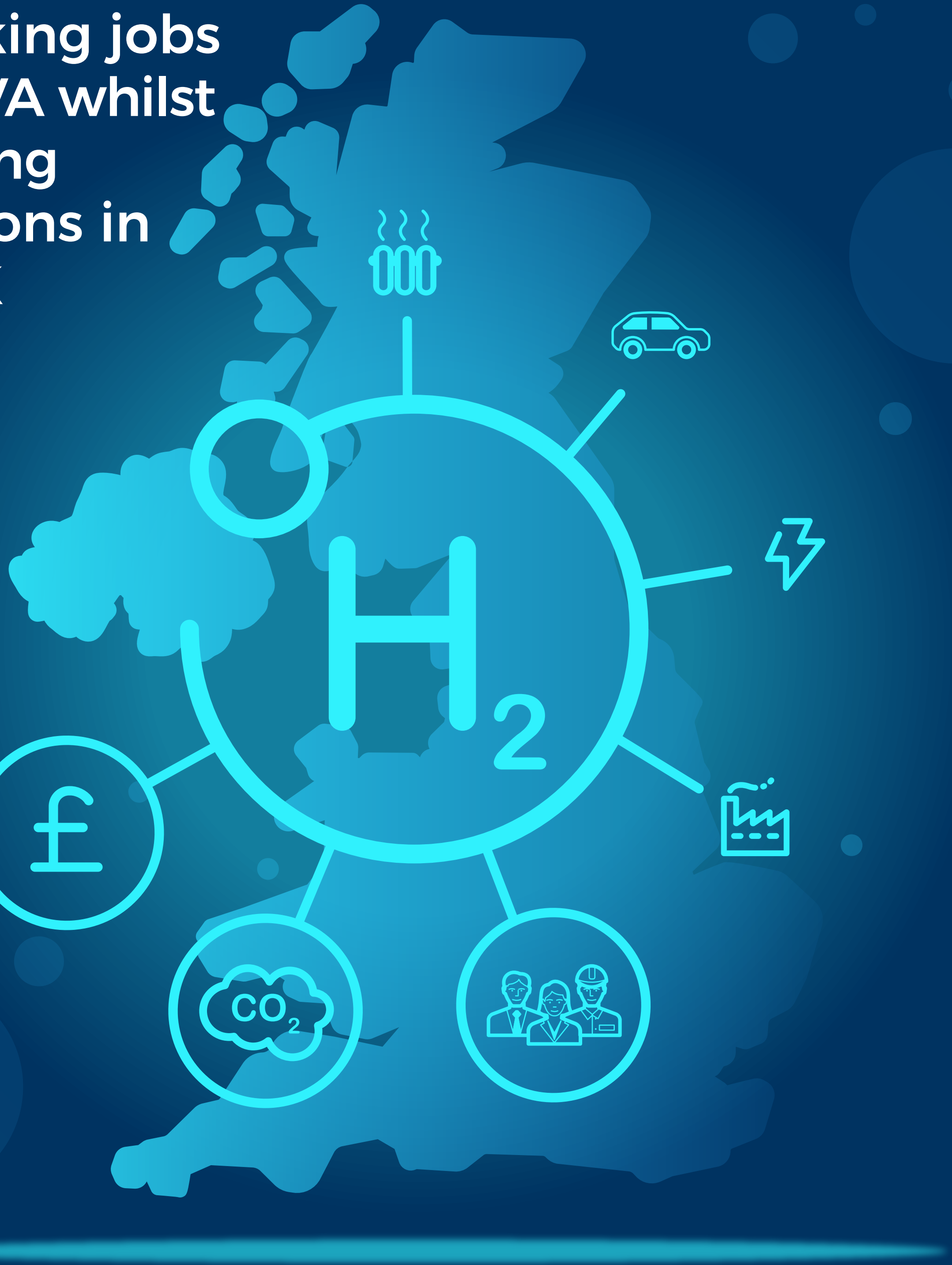
Hy-Impact Series
Study 1: Hydrogen for economic growth

Unlocking jobs and GVA whilst reducing emissions in the UK



Authors

element energy

A report for

equinor

Authors

This report has been prepared by Element Energy.

Element Energy is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. Element Energy provides consultancy services across a wide range of sectors, including carbon capture and storage and industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon vehicles. Our team of over 50 specialists provides consultancy on both technical and strategic issues, believing that the technical and engineering understanding of real world challenges supports the strategy development.

For comments or queries please contact:

Silvian Baltac silvian.baltac@element-energy.co.uk t: +44 (0)203 813 3909

Emrah Durusut emrah.durusut@element-energy.co.uk t: +44 (0)330 119 0982

This report was prepared by Element Energy in collaboration with Equinor. We would like to thank Equinor for the input and data provided, with particular support from:

Henrik Solgaard Andersen, Business Development Manager - Low Carbon Solutions
Dan Sadler, Project Manager – Low Carbon Solutions
Theofilos Sotiropoulos Michalakakos, Business Development Analyst – Low Carbon Solutions

