE (Resource and Energy Efficiency) represents the reduction in emissions from employing efficiency measures, new material choices and reducing consumption*

Net-Zero Humber: the 2040 vision includes a decarbonise cluster, potential for CO_2 imports and hydrogen exports, and thousands of low-carbon jobs created

What would a 2040 Net-Zero Humber look like?

- Deployment of CCS at scale, capturing between 16-28 $MtCO_2$/year of regional emissions. In addition, up to 16 $MtCO_2$ /year is envisaged to be imported via shipping and land transport across the scenarios
- Hydrogen for fuel switching would represent a significant factor of demand, with the majority used for high-heat processed and blending into power generation assets
- Electrification of industrial processes could require between 2-7 TWh electricity in 2040, with the biggest sector of demand being clean-steel manufacturing
- Up to 16 $MtCO_2$ biogenic emissions could be captured, however careful planning of infrastructure will be required to enable the full potential
- Significant investment (£15-32 bn) will be required between now and 2040 to enable cluster decarbonisation

Opportunities for clean growth

- The benefits in terms of Gross Value Added reach between £3-5bn/year for most scenarios, with ~25% being captured in the Humber
- The Humber deployment could create up to 70,000 jobs across the UK, including with the Humber cluster

Decarbonisation of the Humber cluster will require between £15-32 bn cumulative investment

Chart E.3 Breakdown of cumulative cost differential by 2040 (excludes carbon value)

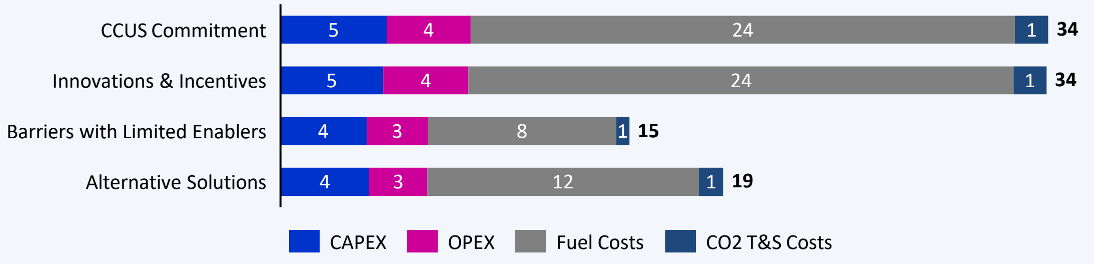


Chart E.4 Breakdown of annual CO_2 T&S demand in 2040

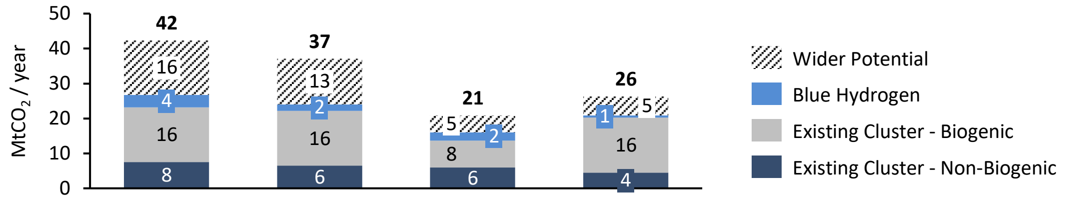


Chart E.5 Potential wider hydrogen demand in 2040

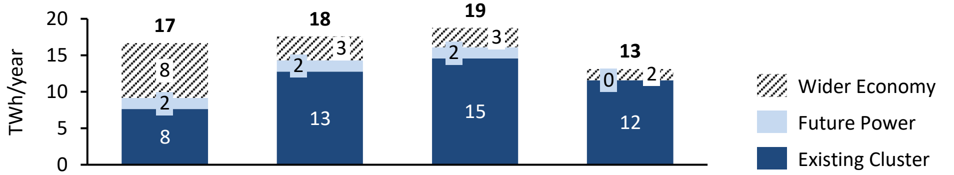


Chart E.6 Potential for electrification in 2040

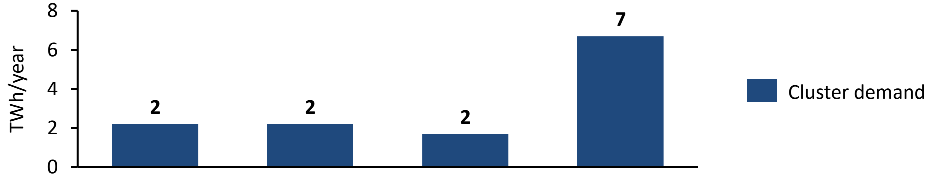
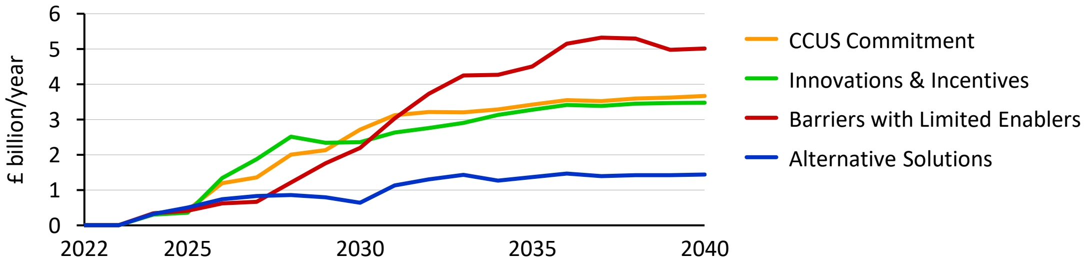
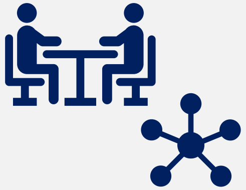


Chart E.7 National UK GVA impact enabled by the decarbonisation of the Humber cluster



Over 20 Conclusions and Recommendations have emerged through the modelling exercise, which could be split into three main categories

Conclusion	Recommendations



Collaboration across the cluster is a key enabler for reducing cross-chain risks across CCS projects

- Successful offshore CO_2 storage development is an immediate priority to allow significant decarbonisation to be achieved by 2030. Storage projects are actively working to meet this demand however their success depends on the government delivering timely CCUS business model announcements to provide both CO2 T&S infrastructure and anchor projects with enough certainty to make final investment decisions.
- CO2 storage projects should collaborate to ensure near-term injectivity rates are met for the region and that risks are minimised for capture projects – for example, by agreeing on compatible CO2 specifications to offer future flexibility.
- Government should continue to recognise the opportunity available in the Humber to act as both a storage hub for the wider UK and an exported of greenhouse gas removals. To capitalise on this opportunity, government should back the continued development of offshore storage via future expansion phases. Government may also need to act upon regulatory developments to enable cross-border imports of CO2 from Europe.

Timely and well-define business models are critical for achieving net-zero in the Humber cluster by 2040

- If hydrogen is to be utilised in applications with high load factors, particularly in CHPs, strong support mechanisms must be put in place to alleviate the additional costs of adoption compared to natural gas. These mechanisms should be detailed as early as possible to improve security of supply and demand in the region and to prevent the lock-in of other technologies before hydrogen is properly scaled up.
- Timely development of infrastructure is critical to the delivery of CCS and hydrogen fuel switching. Delivery of the due diligence process in the Phase-2 Cluster Sequencing process will provide more certainty for BEIS around approving anticipatory investment. Proactive decision making on a pipeline specification for emitters will provide more certainty about which sites can connect and expediate the project delivery.

A holistic approach will be required to facilitate Humber's integration in the net-zero system and establishing a national supply chain

- Further work is needed to understand the potential to expand electricity generation in the Humber and distribute this energy to sites. The feasibility of large scale electrolytic hydrogen routes is dependent upon the ability to deploy additional renewable electricity generation at low-cost and secure appropriate electrical connections. This was not investigated in detail within the current study and could form the focus of future work.
- Developing a skilled labour force that can deliver the deployment of technologies spanning CO2 capture, pipeline networks, compression and hydrogen production technology will be essential to coordinating large scale abatement at speed in the region. A limited work force will cause significant delays and constrain the scope of the project jeopardising the target of reaching net-zero by 2040.

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Humber Industrial Cluster Plan

In 2019 UKRI launched the 2-phase decarbonisation of industrial clusters roadmaps competition. The former Humber Local Enterprise Partnership (LEP), now called HEY LEP, and CATCH were initially funded to carry out a Phase 1 feasibility study, and then successfully received Phase 2 funding to develop their decarbonisation roadmap alongside five other competition winners, each taking a share of £8 million in funding from UKRI. The phase 2 project to deliver the clusters decarbonisation roadmap is known as the Humber Industrial Cluster Plan (HICP) and is being led by HEYLEP and CATCH, with 8 industrial partners.

"The Humber Industrial Cluster Plan (HICP) - a dynamic plan to set out the optimal route to decarbonisation for the Humber Cluster by 2040.

- The Humber Industrial Cluster Plan was set up in January 2021 following the 2-phase decarbonisation of industrial clusters roadmaps competition in 2019 by UKRI.
- The project team includes membership organisation CATCH, the HEY LEP plus 8 industry partners. Partners will work together to develop the Humber Industrial Cluster Plan that will set out the strategic roadmap for the Humber Cluster to follow in order to achieve net zero by 2040.
- The Humber Industrial Cluster Plan will provide confidence to the UK government's ambitions, encompassing how industrial emissions will change over time and provide the region's projects and industry with a well-defined, optimal route to achieving true net-zero in 2040.
- This will be achieved by validating technological pathways, data, literature, interviews, research, supply chains, skills development and defining areas for investment, along with engaging stakeholders and the general public."

humberindustrialclusterplan.org

The Humber required a robust and credible model to support analysis of its net-zero strategy

The Humber cluster required a **robust and credible data analysis solution** to assess **optimum routes** to achieving significant carbon reductions by 2030 and net zero by 2040. This solution had to provide **quantitative evidence** for the Humber Industrial Cluster plan and its roadmap to net zero. Element Energy, an ERM Group company, were commissioned by HICP in November 2021 to develop such a solution.

Objectives:

- Gather best in class **data on decarbonisation technologies** and pathways to net zero to enable the model to operate as designed.
- Develop a **range of complex scenarios**, enabling analysis of the optimum route to the decarbonisation of the Humber given a range of variables and the current uncertainty.
- Develop a cloud-based tool that is capable of **processing large quantities of da**ta with minimal requirement for ongoing technical support
- Develop a cloud-based tool that allows efficient and secure data import and is **useable by the HICP team** (and wider partners & groups)
- Develop a cloud-based tool that enables **data and insight visualisation** that can be used by the HICP team (and potentially wider partners & groups) to **support interpretation and presentation** of findings to stakeholders.

The solution: a cloud-based systems model based on previous CCC analysis methodology, using best in class data, adaptable inputs, clear visualisations and scenario-based investigations – **N-ZIP Humber**.

This document represents the final report and outcomes of the modelling analysis work for HICP (Lot 1).

The contents and structure is as follows:

- Executive Summary
- Introduction
- Overview of the model and scenarios
- Paths to net-zero
- Technology adoption overview
- Uptake and infrastructure
- Deployment costs and Investment Needs
- Jobs and GVA
- Recommendations
- Appendix

Why a cloud-based systems model?

- **Robust** – complex analysis of large datasets and interlinking variables
- **Reusable** – ability to re-run analysis with updated datasets in the future (future proofing)
- **Recommended** – preferred approach to road-map development as recommended in Phase 1

How the model was developed…

- **Consistent with CCC** – analysis approach based on UK N-ZIP model that informed CCC Sixth carbon budget
- **Industry engaged** – involvement of local stakeholders via interviews and presentations
- **Public data, government aligned** – gathering or development of openly available data, with use of official government projections where relevant
- **Independent analysis** – analysis designed to reflect objective decision making based on inputs, independent of proposed projects or targeted policy

N-ZIP Humber is a bottom-up analysis tool, meaning pathways may not fully reflect the ambitions of emerging decarbonisation projects in the Humber:

- The model is an **investigative analysis tool with site-level decisions based on bottom-up analysis** and dependent on a broad range of scenario-dependent assumptions. There are significant uncertainties in these inputs (e.g. fuel prices) and scenario analysis is used to explore a range of future long-term possibilities.
- The model does not attempt to reflect all possible political, commercial or public drivers, and therefore **pathways (including timelines, technologies, and scales) may differ from expectations based on current project plans or government ambitions**. In particular, the model does not account for technology specific policy incentives nor does it act to directly replicate announced projects.
- **The model does not attempt to provide in-depth technical engineering analysis for individual sites.** The analysis is based on an archetypal approach to modelling industrial sites as a set of sector specific processes. The outputs of the model should not be taken to reflect actual project costs, as these require in-depth site-specific engineering analysis.
- The analysis focuses on abating **Scope 1 emissions of large* industrial emitters** in the Humber.

CCC: Climate Change Committee *large industrial emitters refers to point sources reporting on the UK National Atmospheric Emissions Inventory (NAEI)

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The N-ZIP Humber model – a bottom-up, optimisation approach to net-zero pathway analysis

The N-ZIP Humber model determines the **optimal** decarbonisation pathway for the industrial cluster based on a set of **scenario input parameters** – e.g. energy costs, infrastructure availability – and within a given set of development **constraints** - e.g. fuel supply, rates of deployment. For each process on each site, the model selects the **technology** adopted and the **year of deployment**. A net present value (**NPV**) based cost **optimisation** is used considering a **shadow carbon value** to value the benefit of reducing CO_2 emissions.

The model aims to minimise the objective function:

Cost of Abatement (*Discounted additional cost, NPV basis (2022-2050) (£)*) – (*Emissions Abated* (*Scope 1 + upstream fuel (2022-2050) (t/CO_2)*) X *Shadow Carbon Value* (*Discounted (2022-2050). Represents incentive to decarbonise (£/tCO_2)*))

Shadow carbon value: The shadow carbon value is used to **represent the incentive to reduce emissions** – if an abatement measure falls below this cost (£/tCO_2) then the model assumes the abatement measure is preferable to adopt. Incentives could include a **range of policy or market drivers** to reduce emissions (e.g. project grants, carbon tax, product pricing, mandates). The shadow carbon value is a policy neutral representation of these drivers, **consistent with the BEIS approach** to valuing greenhouse gas emissions in policy appraisal[1]

Onshore transport network: Onshore pipeline networks for both hydrogen and CO_2 transport are represented in the model as a series of 'defined points' connected via pipelines (see diagram right). Each modelled site is assigned to a defined point based on proximity and can only access hydrogen supply or CO_2 storage once it becomes available at its defined point – either via local production or pipeline connection. The rate of pipeline build-out is an input assumption in the model, variable by scenario. The cost of transport via the onshore network is demand dependent, reflecting the benefits of economies of scale. Costs are determined via an iterative feedback loop.

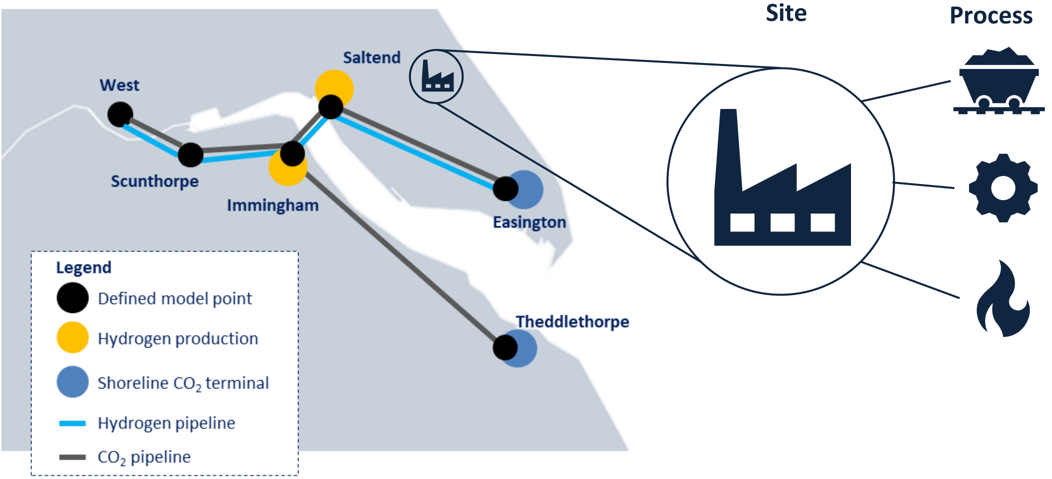
Hydrogen production: The scale of hydrogen production is determined based on the demand calculated via site-by-site analysis in the model. An iterative feedback loop is used to match supply with demand ensuring production is costed appropriately for the scale. Hydrogen production is modelled as being split between Saltend and Immingham, with input assumptions determining the split between CCS-enabled (blue) hydrogen and electrolytic (green) hydrogen produced. Hydrogen costs are influenced by the costs of primary energy supply – natural gas for blue and electricity for green.

Feasibility constraints: Limits are included in the model to restrict the uptake of abatement technologies to fall within a set of theoretical maximum feasibility constraints. These constraints notably include the scale of hydrogen availability pre-2030/35 and the feasible injection rate ramp-ups for CO_2 storage.

N-ZIP Humber Analysis Methodology

1. Set-up of baseline & post-efficiency measure emissions & fuel consumption profiles for each process on each site.
2. Calculation of cost of hydrogen production, transport & storage. | Calculation of cost of CO_2 transport & storage.
3. Site-process level calculation of the NPV, fuel consumption and CO_2 T&S requirements of all feasible abatement pathways (pathway = technology + timeline)
4. Selection of cluster-level optimal NPV decarbonisation pathway that conforms with constraints.
5. Calculation of actual CO_2 T&S and H_2 demand in the cluster.
6. Analysis of economic impact of final pathway and generation of outputs.

Feedback loop to match H_2 supply and CO_2 disposal cost assumptions with cluster demands



The N-ZIP Humber model is an investigative analysis tool, considering different scenarios and not replicating current project and policy plans with fidelity (I/II)

Before reviewing this report, it is important to understand the analysis approach and the consequences of this on the outputs presented. Some key points are highlighted below:

Existing project plans & UK targets

Context

The East Coast Cluster was selected as a Track 1 cluster in the cluster sequencing process, enabling select qualifying decarbonisation projects to receive support if deployed by 2027. **Several projects led by private players have emerged** in the region (see map), with plans announced for industrial & power carbon capture, hydrogen production, and greenhouse gas removals, alongside developments of shared CO_2 transport & storage infrastructure and hydrogen storage sites. The government has also announced targets for UK hydrogen production and CO_2 storage.

Consideration in design

The model does not act to directly replicate announced projects, recognising the future uncertainty surrounding proposals, which are often dependent on successful receipt of economic support or future final investment decisions post-FEED. The model instead decides on abatement technologies, timelines and scales via a bottom-up approach.

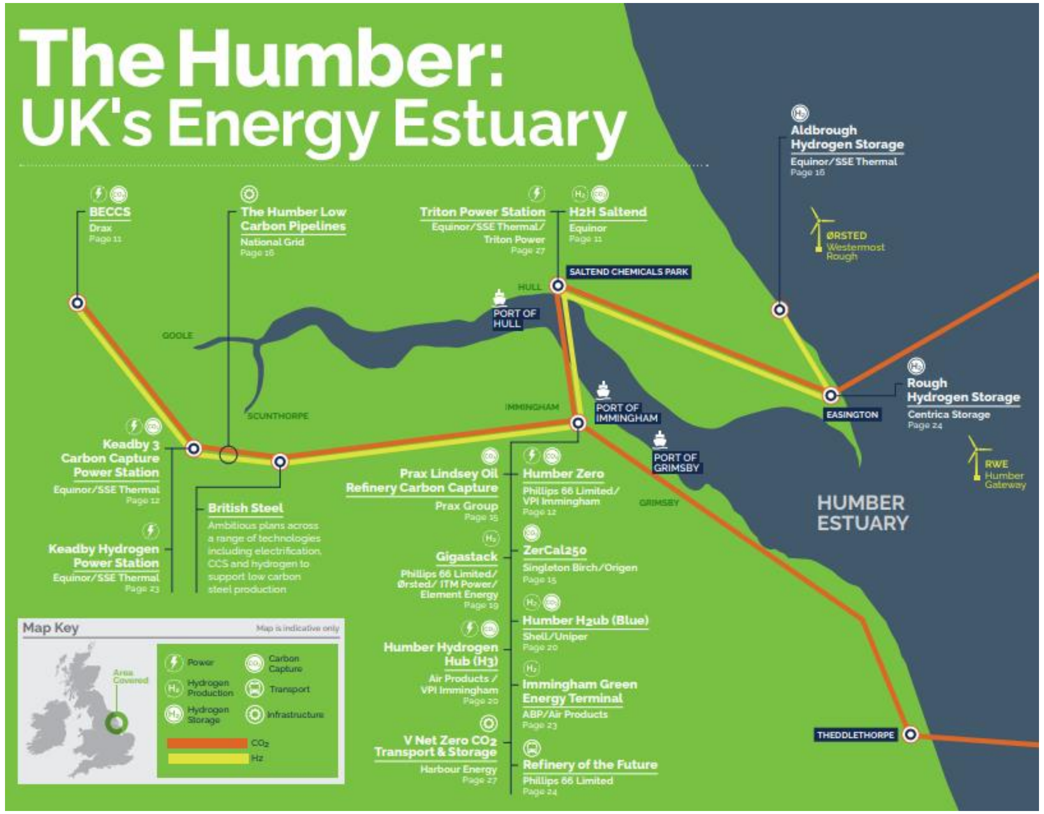
Announced projects are however used to guide several areas of the analysis including:

- selection of suitable abatement technologies for individual sites and their earliest deployment year
- development of constraints on the maximum feasible level of near-term hydrogen supply
- development of constraints on the maximum feasible level of CO_2 storage (injection rate and total capacity)
- near-term assumptions on the relative scale

Consequence

Decarbonisation pathways do not necessarily fully reflect the deployment timelines, technology choices or scales of announced projects. These factors are scenario dependent.

List of decarbonisation projects emerging in the Humber (based on the Humber 2030 vision)



The N-ZIP Humber model is an investigative analysis tool, considering different scenarios and not replicating current project and policy plans with fidelity (II/II)

Before reviewing this report, it is important to understand the analysis approach and the consequences of this on the outputs presented. Some key points are highlighted below:

Decarbonisation incentives – policy support & market drivers

Context

The UK government is in the process of finalising **targeted operational support mechanisms**, known as CCUS business models, that will provide a strong economic incentive for qualifying decarbonisation projects linked to Track 1 clusters. These support packages vary by project type: power, industry, GGR, hydrogen etc. Over the next decade, further mechanisms to drive decarbonisation are also likely to develop and evolve (e.g. updates to UK Emissions Trading Scheme (ETS), offset markets, mandates or regulations). The sites that may qualify for subsidy, the level of subsidy, and future policy developments are all uncertain.

Consideration in design

The model is designed to be policy neutral and does not reflect targeted policy support for individual technologies, sites or sectors. Instead a shadow carbon value is used to provide a consistent incentive across sectors and sites for reducing emissions or achieving greenhouse gas removals. The incentive is a £ / tCO_2 value that increases linearly from 2022 to 2050 in line with BEIS 2021 untraded carbon prices for policy evaluation.

Planned policy support is however considered for assumptions regarding:

- timelines of shared infrastructure development
- timelines of technology availability for sites
- level of shadow carbon value (low, central, high)

Consequence

The mixture and scale of technologies deployed in decarbonisation pathways may not align with expectations based on targeted technology specific government support.

Site assumptions & data limitations

Context

The NAEI dataset contains reported Scope 1 emissions of large industrial sites in the Humber. Although major emission sources at sites can be estimated based on sectoral archetypes, the exact breakdown of emissions and associated fuel-consumption will **vary on a site-by-site basis**. The suitability of decarbonisation technologies for sites is also site specific, alongside the cost of deploying abatement options and the level of abatement provided. Individual sites may have their own estimates for the costs of decarbonising their assets, the feasibility of this, and the wider impacts of the pathway.

Consideration in design

The model does not attempt to provide in-depth technical engineering analysis for individual sites. The analysis is based on an archetypal approach to modelling industrial sites as a set of sector specific processes. The data used to underpin the analysis has been derived from publicly available data or is based upon estimations provided by experts within the project team. Whilst local industries were consulted to guide the selection of these data sources or assumptions, the project has not received any confidential site-specific data from industrials or projects.

Stakeholder consultations and publicly available data has been used to guide high-level modelling assumptions on the scale of equipment at sites, types of energy sources and the suitability of abatement options for individual processes.

Consequence

The capital investment requirements estimated by the model will differ from individual project estimates. The outputs of the model should not be taken to reflect actual project costs, as these require in-depth site-specific engineering analysis.

The net-zero pathways focus on Scope 1 emissions abatement. Biogenic emissions and changes in Scope 2 emissions are also tracked within the model

Scope 1 (Direct) Emissions
Direct green house gas (GHG) emissions occur from sources that are owned or controlled by the reporting company, for example, emissions from onsite combustion. Direct CO_2 emissions from combustion of biomass are excluded from scope 1

Scope 2 (Energy Indirect) Emissions
Emissions resulting from the reporting company's consumption of purchased electricity, heat, steam and cooling. Commonly these are emissions from the generation of purchased electricity that occur at the site of generation.

Scope 3 (Other Indirect) Emissions
Emissions that are a consequence of the activities of the company, but occur from sources not owned or controlled by the company. For example, extraction and production of purchased materials; and use of sold products and services.

Biogenic Emissions
Carbon emissions from biomass combustion are not accounted in Scope 1 Emissions as per the GHG Protocol Corporate Accounting and Reporting Standard. The UK Government guidelines for GHG reporting note that CO_2 is absorbed by fast-growing bioenergy sources during growth, so Scope 1 emissions are set as net zero carbon.

Treatment in N-ZIP Humber model:

Scope 1 emissions are the focus for the N-ZIP Humber decarbonisation pathways. The model aims to identify pathways for abating Scope 1 emissions. A range of abatement technologies are included to reduce an industrial sites onsite emissions.