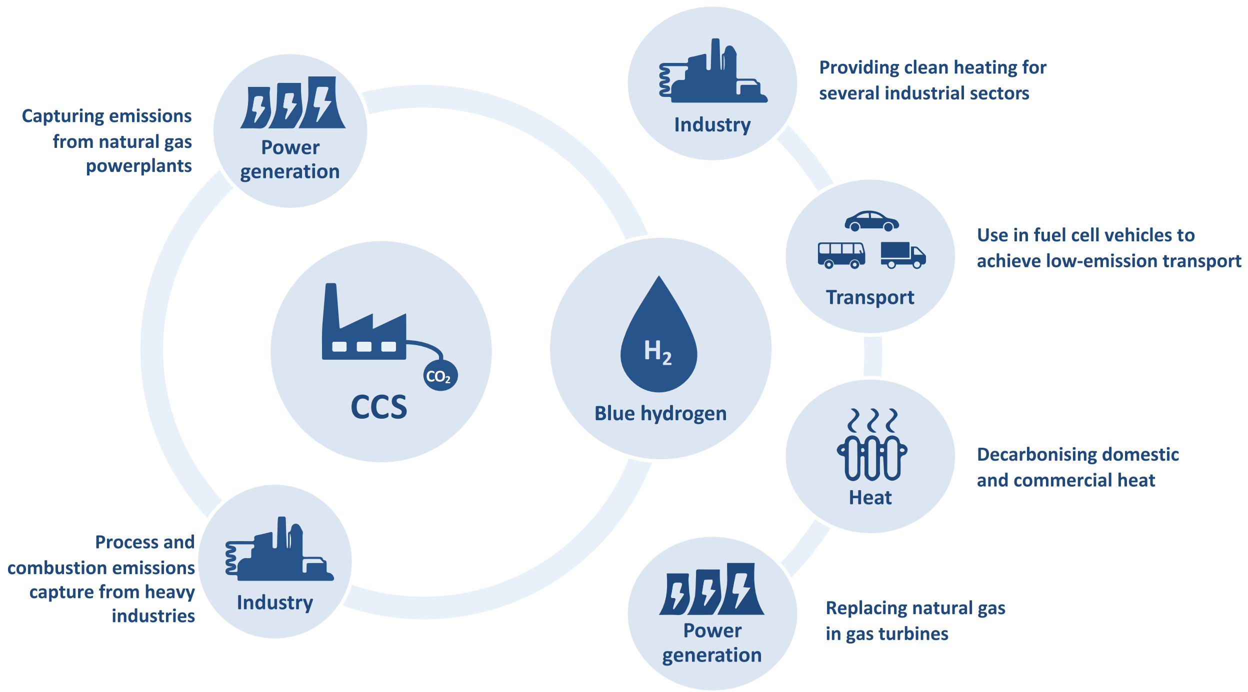
Disclaimer

Final report date: **November 2019**

Executive Summary

Introduction

The UK Prime Minister announced in early June 2019 that the UK will pass legislation to achieve net zero emissions by 2050. This places the UK as the first major economy to make such a commitment and follows the recommendations of the Committee on Climate Change's (CCC) recently published "Net Zero" report, which showed that eliminating emissions by 2050 is technologically feasible. These levels of ambition mean deep decarbonisation, a challenging task for all sectors of the UK economy and will involve large-scale deployment of innovative technologies. Whilst a variety of technologies and approaches are available for decarbonising different sectors of the economy, the CCC recommended prioritising investments into two complementary technologies, Hydrogen and Carbon Capture and Storage (CCS), due to their pivotal roles in enabling long-term decarbonisation. Several public and private stakeholders, including the UK Department for Business, Energy and Industrial Strategy (BEIS) and Equinor, had already expressed interest in deploying these technologies. Ensuring wide-scale hydrogen and CCS deployment will require a strong policy push and a large capital investment. It is thus paramount to understand the financial implications of this deployment, and the opportunities and benefits it provides for industry and the UK as a whole, beyond wide-scale decarbonisation. This study examines the the role hydrogen and CCS could play in the UK economy up to 2050 and beyond.



Hydrogen and CCS are not novel technologies. Hydrogen has been used for a long time as an industrial feedstock and represents the precursor of many industrial products, such as petrochemicals or ammonia. Hydrogen is the simplest and lightest molecule, with a much higher energy content per unit mass than any other fuel. It produces only water upon combustion and represents an attractive energy carrier in several sectors, for example replacing natural gas for heating and power generation and fossil fuels in transport. Although small-scale hydrogen generation has served the growing demand from hydrogen fuel cell vehicles for several years, a wide-scale roll-out will be required to decarbonise the UK economy. To ensure decarbonisation, hydrogen must be produced in a clean way. Whilst hydrogen can be produced following various routes, blue hydrogen represents a viable generation pathway with large-scale potential. Blue hydrogen is obtained from natural gas (potentially mixed with renewable biomethane) by reforming technologies, for example, autothermal reforming (ATR) or steam methane reforming (SMR). This process generates hydrogen and carbon dioxide (CO_2). The CO_2 emissions can then be captured, transported, and stored underground with CCS, greatly reducing the carbon footprint of the hydrogen. Natural gas feedstock mixed with biomethane, combined with the use of CCS, could achieve net-zero emissions or even negative-emissions hydrogen.[1] This resulting hydrogen can be used as an energy carrier similar to natural gas, and is capable of decarbonising multiple sectors, including industry, heating, power generation, and transport. In addition, CCS can play a complementary role in decarbonising other sectors: such as capturing emissions from natural gas powerplants and industries with large process emissions.

There is still uncertainty regarding the scale and timeframe of the deployment of hydrogen and CCS in the UK. For this purpose, three different scenarios, varying in scale, scope, and complexity are examined in this study.

- Scenario 1, **Decarbonised UK industry**, considers decarbonisation in the industry sector by using CCS to capture process and post-combustion emissions from five heavy-industries (cement, ammonia, ethylene, refineries, and iron and steel plants). Additionally, a fuel switch to blue hydrogen in other industrial sectors, including non-ferrous metallurgy, chemicals, paper and pulp, mineral processing, and vehicle manufacturing, is considered.

- Scenario 2, **Decarbonised UK economy**, involves the decarbonisation of heating (by converting gas networks to hydrogen), power generation (using both hydrogen and CCS), and five transport subsectors, in addition to industry.

- Scenario 3 imagines the **UK as a world-leading decarbonised economy** not only capable of decarbonising its own economy but also able to export low-carbon energy carriers such as hydrogen and electricity generated from hydrogen.

The aim of these scenarios is to serve as ***what if*** scenarios to understand the potential development of blue hydrogen and CCS. Technical and economic analyses of each scenario were completed to determine the degree of investment required and the expected benefits, beyond achieving decarbonisation targets.