The majority of 'cluster' focused charts presented in this document present Scope 1 emission reduction pathways from existing industrials in the Humber. Scope 1 emissions from future hydrogen production projects are not included on such 'cluster' charts for existing industrials, but are instead consider as indirect emissions of the industrials.

The N-ZIP Humber model assigns a value to abating Scope 1 emissions equivalent to the Shadow Carbon Value. This drives early abatement of Scope 1 emissions.

It is important that direct emissions abatement does not occur at the expense of overall increases in indirect emissions elsewhere.

Indirect emissions linked to hydrogen production, fuel supply, and additional electricity generation are tracked in the model and considered in abatement technology choices.

A cost to increasing indirect emissions relative to a baseline is applied at a value equivalent to the Shadow Carbon Value, whilst an equivalent benefit is also seen if indirect emissions are reduced. This encourages a technology choice with the lowest abatement costs considering both direct and indirect emissions impacts.

Tracked indirect emissions are presented in an upstream emissions chart in this document.

The N-ZIP Humber model tracks onsite emissions from biomass combustion however these are **excluded for Scope 1 emissions analysis in alignment with standard accounting practices**, UK Government guidelines, and GHG Protocol accounting standards. Indirect emissions from the biomass supply chain fall within Scope 3 and are included in indirect, upstream emissions charts for energy supply.

The N-ZIP Humber model focuses on pathways to abate Scope 1 industrial emissions. As CO_2 from biomass combustion is not reported under Scope 1 emissions accounting, **the model does not seek to explore alternatives to existing biomass combustion processes**.

The UK Government's 2021 Biomass Policy Statement outlines that **sustainable bioenergy with carbon capture and storage (BECCS) can provide net-negative emissions** via greenhouse gas removal. In 2022, the UK Government conducted a consultation on Business Models for GGRs in which they outlined three options for a contract-based support scheme for negative emissions. In each of these options, the GGR provider receives a guaranteed price (£ / tCO2) for negative emissions.

In alignment with this current UK Government minded approach, the N-ZIP Humber model includes a cost-benefit of BECCS equivalent to the Shadow Carbon Value per tCO_2 stored. This incentivises adoption of CCS on existing biomass combustion processes.

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The core model covers 53 existing industrial & power sites within the Humber area

Major sites within each sector category (selected as > 0.75 $MtCO_2$ emissions in 2019)

Power Production
- Drax *(biogenic emissions)*
- South Humber Bank
- Keadby Power

Combined Heat & Power
- VPI Immingham

Iron & Steel
- British Steel Scunthorpe

*A total of **53 sites are included** in the cluster analysis – these cover NAEI point sources in the core cluster area.*

Refining & Fuels
- Phillips 66
- Prax Lindsey Oil Refinery
- Perenco
- GASSCO Easington Terminal 1
- Centrical Storage

Cement, Glass & Minerals
- Singleton Birch
- Guardian Industries

Chemicals
- Tronox Pigment
- Saltend Chemicals Park (various businesses)
- Saltend Cogeneration Plant (Triton)[2]

This model focuses on determining the decarbonisation pathways of industry and power sites situated around the Humber estuary, within the local authorities: North Lincolnshire, North East Lincolnshire, Hull City, and East Riding. These sites are modelled due to their presence in NAEI data as point sources of emissions within the Humber. Drax power station is also included within the set of sites to be modelled as it has a significant impact on infrastructure for the cluster.

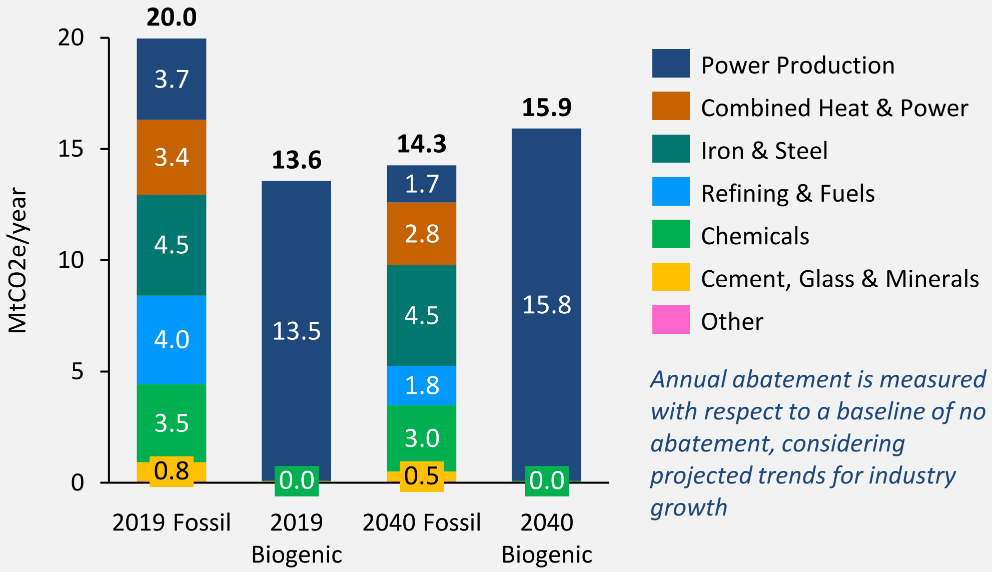
In addition to the 'existing Humber emitters' (referred to as **core cluster**)…

- **Future hydrogen** production projects are also considered in the analysis, including tracking their separate demand for CCS and energy
- **Future power** production projects were not modelled in detail, but their potential demands for H_2 and CCS were considered

The potential for the Humber to support **wider economy** decarbonisation (via H_2 supply, CO_2 storage or GGR deployment) is considered at a high-level based on external analysis, with indicative impacts provided within the results for wider context.

Chart 2.1 Breakdown of Humber Cluster emissions by sector

2040 emissions are BEIS 2021 EEP baseline projected emissions



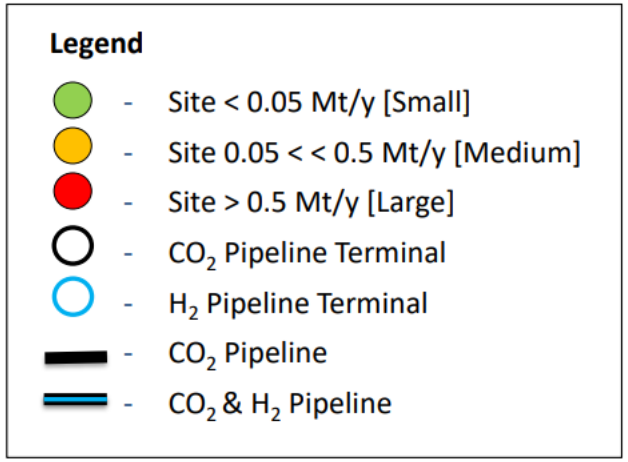
Annual abatement is measured with respect to a baseline of no abatement, considering projected trends for industry growth

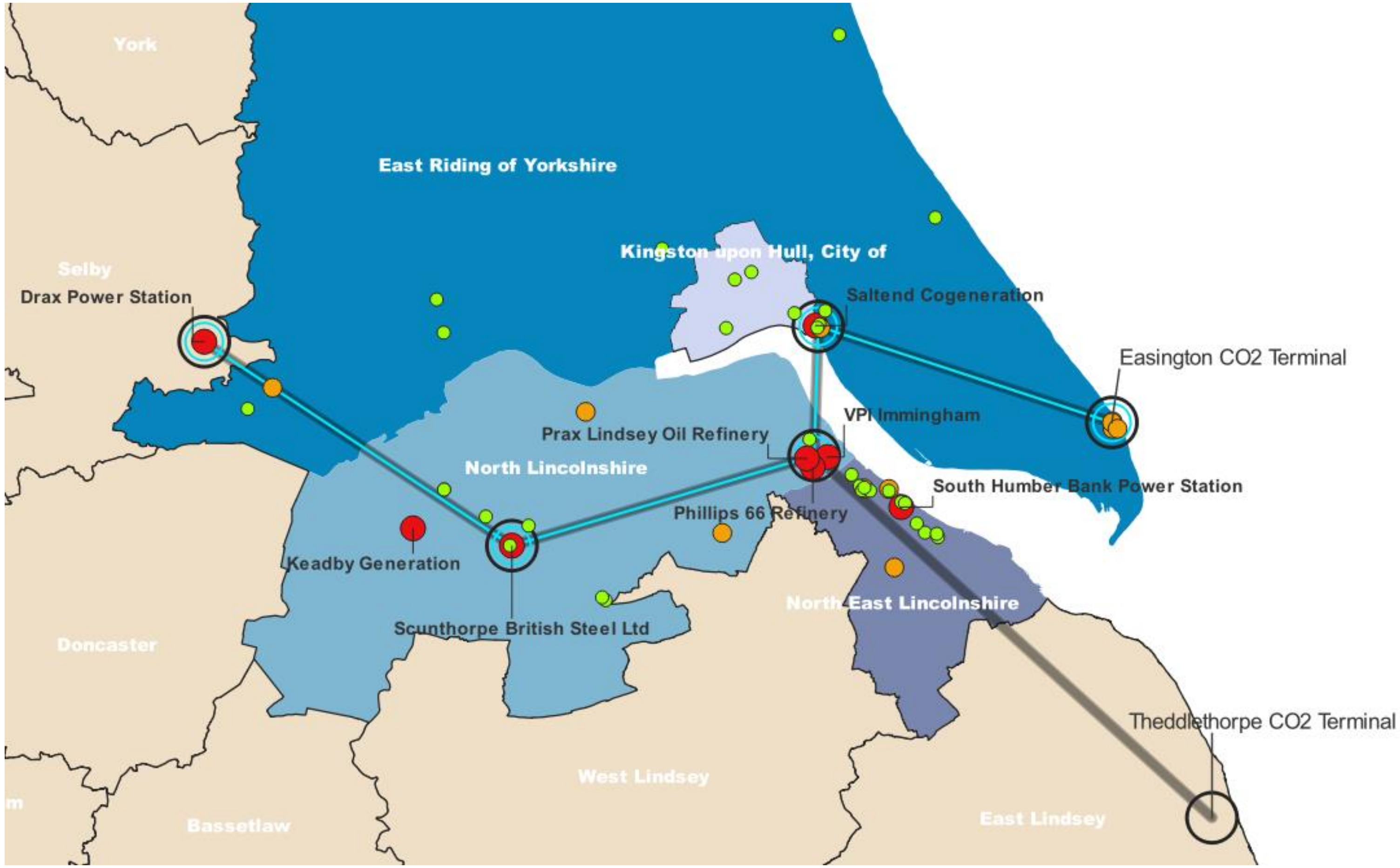
- The Business As Usual (BAU) emissions of industrial sectors within the cluster are projected using national baselines for greenhouse gas emissions. These baselines account for anticipated electricity and fuel costs, population size and potential demand changes. The 2021 baseline projections account for the impact of climate change policies that are significantly developed and funded at the time of publishing.
- The most noticeable change in baseline emissions is within the **Refining & Fuels** sector due to anticipated demand reduction. This has knock on effects for the **Combined Heat & Power** sector that provides for the **Refining & Fuels** sector in the Humber. As the generation mix of the **Power Production** sector evolves, a substantial decrease in emissions is anticipated in the baseline.
- The remaining level of emissions to be abated in the cluster every year is compared to the projected baseline emissions of the industry and power.

[1] Baseline emissions represent a business as usual case in which there is no adoption of energy efficiency or resource efficiency measures, and in which there is no adoption of deep decarbonisation technologies. [2] Saltend Cogeneration Plant has been categorised under Chemicals rather than Combined Heat & Power to reflect end-users of the heat & power.

The sites are categorised into geographic areas based on proximity to points along a modelled H_2 and CO_2 pipeline network

- Connection to the pipeline is modelled to occur at the defined points of:
  - Easington
  - Theddlethorpe
  - Saltend
  - Immingham
  - Scunthorpe (includes Keadby)
  - West (located near Drax)
- The locations relate to the location of some of the emerging decarbonisation projects, including H2H Saltend and Humber Zero.
- The pipeline trajectory also follows a similar direction as the emerging plans in the Humber developed by Zero Carbon Humber and V Net-Zero
- Each site is assigned a defined point for connection based on proximity.





Illustrative CO_2 and hydrogen pipeline trajectory

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The optimal pathway is dependent on many wider influencing factors that may be out of control of Humber cluster decision making

Wider influencing factors impacting the optimal decarbonisation pathway for the Humber include fuel costs, level of incentives (modelled via a shadow carbon price), the type of hydrogen production routes developed, and the timelines for shared infrastructure development. The influence of each of these factors is complex. The N-ZIP Humber model has been developed to allow exploration of these factors, considering wider interlinkages and knock-on impacts.

To illustrate the impact of these wider influencing factors, a sensitivity analysis was performed in which each factor was varied individually between a range of potential possibilities:

- **Fuel costs:** The costs of natural gas and electricity were varied considering the Treasury's Green Book low, central and high cost projection ranges.
- **Shadow carbon price (£/tCO_2 incentive):** The shadow carbon price is based on the BEIS 2021 untraded carbon prices for policy evaluation. BEIS publishes low, central and high projections for use in analysis.
- **Infrastructure development timelines:** It is possible that external factors, such as delays to support or limited workforce, or unforeseen challenges could impact the timely deployment of the initial CO_2 and H_2 trunklines and hydrogen production projects. This would have knock-on impacts for sites planning to connect to these networks. Three different variations of timelines are explored: current plans, initial delay, and expansion barriers.
- **Long-term hydrogen production preference:** Although there are already well-established hydrogen production plans in the Humber, the continued development of hydrogen production and the long-term preference towards electrolysis versus CCS-enabled routes is uncertain. This could be impacted by public or political preference, or by the relative costs of electricity and gas prices. Two long-term variations are considered - a roughly 50% electrolysis mix by 2040 and a roughly 75% electrolysis mix by 2040.

Infrastructure development timelines – access to CO_2 transport & H_2 supply by location

	Current Plans		Initial Delay		Expansion Barriers	
Defined point	**CO_2 Storage**	**Hydrogen**	**CO_2 Storage**	**Hydrogen**	**CO_2 Storage**	**Hydrogen**
Easington	2026	2026	2029	2029	2027	**2029****
Saltend	2026	2026	2029	2029	2027	**2029****
Theddlethorpe	2027	-	2030	-	2029	-
Immingham	2027	**2025***	2030	**2025***	2029	**2025***
Scunthorpe	2027	2027	2031	2031	2031	2031
West	2027	2027	2032	2032	2033	2033

Chart 2.2 Split of different hydrogen production types (Blue/Green) over time (% total production)

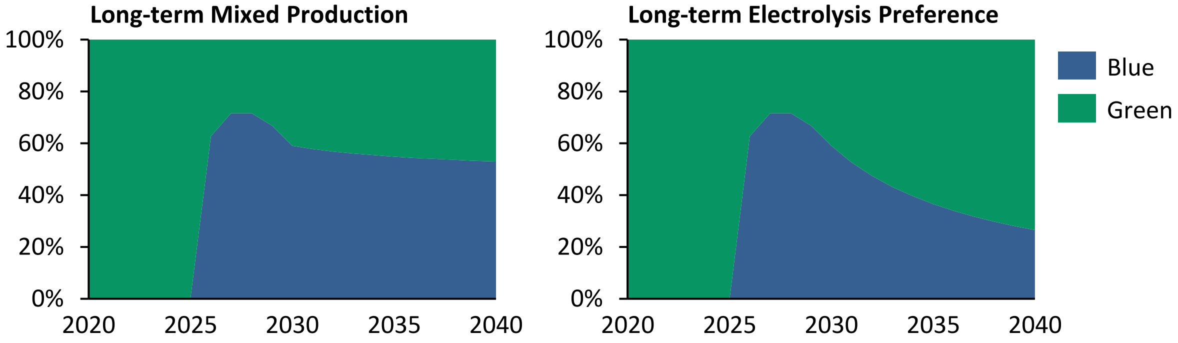
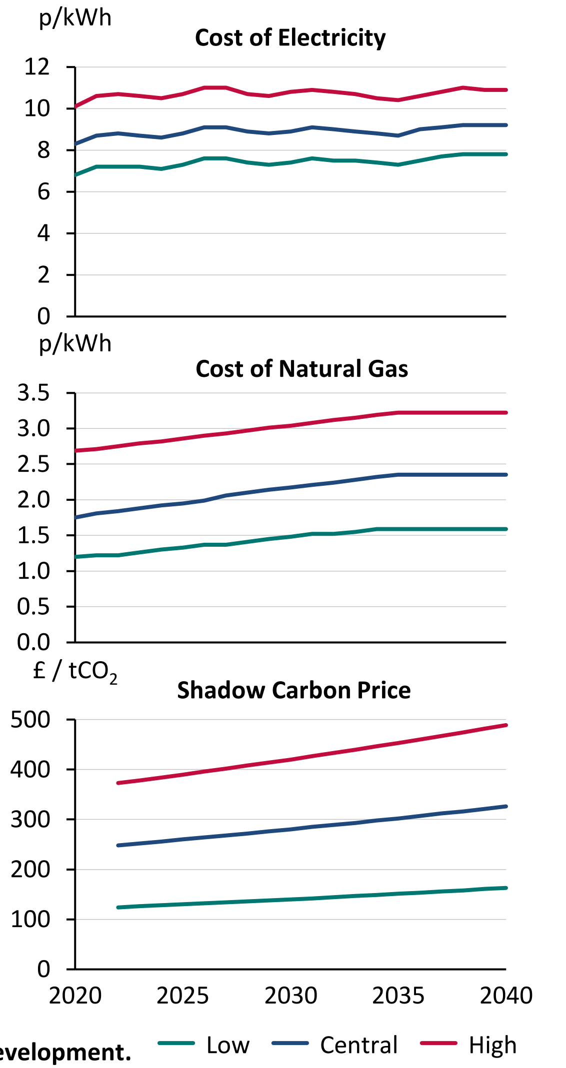


Chart 2.3 Energy and carbon value costs over time



These variations were performed against a base case of central fuel costs and incentives, mixed hydrogen production in the long-term and current plans infrastructure development.

*Immingham sites have access to local green hydrogen production ahead of trunkline deployment; **The CO_2 trunkline is available however access to blue hydrogen production projects is delayed

Impact of influencing factors in achieving near-term decarbonisation (2030)

Non-biogenic emissions abatement – $MtCO_2$ abated in 2030 (annual)

Variation	Impact >>	Hydrogen	Carbon capture	Electrification	Unabated
Base Case	Central	0.2	5.1	2.1	7.3
Incentives (shadow carbon price)	High	0.2	**6.0**	2.1	6.4
	Low	0.2	**0.0**	**0.3**	**14.1**
Electricity Cost	High	0.2	4.8	2.0	7.8
	Low	**0.7**	5.2	2.1	6.7
Gas Cost	High	0.2	5.0	2.1	7.4
	Low	0.2	5.3	2.1	7.2
Long-term Hydrogen Preference	Electrolysis	0.2	5.1	2.1	7.4
Infrastructure Development	Initial Delay	**0.1**	**2.3**	2.3	**10.0**
	Expansion Barriers	**0.0**	**3.3**	2.1	**9.4**

Hydrogen
Carbon capture
Electrification
Unabated

Base case refers to central fuel costs and incentives, mixed hydrogen production in the long-term and current plans infrastructure development (see previous slide)

Hydrogen uptake in the near-term is most sensitive to the cost of electricity. Therefore infrastructure or policy developments to lower electricity costs could significantly increase the near-term uptake of hydrogen through reducing the cost of electrolysis production routes.

Carbon capture uptake is sensitive to incentives and infrastructure development. A low shadow carbon price results in no uptake of carbon capture technologies by 2030. Barriers to infrastructure deployment, either initially or in expansion phases, results in significant reductions to near-term abatement via carbon capture. This emphasises the need for government support (e.g. through the CCS business models) in achieving near-term targets.

Near-term electrification of large sites cannot be achieved without government support, or alternative market incentives. A low shadow carbon price prevents the near-term uptake of large scale electrification technologies at British Steel, with the only near-term uptake being that of heat pumps replacing steam boilers at small sites.

Ability to achieve significant emission reductions by 2030 is most sensitive to incentives and infrastructure timelines. A decrease in the level of incentives provided (modelled via a shadow carbon price) would almost double the amount of remaining emissions in 2030 compared to the central case. Barriers to infrastructure deployment, either initially or in expansion phases, also have a considerable impact – increasing annual remaining emissions from 7.3 $MtCO_2$ to 9-10 $MtCO_2$.

Impact of influencing factors in achieving long-term decarbonisation (2040)

Non-biogenic emissions abatement – $MtCO_2$ abated in 2040 (annual)

Variation	Impact >>	Hydrogen	Carbon capture	Electrification	Unabated
Base Case	Central	1.9	7.7	2.1	0.7
Incentives (shadow carbon price)	High	1.9	7.7	2.1	0.7
	Low	**0.5**	**6.5**	2.2	**3.0**
Electricity Cost	High	**0.2**	8.0	2.1	**2.1**
	Low	1.9	7.7	2.1	0.7
Gas Cost	High	1.9	7.7	2.1	0.7
	Low	**1.1**	8.0	2.1	**1.2**
Long-term Hydrogen Preference	Electrolysis	**0.2**	8.0	2.1	**2.1**
Infrastructure Development	Initial Delay	2.0	**6.0**	2.3	**2.0**
	Expansion Barriers	1.9	7.7	2.1	0.7

- Hydrogen
- Carbon capture
- Electrification
- Unabated

Base case refers to central fuel costs and incentives, mixed hydrogen production in the long-term and current plans infrastructure development (see previous slide)

Some level of remaining emissions exist in 2040 across all variations as a result of several smaller pieces of equipment that have prohibitively high costs of abatement and also as a result of incomplete capture by carbon capture technologies. Difficult to abate remaining emissions could be offset by greenhouse gas removals.

Uptake of hydrogen in the long-term could be impacted by preferences towards production routes. The cost of hydrogen from electrolysis is highly sensitive to the price of electricity. If there is a strong push to favour development of electrolysis rather than CCS-enabled production routes, for example due to public or political preferences, then the long-term uptake of hydrogen is significantly reduced (from 1.9 to 0.2 $MtCO_2$ abated) if actions are not also taken to reduce electricity costs.

Low natural gas costs could reduce uptake of hydrogen, with sites favouring carbon capture solutions or no abatement. A lower natural gas cost makes the business as usual pathway (often natural gas combustion) for sites more favourable. If hydrogen is produced via a 50/50 mixture of CCS-enabled and electrolysis production routes, then a reduction in natural gas cost only has a partial influence on the cost of hydrogen, with electricity prices dominating fuel costs. Compared to the base case, using a lower cost of gas means that sites are more likely to favour continued use of cheap natural gas over hydrogen. In some cases, carbon capture may then become a preferred solution, enabling continued natural gas use whilst abating emissions.

The long-term uptake of CCS is relatively consistent, with only some sensitivity to levels of incentive and infrastructure timelines. Carbon capture is a relatively low-cost abatement route with average abatement costs ranging from £90-135/tCO_2 across the explored variations. This means that most implementations of the technology could still be cost-effective even with a lower shadow carbon price. If a central shadow carbon price is used, then variations in electricity and gas costs have minimal impact on the uptake of carbon capture technology.

Several factors impact the ability to achieve significant emissions abatement by 2040. This is largely those factors that have negative impacts on the uptake of hydrogen (low incentives, high electricity cost, low natural gas cost, and preference towards electrolysis production routes) as well as initial delays to infrastructure development impacting the success of carbon capture projects.

Impact of influencing factors on cost of decarbonisation (2022-2050)

Impact on cost of decarbonisation (2022 - 2050)

Variation		Impact >>	Cumulative additional capital investment (£ billion)	£ / tCO_2	Unabated emissions ($MtCO_2$)
	Base Case	Central	4.6	124	0.7
£	**Incentives (shadow carbon price)**	High	4.6	**135**	0.7
		Low	**3.2**	**83**	**3.0**
	Electricity Cost	High	4.6	119	**2.1**
		Low	4.6	119	0.7
	Gas Cost	High	4.6	124	0.7
		Low	4.7	120	**1.2**
	Long-term Hydrogen Preference	Electrolysis	4.6	119	**2.1**
	Infrastructure Development	Initial Delay	**3.9**	121	**2.0**
		Expansion Barriers	4.6	118	0.7

Base case refers to central fuel costs and incentives, mixed hydrogen production in the long-term and current plans infrastructure development (see previous slide)

Cumulative additional capital investment (£ billion)
(**excludes H_2 production and pipeline infrastructure**)

£ / tCO_2 — Average cost of abatement (£ / tCO_2)
(**excludes shadow carbon price**)

Unabated emissions ($MtCO_2$)

The overall additional capital investment by <u>industrial emitters</u> correlates with the level of carbon capture uptake. In the analysis, the adoption of hydrogen as a fuel at industrial sites typically requires only low levels of additional capital investment by the adopting industrial site – that required to replace burners, retrofit existing equipment, or upgrade equipment already scheduled for replacement. The adoption of carbon capture technologies however requires much greater upfront capital investment by the industrial site – to purchase the capture equipment, purchase the compressors and pay for the installation.

The average cost of abatement is most sensitive to the level of incentive provided. The model is set-up to optimise on an NPV basis considering a shadow carbon price as a driving incentive for abatement. Therefore a technology is only adopted if the £/tCO_2 cost over the lifetime falls below that of the cost of paying the shadow carbon price. A higher incentive means that on average the cost of implemented abatement is higher and more emissions are abated in total (as more expensive abatements become economically feasible). A lower incentive means that the average cost of implemented abatement is lower and fewer emissions are abated in total (as only low-cost abatements are economically feasible).

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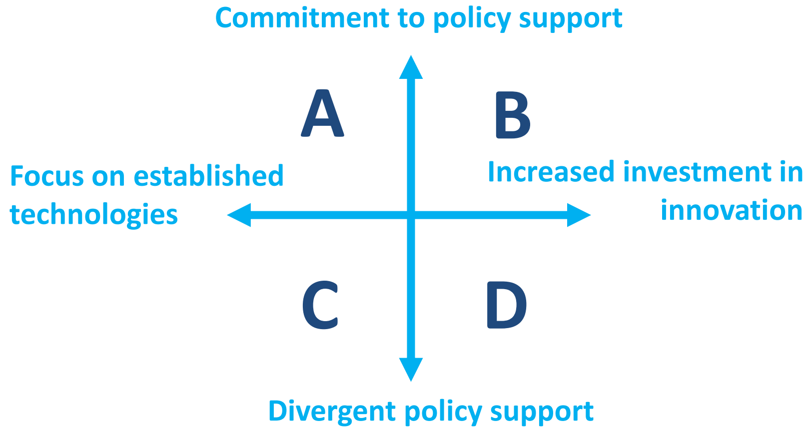
Understanding of influencing factors informs the selection of self-consistent, realistic and interesting core scenarios to analyse

Whilst individual parameter sensitivity analysis is useful for understanding the specific impact of those parameters, it is unlikely that these variations would occur in isolation. For example, a lower electricity cost may tilt the hydrogen preference more towards electrolysis; and a lower level of incentives from government may correlate with delays in supporting shared infrastructure deployment. There are also further model inputs that may correlate with these wider influencing factors – such as adoption of resource & energy efficiency, use of infrastructure for CO_2 imports or hydrogen exports, or the level of investment in GGRs.

A scenario analysis approach is necessary to fully consider potentially likely futures for the Humber and to allow their exploration in detail. As detailed above, variation of individual inputs alone is not representative of likely future scenarios. A scenario analysis approach has therefore been taken for this work in which a set of four potential future narratives were built, run in the model via self-consistent input assumptions, and investigated in detail to provide in-depth pathway analysis. These scenarios are compared and contrasted in later sections of this report.



Core scenarios selected for deeper analysis:

CCUS Commitment (Scenario A): Investigates a situation similar to the current expectations in the Humber, in which there is a high level of policy support and this support is targeted towards CCS and hydrogen projects, with prompt deployment of large-scale hydrogen production and prompt deployment of shared transport and storage infrastructure. **There is a long-term commitment to both CCS-enabled hydrogen production and electrolysis routes (50/50 mix) with continued long-term development of CO_2 storage in the North Sea.** This commitment to infrastructure links to the Humber being a location for significant CO_2 imports for storage from both the UK and abroad, as well as potentially becoming a hub for GGR technologies requiring CCS. The region also has the capacity to export hydrogen to support wider economy decarbonisation. This scenario sees higher electricity costs as there is limited UK focus on driving low electricity prices to enable electrification.

Innovations and Incentives (Scenario B): As for scenario A, scenario B investigates an initial situation similar to the current expectations in the Humber, in which there is a high level of policy support and this support is initially targeted towards CCS and hydrogen projects, with prompt deployment of large-scale hydrogen production and prompt deployment of shared transport and storage infrastructure. **This scenario however explores the impacts of a greater focus towards lowering electricity costs and progressing electrolysis routes for hydrogen production as the long-term preferred option.** There is less of a focus on providing CO_2 storage and hydrogen infrastructure for the wider economy, as the wider economy moves towards electrification options where appropriate. This scenario also has more of a focus on developing resource & energy efficiency measures.

Barriers with Limited Enablers (Scenario C): Investigates a situation in which t**here is a lower level of policy support for decarbonisation, with initial hesitations, regulatory barriers, delays in supporting business models, or unresolved technical issues impacting the initial timelines of shared infrastructure deployment (cluster sequencing is delayed).** As a result of this, several near-term hydrogen production projects are delayed and some major projects change their decarbonisation strategies. In the long-term however there is a commitment to development of CO_2 storage in the North Sea, with hydrogen production occurring via both CCS-enabled hydrogen production and electrolysis routes (50/50 mix). These early delays mean that the Humber region loses out on opportunities (CO_2 imports and hydrogen exports) to support the wider economy in decarbonisation. The scenario sees central electricity costs and additional focus on resource & energy efficiency measures.

Alternative Solutions (Scenario D): Investigates a situation in which long-term policy support for decarbonisation is less targeted towards development of CO_2 storage in the North Sea. Although initial trunkline deployment goes ahead with only minor delays, CCS-enabled hydrogen production projects see hesitations and some projects are cancelled. Expansion of the trunkline to the west of the region is also delayed. **In this scenario, there are efforts to decouple electricity and gas prices, with electricity cost reducing with increased renewables investment and gas costs increasing.** In the long-term, there is a focus on electrolysis routes for hydrogen production in-line with lower electricity costs and less support for CCS. Several major projects change their decarbonisation strategies moving towards developing alternative electrification solutions. The focus on enabling electrification means that the Humber has fewer opportunities to support the wider economy via CO_2 storage or hydrogen production.

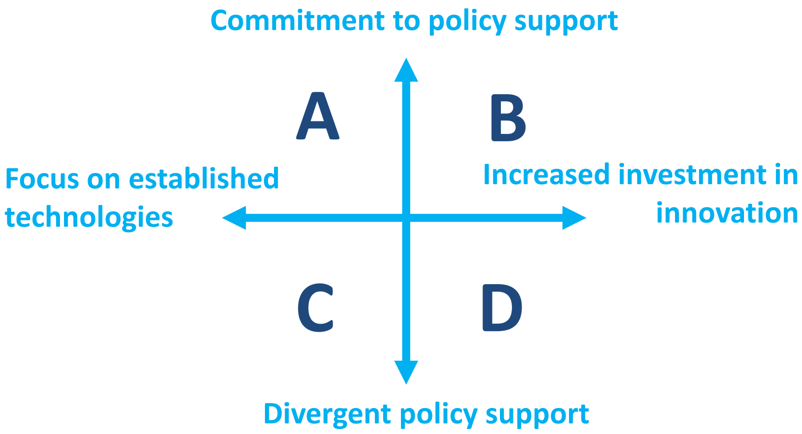
Summary of how the core scenario narratives are investigated within the model

Scenario A: CCUS commitment

Scenario B: Innovations & incentives

Scenario C: Barriers with limited enablers

Scenario D: Alternative solutions



Key Scenario Input Assumptions	A	B	C	D
Shadow Carbon Price (Incentives)	High	High	Central	Central
Electricity Cost	High	Low	Central	Low
Gas Cost	Central	Central	Central	High
Long-term Hydrogen Preference	Mixed (50/50)	Electrolytic (70-80%)	Mixed (50/50)	Electrolytic (70-80%)
Pipeline Development	On Track	On Track	Initial Delay	Barriers to later expansion
Pre-defined Site Technologies	Initial abatement options aligned with current plans, including: • Use of advanced amines CCS • EAF at British Steel • Mixture of CCS & H_2 at refineries & CHPs		Limited adoption of BECCS	More electrification options available to sites

Table shows selected input variables with particular impact on technology uptake. Other inputs are also varied across scenarios to be consistent with the narrative (e.g. CO_2 imports, hydrogen exports, resource & energy efficiency measures)

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All pathways to net-zero achieve a 96% reduction in Scope 1 emissions by 2040

In all four of the core scenarios, deep-decarbonisation is achieved by 2040. A 96% reduction in cluster emissions compared to 2022 levels leaves a remaining level of 0.5-0.7 $MtCO_2$/year from the cluster that must be removed with greenhouse gas removals.

The most rapid decarbonisation occurs in the **Innovations & Incentives** scenario – **80% reduction by 2030** – this is driven by a high carbon value incentive, prompt access to pipeline infrastructure and relatively low fuel prices. This scenario represents the pathway with the most aggressive action and results in an additional cumulative emissions saving of 53 $MtCO_{2e}$ by 2040, 43% higher over the **Barriers with Limited Enablers** scenario.

Scenarios with delays to blue hydrogen projects and pipeline network deployment have a more gradual decline – Barriers with Limited Enablers lags the other scenarios with only **31% reduction by 2030.** In this scenario, initial delays to infrastructure means that a significant deployment of decarbonisation options has to be deployed quickly in the early 2030s to get to deep decarbonisation by 2040.

In all scenarios a low level of remaining emissions exist in 2040. Several small pieces of equipment in the model find it prohibitively expensive to abate their emissions and no-cost effective solution is identified. At this point it becomes cheaper to adopt greenhouse gas removals to achieve net-zero.

An underlying 0.5 $MtCO_{2e}$ remain across the Iron & Steel, Chemicals and CHP sectors in 2040. These sectors heavily adopt carbon capture; however, due to the incomplete capture rate of the technologies, a low level of emissions remains that must be removed with greenhouse gas removals.

Chart 3.1 Total Scope 1 emissions over time (cluster*)

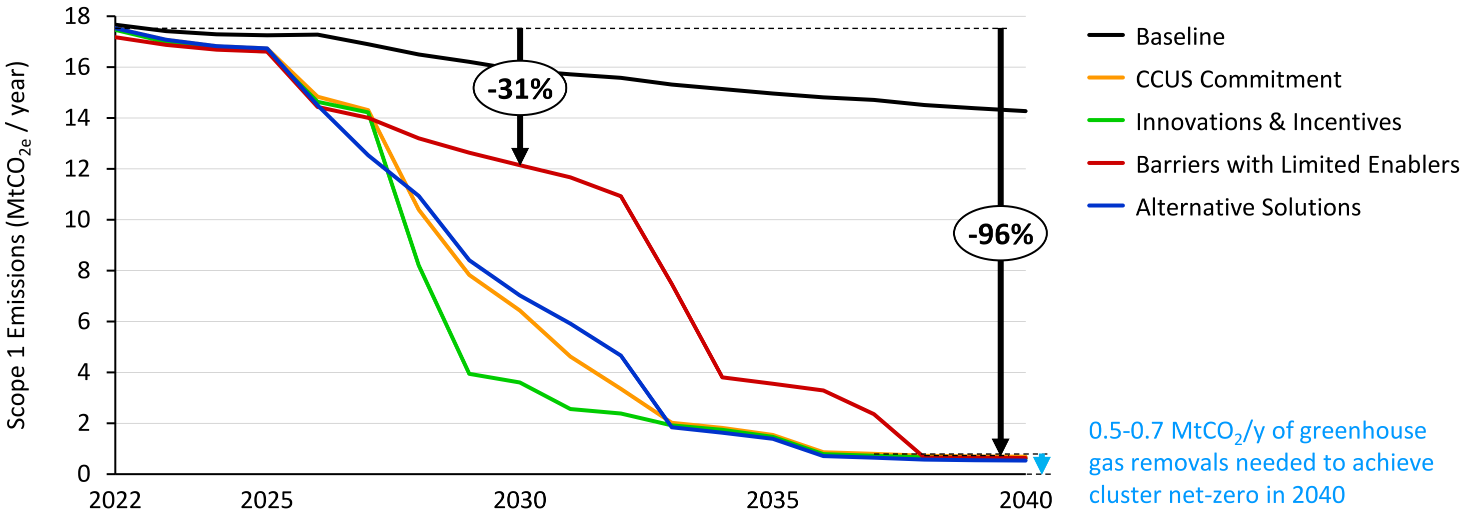


Chart 3.2 Remaining non-biogenic emissions in 2040 (cluster*)

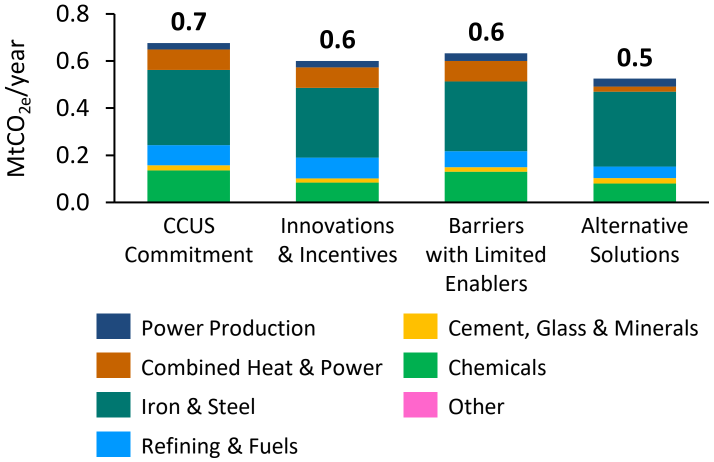
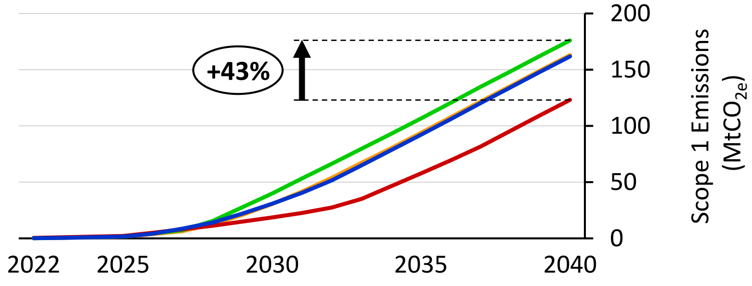


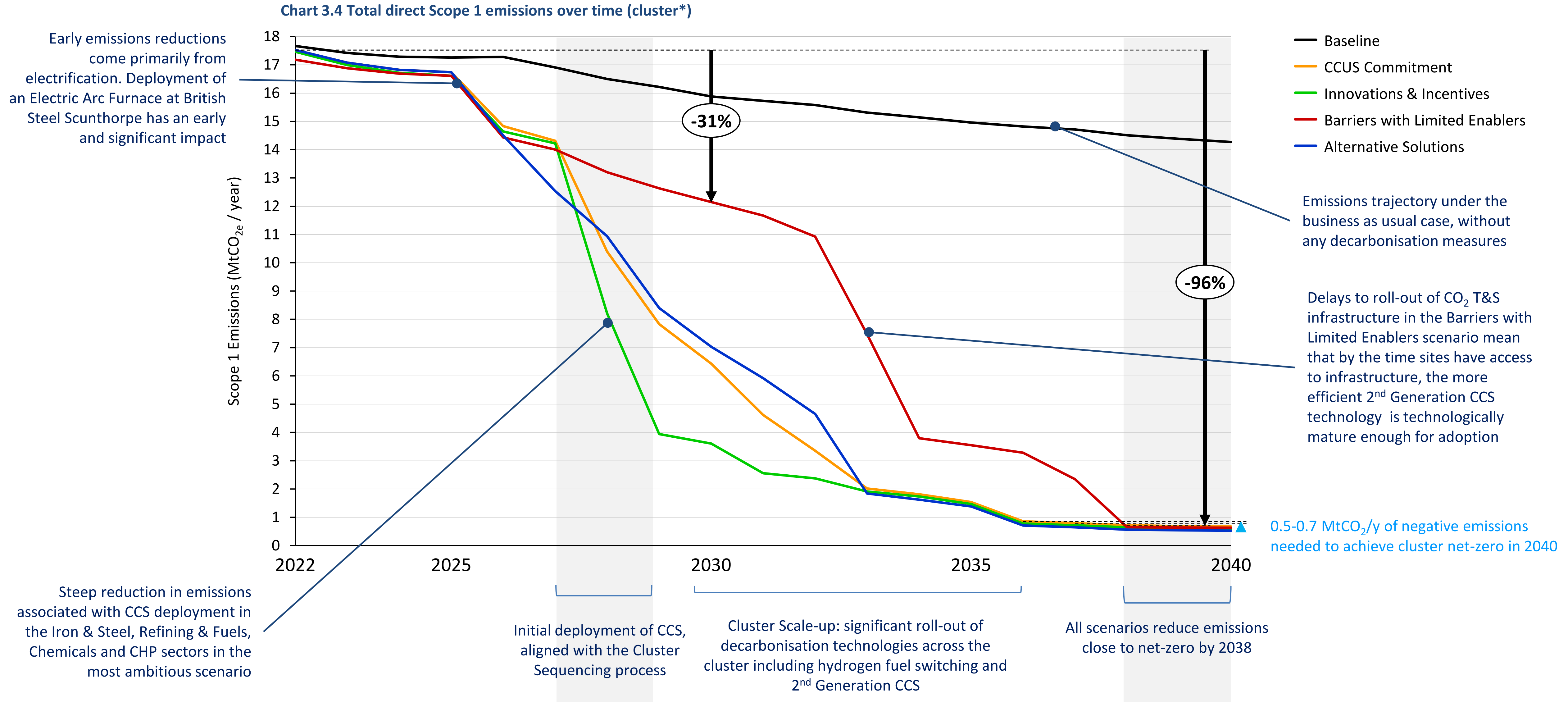
Chart 3.3 Cumulative Scope 1 emissions abated relative to the baseline



- Action towards decarbonisation should be taken early to enable large scale emission reductions across the Humber.
- **Early action and innovation could help abate over 50 MtCO2 more by 2040, compared to the more pessimistic scenarios.**

* The term cluster refers to the emissions of existing industrial sites in the region only and does not account for blue hydrogen production sites. Residual emissions from blue hydrogen production (e.g. due to incomplete capture) are treated as upstream emissions (presented here) since they do not occur directly at the sites that use the hydrogen as fuel.

Inflexion points in the decarbonisation pathways exist due to abatement options becoming available and getting adopted in specific years



* The term cluster refers to the emissions of existing industrial sites in the region only and does not account for emissions from blue H2. Emissions from blue H_2 are treated as upstream emissions since they do not occur directly at the sites that use the hydrogen as fuel.

By 2040 at least 79% of emissions abatement is achieved through electrification, hydrogen fuel switching and CCS, with preference for each technology varying across scenarios

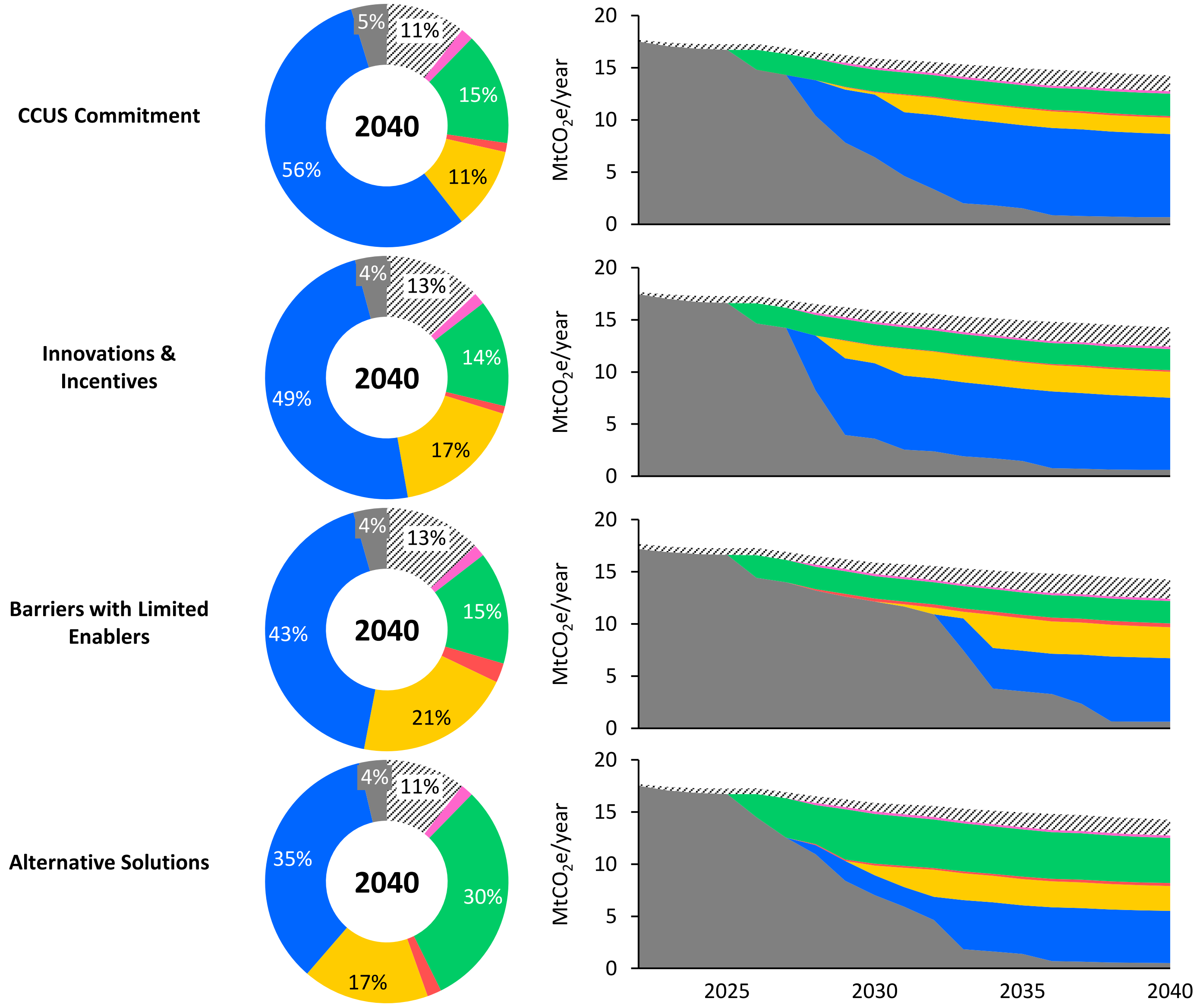


Chart 3.5 Emissions abatement by abatement technology category

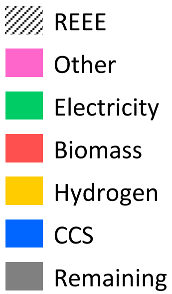
Units: Scope 1 Emissions abatement ($MtCO_{2e}$ / year)

Scope: *Core Cluster (does not include emissions from Future Power or Future Hydrogen - CO_2 volumes from CCS-enabled hydrogen are accounted later as part of the CCS infrastructure analysis)*

Note: *Capture of biogenic emissions resulting in greenhouse gas removals is not included in Scope 1 abatement graphs.*

Resource and Energy Efficiency (REEE) projections reflect the reduction in emissions achievable from the baseline case by sites employing energy efficiency measures, making improvements to material choices and reducing consumption of resources. Applying REEE projections to a site's baseline emissions reduces the emissions that require abating by abatement technologies. In 2040, REEE is responsible for **11-13%** of the in-year emissions abated across al scenarios.

CCS is the most significant abatement option across all scenarios while hydrogen fuel switching and electrification also have a significant effect. The Biomass fuel switching and Other abatement options have a small contribution to the overall abatement; however, these tend to be deployed on remote sites with small emissions and don't have a significant impact on the demand for infrastructure or cost of abatement in the cluster.



- **CCS is deployed rapidly in Innovations & Incentives reflecting the ambitious roll-out capability in this scenario**; however, CCUS Commitment has the greatest uptake of CCS by 2040. The Barriers with Limited Enablers scenario has a delayed uptake of CCS but ultimately adopts the technology heavily.
- **Hydrogen fuel switching is adopted reasonably consistently across all scenarios**. Higher electricity costs make this a more expensive option in CCUS Commitment which sees more CCS adopted.
- The model chooses to **deploy an Electric Arc Furnace at British Steel in all scenarios providing a significant amount of early abatement**. In the Alternative Solutions scenario low cost electricity is available while relatively higher gas costs dissuade from Hydrogen and CCS options resulting in increased electrification.

REEE: Resource Efficiency & Energy Efficiency

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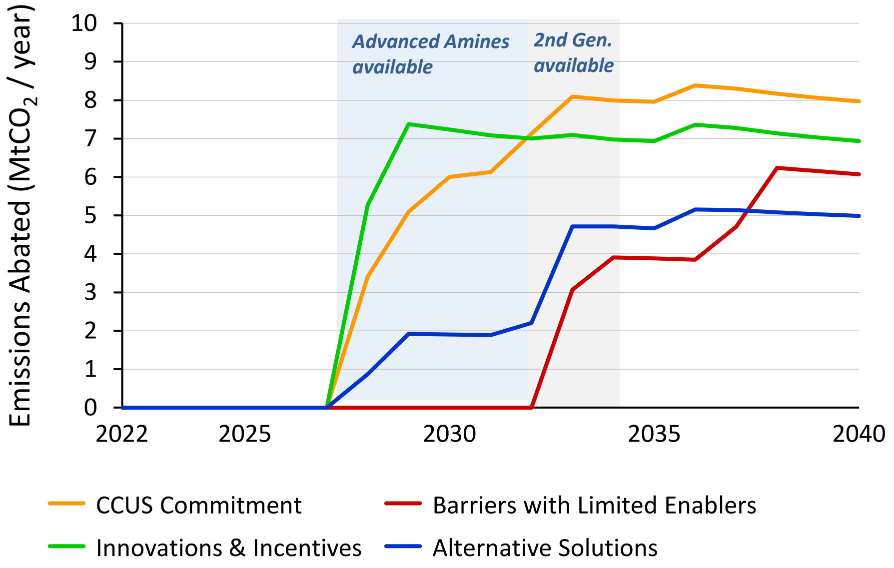
Carbon capture technologies are adopted most rapidly in the late 2020s and early 2030s, with 5.0 – 8.0 $MtCO_2$ captured annually by 2040

Chart 4.1 Uptake of Carbon Capture technologies across scenarios (excl. biogenic capture)



With 35-56 % of all annual Scope 1 emissions in 2040 abated using carbon capture technologies, CCS is the most prolific abatement technology in the Humber across all scenarios due to its suitability for abating emissions on sites with the largest processes.

Deployment of CCS on a relatively small number of the large sites can have a very significant impact of the region's total emissions. As a CAPEX heavy abatement technology, economies of scale make CCS most suitable for deployment on processes with large sources of emissions (>0.1 $MtCO_2$).

CCS requires little modification to the operation of the counterfactual technology at a site which preserves the nature and product of the pre-existing industrial process. This is particularly important for controlling the grade of metal in Iron and Steel production.