1 Net-zero Hydrogen: Hydrogen production with CCS and bioenergy, Element Energy for Equinor, 2019

43,000 jobs could be generated by decarbonising the UK industry alone

The decarbonisation of UK's industry is estimated to require a capital expenditure (CAPEX) of around £40 billion between 2020 and 2050. This capital will be spent by deploying CCS and blue hydrogen across all six main British industrial clusters. Five energy intensive industrial sectors (cement, ammonia, ethylene, refining and iron and steel) will deploy CCS, with remaining sectors switching to hydrogen as an alternative fuel. In all, **over 52 $MtCO_2$/year will be captured by 2050** thanks to the capture of industrial emissions and replacement of industrial fossil fuels by hydrogen.

To ensure swift decarbonisation, work will start in the early 2020s, with the first installations becoming operational in 2025. A slow-uptake phase is expected in the early years up to 2035, followed by a rapid infrastructure roll-out and a consolidation phase onwards to 2050. By 2035 three UK industrial clusters will have operational hydrogen and CCS infrastructure, with deployment extending to six major industrial clusters by 2050.

In terms of emissions, by 2030, ~3 $MtCO_2$/year from process and post-combustion emissions will be captured by industrial CCS, reaching ~23 $MtCO_2$/year in 2050. It is estimated that the hydrogen demand from industry will reach 115 TWh/year by 2050. In addition to the required capital expenditure of £38.2 billion between now and 2050, operational costs are expected to total £3.5 billion in 2050. Operational costs will mainly be derived from costs associated with hydrogen production feedstocks and CO_2 capture.

The investment will generate a total of 43,000 jobs by 2050. 13,700 direct jobs related to the infrastructure deployment, 9,000 jobs in the operation of the newly built facilities, and over 20,000 indirect jobs in the supply chain. The total internal gross output for the UK will be £5.6 billion in 2050, representing 86% of the total investment, while the remainder will be satisfied by imports. The associated gross value added (GVA) to the UK economy is estimated at £4.0 billion.

A 4-fold GVA growth could be expected for an economy-wide UK decarbonisation

Decarbonising the whole UK economy will require transformation across all four main energy-related sectors: power generation, heating, industry, and transport.

A nation-wide deployment of hydrogen production facilities will be required, alongside the related infrastructure for emissions management through CCS, inter-seasonal hydrogen storage and hydrogen transmission and distribution. A new hydrogen-dedicated transmission system needs to be built, whilst the existing gas distribution network will be converted allowing bulk availability and cost savings. End users will switch to hydrogen-capable appliances, whilst investment in power generation will focus on replacing aging oil and gas powerplants with a hydrogen-centric generation fleet (20.5 GW_e installed capacity use in power generation in 2050). The large-scale uptake of hydrogen will likely lead to a proliferation of hydrogen transport, with over 6,000 hydrogen refuelling stations (HRSs) being operational and delivering 120 TWh/year hydrogen by 2050. In terms of overall hydrogen demand, a total of 735 TWh/year hydrogen will be required in 2050, produced by a hydrogen generation network of 89 GW_e installed capacity (assuming a 95% availability).

In addition to CCS use in clean hydrogen production, it will capture process and combustion emissions in some heavy industry and natural gas power plants, reaching 197 $MtCO_2$/year captured by 2050.

The impact of this decarbonised environment will be wide ranging. First of all, an investment of £160 billion will be required between 2020 and 2050, leading to **42,000 people directly employed in infrastructure deployment in 2050**. The large-scale infrastructure will require an annual operational expenditure of £12 billion/year in 2050 and will create **38,200 long-term jobs**. It is estimated that the production of fuel cell components for the fleet of hydrogen vehicles will create an additional 30,400 jobs. Overall, 110,600 direct jobs will be created, with an additional 84,600 indirect jobs in supply-chains. This will create an internal gross output of £22.2 billion/year in 2050, generating a gross value added (GVA) of almost £16 billion – a GVA four times higher than decarbonising the industry sector alone.

Becoming a world-leading decarbonised economy could bring additional benefits

The UK is not the only European country with plans to decarbonise its economy. It is estimated that a hydrogen demand of 490 TWh/year would be required by France and Germany alone in 2050, as later detailed in this report.

- Some of the European demand will be sourced locally, however the UK could supply blue hydrogen via pipeline to Western European countries as early as 2040, potentially supplying a demand of 103 TWh/year hydrogen in 2050. In addition, by utilising planned interconnector capacity, 21 TWh/year of electricity produced using blue hydrogen could be supplied in 2050.

- To achieve these goals the UK will need to install an additional 18 GW of hydrogen generation capacity between 2040 and 2050, requiring an investment of £17 billion compared to the non-export case, and an additional £14 billion between 2050 and 2060. In terms of electricity production, analysis indicates that the generation fleet assumed in this scenario could be used to produce additional electricity for export, simply by increasing load factors.

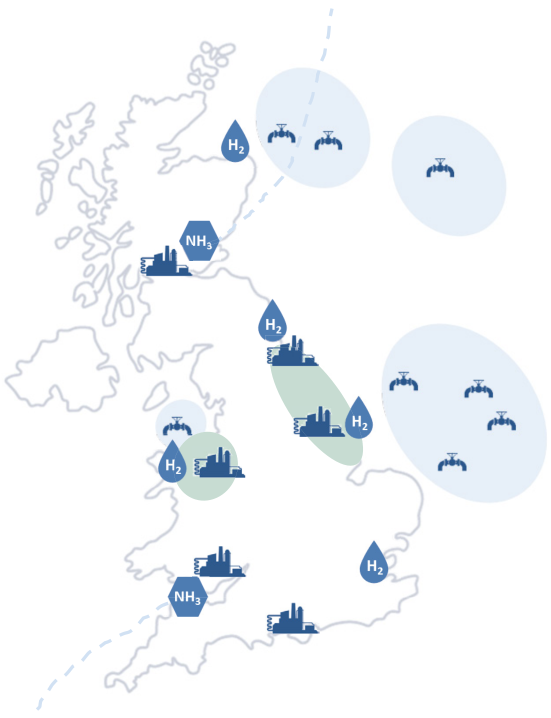
- The operational expenditure in 2050 is estimated to be £1.7 billion/year higher than in the case of decarbonising the UK only, reaching £15.8 billion/year by 2050. **However, this scenario provides 26,000 more jobs than the UK decarbonisation scenario, reaching 221,000 jobs by 2050**. By 2050 the scenario unlocks £17.8 billion/year in GVA and enables capture of an estimated 260 $MtCO_2$/year.