Main Adopters of Carbon Capture Technologies across scenarios

Sector	Main deployments across scenarios	Abatement in year of deployment ($MtCO_2$) across scenarios				Range in deployment year across scenarios
		A	B	C	D	
Chemicals	Triton Saltend (1-2 trains)	2.1	2.1	0.53	0.53	2028-32
CHP	VPI Immingham (1-2 trains)	1.84	1.77	1.69	1.82	2028-32
Iron & Steel	British Steel (1 x BF-BOF Train)	1.84	1.84	1.84	1.84	2028-29
Refining	Various Units at P66 and Prax	2.29	2.46	1.01	1.01	2028-32
Power Prod.	South Humber Bank Power Station	0.57	0.57	0.57	0.57	2035-2036

Sites in the model are not overly constrained across all scenarios to follow a set technology pathway corresponding directly to publicly announced commercial plans. Some scenarios allow flexibility for sites to explore alternative options.

Significant CCS deployment is possible before 2030 if T&S infrastructure is available and incentives to do so are put in place. This is evident from the CCUS Commitment and Innovations & Incentives scenarios which prioritise rapid adoption with a high shadow carbon value and readily deploy CCS as soon as the technology becomes available.

However, to ensure CO2 transport and storage infrastructure deployment, carbon capture must be deployed at the main industrial sites, which may require adequate policy support. Two main technologies are available in the model (as explained here)

- An incumbent form of CCS technology with high technical readiness exists in the model (Advanced Amines); however, development and innovations in the technology are expected in the future leading to improved fuel efficiency.
- This future CCS technology is represented in the model by the 2nd Generation CCS tech that becomes available for deployment for sites in the early 2030s.

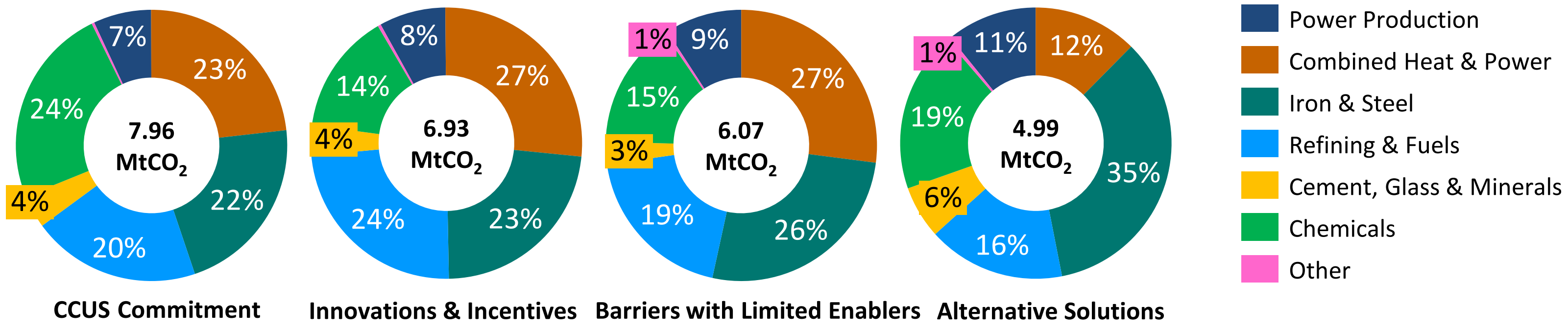
Significant delays in pipeline infrastructure in the Barriers with Limited Enablers scenario means that sites gain access to CO_2 infrastructure coinciding with the commercial availability of 2nd Generation CCS technology which becomes the dominant capture technology for that scenario.

In the Alternative Solutions scenario there is less of a focus on finding support for CCS technologies and sites may choose to take time to adopt the more efficient, 2nd Generation CCS technology than push for immediate deployment of the established Advanced Amines. This leads to a mix of adoption of the two technologies.

Emissions abated refers to Scope 1 emissions (non-biogenic emissions) through the use of carbon capture technology with permanent geological storage.

Significant carbon capture deployment occurs within industrial sectors characterised by processes with large point sources of emissions

Chart 4.2 Breakdown of in year emissions abatement by carbon capture technology in 2040



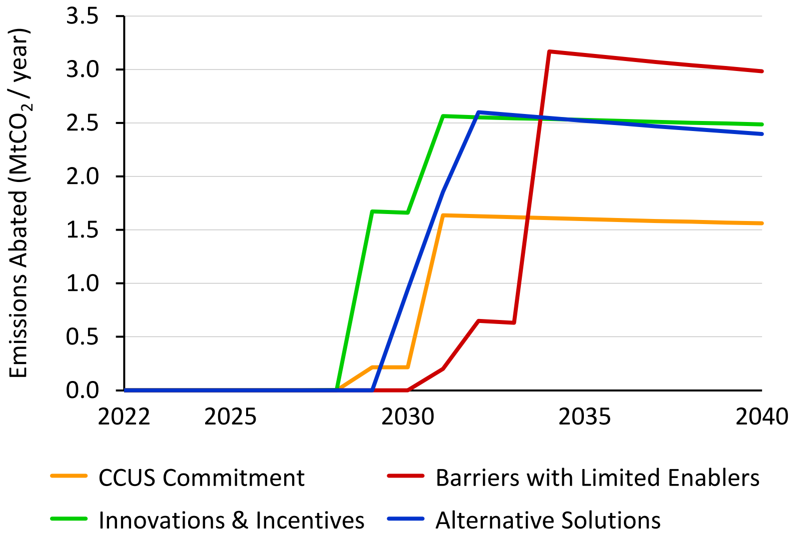
- **The** ***sectors Combined Heat & Power, Iron & Steel, Refining & Fuels*** **and Chemicals contribute to the majority of the emissions abated by carbon capture technologies.**
- The high capital costs of carbon capture technology mean that it becomes most favourable for large industrial processes with significant emissions, where economies of scale act to make the cost of abatement more competitive

	Sector	Main deployments across scenarios
	CHP	Installing carbon capture on large CCGT units accounts for a significant proportion of emissions abatement across most scenarios. VPI Immingham deploys CCS on at least one CCGT train across all scenarios. In the Alternative Solutions scenario, the power and steam provided by CHPs can be provided by increasing the electrical import from the grid to provide power and using a large scale electric boiler for steam production. In this scenario – with low electricity costs, this becomes the optimal abatement option on an NPV basis for some of the CCGT trains at CHPs in the region.
	Iron & Steel	British Steel consistently deploys CCS on one of its integrated steel routes at the Scunthorpe sites across all scenarios providing a significant proportion of emissions abatement for the site. A steel production route that maintains the production of high purity Iron is important in all scenarios to preserve the ability to produce steel suitable for rail production.
	Refining	Refineries in the Humber consistently deploy a mixture of CCS and Hydrogen abatement technologies across all scenarios; however, CCS options are typically more significant and deployed on the sites earlier than Hydrogen options.
	Chemicals	The large Triton CCGT plant at the Saltend Chemicals Park provides the surrounding Chemicals sites with steam and power. Triton deploy CCS on at least one CCGT train across all scenarios leading to a significant proportion of emissions abatement in the Chemicals sector.
	Power gen.	A CCGT train at the South Humber Power Bank station deploys CCS across all scenarios.

Emissions abated refers to Scope 1 emissions (non-biogenic emissions) through the use of carbon capture technology with permanent geological storage.

Hydrogen fuel switching technologies are adopted rapidly between 2027-2034 and are responsible for 1.5 – 3.0 $MtCO_2$/yr of in year emissions abatement by 2040

Chart 4.3 Uptake of hydrogen fuel switching technologies across scenarios



Main Adopters of Hydrogen Fuel Switching Technologies across scenarios

Sector	Main deployments across scenarios	Abatement in year of deployment ($MtCO_2$) across scenarios				Range in deployment year across scenarios
		A	B	C	D	
Chemicals	Triton Saltend (1-2 trains)	0.91	1.86	1.86	1.86	2028-31
CHP	VPI Immingham (1-2 trains)	0.51	0.53	0.0	0.0	2029-31
Iron & Steel	British Steel (Small heating process)	0.20	0.20	0.0	0.0	2028-29
Refining	Various Units at P66 and Prax	0.03	0.10	0.77	0.77	2032

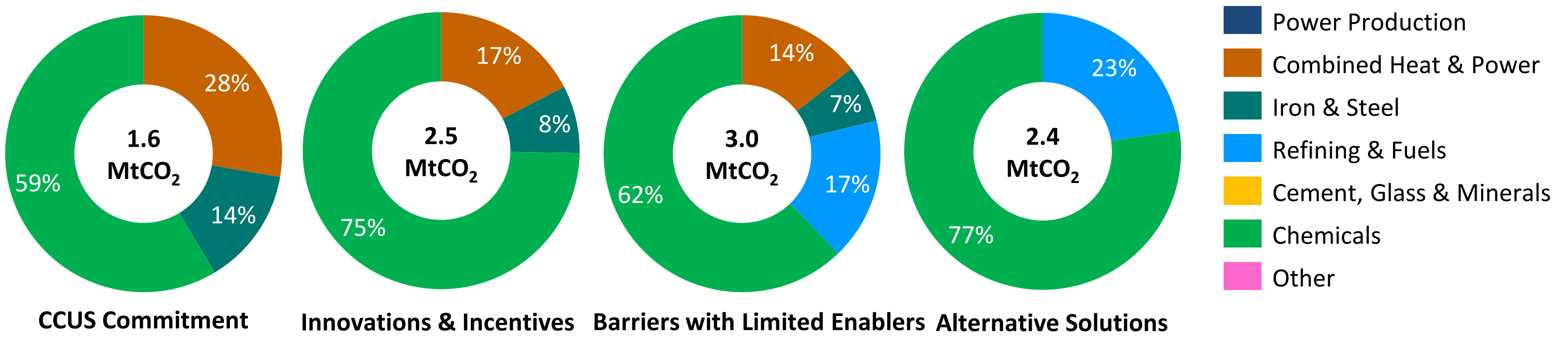
Sites in the model are not overly constrained across all scenarios to follow a pre-determined technology pathway corresponding directly to publicly announced commercial plans. Some scenarios allow flexibility for sites to explore alternative options.

Hydrogen plays an important part in decarbonising industry: fuel switching accounts for the abatement of 11-21 % of the cluster's in-year Scope 1 emissions by 2040.

Availability of hydrogen supply is not a limiting factor for the long term adoption of hydrogen for industrial fuel switching. This is also supported by plans for medium term hydrogen deployment in the Humber, where projects, such as H2H Saltend, are looking to leverage the opportunity to supply local industry and export hydrogen via the grid.

Many large industrial processes in the model operate by the combustion of natural gas and will primarily opt between hydrogen fuel switching and deploying CCS for abatement. The potential for hydrogen fuel switching is limited by the high unit cost of hydrogen for sites which often makes CCS a more economical option when optimising the system by NPV. If the unit cost of hydrogen is reduced, the number of large processes seen fuel switching to hydrogen instead of deploying CCS would increase.

Chart 4.4 Breakdown of in year emissions abatement by hydrogen fuel switching in 2040

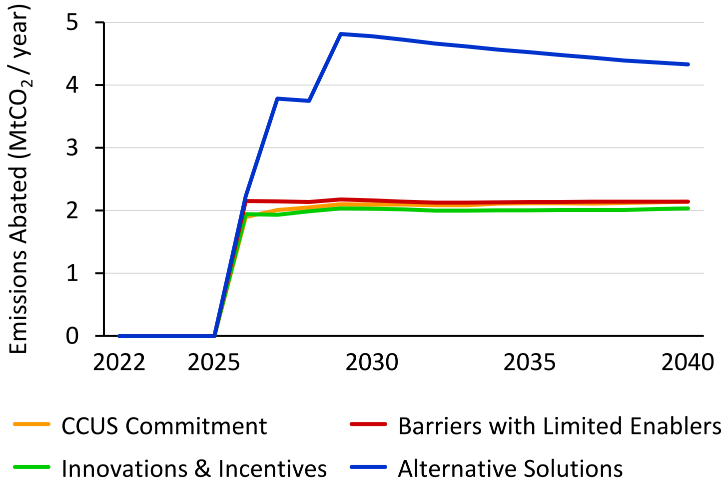


- H_2 fuel switching is typically favoured over CCS for smaller units with more intermittent generation since it is dominated by fuel costs, while CCS is a CAPEX heavy abatement option
- High levels of uptake in the Chemicals sector align with the plans of Equinor and SSE Thermal to potentially transition Triton to hydrogen providing heat and power for the Saltend Chemicals Park. Uptake in the CHP sector corresponds to that of VPI Immingham which may fuel-switch their 3rd CCGT train

Emissions abated refers to Scope 1 emissions (non-biogenic emissions) through the use of hydrogen fuel switching technology.
Primary energy requirements for hydrogen production are presented in the Energy Demand section.

An additional 0.46-1.26 GWe of power production will be required between 2026-2029 for the electrification of industrial processes

Chart 4.5 Uptake of electrification technologies across scenarios



Main Adopters of Electrification Technologies across scenarios

Sector	Main deployments across scenarios	Abatement in year of deployment ($MtCO_2$) across scenarios				Range in deployment year across scenarios
		A	B	C	D	
CHP	Replacement with electric steam boiler and grid import of electricity (2 large trains)	0.0	0.0	2.14	2.14	2027-29
Iron & Steel	British Steel (1 x BF-BOF Train)	1.87	1.80	1.80	1.87	2026-27
Refining	Various Small Processes at P66	0.0	0.0	0.28	0.28	2027
Chemicals	Small units at Saltend Chemicals Park	0.47	0.47	0.54	0.54	2036

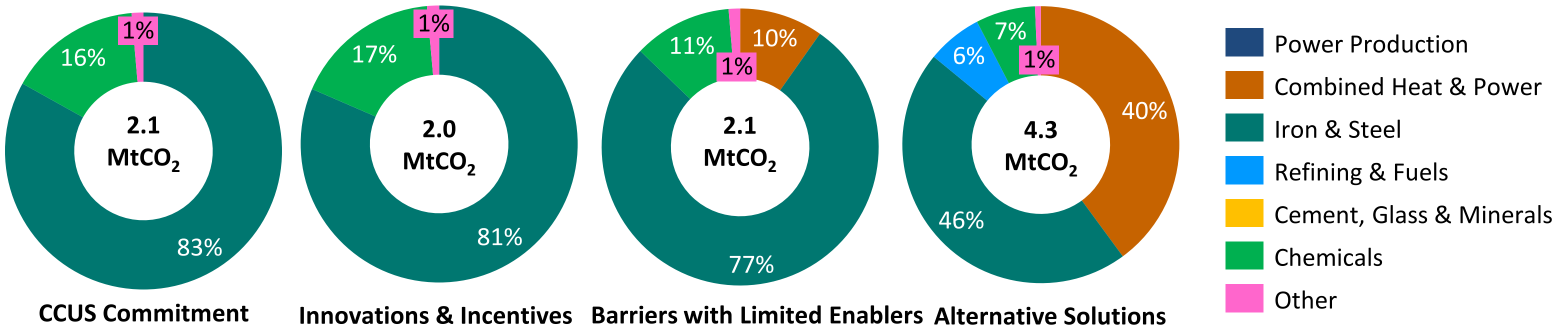
Sites in the model are not overly constrained across all scenarios to follow a pre-determined technology pathway corresponding directly to publicly announced commercial plans. Some scenarios allow flexibility for sites to explore alternative options.

In most scenarios electrification abates 15 % of Scope 1 in year emissions by 2040.

Electrification technologies do not have to wait for pipeline infrastructure and tend to deploy earlier than CCS or H_2 fuel switching options.

An additional (0.5 GWe) of low-carbon electricity generation is required to power electrification of the industrial processes across most of the scenarios. The majority of this power goes directly to British Steel. The electricity required for hydrogen production and CCS is 2-3 times higher than this.

Chart 4.6 Breakdown of emissions abatement by electrification technologies in 2040



An Electric Arc Furnace at British Steel Scunthorpe dominates the abated emissions from electrification. This piece of equipment makes a change to the production process removing the need for many integrated processes and their associated emissions.

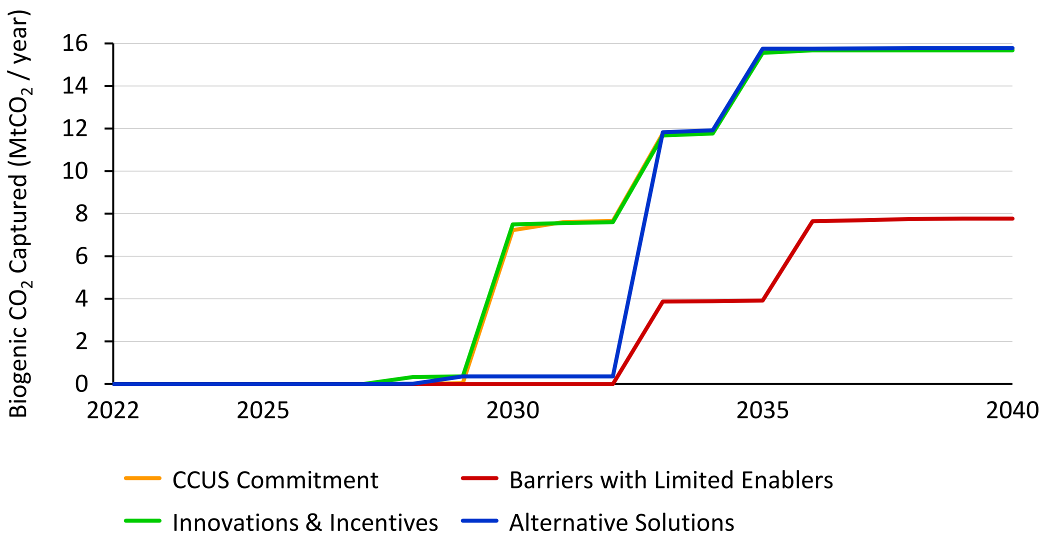
The majority of sites deploying electrification options have very small process sizes and need to abate a low level of emissions on a small piece of equipment (total ~ 0.2 $MtCO_{2e}$). This is where the relatively low CAPEX of electrification equipment works out as much more economical than options such as CCS or Hydrogen fuel switching.

In the Barriers with Limited Enablers and Alternative Solutions scenarios, CCGTs at CHP sites are given the abatement option of being replaced by grid imported electricity for the power deficit associated with decommissioning them. An electric steam boiler provides the steam previously produced by the CHP. Relatively higher gas and low electricity costs in Alternative Solutions mean that two large CCGT units select this option rather than decarbonising the assets themselves. Reductions in the baseline for the refining sector reduce the power and heat demand from associated CHPs and consequently the emissions abated from electrifying the CHPs decrease with time.

Emissions abated refers to Scope 1 emissions (non-biogenic emissions) through electrification of processes.

Application of carbon capture to biogenic emissions (particularly in the Power Production sector) provides an opportunity for up to 16 Mt of greenhouse gas removals

Chart 4.7 Application of Carbon Capture technologies to biogenic emissions



- Multiple sites in the Humber use biofuels as part of their fuel mix – most notably, the Drax power station which operates 4 large biomass combustion units.
- Any CO_2 released as a result of combusting biofuels is treated as biogenic and consequently does not require abatement in the net-zero pathways.
- Capturing biogenic emissions provides the opportunity to generate negative emissions which could be used to offset emissions from hard-to-decarbonise processes, either in the Humber or across the wider UK.

- Within the cluster, a low level of captured biogenic emissions is achieved when CCS is deployed on industrial processes (such as some industrial dryers, some small scale power units, and waste incineration facilities) that partially use biomass as fuel. Since this is usually only a small proportion of the fuel mix the captured emissions from this are low and appear in the uptake profile as a small increase during early years.
- The significant uptake in biogenic emission capture comes from the Drax power station deploying CCS on its existing biomass combustion units. Drax's current ambition is to deploy CCS on two of its combustion units with a target of capturing 4 $MtCO_2$ by 2027 and a further 4 $MtCO_2$ by 2030. The N-ZIP Humber model aims to assess the opportunity for negative emissions from biogenic capture and consequently all 4 of the biomass combustion have the option of deploying BECCS if it is economical to do so, with the exception of Barriers with Limited Enablers which is limited to CCS on two units.

- Each scenario shows BECCS deployment on every unit available to it by 2036 with CCUS Commitment, Innovations & Incentives and Alternative Solution all capturing 15.8 $MtCO_2$ and Barriers with Limited Enablers achieving 7.9 $MtCO_2$, corresponding to BECCS on 4 units and 2 units respectively. The time frame in which technologies are deployed is unconstrained in the model and is not forced to match the current plans of a site (deployment of BECCS at only two units), and consequently the CCUS Commitment and Innovations & Incentives scenario show BECCS installed on the first 2 units in the same year (2030) adopting the Advanced Amines CCS technology.
- The 3rd and 4th units at Drax both wait until the 2nd Generation CCS technology is available and apply this in two stages (one unit in 2033 and one in 2035). In CCUS Commitment and Innovations & Incentives, Units 1 and 2 are restricted from selecting the 2nd Generation CCS technology to prompt them to adopt the Advanced Amines technology which is available in an earlier year – better reflecting current ambitions for deployment. The units in the Alternative Solutions scenario are free to pick between the two generations of CCS technologies and the outputs show 2nd Generation being deployed on Units 1,2 and 3 in 2033 before also deploying on Unit 4 in 2035. Delays to CO_2 infrastructure roll-out int the Barriers with Limited Enablers scenario prevent Drax from adopting BECCS until it has connected to the main pipeline in 2033, at which point it deploys BECCS across Units 1 and 2 between (2033-2035).

The Humber cluster only requires **0.5-0.7 $MtCO_2$/year of Greenhouse Gas Removals to reach net-zero**, with remaining removals contributing to wider UK removals targets

- This can easily be satisfied using the Drax biogenic emissions, whilst allowing the Humber to export up to 15 $MtCO_2$/y negative emissions to other regions of the UK or trade certificates on an international (voluntary) market
- To achieve full capture potential from the Drax power plant, the onshore pipeline network must be sized appropriately to transport and store the captured emissions from the West end of the cluster

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Target injection rates and capacity of planned CO_2 storage projects are sufficient to bring the cluster to net-zero using CCS

Injection Rate represents the physical constraint on injecting CO_2 into a geological storage site through a well. The injection rate can be increased over time by drilling more wells; however, in the short term the limit on injection rate provides a limit on the rate of carbon capture in the cluster.

Storage Capacity represents the physical volume constraint of a geological storage site on how much CO_2 it can safely store. Storage capacity can be increased with expansion phases to other co-located geological stores.

Alignment with emerging CCS projects

Two CO_2 T&S projects are initially planned for transporting CO_2 from the Humber in offshore pipelines and injecting it into subsea storage.

Within the model, demand for CO_2 capture is calculated using a bottom-up approach; however, constraints to injectivity are set to keep injection within technically possible limits. Up to 2035, this constraint is based off the targets of the planned projects in the region:

- **Northern Endurance Partnership**
    - 8.25 $MtCO_2$/yr in 2030
    - 17+ $MtCO_2$/yr by 2035
- **V Net Zero (now Viking CCS)**
    - 11 $MtCO_2$/yr by 2030
    - 12+ $MtCO_2$/yr by 2035

Similarly, the <u>storage capacity</u> of the planned projects is considered:

- **Northern Endurance Partnership:** uses the Endurance aquifer with capacity of 520 $MtCO_2$. Further sites have the potential to bring storage up to 1000 $MtCO_2$
- **V Net Zero (now Viking CCS): u**ses depleted gas fields including Victor and Viking with a capacity of 328 $MtCO_2$

Chart 5.1 CO_2 annual T&S demand for carbon capture *(cluster + blue H_2)*

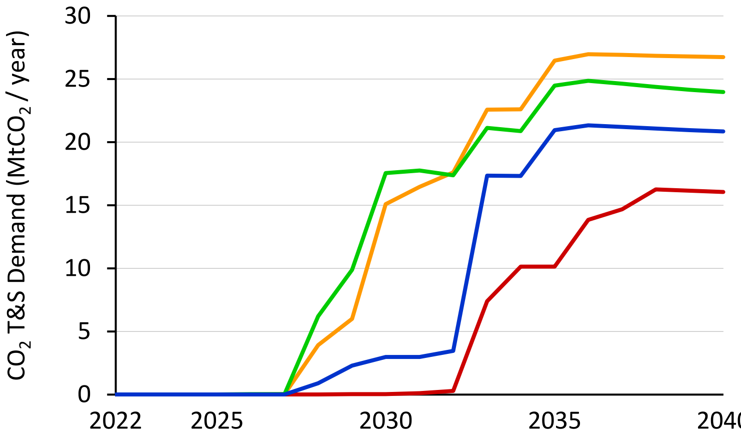
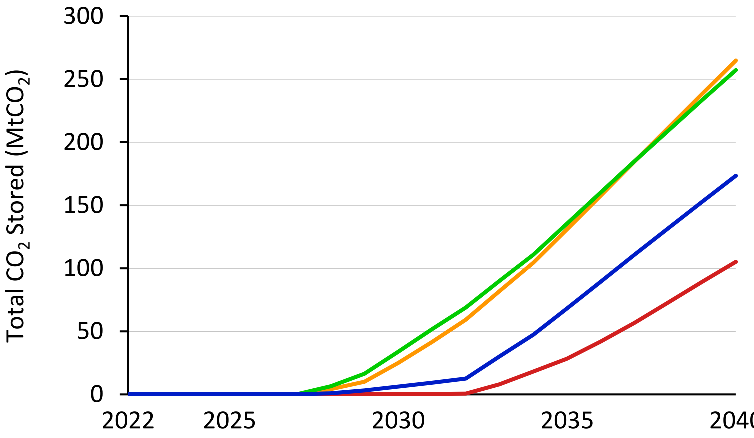


Chart 5.2 Cumulative CO_2 stored (cluster + blue H_2)



CCUS Commitment and Innovations & Incentives require regional CO_2 storage injectivity to ramp up quickly with as much as **6 $MtCO_2$/year required in 2028** and **17.5 $MtCO_2$/year required by 2030**. In most scenarios, injection rate flatlines after 2036 since no additional CCS is deployed in the cluster. The highest steady-state injection rate required is in the CCUS Commitment scenario **with a required annual injection of 27 $MtCO_2$/year from the core cluster and blue H_2 production.**

Demand in the model from industrial sites and blue H_2 production never exceeds the injection targets of planned projects - even by 2040. Consequently, **Injectivity is not anticipated to pose a constraint on Carbon capture for the Humber:** the most ambitious near-term injectivities from the model are feasible within the assumptions of planned T&S projects in the region:

As with injection rate, most scenarios necessitate CO_2 storage capacity to become available in 2026, with the exception of **Barriers with Limited Enablers,** where infrastructure deployment is delayed until the mid-2030s. Once injection rates have flatlined the cumulative CO_2 stored increases linearly with up to 265 $MtCO_2$ stored by 2040 from CO_2 captured in the cluster.

Storage capacity does not provide an immediate constraint and even if the most CCS focussed scenarios, there is ample available storage for the cluster to reach net zero by 2040. If the cluster is to remain reliant on CCS for sustained in year abatement of emissions beyond 2040, storage expansion phases will eventually be required beyond the capacity of the currently planned projects.

There is a strong opportunity for the Humber to import CO_2; however, expansion phases beyond current storage plans are important to maximise potential

There is **potential for industries outside the cluster to utilise the infrastructure in the Humber.** Even in the most ambitious CCS focused scenarios there is headroom in the regional CO_2 Transport and Storage infrastructure with respect to the targets of the planned projects in the region.

This provides an opportunity to accept CO_2 from the wider economy, particularly if further expansion phases in regional undersea storage occur. BP and Equinor have been awarded two carbon storage licences for additional storage sites building on the existing licences granted for the Endurance and V Net Zero.

Wider economy demands for the Humber's CO2 T&S infrastructure come from:

- ***Additional GGRs***: This considers the development of engineered greenhouse gas removals in the Humber which promote investment in the region and require access to the CO_2 transport and storage infrastructure. These removals are additional to any modelled industrial site adopting biogenic capture. As an area with significant power generation and access to CO_2 transport and storage infrastructure, there is a direct opportunity for engineered removals in the Humber. The quantity of engineered GGRs is higher in the scenarios with a focus on capture technologies. Removals from these additional GGRs in the Humber are not depicted on any graphs showing abatement pathways to net-zero for the region.
- ***UK and EU Shipping***: The Humber region currently has access to 80% of the UK's licensed CO_2 storage capacity presenting a strong opportunity to import shipped CO_2 from regions without access to storage. This includes clusters within the UK such as SWIC and Southampton, as well as potential European shipping
- ***Road and Rail***: Many large industrial sites exist in local authorities surrounding the core cluster which could benefit from utilising the Humber CO_2 T&S infrastructure. These sites would transport their CO_2 to the main pipeline by road and rail before it is fed into the main pipeline network and transported to undersea storage.
- ***Future Power***: Capture of CO_2 from possible future power stations such as Keadby 2 & 3

The additional injectivity required to receive CO_2 from outside the cluster exceeds the target injection rates of the near-term (pre 2035) planned projects. To accommodate CO_2 from wider users, expansion projects to drill more wells and increase the injection rate in the region will be required. This is within the scope of the additional storage sites under investigation.

The CCUS Commitment scenario with the highest injection rate and significant imports from wider users, the total CO_2 stored would reach full capacity for the planned projects (848 $MtCO_2$) in the year 2050. This shows the need for storage expansion phases to secure additional storage capacity if an aggressive CO_2 storage pathway is pursued with lots of CO_2 imports.

Chart 5.3 Breakdown of annual CO_2 T&S demand in 2040

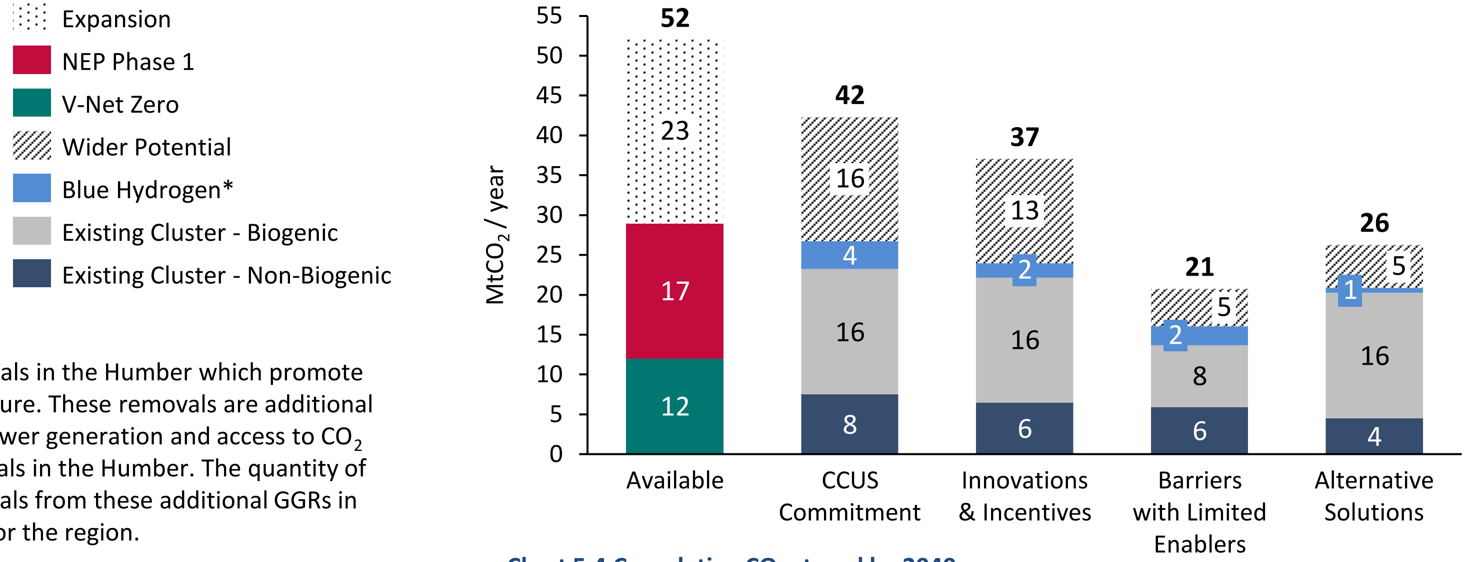
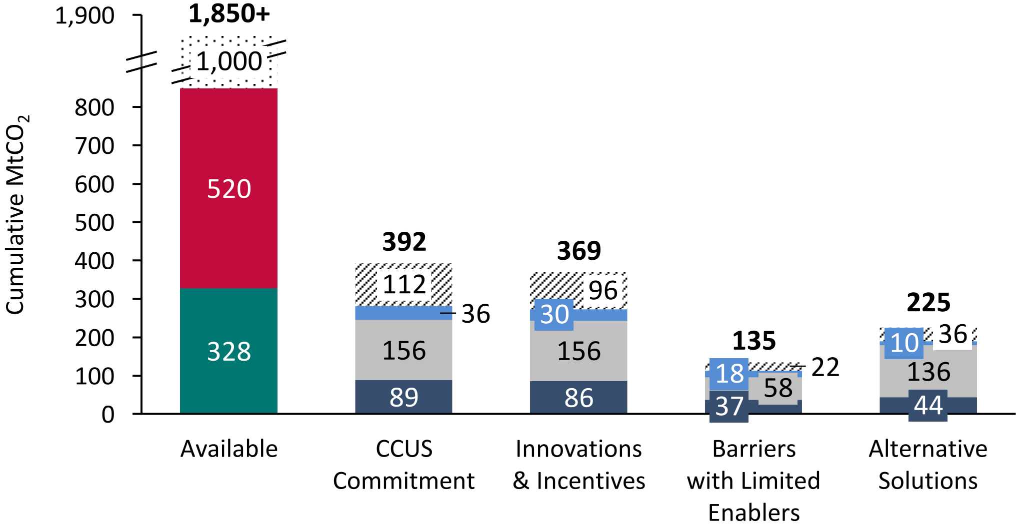


Chart 5.4 Cumulative CO_2 stored by 2040



*Blue hydrogen values cover the scale of hydrogen required for industrial fuel-switching in the scenario as well as an assumed demand from the wider economy (see Hydrogen Uptake section). An assumption is made for each scenario on the split between blue and green hydrogen production routes (20-50% blue hydrogen in 2040).

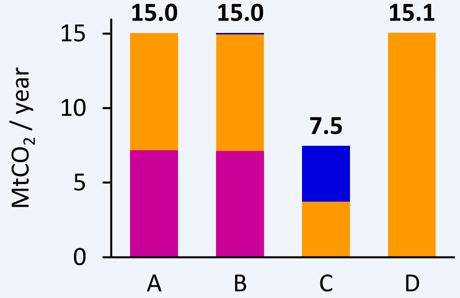
Deployment of a CO_2 pipeline is critical, with significant demand at Immingham and in the Western part of the cluster

- Timely deployment of the onshore pipeline network is critical for maximising the cumulative level of emissions abated and allowing projects to deploy in line with planned proposals.
- Current Track-1 deployment plans by Zero Carbon Humber (ZCH) are for a pipeline with capacity of up to 17.8 $MtCO_2$/yr running from Drax to Easington (North Humber terminal) via Scunthorpe and Immingham deployed by 2027.
- The V-Net Zero project has plans for a pipeline running from Immingham to Theddlethorpe (South Humber terminal) with a capacity up to 30 $MtCO_2$/yr – this project would re-use the existing LOGGS pipeline.
- Outcomes from the model suggest that annual transport to offshore storage could reach 27 $MtCO_2$/year with 9.2-18.3 Mt of this coming into Immingham from West and Scunthorpe combined.
- This demand into Immingham would exceed that of the initially proposed Zero Carbon Humber pipeline. This is largely due to the model selecting carbon capture for all 4 Drax units when current plans are only for 2 units to have capture technology installed initially.
- Later capacity expansion phases of the western part of the network would therefore be necessary if carbon capture were to be adopted across all 4 Drax units.

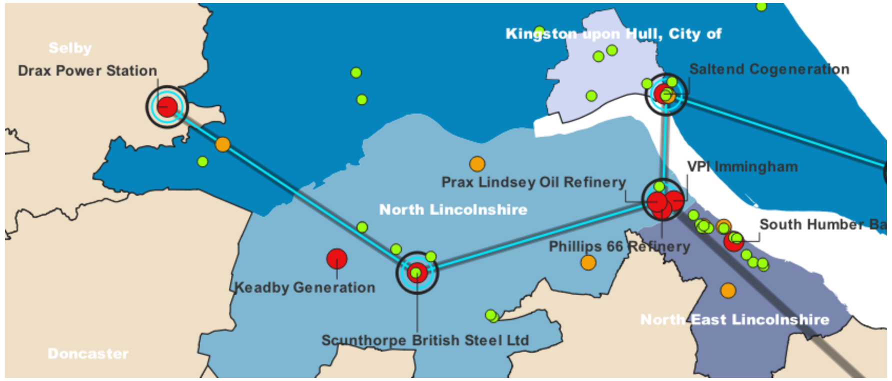
Chart 5.5 CO_2 injection rate over time for each defined point along the CO_2 pipeline ($MtCO_2$/year)

West

Deployment of BECCS at Drax power station has the opportunity for a significant amount of capture leading to negative emissions. Drax currently plan to deploy BECCS on two biomass units resulting in up to 8 $MtCO_2$/yr of demand for the shared pipeline infrastructure. The significant amount of throughput from Drax has the potential to act as a buffer for the conjoined pipeline segments.



Local injection demand in:
2030 2035 2040

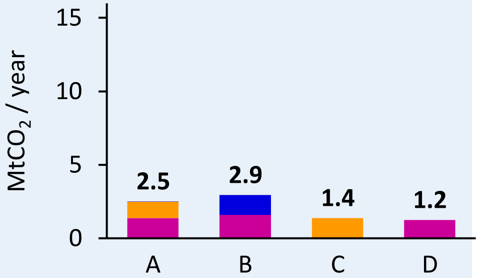


Required pipeline capacity by 2040 ($MtCO_2$/year)

Numbers show range of additional requirement per pipeline segment across scenarios.

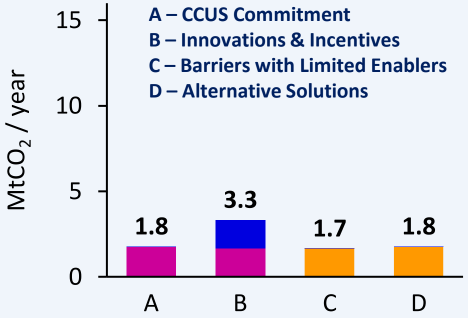
Saltend

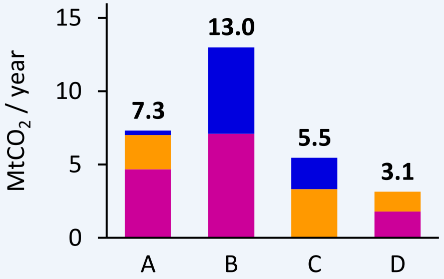
Although adoption of CCS among industrial sites at Saltend is reasonably limited, connection to the CO2 pipeline is critical for the blue hydrogen production at this point including the H2H Saltend projects.. This defined point also forms the connection for pipeline crossing the Humber from the south connecting the remaining network to storage associated with the Northern Endurance Partnership.



Scunthorpe

British Steel is the major adopter of CCS connecting to the Scunthorpe defined point. Since this is consistent across all scenarios this site depends on pipeline connection for its abatement. This connection is also essential for future power at Keadby with CCS.





Immingham

CCS demand at Immingham is significant due to its use for abatement at the refineries and VPI Immingham. This demand is lower in scenarios where alternative abatement options are available for these sites. Delays to pipeline connection for Immingham will prevent the capture of a significant amount of emissions across all scenarios.

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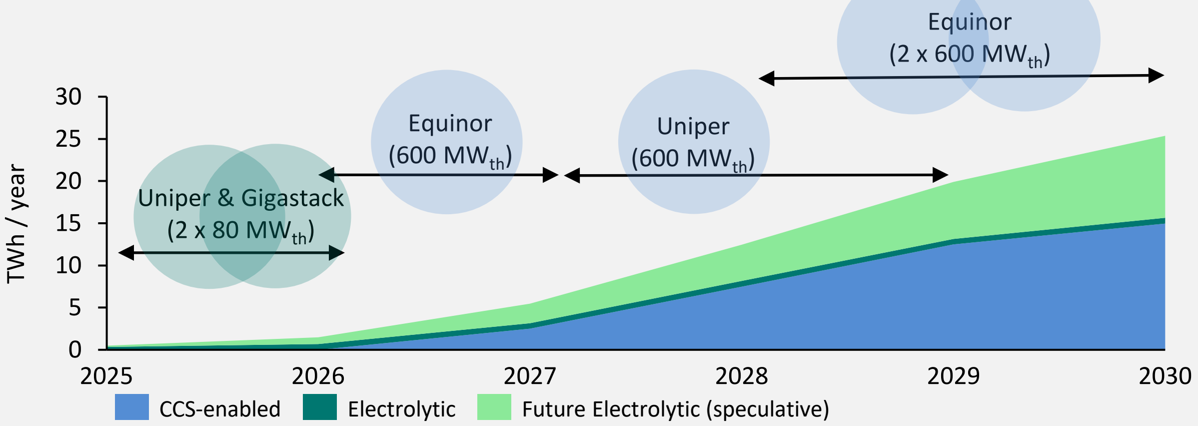
Most scenarios require 1-2 GW of hydrogen supply by the early 2030s, consistent with a rapid roll-out of production projects

Equinor's H2H Saltend CCS-enabled hydrogen production project, due to be deployed in 2026-2027, forms the anchor project for the Zero Carbon Humber pipeline. Zero Carbon Humber has plans to build a 10 GW hydrogen transportation system, with potential to see hydrogen exported out of the region to supply other areas of the UK.

Several other CCS-enabled and electrolytic hydrogen production projects have been announced in the Humber including those indicated below. The UK government has set targets for 10 GW of low-carbon hydrogen production across the UK by 2030, with at least half coming from electrolytic hydrogen. Future scales of electrolytic hydrogen are uncertain, but this technology is modular and could expand to meet demand. The below chart includes a speculative 1.25 GW of additional electrolytic hydrogen production in the Humber by 2030. These projects will require significant capital investment in the short term to ensure production of low-carbon hydrogen and enable cluster decarbonisation.

Chart 5.6 Illustrative near-term Humber hydrogen production potential



There is a significant opportunity for the Humber as a first mover in the development of CCS and hydrogen infrastructure, and therefore announced projects are planning for a hydrogen production capacity beyond the local demand within the cluster.

For the core scenarios analysed, an assumption is made on the wider economy demand for hydrogen that ranges from 1.5-7.5 TWh of hydrogen per year in 2040, considering potential demand from truck transport and heating for buildings. Demand for a dispatchable hydrogen power peaking plant (e.g. Keady Hydrogen) is also considered, with an assumed load factor in 2040 of 11.5% to reflect dispatchable operation.

Chart 5.7 Hydrogen demand for the Humber cluster (cluster + future power)

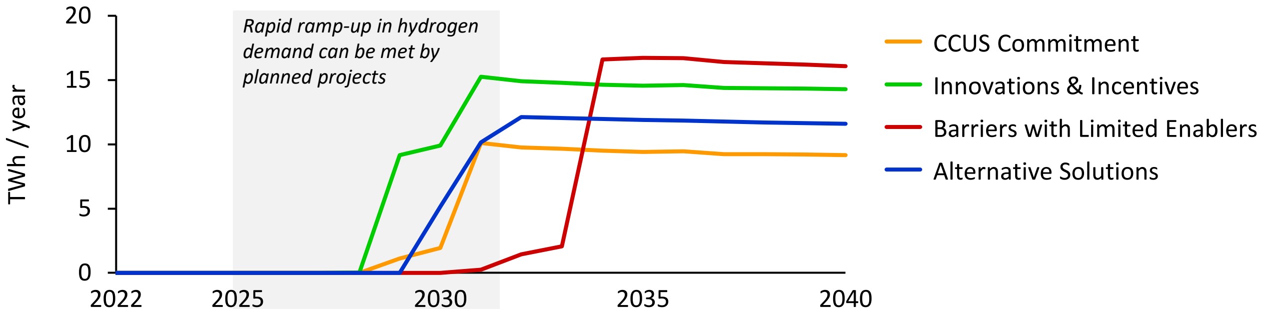
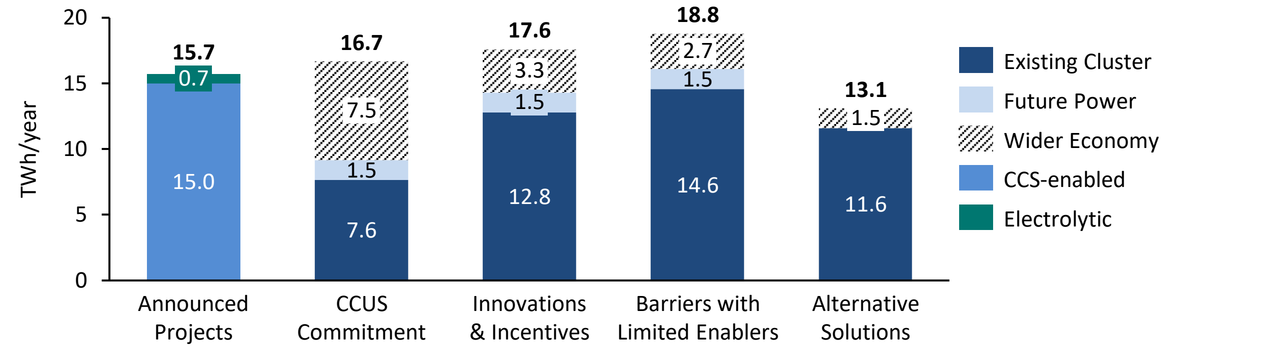


Chart 5.8 Potential wider hydrogen demand in 2040



- **By 2031, most scenarios require between 10-15 TWh of annual hydrogen production** to abate cluster emissions from industry – equivalent to 1-2 GW of continuous production with storage.
- This capacity could be met by the **successful pre-2030 deployment of 2-4 x 600 MW CCS-enabled hydrogen** production units. Currently plans for four such units have been announced in the region, showing the Humber's capability to meet this rapid increase in demand if projects are supported.
- After the initial ramp-up phase (2026-2031), **most scenarios show a plateau in demand for hydrogen** from the existing cluster as all the major hydrogen fuel switching projects have deployed.
- Further increases in demand may result from uptake of hydrogen in the **wider economy, such as within the transport sector, or for use in a hydrogen power plant.**

Assumptions on the development of future hydrogen demand from the wider economy and future hydrogen power are included in the Appendix. These assumptions do not necessarily align with those of projects in the region. For dispatchable hydrogen power plants a load factor of 11.5% in 2040 is assumed.

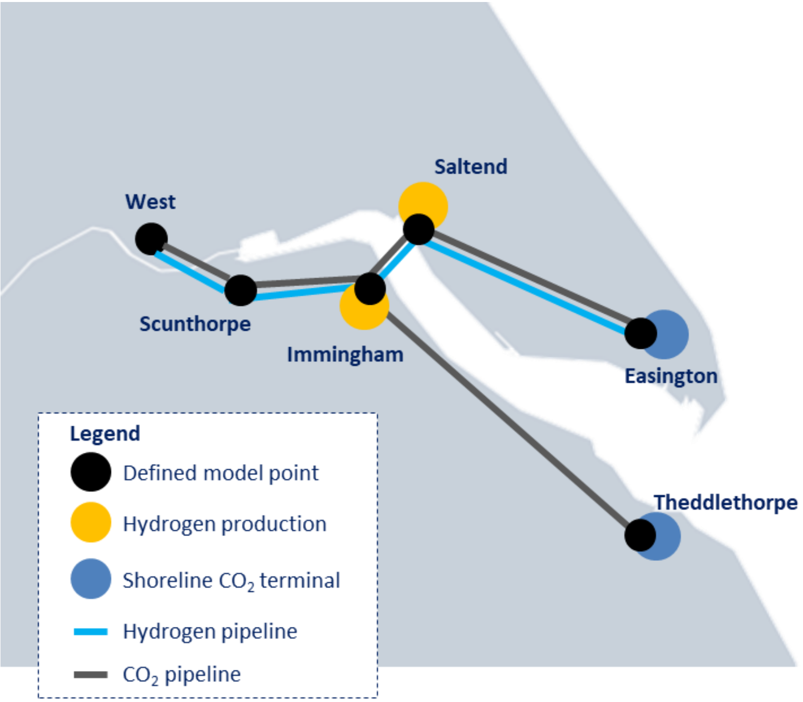
Immingham and Saltend represent the majority of the demand for hydrogen uptake, due to the location of the refineries, Triton power and Saltend Chemicals Park.

Chart 5.9 Demand for hydrogen by location and year of adoption

Units: TWh hydrogen demand (TWh / year)

Scope: *Core Cluster and Future Power**

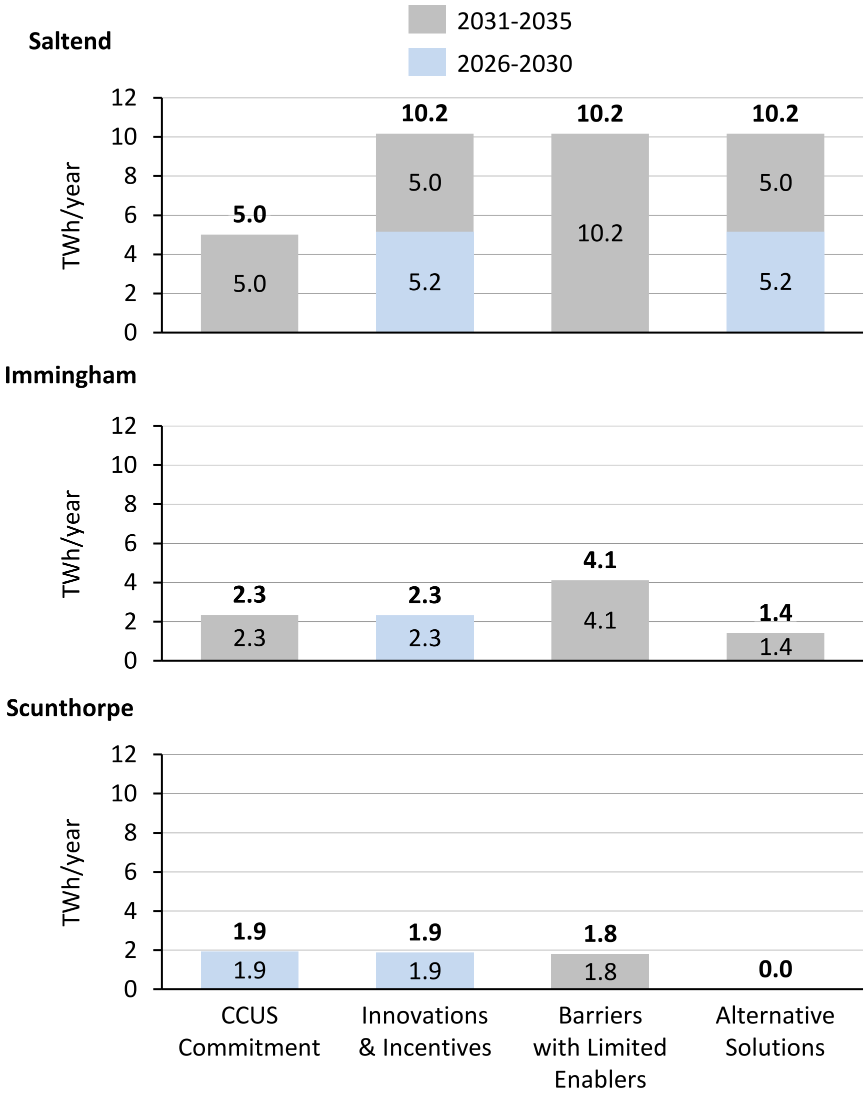
Note: *Existing hydrogen demand is not included. Graph shows uptake of hydrogen across geographic areas for purposes of fuel switching away from fossil fuels.*



Saltend and Immingham represent the defined points with local hydrogen production at scale. As a result, sites located near these defined points have announced plans for a degree of H_2 fuel use. The Triton CHP plant (Chemicals) which provides power and steam to the adjacent Saltend Chemicals Park represents a large proportion of demand at Saltend while refineries and VPI Immingham make up the majority of the demand at the Immingham defined point.