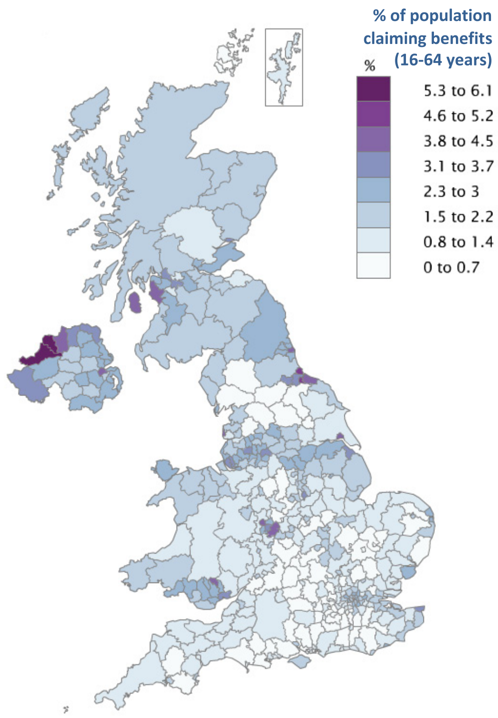
- While most of the UK economy will be decarbonised by 2050, further infrastructure deployment will be required to sustain growing hydrogen demand from the continent beyond 2050. This maintains the need for jobs in activities related to infrastructure deployment, with the whole system requiring £4.7 billion/year additional operational expenditure in 2060 to support exports.

Unlocking jobs and GVA whilst reducing emissions in the UK

2050	Industry decarbonisation	Decarbonised UK Economy	World leading decarbonised economy
Total capital expenditure by 2050	£38 bn	£160 bn	£176 bn
Hydrogen demand (TWh/year)	115	735	1,040
CO_2 captured ($MtCO_2$/year)	48	197	260
GVA (£ billion / year)	4	16	18
Total jobs	43,000	195,000	221,000

50 TWh hydrogen demand
10,000 total jobs





Industry hub | Hydrogen production | Ammonia infrastructure | H_2 storage area | CO_2 storage area

Wider benefits are awaiting

In addition to creating up to 221,000 jobs and £18 billion/year in GVA by 2050, hydrogen and CCS roll-out can create employment opportunities in industrial areas. The deployment of the new infrastructure and facilities is likely to be around major industrial clusters (e.g. the Humber, Grangemouth, Merseyside and South Wales). This would enable jobs in construction and operation of facilities in areas which often have high unemployment. Coupled with the potential future transition to green hydrogen, these jobs can be sustained long-term through further skills development.

The industrial clusters capable of transporting and injecting CO_2 undersea (e.g. Humberside, Teesside, Grangemouth, and Merseyside) will have the opportunity to help develop other CCS clusters across the UK and Europe where CCS infrastructure is not available, contributing towards wider decarbonisation. These clusters, such as South Wales, will require shipping of the CO_2 captured on site to appropriate injection sites, where transport and storage infrastructure is available. Significant domestic and international demand for CO_2 shipment within UK's waters is projected, leading to investments in port infrastructure and injection technologies, with long-term local and national benefits.

In addition, the UK could provide Storage as a Service (SaaS) for CO_2 shipped from Europe and stored within the UK's carbon storage fields. This would increase the turnover of the CO_2 transport and storage industry, generating revenues and aid in the decarbonisation of other countries.

The UK is already a leader in exporting renewable technology. The wide-scale deployment of hydrogen and CCS will lead to increased expertise in these areas, including CCS and gas network infrastructure, and hydrogen end-use appliances. All of this knowledge could be leveraged into long term benefits, from exporting both expertise in the form of consulting and support activities, and technologies like hydrogen boilers. The UK's position as a leader in hydrogen and CCS technologies will also enable exports of a new series of low carbon commodities, such as sustainable hydrogen and ammonia, to a growing international market.

As the UK decarbonised economy matures, growth in green hydrogen generation using large-scale electrolysis and renewable electricity is envisaged. Whilst green hydrogen is already present in the UK energy landscape, its share of hydrogen demand will increase in the long term. The skills and infrastructure built during the initial roll-out of blue hydrogen will continue to be used as the share of green hydrogen increases. These will involve a mix of building new infrastructure, decommissioning, and replacing some blue hydrogen assets, all of which will benefit from lessons learnt in the initial deployment.

Action is needed now

To ensure these benefits of blue hydrogen and CCS are fully exploited, investment in the sector must start immediately. Early investment will ensure successful roll-out, validating the concept and increasing awareness and acceptance of the technology. Pilot projects should aim to address remaining barriers and demonstrate safety, taking the UK closer to reaching its ambitious net-zero goal by the middle of the century.

It is thus paramount that public and private stakeholders work together in providing funding incentives, investment, and a favourable policy environment to enable large-scale deployment of blue hydrogen and CCS and realise their associated economic and environmental benefits.