British Steel and Keadby H_2 make up most of the demand at the Scunthorpe defined point. No major H_2 production projects are currently confirmed for this location so pipeline connection between Scunthorpe and the H_2 production at Immingham/Saltend will be required. The **Barriers with Limited Enablers** scenario delays the adoption of Hydrogen in Scunthorpe due to delays in the roll-out of the pipeline network and construction of H_2 power projects.

Pipelines should be sized to account for the peak demand rather than the yearly average to account for potential seasonal demand peaks



*Assumptions on the annual demand for hydrogen for power are detailed in the Appendix. These assumptions do not necessarily align with those of projects in the region. For dispatchable hydrogen power plants a load factor of 11.5% in 2040 is assumed.

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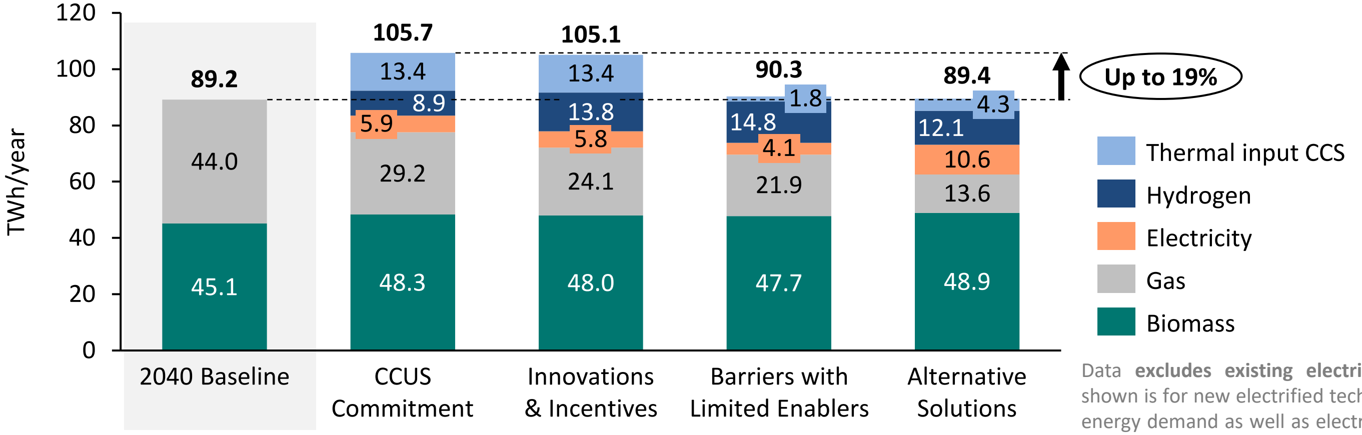
Energy demand is expected to increase by up to 19% across scenarios relative to the baseline

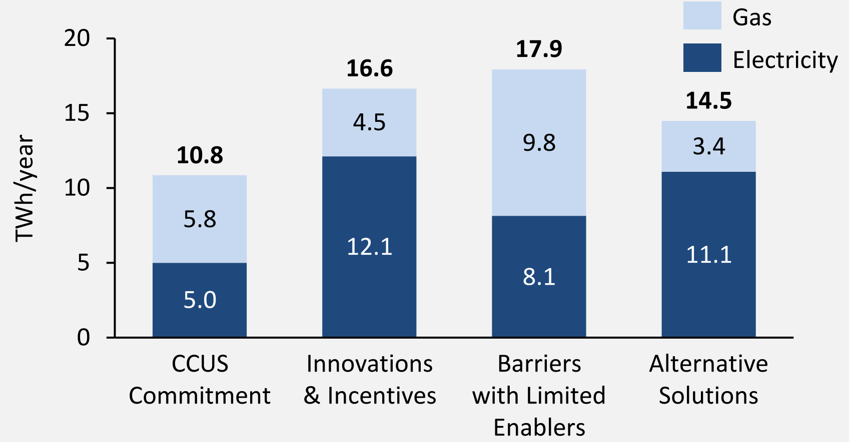
Chart 5.10 On-site industrial energy demand in 2040 (excl. existing electricity demand)



Total including primary energy for hydrogen:	107.6	107.9	93.4	91.8

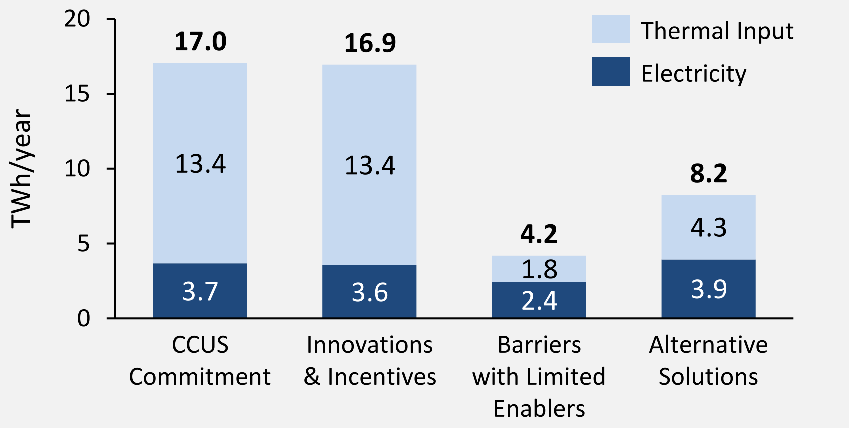
Data **excludes existing electricity** demand. Electricity shown is for new electrified technologies replacing fossil-energy demand as well as electricity for CCS. In addition, minor amounts of fossil oil & coal are used for infrequent start-up operations and coking (excluded from chart). **Gas values reflect gas used for on-site combustion only.**

Chart 5.11 Primary energy requirements for H_2 production in 2040



The efficiency of electrolytic hydrogen technologies is modelled as 73% in 2020 rising to 82% by 2050, compared to 84% assumed for CCS-enabled routes.

Chart 5.12 Energy requirements for Carbon Capture in 2040



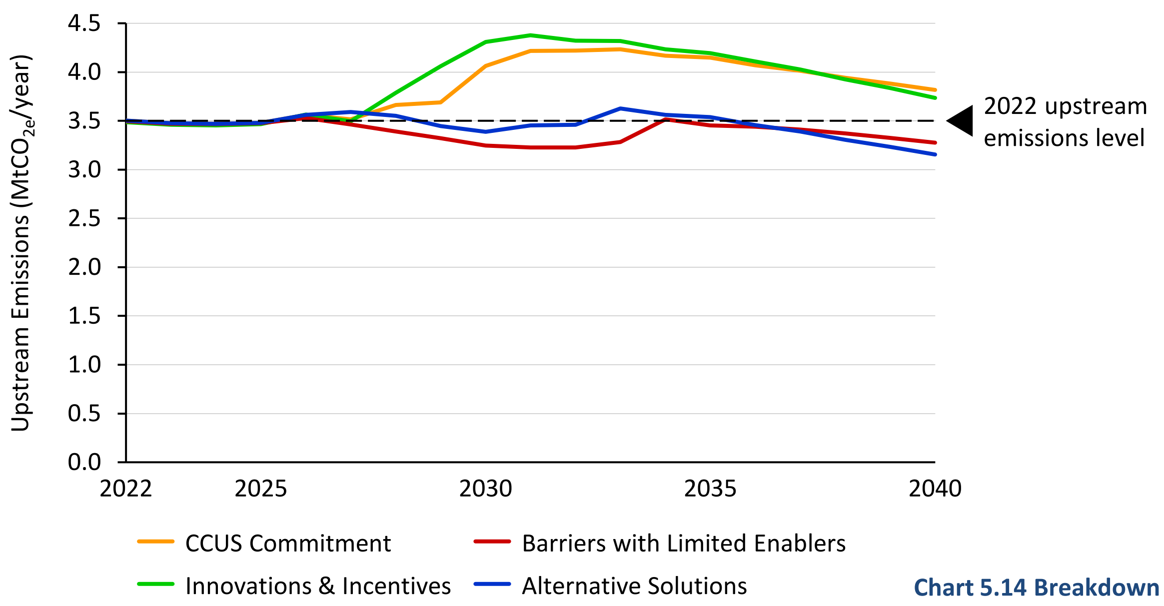
- **By 2040, industrial energy demand could be up to 19% higher in a net-zero pathway** compared to the counterfactual case with an increase of up to 21% for the Humber region once efficiency losses in hydrogen production are incorporated.
- **Increases in energy demand are dominated by the deployment of carbon capture equipment with high thermal input requirements.** The CCUS Commitment and Innovations & Incentives scenarios both have significant deployments of advanced amine carbon capture technologies. These established technologies have a much higher thermal energy requirement compared to the emerging 2nd Generation capture technologies that tend to be adopted in other scenarios.
- **Total on-site natural gas consumption decreases by 34-69% by 2040.** Onsite demand decreases are due to replacement of fossil-fuels with hydrogen or electrification of equipment. The decrease is most significant in the Alternative Solutions scenario where the power provided by CCGTs from the CHP sector is replaced by importing grid electricity. Increases in natural gas consumption could occur at some sites if natural gas were chosen as the thermal input for carbon capture technologies. Our modelling however assumes that a low-carbon thermal input (such as hydrogen, waste heat or electrically generated heating) is used to power carbon capture technologies.
- **Electricity requirements for hydrogen production are significant (0.6-1.5 GW) and may exceed that for industrial electrification or CCS.** The scenarios analysed include assumptions on the level of hydrogen production via electrolytic and CCS-enabled routes, ranging from 50-80% electrolytic by 2040. Under this range of assumptions, an increase in electricity supply to the Humber of 0.6-1.5 GW is needed for hydrogen production by 2040. This is on top of the additional 0.5-1.2 GW supply required for onsite electrification or carbon capture power.
- **Natural gas for CCS-enabled hydrogen production limits reduction in overall gas demand** to between 3-61% across scenarios.

The model does not account for availability of suitable power connections and additional UK-level grid generation that would enable electrification.

By 2040 all scenarios have remaining upstream emissions of 3.82 $MtCO_2e$ or less associated with their primary energy demand

Chart 5.13 Total upstream emissions over time (Cluster)

Using BEIS 2021 Well-to-tank conversion factors. Data excludes existing electricity demand.



The upstream emissions of a fuel are a result of the *production, processing and transport* stages that occur before its use on site. These emissions are produced as a consequence of the end-user of the fuel since the demand drives the production. Consequently, it is important to consider the impact on the upstream emissions when making abatement choices.

All scenarios reach similar levels of remaining Scope 1 emissions by 2040 (0.5-0.7 $MtCO_2e$); however, there is a wider range in remaining upstream emissions (3.15-3.82 $MtCO_2e$) by 2040. Scenarios with more electrification and less CCS-enabled hydrogen production benefit from a decarbonising electricity grid with lower upstream emissions from the late 2020s onwards

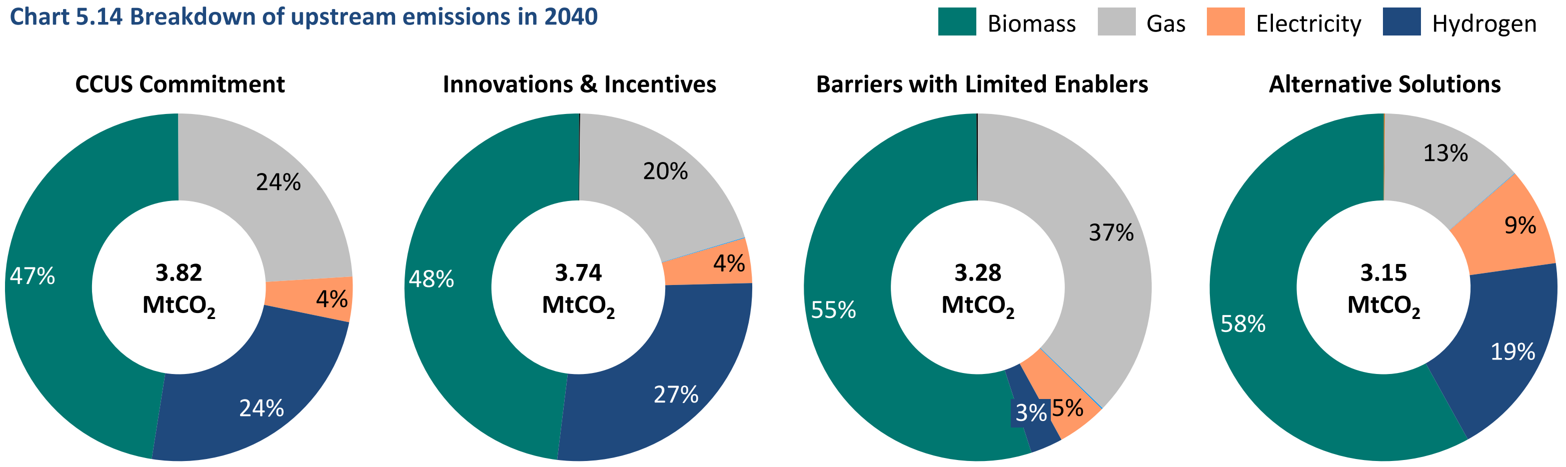
To ensure upstream emissions from fuels are minimised, sites should attempt to purchase their energy from low carbon production routes and ensure suppliers have plans to decarbonise their supply chains. In practice upstream emissions that are difficult to decarbonise must be abated with GGRs.

Accounting for upstream emissions in modelling

Although these emissions do not appear in the industrial decarbonisation pathways as remaining emissions they are accounted for within the NPV calculation for an abatement option. The net savings in Scope 1 and Upstream emissions as a result of the abatement method is multiplied by the carbon value – to prevent a situation where the savings in Scope 1 emissions are outweighed by a significant increase in upstream emissions.

Data **excludes upstream emissions from existing electricity** demand. Upstream emissions for fuels are fixed as the 2021 values as reported in BEIS **2021 well-to-tank**, or the national **grid average** projections for electricity emission intensities also reported there. It is noted that upstream emissions for electricity may be reduced in the near-term via renewable PPA's or dedicated renewable production, however the wider impact on the UK grid electricity should be considered to avoid knock-on impacts. It is also noted that future upstream emissions from natural gas may reduce with improved methane-leakage management, however these reductions have not been included due to high levels of uncertainty.

Chart 5.14 Breakdown of upstream emissions in 2040



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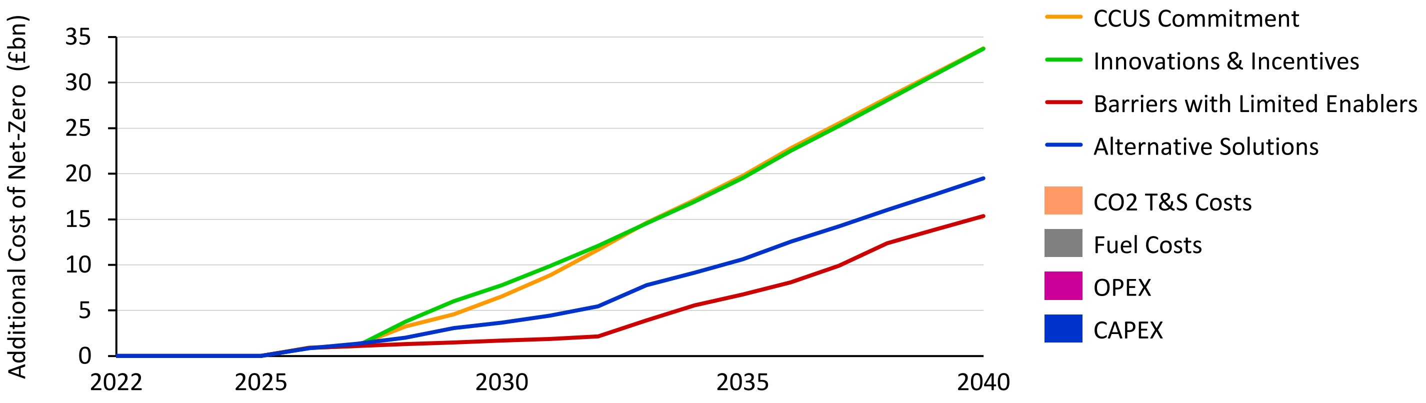
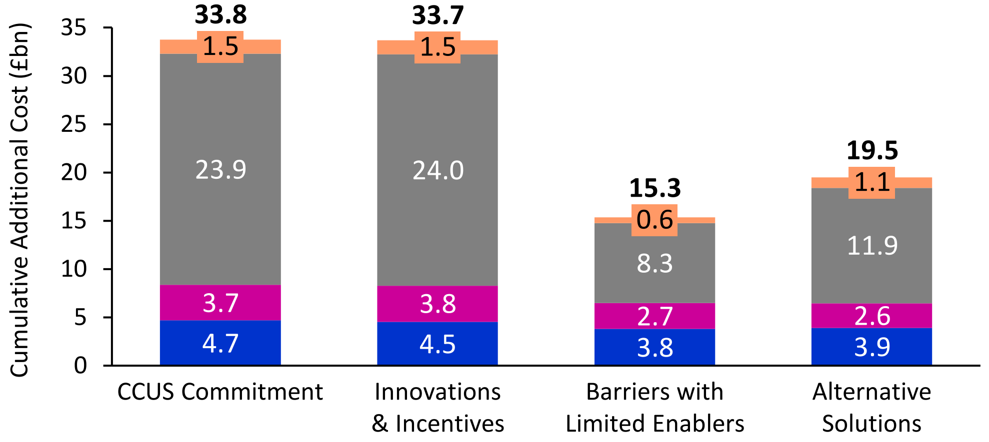
The additional cost to industry compared to the business as usual pathway ranges between £15.3 - 33.8 billion

Chart 6.1 Cumulative additional cost of decarbonisation (excludes carbon value)



The "additional cost" to industry is the investment difference between an abatement pathway and the counterfactual pathway

Chart 6.2 Breakdown of cumulative cost differential by 2040 (excludes carbon value)



The cost of hydrogen production, transport and storage is aggregated into a unit cost of hydrogen for a consumer. These costs are represented within 'Fuel Costs' in the graph above.

Faster acting scenarios incur increased cumulative additional costs for abatement. The faster acting CCUS Commitment and Innovations & Incentives scenarios abate their emissions rapidly and deploy most of their large abatement options before 2030 while the Barriers with limited Enablers and Alternative Solutions scenarios deploy CCS predominantly in the form of the 2nd Generation technology which becomes available in the early 2030s.

The steeper gradient of the faster acting scenarios reflects the greater fuel costs incurred from acting rapidly and adopting the incumbent CCS technology which requires a greater thermal input for CO_2 capture.

Excluding fuel costs, between £ 7.1 - 9.9 billion in additional investment is required by 2040. This demonstrates that the investment in technology is reasonably similar across scenarios, while fuel costs provide the most variation.

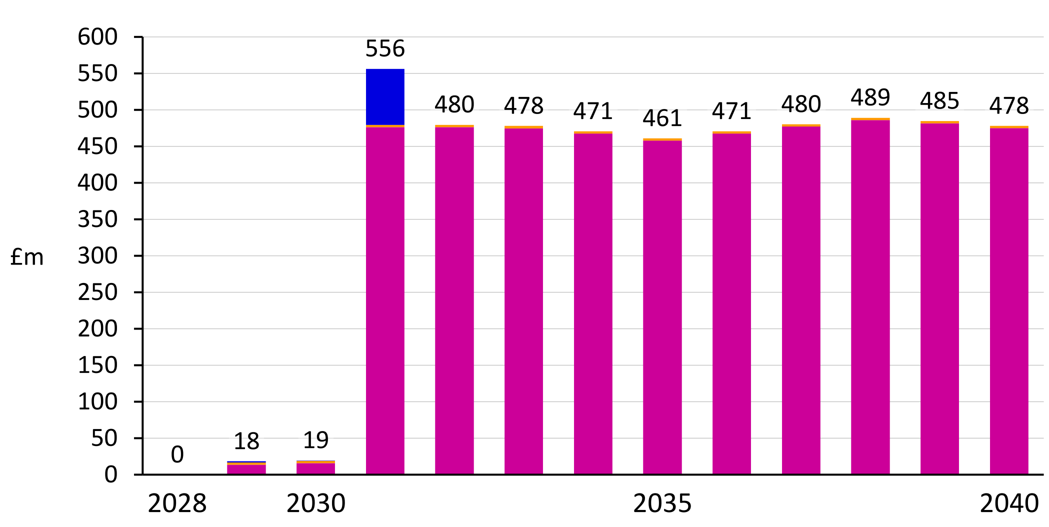
Average cost of abatement up to 2040 (£/tCO_2) – excludes carbon value

CCUS Commitment	Innovations & Incentives	Barriers with Limited Enablers	Alternative Solutions
207.4	191.5	124.7	120.3

To make rapid decarbonisation a viable NPV option in the model, a policy incentive in the form of a shadow carbon price is required to incentivise first-mover decarbonisation over delays. This reflects the need for strong policy support if the cluster is to decarbonise rapidly and economically.

The unit cost of Hydrogen is dominated by the cost of electricity for electrolytic production

Chart 6.3 Annual additional costs for Hydrogen fuel switching industrial sites in the CCUS Commitment Scenario



For sites adopting hydrogen fuel switching technologies the CAPEX and OPEX costs associated with fuel switching the existing equipment are small compared to the cost of hydrogen fuel. The cost of hydrogen fuel is based on the unit cost of hydrogen which is the same for all sites and includes all upstream costs associated with hydrogen before it meets the consumer.

In a scenario where sites adopting hydrogen had much lower load factors, the relative proportion of the sites costs from fuel would decrease.

The unit cost of hydrogen is found by aggregating the total production, transport and storage costs across the network and dividing this by the total hydrogen demand.

The production costs include the CAPEX and OPEX of the production equipment as well as the fuel costs associated with production. The transport and storage costs include the costs associated with deploying and operating a main pipeline transport network for the cluster, as well as the cost of any storage requirements.

Individual sites all pay the same price per unit of hydrogen. The cost of connecting a site to the main hydrogen transport network and the cost of adapting technologies to utilise hydrogen as a fuel are unique to a site and are not included in the unit cost of hydrogen.

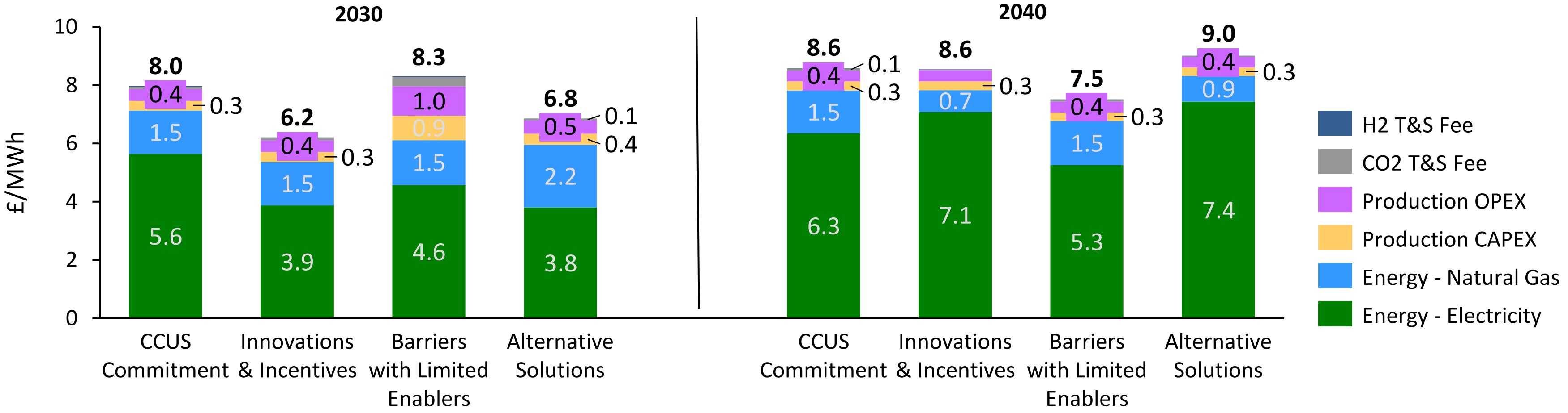
Although production CAPEX is considered within the unit cost of hydrogen for the analysis, it is noted that hydrogen production projects will require significant capital investment between 2025-2030 to rapidly deploy and meet demand.

The unit cost of hydrogen is most influenced by the cost of electricity for green hydrogen production and natural gas for blue hydrogen production. The relative influence of both fuel costs varies over time and by scenario - dependent on the split of production between green and blue, as well as the fuel cost projections used.

The Innovations & Incentives and Alternative Solutions scenarios both see an increase in the unit cost of hydrogen between 2030 and 2040 due to a long term preference for green hydrogen production methods over blue.

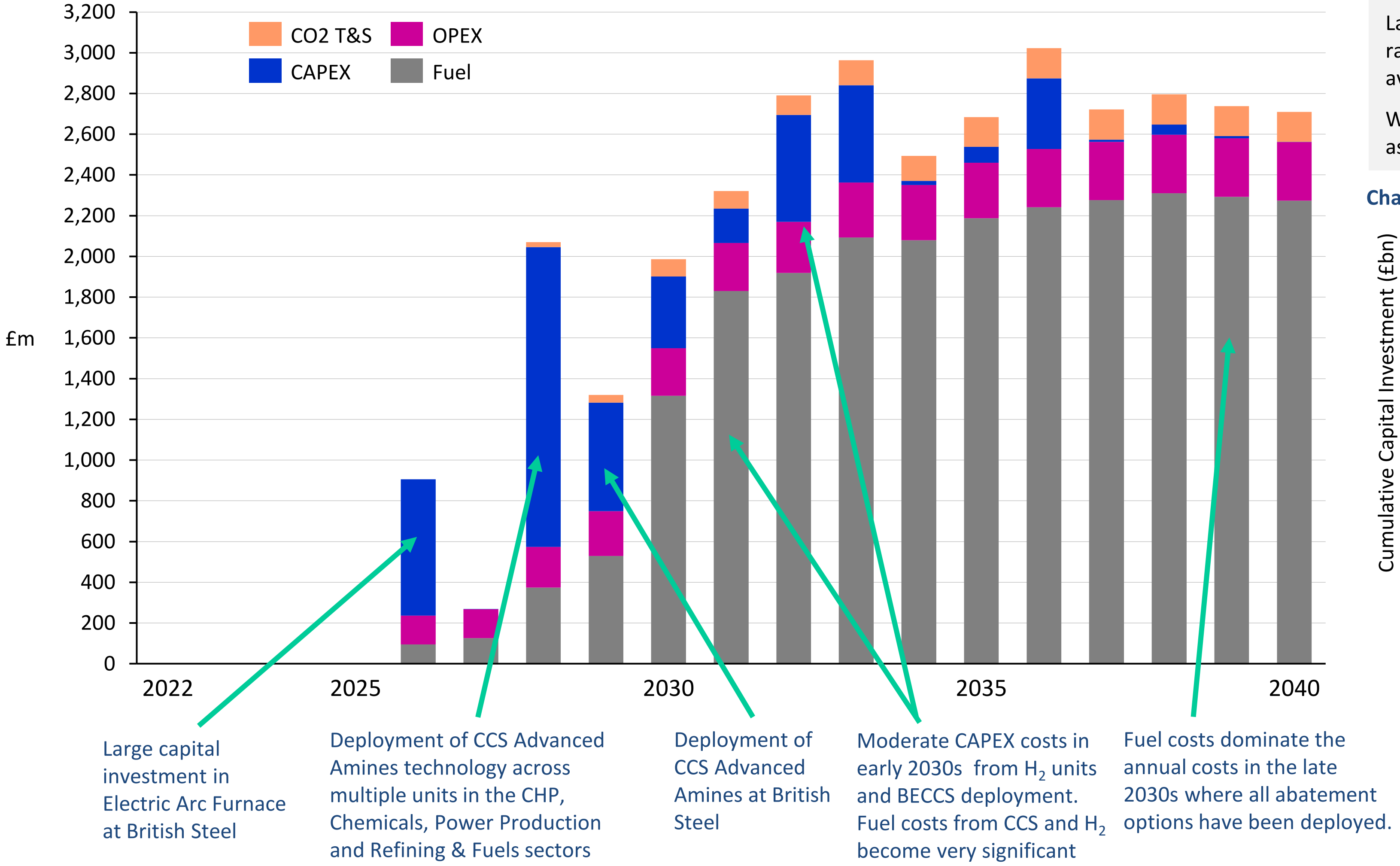
The projected industrial costs for electricity remain substantially above natural gas meaning that increasing the proportion of green production has the effect of increasing the unit cost. To prevent high hydrogen costs in a scenario with significant green production will require access to low cost renewable electricity.

Chart 6.4 Breakdown of the unit cost of Hydrogen for fuel switching industrial sites



The CCUS commitment scenario requires early CAPEX investment and sustains high future energy costs

Chart 6.5 Annual additional costs to the Humber as a result of decarbonisation in the CCUS Commitment Scenario

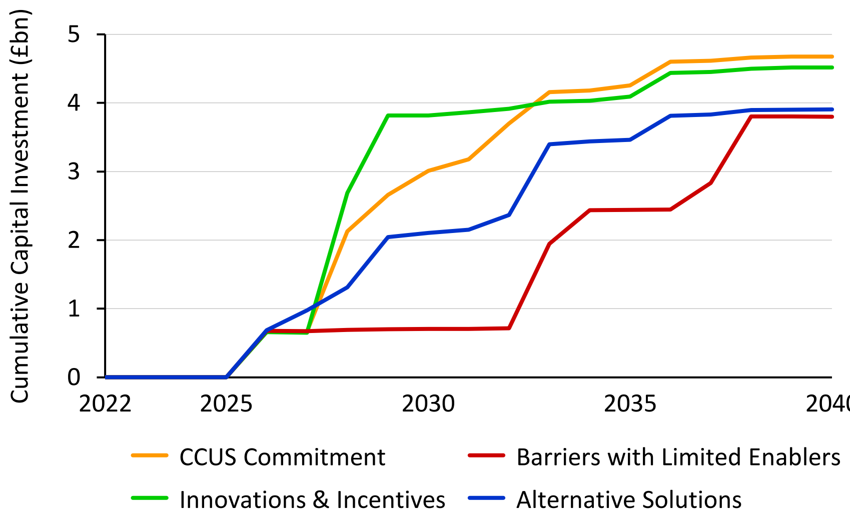


The CCUS Commitment scenario is the scenario the most closely reflects the current infrastructure and abatement plans for sites within the Humber while incorporating central - high fuel cost projections for electricity and gas

Large CAPEX investments are made in early years, particularly from the rapid adoption of Advanced Amines in the year that it becomes widely available at Immingham (2028).

With a significant deployment of CCS and Hydrogen in this scenario, the associated fuel costs become dominant.

Chart 6.6 Cumulative additional capital investment over time up to 2050



- Since CAPEX only depends on the abatement technologies and not other input parameters there is less variation across scenarios than other costs such as fuel
- Abating emissions rapidly as shown in the Innovations & Incentives scenario will require a CAPEX investment of £3.8 Bn by 2030

Most decarbonisation options deployed in the cluster cost below 200 £/tCO_2

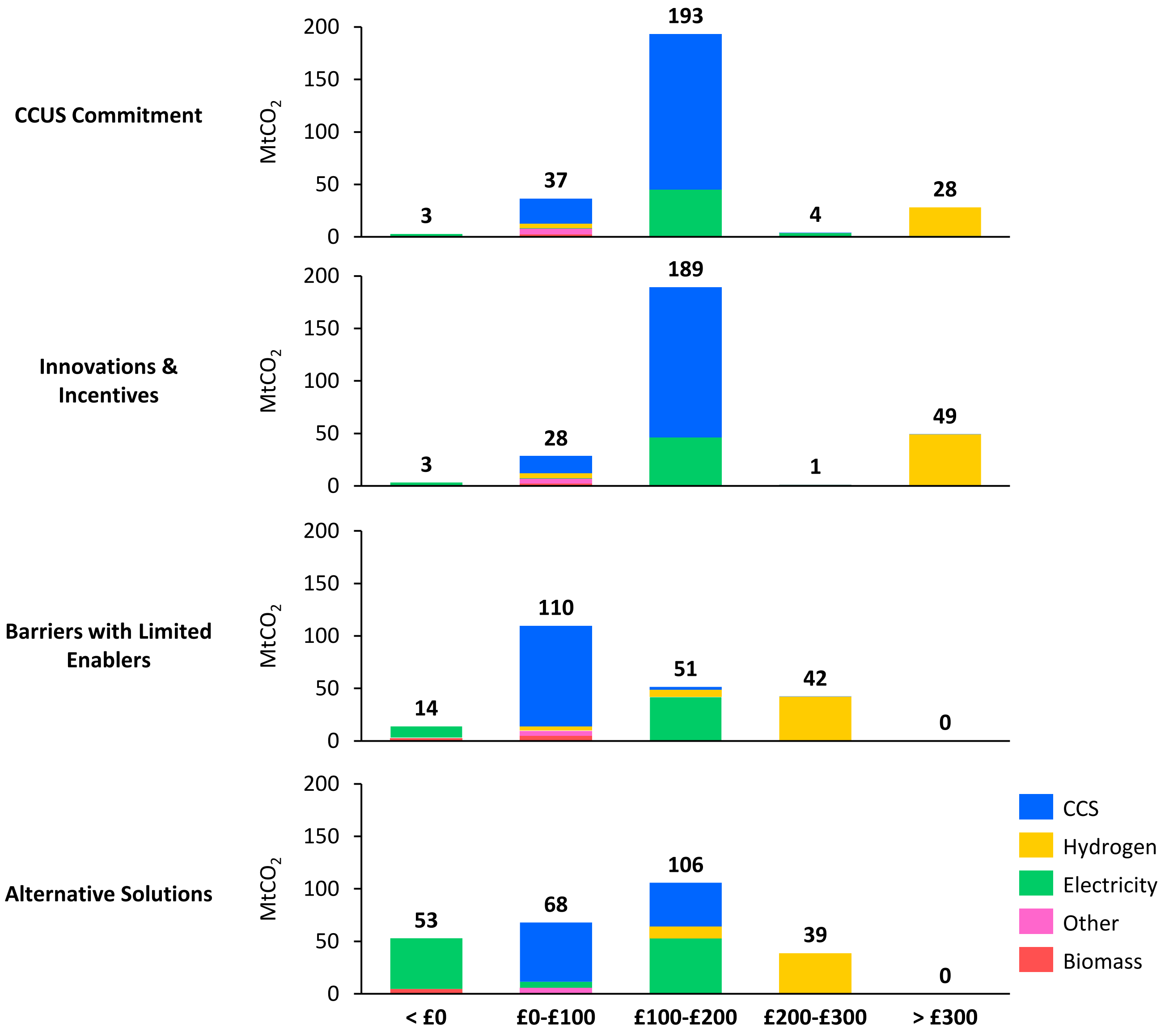


Chart 6.7 Average cost of abatement

Units: $MtCO_2$ Scope 1 abated emissions per cost bracket

Scope: *Core Cluster*

Note: *Includes abatement of non-biogenic emissions only.*

- **The Average Cost of Abatement assesses the relative expense of the abatement options deployed in each scenario considering the amount of emissions abated.**
- **The cost of abatement is influenced significantly by the fuel consumption of a technology** and the fuel cost assumptions in a particular scenario. The fuel costs for producing green hydrogen dominate the unit cost of hydrogen in all scenarios. Scenarios with **high proportions of green production** and those with **high electricity costs** can expect to see more expensive hydrogen. The average fuel costs for hydrogen fuel switching options are high in the CCUS Commitment scenario due to high electricity prices dominating the unit hydrogen cost. This average hydrogen cost in Innovations & Incentives is also high despite low electricity costs due to a high proportion of electrolytic hydrogen production. In these scenarios a higher carbon value (more policy support) is required to make this technology affordable. A combination of low electricity costs and higher average proportions of blue H_2 generation make the average cost of H_2 over time cheaper in the Barriers with Limited Enablers and Alternative Solutions scenarios.
- **Electrification technologies tend to be small scale and offer low cost abatement** with relatively low capital costs and efficient energy consumption. The exception to this is the Electric Arc Furnace (£100-200 /tCO_2) which is a large technical piece of equipment with significant energy consumption due to the high power required by the arc for steel production.
- **Despite the high capital costs associated with carbon capture technologies, these benefit from economies of scale due to their application on large industrial processes.** The CCUS Commitment and Innovations & Incentives scenarios act early to decarbonise by deploying the Advanced Amines technology. This is less efficient than the 2nd Generation technology which is preferred for deployment in the Barriers with Limited Enablers and Alternative Solutions scenarios. The more efficient 2nd Generation Technology consumes less fuel, incurring lower fuel costs per unit of CO_2 captured helping to lower the average price of abatement of this technology category in these scenarios.

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The economic analysis uses the investment and expenditure data to calculate impacts at the national and local level across the scenarios

Analysis was conducted to estimate the **impact on GVA and job creation that might result from the investments made in abatement technologies and infrastructure** (such as new equipment or hydrogen supply) and the knock-on impacts of these investments along the supply chain.

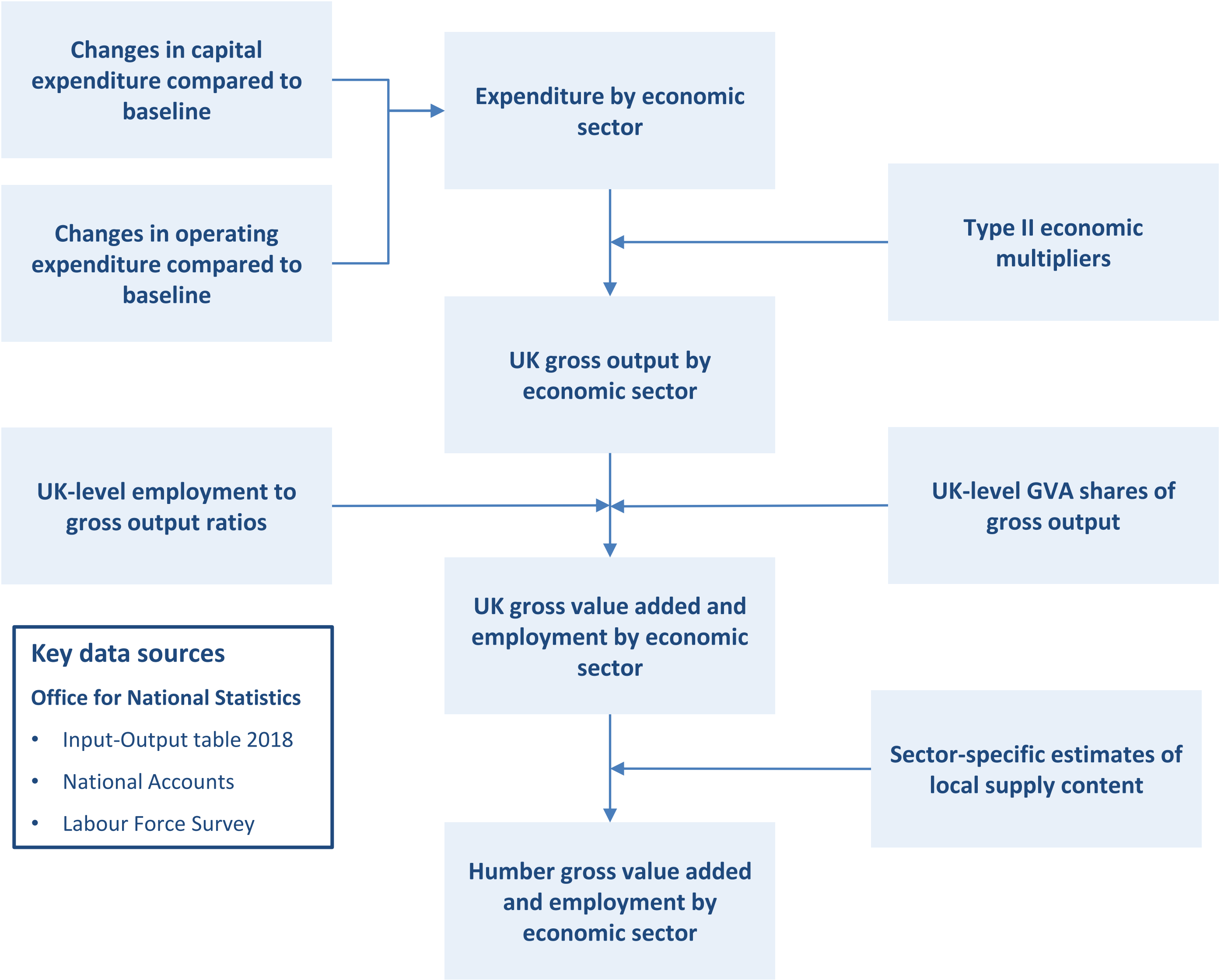
The flowchart to the right shows how changes in expenditure, linked to different technology deployments in the scenarios, are used to construct estimates of economic activity that results in the Humber and across the UK as a whole.

The economic multipliers are drawn from the latest UK Input-Output table for the UK, published by the Office for National Statistics (ONS) and based on data for 2018. The Input-Output table maps supply chains across the UK economy, and how changes in economic activity in a single sector create additional demand upstream for inputs to production.

The multipliers themselves show how much additional economic activity is created across the different sectors of the economy from a £1 increase in demand from a single sector. Using this information, we calculate how much total output of the UK economy (known as gross output) increases by as a result of the additional expenditure modelled in the scenarios. We then apply GVA shares of gross output by sector, drawn from ONS national accounts data, to estimate how much of the increase in output accrues as GVA, and use ONS Labour Force Survey data to estimate how many jobs are created by the increased demand across the economy.

Because the Input-Output table used is for the UK, it estimates these impacts based on UK supply chains (and imports/exports to/from the UK). However, the impacts within the Humber will clearly be a subset of these, with a substantial proportion of the economic activity taking place in the rest of the UK. We apply sector-specific local content shares to estimate how much of the economic activity will stay within the Humber. These shares reflect the extent to which the demand for inputs to production will be met from local producers.

Note that the economic analysis refers to **additionalities above a baseline** due to investment in abatement technologies and infrastructure modelled in the N-ZIP Humber analysis. It **does not include** any analysis of existing jobs in the Humber region nor potential regional growth due to new industry creation or industry retention.



Key data sources

Office for National Statistics

- Input-Output table 2018
- National Accounts
- Labour Force Survey

The benefits in terms of Gross Value Added reach between £3-5bn/year for most scenarios, with ~25% being captured in the Humber

National level impacts

Regional level impacts

Economic impacts

Chart 7.1 National UK GVA impact

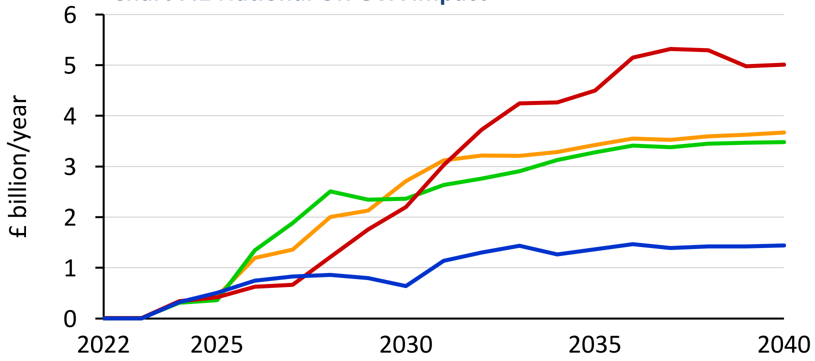
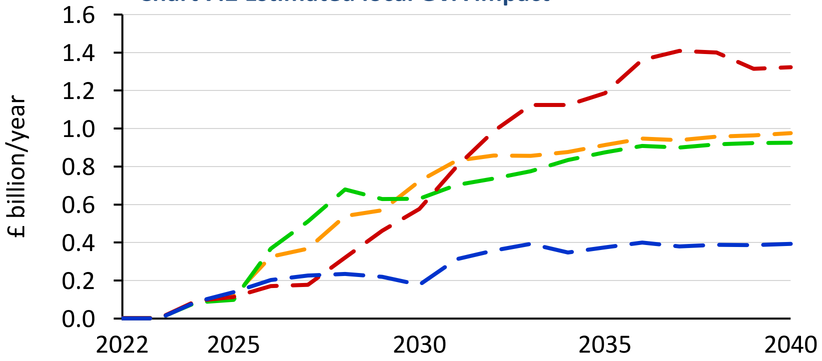


Chart 7.2 Estimated local GVA impact



Employment impacts

Chart 7.3 National UK job creation

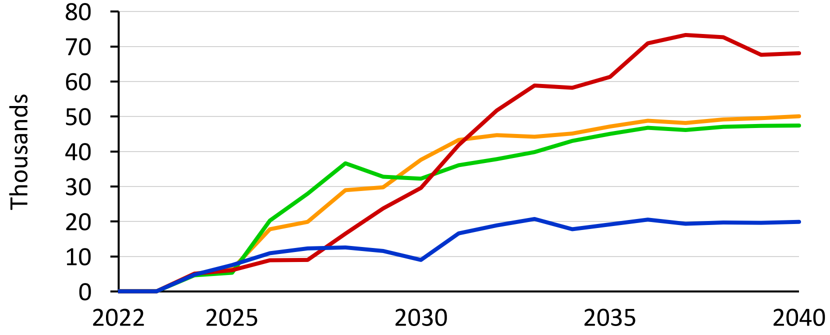
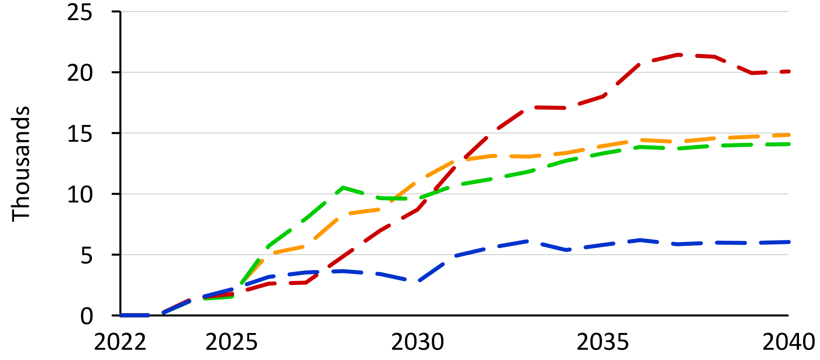


Chart 7.4 Estimated local job creation



CCUS Commitment — Innovations & Incentives — Barriers with Limited Enablers — Alternative Solutions

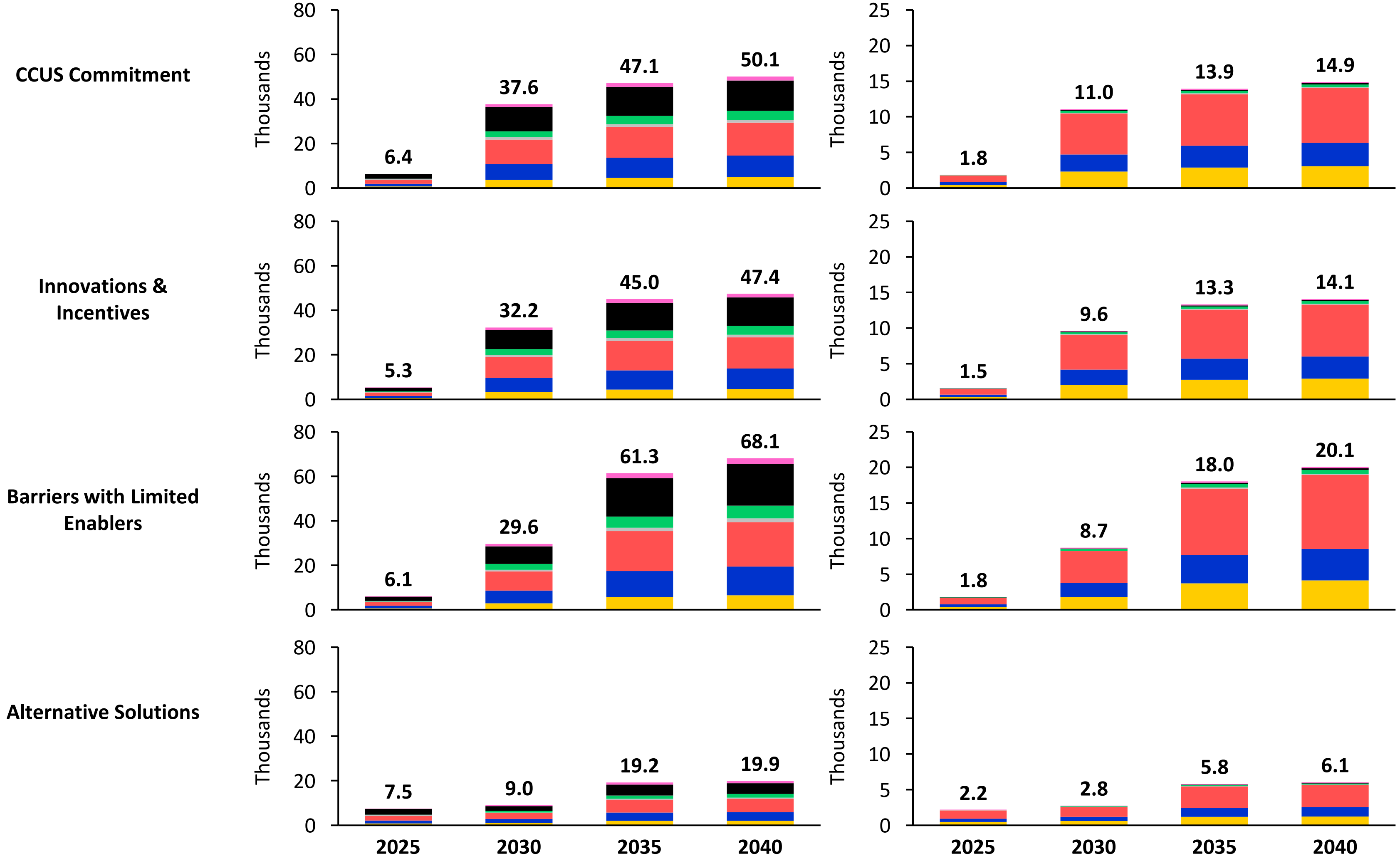
GVA and job creation refer to **GVA increase and additional jobs** created from **investment in abatement technologies and infrastructure** (such as new equipment or hydrogen supply) and the knock-on impacts of these investments along the supply chain. Results are calculated from **multiplications of the UK Gross Output by Economic sector** – see method overview – and therefore charts track the same pattern.

- The ratios between national and local growth are similar across the scenarios, reflecting the underlying assumptions and that the economic structure of the spending is broadly similar.
- In the Barriers with Limited Enablers scenario, large investments are delayed until later in the projection period, and as a result GVA impacts also occur later. Due to the concentrated substantial investment an higher operating costs that occur in particular from the mid-2030s onwards, GVA impacts are greater in this scenario than any other.
- Expenditure in the Alternative Solutions scenario is substantially lower than in the others, reflected in a smaller positive impact on GDP.
- The differences between scenarios in terms of employment broadly mirror those in GVA, reflecting the similar structure of expenditure across the scenarios.
- The most additional jobs are created in the Barriers with Limited Enablers scenario, as a result of the substantial investment stimulus; up to 70,000 new jobs are created per year nationally, and 20,000 in the Humber, between 2035 and 2040.