Contents

Acronyms

ATR	Autothermal Reforming
BAT	Best Available Technology
BEV	Battery Electric Vehicle
BEIS	UK Department for Business, Energy and Industry Strategy
CAPEX	Capital Expenditure
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCS	Carbon Capture, Utilisation, and Storage
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
FCEV	Fuel Cell Electric Vehicle
FOAK	First of A Kind
FEED	Front End Engineering Design
GHG	Greenhouse gas
H_2	Hydrogen
LTS	Local Transmission System
MHPS	Mitsubishi Hitachi Power Systems
Mt	Megatonne
NG	Natural Gas
NOAK	Nth of A Kind
NTS	National Transmission System
O&G	Oil and Gas
ONS	Office for National Statistics
PHEV	Plug-in Hybrid Electric Vehicle
SIC	Standard Industrial Classification
SOAK	Second of A Kind
ULEV	Ultra-Low Emissions Vehicle

Note on terminology

Throughout the report, **blue hydrogen** refers to hydrogen produced from a feedstock of natural gas (with or without any biomethane mixing) by autothermal reforming (ATR) coupled with carbon capture and storage (CCS) of the resulting carbon dioxide emissions. The costs used for the purpose of economic impact assessment are for blue hydrogen generated using a natural gas feedstock containing a 4% fraction of biomethane, corresponding to a net-zero emissions hydrogen.

Introduction

Introduction

1.1 Background

Earlier this year the UK was the first major economy to commit to reaching net-zero emissions by 2050.[2] This follows the recent publication of the “Net Zero” report of the Committee on Climate Change (CCC) urging the implementation of these targets and showing that reaching them is technologically feasible. One of the immediate priorities recommended by the CCC report is the deployment of carbon capture and storage (CCS), due to the time required for its implementation and its central role in enabling future decarbonisation options. The deployment of CCS is not a new addition to policymakers’ agenda. In 2018, the UK Department for Business, Energy and Industry Strategy (BEIS) published an action plan recognising the economic benefits of CCS as a pillar of decarbonising the UK economy while retaining competitiveness of UK industry.[3] At the same time, the BEIS publication pledged to provide a supportive business environment for the nascent CCS industry. Deployed on a large scale, CCS represents a fundamental step towards the removal of industrial and fossil fuel power generation emissions. In addition, CCS serves as a key step in the long term decarbonisation of several other sectors through blue hydrogen. This is generated using reformation of natural gas coupled with CCS to remove the greenhouse gas (GHG) emissions, both technically achievable and cost effective technologies.

It is important to note that blue hydrogen is an essential vector for achieving long-term climate goals as it helps provide low-carbon energy using available resources (natural gas) and technologies (methane reformation and CCS). Deployment of blue hydrogen will require crucial infrastructure (e.g. dedicated hydrogen infrastructure and appliances) and help develop the expertise needed to support future decarbonisation. However, deployment of blue hydrogen does not impede the proliferation of green hydrogen. In fact, both blue and green hydrogen will coexist in a decarbonised economy. A future economy could use the infrastructure deployed for blue hydrogen to enable an increasingly large share of green hydrogen, once renewable power generation and water electrolysis reach the required cost, technology maturity and scale.

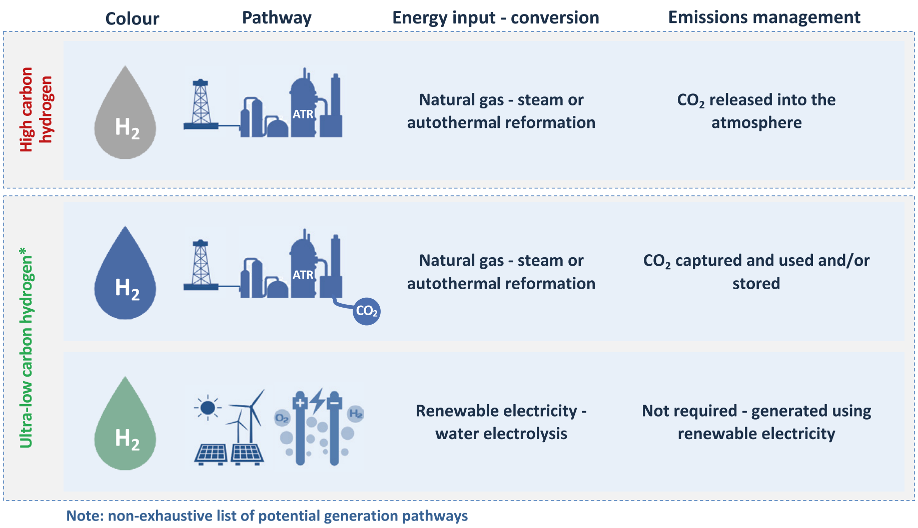


Figure 1: Visualisation of different hydrogen ‘colours’[4]

2 UK Government, PM Theresa May: we will end UK contribution to climate change by 2050, June 2019

3 Clean Growth, The UK Carbon Capture Usage and Storage deployment pathway – An action plan, BEIS, 2018

4 Note: non-exhaustive list of potential generation pathways; * Ultra-low carbon hydrogen is line with the CertifHy accreditation threshold of < 36.4 gCO_2/MJ = 132 gCO_2/kWh, CertifHy-SD Hydrogen Criteria (2019)

Hydrogen, has already received significant interest from both public and private stakeholders, given its applications in decarbonising industry, heat, power, and transport.

Heat across buildings and industry accounts for 32% of total UK emissions[5]. Options for deep decarbonisation of industrial heat include CCS, or fuel switching to electricity, biofuels or hydrogen. Hydrogen has the highest technical potential for fuel switching due to its physical, chemical, and operational similarities to natural gas. The H21 studies, conducted by Northern Gas Networks and Equinor, examined the conversion of City of Leeds and the North of England region to blue hydrogen, concluding that a demand across heating and industry alone of up to 540 TWh/year hydrogen in 2050 could be expected in the case of deep hydrogen-centric decarbonisation.[6,7] The reports also provided a 'H21 Max scenario' where significant additional supply of hydrogen was delivered for hydrogen fuel cell vehicles and replacing natural gas with hydrogen for power generation. This transition would require a large infrastructure deployment including hydrogen generation, interseasonal storage, associated CCS mechanisms, a newly built hydrogen transmission system, a UK-wide conversion of the natural gas distribution grid and appliances for end-use of hydrogen. The UK Government is already aware of the required infrastructure transformation, with a study examining the decarbonising the UK's heat infrastructure being commissioned by the National Infrastructure Commission and led by Element Energy in 2018[8].

In addition, there is already significant ongoing interest in the conversion of domestic and industrial appliances to hydrogen within the UK's public stakeholders. The Hy4Heat programme, a BEIS initiative, aims to establish if it is technically possible, safe, and convenient to replace natural gas with hydrogen in residential, commercial and industrial buildings and gas appliances.[9] A key aspect of the the programme is understanding the feasibility of retrofitting and converting current domestic and industrial natural gas equipment and appliances, leading to cost savings and operational synergies in contrast to conducting complete overhaul and replacement.

The idea of using hydrogen for power generation is not new and it is expected that hydrogen will play a significant role in future large scale electricity generation. Its feasibility is already trailed by a number of energy players. Most notably, in March 2018 Mitsubishi Hitachi Power Systems (MHPS) announced the partnership with the Netherlands Carbon-Free Gas Power project to support the conversion of the Dutch 1.32 GW Magnum gas-fired powerplant to run partly on hydrogen.[10] Assuming successful demonstration, the future may see several gas-power plants converted partially or fully to hydrogen whilst new powerplants running on hydrogen are built to replace aging polluting assets.

5 UK Clean Growth Strategy, BEIS, 2017
6 H21 Leeds City Gate, Northern Gas Networks, 2016
7 H21 North of England, Northern Gas Networks and Equinor, 2018
8 Cost analysis of future heat infrastructure options, Element Energy and E4tech for the National Infrastructure Commission, 2018
9 Hy4Heat website
10 Power Magazine, MHPS Will Convert Dutch CCGT to Run on Hydrogen, January 2018

Through the Road to Zero published last year, the UK government committed to putting the UK at the forefront of the design and manufacturing of zero emission vehicles and set the target of ending the sale of new petrol and diesel cars and vans by 2040.[11] With this strong governmental backing, decarbonisation in the transport sector will become a reality. Two low-emission vehicle powertrains are available, battery electric and hydrogen fuel cell vehicles. The powertrain mix in the future UK vehicle market will depend on the cost and performance of the vehicles, as well as the availability of charging and refueling infrastructure. Fuel cells vehicles already exist, and their proliferation could be encouraged by synergies resulting from the deployment of blue hydrogen in decarbonising the heating and power sectors. Potential demand from five different transport subsectors are investigated in this study.

The UK is already moving forward in the integration of CCS and hydrogen generation in key areas. For example, at the end of May 2019, the Drax Group, Equinor and National Grid Ventures announced a partnership to explore how a large-scale CCS network and a hydrogen production facility could be constructed in the Humber in the mid-2020s.[12] This could be the UK's first zero carbon cluster and will help the UK achieve a leading position in global decarbonisation, potentially supporting other economies to decarbonise.

There is increasing global interest in the use of hydrogen as an important part of decarbonisation strategies. A Hydrogen Council was formed in 2017 by thirteen key international stakeholders, including important European players, such as Air Liquide, BMW, Royal Dutch Shell, and the Linde Group. The aim of the council, which has reached 53 members, is to accelerate investment in the hydrogen and fuel cell sectors and encourage other public and private stakeholders to back hydrogen technologies. It is likely that significant hydrogen demand will emerge on the continent, some of which the UK will be able to capitalise on. In addition, as Europe is moving towards power decarbonisation, the UK could export low-carbon electricity produced from hydrogen through the existing interconnector infrastructure.

The UK could realise additional benefits of hydrogen roll-out, such as the export of related skills and the provision of carbon storage services. These are explored in section 4.2 of this report.

11 The Road to Zero, Department for Transport, July 2018

12 Leading energy companies announce new zero-carbon UK partnership, Drax press release, 27th May 2019

1.2 Objectives and scope of the work

The aim of this study is to estimate the market potential for the different roles that CCS and blue hydrogen could play in the UK ranging from "industrial CCS only" to exporting power and blue hydrogen while decarbonising UK economy. This study employed a step-by-step approach, starting with the development of three hydrogen and CCS deployment scenarios followed by techno-economic and macro-economic assessment. The scenario analysis focussed on a timescale up to 2050, with some outputs for 2060 being provided in the third scenario. In order to achieve a detailed understanding of the potential of CCS and blue hydrogen, three different scenarios, ranging in complexity, scale, and scope were developed:

- **Decarbonised UK Industry** examines the decarbonisation of the UK's industrial sectors
- **Economy-wide UK decarbonisation** looks at how an economy centred around blue hydrogen and CCS could be developed by addressing decarbonisation needs from industry and three additional sectors (heating, power generation, and transport)
- **UK's position as a world-leading decarbonised economy** imagines the UK as world-leader in decarbonisation, with considerable expertise and capacity to export low-carbon energy carriers to European markets.

Figure 2: Overview flowchart of the project approach

All scenarios were developed based on both literature findings and ongoing research conducted by Element Energy for public and private stakeholders, examining the feasibility of CCS and blue hydrogen in different sectors of the economy.

The techno-economic aspects of each scenario were assessed to determine the roll-out schedule, the required capital expenditure and the long-term operational expenses. These associated costs were then assessed at a macroeconomic level to understand the gross value added (GVA), the number of jobs created, and the international trade needed to achieve decarbonisation. The major benefits of the three scenarios were compared, with other additional benefits being explored and detailed at a high level, such as potential for providing CO_2 shipping and Storage as a Service (SaaS) and the potential of exporting skills and low-carbon technologies to other markets.

1.3 Approach and structure of the report

The remainder of this report is structured into 5 chapters as follows:

Chapter 2 describes three decarbonisation scenarios, different in scale, complexity, and scope:

- Section 2.1 shows how the UK can achieve a low carbon industrial sector, in terms of the roll-out of the key technologies that can be deployed, and the investment required.
- Section 2.2 examines in detail a wide decarbonisation of the UK economy, not only focussing on industry, but also considering the role and impact of blue hydrogen and CCS in the heating, power, and transport sectors.
- Section 2.3 considers a consolidated low-carbon UK economy capable of exporting blue hydrogen and power to Europe, evaluating potential demand, supply bottlenecks, and the required additional investment in generation capacity.