The Humber deployment could create up to 70,000 jobs across the UK, however less than a third of these are likely to fall within the Humber

Chart 7.5 National UK Job Creation

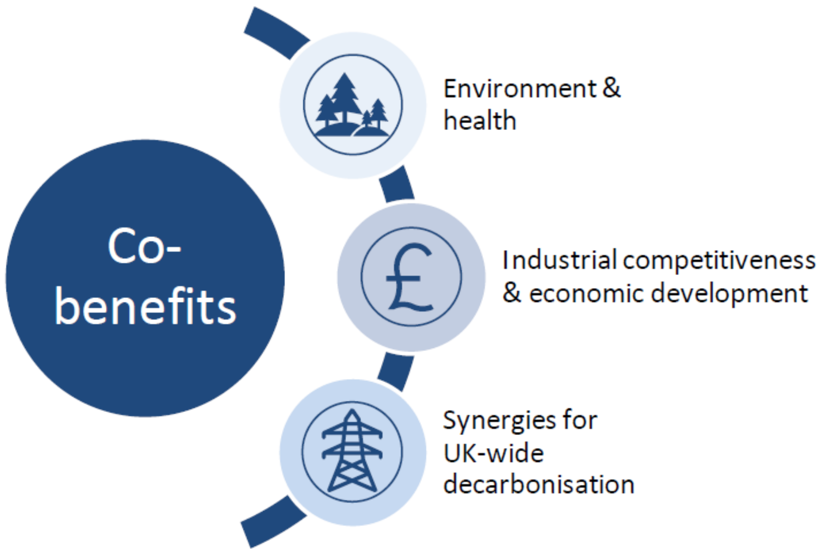
Chart 7.6 Local Humber Job Creation



- Across scenarios it can be seen that the largest positive impacts at the UK level are seen in consumer services and manufacturing.
- Manufacturing impacts are primarily supply-chain driven; increased CAPEX means higher demand for manufactured equipment. Consumer services impacts are due to their centralised role in the economy; in particular retail services are used by consumers and businesses alike and therefore benefit from increases in spending across other parts of the economy.
- Energy supply creates a lot of additional economic activity – but due to the high productivity of workers in this sector, relatively few additional jobs are created.
- Consumer services (dominated by retail trade effects) dominate the creation of local jobs across scenarios, because of the integral role of retail in supply chains and induced effects from higher consumer spending (linked to higher employment in other sectors).
- Local impact on manufacturing employment is relatively small, because the kind of specialised manufactured products required are relatively likely to be manufactured outside of the Humber – however this could be changed by well-targeted industrial strategy to encourage the creation of localised supply chains.
- Local job creation in the construction sector is similarly small – this is also linked to the highly-specialised nature of the construction work that is required during the construction phase of these projects.

Policy implications of the economic analysis

- Deep industrial decarbonisation in the Humber can lead to economic gains, in the form of a larger economy and the creation of new jobs, both within the region and across the wider UK. This economic activity is linked to the manufacturing and installation of new infrastructure in the cluster, as well as it's ongoing operation and maintenance.
- In addition to this there are further co-benefits, including the wider impacts of improved industrial competitiveness, and the jobs preserved in energy- and emission-intensive industries that would not have a long-term future in the UK without this investment.
- The zero- and negative-emission facilities that are foreseen in these scenarios have the potential to safeguard a large number of jobs in those sectors that are most difficult to decarbonise, within the Humber and the UK.
- In the longer term, the region's economy could also benefit from exports of hydrogen and related products, creating further jobs and improving the UK's trade balance.
- Finally, the environmental benefits associated with decarbonisation and cleaner activities, including (internationally) reduced climate change impacts, the reduced production of pollutants which impact ecosystems and human health locally, and reduced resource consumption, are a key driver of developing the Humber into a deep decarbonisation cluster and should not be forgotten.



Linkage with the HICP Market, Policy and Regulatory (MPR) studies

Opportunities for investment in the Humber[1]

- Investment in supply chains will be required for carbon capture, hydrogen fuel switching and electrification pathways to ensure that net-zero compatible pathways for the Humber can be delivered. Early supply chain constraints have been identified for key components in the carbon capture supply chain (such as CO_2 compressors), that could result in delays in project delivery without increased investment in manufacturing capacity.
- The development of hydrogen and CO_2 transport and storage infrastructure in the Humber will require large-scale investments, alongside continued operational expenditure. All net-zero pathways will rely on increased deployment of renewable generation as well as significant upgrades to the existing electricity transmission and distribution infrastructure.
- The Humber has the potential to exploit opportunities for circularity in industrial supply chains. Waste streams could be utilised as feedstocks or energy inputs in the production of industrial products via investments in processing and interconnecting infrastructure.

Opportunities for job creation and retention in the Humber[1]

- Existing carbon-intensive facilities in the industry and power sectors have access to a large number of skilled workers. Ensuring pathways for these workers to transition to low-carbon sectors via training programmes will be essential in retaining local jobs in the Humber region.
- New-jobs will be essential to delivering net zero in the Humber. Increased investment in early career development will be required to develop the required work force capacity in low-carbon sectors.
- The Humber Freeport can serve as a mechanism for advancing net zero in the local region. Investment in low-carbon and advanced manufacturing capacity will bring added value to the region whilst also creating local high quality jobs.

[1] Opportunities for investment and job creation and retention in the Humber are considered in greater detail in the market, policy and regulatory (MPR) study.

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Shared infrastructure development: CO_2 transport & storage

Analysis findings:

- **CO2 storage projects are underpinned by large scale emitters, called "anchor projects".** These are usually large industrial sites deploying CCS (e.g. around the refining sector in Immingham – Humber Zero) or Saltend (e.g. aligned with the ambitions of H2H Saltend developed by Equinor). To provide the Humber with key enabling CO2 T&S infrastructure and de-risk cross-cluster investment, the anchor projects should receive appropriate support for financial close.
- **Near-term commitment to carbon capture requires rapid ramp up of CO_2 storage injectivity rates in the late 2020s** – in scenarios aligned with current expectations for the Humber as a Track-1 cluster, injection rates of up to 6 MtCO2 / year are needed by 2028 rising to almost 18 MtCO2 / year by 2030 (Scenarios A & B). If plans were to diverge or if support were to hesitate, then ramp up may be stunted to less than 3 $MtCO_2$ / year by 2030 with a rapid increase delayed to the early 2030s, sacrificing several years of emissions abatement potential (Scenarios C & D).
- **A combination of both initial NEP and V-Net Zero storage projects provide sufficient capacity to decarbonise <u>existing Humber industry</u> by 2040, and to continue this annual abatement to 2060** - an annual storage injection rate of 16-27 $MtCO_2$ / year is needed by 2040 to decarbonise existing industry in the cluster alone, which is within our estimates of injection rates achievable with both projects combined (29 $MtCO_2$ / year). This feasibility is true also for near-term roll-out injectivity, with the most ambitious near-term injectivities being within the abilities of planned projects of the region. Considering the highest demand estimate, initial projects would reach full capacity (848 $MtCO_2$) by 2060 if injection were to continue at this rate. If the cluster is to remain reliant on CCS for sustained in year abatement of emissions beyond this period, storage expansion phases will be required.
- **Future expansion of storage projects is needed for the Humber to capitalise on its potential as a storage hub** – if the wider potential for the region as a storage hub is included, considering imports from the wider UK and Europe as well as future GGR deployments (such as DACCS), then the required annual injection rate could rise to 21-42 $MtCO_2$ / year by 2040. Future new industry or power developments in the Humber could further increase this demand. Based on our estimates, expansion to southern North Sea storage projects would allow for up to 50 $MtCO_2$ to be injected annually to meet this demand, with theoretical storage capacity of over 1850 $MtCO_2$ available.
- **The Humber has significant potential to export greenhouse gas removals via storage of biogenic CO_2** – all scenarios analysed included between 8-16 $MtCO_2$ stored from biogenic origin, principally via carbon capture at Drax power units. Considering existing industry, by 2040 the remaining emissions in the Humber are expected to decrease to 0.5-0.7 $MtCO_{2e}$ of Scope 1 emissions alongside 3-4 $MtCO_2$ of upstream emissions from primary energy supply. This potentially means that the Humber as a region could offer between 3-12 $MtCO_2$ of net greenhouse gas removals to support wider UK decarbonisation.

Recommendations:

- Successful offshore CO_2 storage development is an **immediate priority** to allow significant decarbonisation to be achieved by 2030. Storage projects are actively working to meet this demand however their success depends on the government delivering **timely CCUS business model announcements** to provide both CO2 T&S infrastructure and anchor projects with enough certainty to make final investment decisions.
- CO_2 storage projects should **collaborate to ensure near-term injectivity** rates are met for the region and that **risks are minimised** for capture projects – for example, by agreeing on compatible CO_2 specifications to offer future flexibility.
- Storage projects should aim to **secure additional storage capacity** to allow for future storage expansion phases, considering the regions potential as a CO_2 storage hub.
- Government should continue to **recognise the opportunity** available in the Humber to act as both a storage hub for the wider UK and an exported of greenhouse gas removals. To capitalise on this opportunity, government should **back the continued development of offshore storage** via future expansion phases. Government may also need to **act upon regulatory developments** to enable cross-border imports of CO_2 from Europe.

Shared infrastructure development: H_2 supply & demand

Analysis findings:

- **The cost of hydrogen supply is highly dependent upon primary energy costs.** Energy costs dominate the unit price of hydrogen for both CCS-enabled and electrolytic production routes. Based on modelling assumptions, the long-term costs of CCS-enabled hydrogen are often much cheaper than those of electrolytic hydrogen unless very low projections for electricity prices are used. Future energy prices however are significantly uncertain, posing added risk to industries looking to adopt hydrogen.
- **Rapid deployment of hydrogen production is a key component to the Humber's path to net-zero, necessitating a near-term focus on CCS-enabled production routes unless drastic ramp-up in electrolytic production is achieved.** By 2031, most scenarios require between 10-15 TWh of annual hydrogen production to abate cluster emissions – equivalent to 1-2 GW of continuous production with storage. This capacity cannot feasibly be achieved via electrolytic hydrogen production alone, with near-term electrolytic projects having scales in the order of 20-100 MW. This capacity could instead be met by the successful pre-2030 deployment of 2-4 x 600 MW CCS-enabled hydrogen production units. Currently plans for four such units have been announced in the region, showing the Humber's capability to meet this rapid increase in demand if projects are supported.
- **Early projects are likely to dominate the Humber's hydrogen supply chain over the long-term, unless a significant export market is established.** After the initial ramp-up phase (2026-2031), most scenarios show a plateau in demand for hydrogen from the existing cluster as all the major hydrogen fuel switching projects have deployed. Further increases in demand may result from uptake of hydrogen in the wider economy, such as within the transport sector. This demand however is limited in comparison to that from industry, with a potential wider economy demand of between 1.5-7.5 TWh of hydrogen per year by 2040 is considered in the analysis. In order to drive capacity increases beyond the early-2030s, the Humber would need to establish a significant export market.
- **If the Humber were to focus on electrolytic production then this would necessitate significant expansion of renewable electricity generation supplied at low-cost.** The scenarios analysed include assumptions on the level of hydrogen production via electrolytic and CCS-enabled routes, ranging from 50-80% electrolytic by 2040. Under this range of assumptions, an increase in electricity supply to the Humber of 0.6-1.5 GW is needed for hydrogen production by 2040.

Recommendations:

- Measures to reduce hydrogen price volatility would be beneficial for understanding the business case for hydrogen, both compared to the counterfactual and compared to alternative abatement routes.
- Established hydrogen production projects should aim to deploy pre-2030 targeting major industrials within the Humber and enabling their rapid decarbonisation.
- Smaller scale or emerging hydrogen production projects should initially seek to establish demand from the wider economy (e.g. transport) with potential to subsequently set-up export markets for wider or new industries.
- To allow long-term flexibility in hydrogen production routes, renewable electricity generation should be expanded, ideally with costs de-coupled from gas.

Technology development, support and adoption

Analysis findings:

- **Half the in-year Scope 1 emissions of the cluster in 2040 can be abated with CCS** – across scenarios, CCS accounts for 35-56% of Scope 1 emissions abatement and is a key measure for abating emissions on large industrial processes
- **Hydrogen fuel switching may be needed for intermittent or smaller scale processes** – hydrogen technology abates 11-21% of Scope 1 emissions in 2040 and is deployed over a limited number of sites
- **Hydrogen uptake is heavily dependent on fuel-costs and incentives –** The high costs of electricity and natural gas increase the unit cost of hydrogen for an industrial site, making the economics of fuel switching often unfavourable. This unit cost is highly dependent on the assumed primary energy costs and split of production methods, making the future economic case uncertain unless incentives are high.
- **Most electrification occurs at small-scales however, large-scale electrification occurs at British Steel with a process change to EAF –** Electrification is typically only adopted for smaller scale equipment. Significant emissions abatement occurs from deployment of an EAF at British Steel which represents the only site adopting large-scale electrification in all 4 scenarios.
- **Electrification is a potential alternative to hydrogen –** low **r**ound-trip efficiencies of hydrogen production means that in scenarios with high energy costs it may be cheaper to directly electrify a process with new equipment rather than use a lot of energy to produce hydrogen for fuel switching the industrial process. Particularly In scenarios where renewable electricity is abundant and cheap it could be more cost effective for large sites meeting their heat and power requirements with a gas fired CHP to import more grid electricity and produce heat with and electric steam generator.
- **Decarbonisation requires a cumulative additional investment in the Humber of £15-32 billion –** Scenarios where the cluster acts as and industry leader and deploys abatement technologies more rapidly incur greater cumulative additional costs due to greater lifetime fuel usage
- **High levels of incentives are required to drive uptake** – incentives of £200/tCO_2 would drive uptake in many cases; however, decarbonisation of some processes could exceed £300/tCO_2 , particularly if hydrogen fuel switching is required

Recommendations:

- To achieve significant abatement using CCS before 2030, support mechanisms should reward early deployment of technologies so that there is a key incentive for large sites to deploy capture technologies as soon as they can rather than waiting for the technology to become more ubiquitous before adopting. Low cost capital financing for CCS tech with well defined revenue models will help alleviate some of the risk associated with adoption. To reduce cross-chain risks, funding could be prioritised for large-scale “anchor” emitters, such as those shortlisted during the Phase 2 of Track-1 cluster sequencing.
- If hydrogen is to be utilised in applications with high load factors, particularly in CHPs, strong support mechanisms must be put in place to alleviate the additional costs of adoption compared to natural gas. These mechanisms should be detailed as early as possible to improve security of supply and demand in the region and to prevent the lock-in of other technologies before hydrogen is properly scaled up.
- Timely development of infrastructure is critical to the delivery of CCS and hydrogen fuel switching. Delivery of the due diligence process in the Phase-2 Cluster Sequencing process will provide more certainty for Ofgem around approving anticipatory investment. Proactive decision making on a pipeline specification for emitters will provide more certainty about which sites can connect and expediate the project delivery.
- Developing a skilled labour force that can deliver the deployment of technologies spanning CO_2 capture, pipeline networks, compression and hydrogen production technology will be essential to coordinating large scale abatement at speed in the region. A limited work force will cause significant delays and constrain the scope of the project jeopardising the target of reaching net-zero by 2040.

Energy requirements & upstream emissions

Analysis findings:

- **The net-zero pathways analysed had increased energy consumption compared to the business as usual case.** Additional energy demand (3-19 TWh/year) arises from deployment of carbon capture technologies, requiring electrical and thermal input, as well as hydrogen production technologies, where there are inefficiencies in energy conversion. Energy demands are lowest in scenarios where more efficient 2nd generation carbon capture technologies are deployed or where there is a greater focus on electrification routes. In contrast, scenarios where CCS is deployed mostly in the late 2020s do not benefit from the advances in capture technology energy reductions that are expected over the next decade resulting in higher overall energy consumption.
- **A long-term focus on electrification and electrolytic hydrogen routes could require 1-3 GW of additional electricity generation for Humber cluster decarbonisation.** The scenarios analysed include assumptions on the level of hydrogen production via electrolytic and CCS-enabled routes, ranging from 50-80% electrolytic by 2040. Under this range of assumptions, an increase in electricity supply to the Humber of 0.6-1.5 GW is needed for hydrogen production by 2040. This is on top of an additional 0.5-1.2 GW supply required for onsite electrification and powering carbon capture equipment.
- **Net-zero pathways do not decarbonise upstream emissions associated with energy supply.** In 2040 the upstream emissions from Humber industry energy supply range from 3.2-3.8 $MtCO_{2e}$ per year, dominated by supply chain emissions for biomass pellets, upstream methane leakage for natural gas, and incomplete capture for CCS-enabled hydrogen production.

Recommendations:

- Projects deploying carbon capture technologies should **investigate options to reduce thermal input requirements**. For example, projects could co-locate capture technologies near waste heat sources or opt for emerging technologies that may be more energy efficient. Projects should ensure thermal input for carbon capture is derived from low-carbon heat sources or that emissions from heating are captured.
- Over time, electrolytic hydrogen projects should target improved efficiencies to reduce energy demands.
- Further work is needed to **understand the potential to expand electricity generation in the Humber** and distribute this energy to sites. The feasibility of large scale electrolytic hydrogen routes is dependent upon the ability to deploy additional renewable electricity generation at low-cost and secure appropriate electrical connections. This was not investigated in detail within the current study and could form the focus of future work.
- Industrials should aim to **minimise upstream emissions from energy** supply. This could include measures such as securing renewable PPAs for electricity supplies, encouraging suppliers (e.g. hydrogen producers) to minimise emissions, or altering supply chains to use lower emission energy sources. In particular, measures should be taken to ensure upstream emissions associated with biomass pellet production and transport are monitored and kept to a minimum.
- Over time, CCS-enabled hydrogen projects should target continued **improvements in capture rates** to reduce emission intensity of hydrogen supply. These projects should also aim to encourage **reductions in fugitive emissions** within the natural gas supply chain.

Investment, Jobs and GVA impacts

Analysis findings:

- **A total additional investment of between £15.3-33.8 billion is required to reach net-zero by 2040.** £4-5 billion is required in capital investment, the majority of which occurs over the late 2020s and early 2030s
- **Decarbonising the region produces £ 3-5 billion/year in UK National Gross Value Added.** £0.4-1 billion Gross Value Added is retained in the Humber.
- U**p to 70,000 new jobs are created per year nationally, and 20,000 in the Humber, between 2035 and 2040**.
- **Scenarios with a stronger focus on CCS and Hydrogen adoption result in significantly increased GVA and jobs added** created due to the complex supply chains associated with these abatement technologies
- **Some highly specialised roles are created in the region; however, new local jobs are primarily in the consumer services space** – Retail trade roles play an integral part in supply chains and higher employment in other sectors leads to increased consumer spending

Recommendations:

- **Employ well-targeted industrial strategy** within the cluster to establish strong localised supply chains in advance
- **Co-ordinate project timeframes considering demand for skilled workforce** in other projects and developments in the cluster
- **Engage in re-skilling to preserve employees** and prevent a knowledge shortage delaying project development on sites

Further insights on the economic analysis

The central narrative to the economic analysis can be summarised as:

- Additional investment in the Humber Cluster will lead to more economic activity, principally in the manufacturing and construction sectors, to build the new assets outlined in the scenarios, and consumer services, as a result of the creation of retail jobs in industry supply chains and as consumers spend additional wages in the economy.

- Associated operating expenditures will create local economic activity and jobs, in order to keep these facilities operating and maintained.

- This boosts demand across these sectors, leading to both direct impacts and upstream impacts through supply chains; in all cases, gross value added (GVA) and employment is increased, although the specific increases vary with the timing of investment and the specific profile of assets that are being invested in and subsequently operated (reflecting the productivity and labour intensity of the different asset types).

- The economic impacts are felt across the UK, as supply chains stretch across the country. Typically, more specialised occupations and sectors require greater inputs from outside of the local area, while less specialised activities have a greater local share. This even applies within sectors – for example construction activities will include a range of specialised and non-specialised activities, and the latter are more likely to be filled by local workers.

- This analysis focusses on the impacts of additional investment and operating expenditure – it does not consider the potential economic impact if the same money was spent in other ways, either in the Humber of the rest of the UK.

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Comparison of Advanced Amines and 2nd Generation CCS Technologies

Both Advanced Amines and 2nd Generation CCS represent post-combustion capture systems. Advanced Amines represents the incumbent carbon capture technology while 2nd Generation CCS represents a future Calcium Looping technology with the potential to be the lowest-cost future capture technology across the majority of sectors.

The nature of the future 2nd Generation Technology means that a lower thermal input is required for operation than with the Advanced Amines. Since fuel is required to provide the thermal input for CCS, a less heat intensive process will result in fuel cost savings across the lifetime of the technology. The fuel cost savings of the 2nd Generation technology over the Advanced Amines are significant and will result in a more favourable NPV. This results in some sites waiting until the 2nd Generation CCS technology becomes available rather than deploying the less fuel efficient Advanced Amines technology at an earlier date.

Technology	Thermal input (kWh/tCO_2)	Electricity Input (kWh/tCO_2)	Earliest Year of Availability
Advanced Amines CCS	833.3	55.5	2028
2nd Generation CCS	121.9	92.0	2033

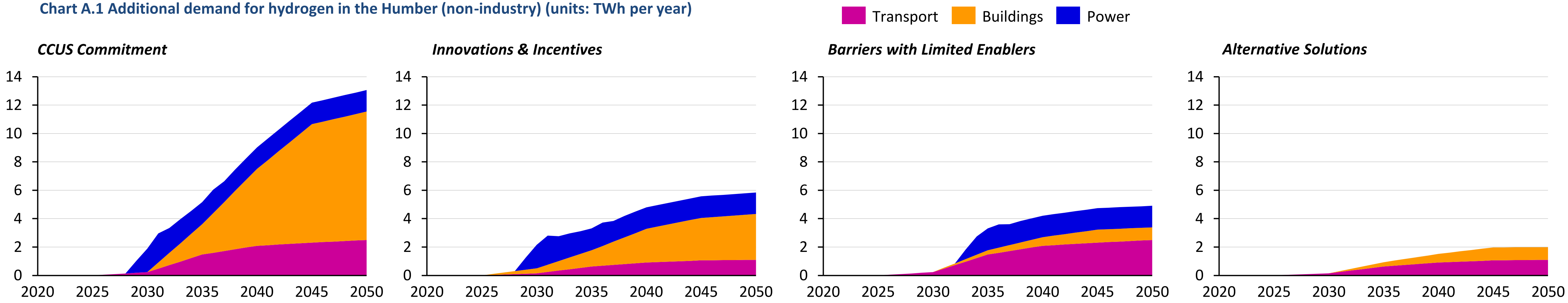
To ensure that not all sites delay adoption of CCS until the 2nd Generation technology is available, some sites in the region that are known to have ambitious plans to deploy CCS early are restricted only having the Advanced Amines technology available to them rather than having the option to pick between the two technologies.

This applies more significantly in the **CCUS Commitment** and **Innovations & Incentives** scenarios; whereas, sites are free to choose in the **Barriers with Limited Enablers** and **Alternative Solutions** scenarios. Scenarios where some sites are restricted to selecting Advanced Amines CCS see greater expenditure on fuel for thermal input over the modelled time period. This establishes that strong policy support would be required to incentivise sites to act as leaders and deploy CCS technologies early to achieve early emissions abatement.

Potential wider economy demands for hydrogen

The below graphs highlight the assumptions made when considering potential wider economy demands for hydrogen.

Chart A.1 Additional demand for hydrogen in the Humber (non-industry) (units: TWh per year)



Assumptions:	***Assumptions:***	***Assumptions:***	***Assumptions:***
• *Heavy-duty transport opts for hydrogen fuel-cells as a preference* • *FES System Transformation scenario for buildings – here hydrogen is a preferred choice.* • *Keadby Hydrogen goes ahead with expected timelines (2029).*	• *Heavy-duty transport opts for electrification solutions as these become available.* • *FES Leading the Way scenario for buildings – fastest credible decarbonisation with mixture of electrification and hydrogen.* • *Keadby Hydrogen goes ahead with expected timelines (2029).*	• *Heavy-duty transport opts for hydrogen fuel-cells as a preference.* • *FES Consumer Transformation scenario for buildings – preference for electrified heating.* • *Keadby Hydrogen goes ahead with delayed timelines (2033).*	• *Heavy-duty transport opts for electrification solutions as these become available.* • *FES Consumer Transformation scenario for buildings – preference for electrified heating.* • *Keadby Hydrogen does not go ahead.*

Sources:

- Hydrogen demand in the transport sector is derived from Element Energy analysis for Cadent on the adoption of hydrogen in heavy duty vehicles[1].
- Hydrogen demand in the built environment is derived from Element Energy analysis of National Grid Future Energy Scenarios.
- Hydrogen demand for power considers deployment (or not) of a new hydrogen powered dispatchable power plant (such as the proposed Keadby Hydrogen Power Plant). A plant with a peak hydrogen demand of 1.8 GW hydrogen is considered. A load factor of 11.5% is assumed in this analysis to reflect potential peaking operations in a net zero energy system.[2]

1 Element Energy analysis for Cadent The Future Role of Gas in Transport (2021)

2 The future load factors of such plants is uncertain and project developers may use different assumptions.

Element Energy is a leading low carbon energy consultancy working in a range of sectors including industrial decarbonisation, carbon capture utilisation and storage (CCUS), hydrogen, low carbon transport, low carbon heat, renewable power generation, energy networks, and energy storage. Element Energy works with a broad range of private and public sector clients to address challenges across the low carbon energy sector.

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