Chapter 3 presents the investment required for achieving these deployment scenarios and the macroeconomic benefits of successful deployment, in terms of GVA growth, jobs created, and trade.

Chapter 4 serves as a value proposition of supporting CCS and blue hydrogen deployment, summarising the findings of this study and highlighting other additional benefits (such as exports of skills) of large-scale decarbonisation.

This report is also accompanied by an appendix detailing the macroeconomic modelling approach and assumptions.

Decarbonisation scenarios

2 Decarbonisation scenarios

2.1 Scenario 1: Decarbonised UK industry

2.1.1 Context

This scenario examines the decarbonisation of the UK industry by deploying two different technologies: switching to blue hydrogen as an industrial fuel and implementing CCS of post-combustion and process emissions. To achieve these goals, natural gas will still play an important role for industrial activities, as a feedstock for hydrogen production via ATR and as an industrial fuel in specific sectors. Emissions related to natural gas usage, both at the hydrogen production level and on some industrial sites, will be captured and transported for permanent sequestration and storage in appropriate geological formations under the North and East Irish Sea. It is assumed that each of the UK's main six industrial clusters will be decarbonised in this way. The deployment of CCS and blue hydrogen is examined for five industrial sectors in this scenario.

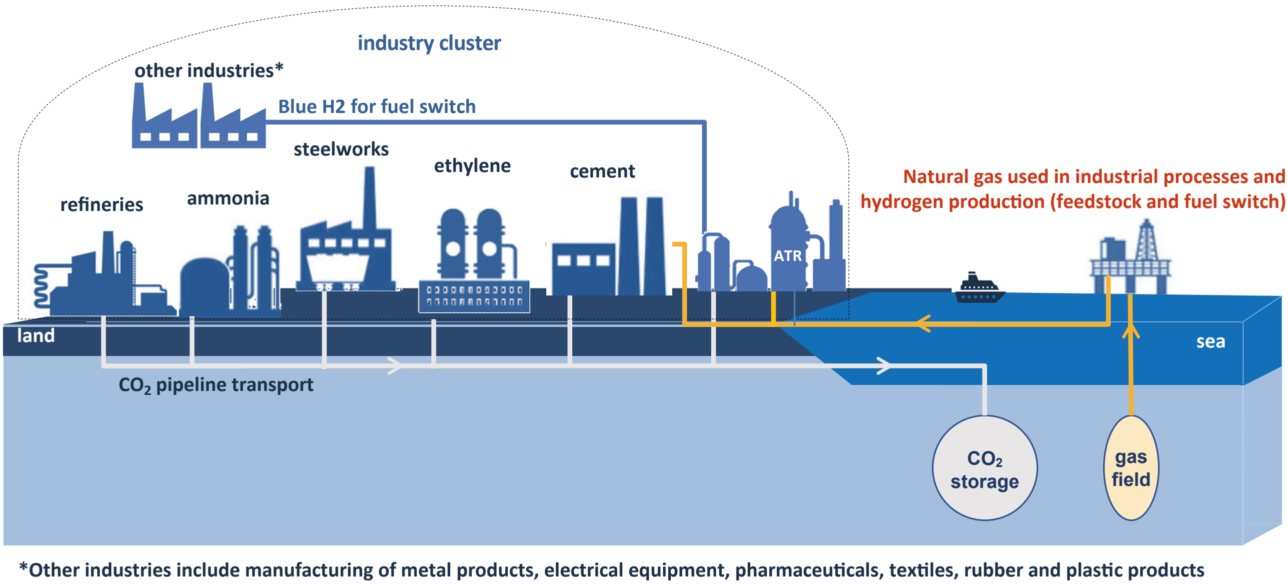


Figure 3: Overview of the industrial cluster decarbonisation

2.1.2 Areas of decarbonisation and technology availability

This scenario examines the potential of decarbonsing through CCS and fuel switching to blue hydrogen. The general consensus, in line with the latest report published by the CCC, is that the largest five of the main heavy-industry sectors, which account more than 30% of the total UK industrial CO_2 emissions, will deploy CCS, whilst several other industrial sectors will switch to hydrogen.

The industries deploying CCS are:

- **Ammonia** manufacture produces large amounts of CO_2 as a by-product, which can be captured through CCS at relatively low cost, due to the high CO_2 concentration.

- **Cement** manufacturing is a major contributor to global CO_2 emissions. The manufacture of cement involves the production of large volumes of CO_2 from fuel combustion and calcination of limestone in kilns. Pre-combustion capture is generally considered to be the least suitable capture technology for cement production, as process CO_2 emissions produced from calcination of limestone typically account for around 60-70% of total plant emissions and would not be available for capture. Furthermore, properties of hydrogen would entail significant modification to the clinker production process. As the role of post-combustion technology has received more attention and is considered potentially suitable for both new-build plants and retrofits, this scenario assumes this technology is used in decarbonising the cement industry.

- **Refineries** – large oil refining complexes offer a number of CO_2 sources potentially suitable for post-combustion capture. Refineries are typically situated in coastal locations offering potentially close proximity to offshore storage sites and are also often located within large industrial complexes where CCS clusters are more likely to develop over time.

- **Steelworks** – these produce 8 million tonnes of steel annually, employ 32,000 people and have an economic output of £1.6 billion (0.1% of the UK economy).[13] The largest iron and steel producers emitted an estimated of 12.8 $MtCO_2$ /year in 2016, accounted under the EU-ETS scheme. A large number of decarbonisation approaches and capture configurations are feasible in the iron and steel sector, including electric heating and post-combustion emissions capture (e.g. from blast furnaces). In this scenario it is assumed that iron and steel sectors are decarbonised using CCS.

- **Ethylene** is manufactured by the cracking of hydrocarbons, a process involving high-temperature heat usually generated by burning fossil fuels. Due to the difficulty of separating carbon emissions from other gases in the exhaust, CCS is deployed only following the availability of the best available technologies (BAT), after 2030.

In addition, industries such as non-ferrous metallurgy, chemicals, paper and pulp, mineral processing, vehicle manufacturing, and others will switch to blue hydrogen. The roll-out of both industrial carbon, utilisation, and storage, and blue hydrogen is detailed in the next section.

13 UK Steel industry: statistics and policy, briefing paper 2018

2.1.3 Infrastructure roll-out and investment required

Carbon capture and storage

To enable deployment of CCS in industrial settings in the early to mid-2020s, readily available capture technologies will have to be deployed. In this scenario, it is assumed that mature technologies (namely the first generation of amines) are initially deployed. By 2030, it is expected that more efficient capture technologies (called ***best available technologies*** or ***BATs onwards***) reach market readiness and are deployed (e.g. second generation amines and calcium looping). In both cases, it is assumed that both technologies will have a lifetime of 15 years, with the capture facilities built in the mid-2020s replaced by the best available technologies in the early 2040s. The main difference between the two generations of capture technologies arise from the costs associated with CO_2 capture, as BATs are expected to reach lower capital and operational costs by 2030, compared to ***Mature technologies***.

We envisage CCS deployment to take place in two phases: **A slow uptake** (2020-2035), where CCS is deployed at three industrial clusters, one-by-one, and a **ramp-up and consolidation phase** (from 2035 onwards) with existing infrastructure being consolidated and new CCS clusters opening, once technology matures and becomes widely accepted across the industrial sector. This uptake schedule is in line with the recommendations of two key recent publications:

- The 2018 Committee on Climate Change's Progress Report to Parliament stating that ***CCS could be feasible in a range of industrial sectors during the 2020s, reducing emissions by approximately 3 MtCO2/year by 2030.***[14]
- The emissions abated by 2050 also align with the analysis included in the UK Clean Growth Strategy published in 2017, highlighting that Industrial ***CCS is the largest contributor to decarbonisation, with a total emission reduction potential of 23 MtCO2/year in 2050.***[15]

The deployment of industrial decarbonisation, in terms of the captured emissions and industrial clusters opened, and the required CAPEX are shown in Figure 4 below:

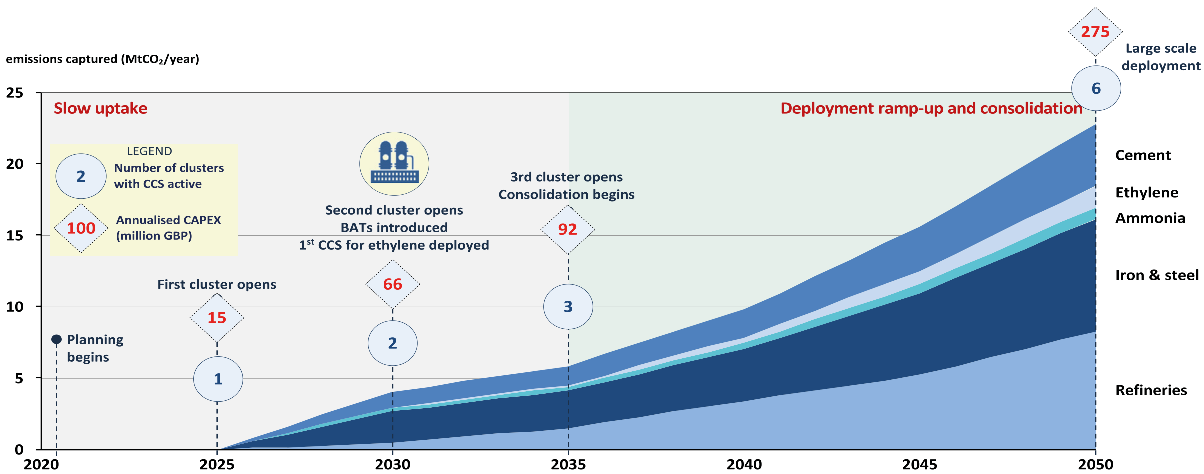


Figure 4: Roll-out schedule of industrial decarbonisation

14 CCC 2018 Progress Report to Parliament

15 2050 Roadmaps Cross-Sector Summary report (2015) used in the UK Clean Growth Strategy (2017)

Early uptake: Early uptake of industrial CCS and fuel switching to blue hydrogen will begin in the early 2020s, with the first capture facilities becoming operational in 2025. It is expected that deployment will focus on one industrial cluster and will take several years to cover several sites within the cluster. The first deployment will be based on the mature capture technologies available at the time. By 2030, a second cluster will start to be decarbonised and post-2030, capture technologies based on BATs will have reached market readiness. A third cluster opens in 2035, marking the end of the slow uptake phase.

Deployment ramp-up and consolidation: The learnings of the first phase contribute to a rapid roll-out and consolidation post-2035, with the first three sites consolidating their assets whilst three other sites opening by 2050. At the beginning of the 2040s, the first deployed assets, based on Mature technologies, reach their end life, being retired and replaced by BATs. It is expected that by 2050, CCS and blue hydrogen deployment will have reached all six main industrial clusters (Figure 7).

Blue Hydrogen

This study builds on previous work conducted by Element Energy for the Committee on Climate Change[16], which focussed on the industrial applications in which decarbonisation is likely to be infeasible without hydrogen. This scenario is aligned with the scope of the deployment of CCS in industry scenario mentioned above and assumes that hydrogen is not deployed where there are overlaps with other potential cost-effective abatement options (e.g. CCS). Industries considered for fuel switching to blue hydrogen include non-ferrous metallurgy, chemicals, paper and pulp, mineral processing, vehicle manufacturing, and others: accounting for a total of 115 TWh/year of hydrogen demand in 2050 (Figure 5).

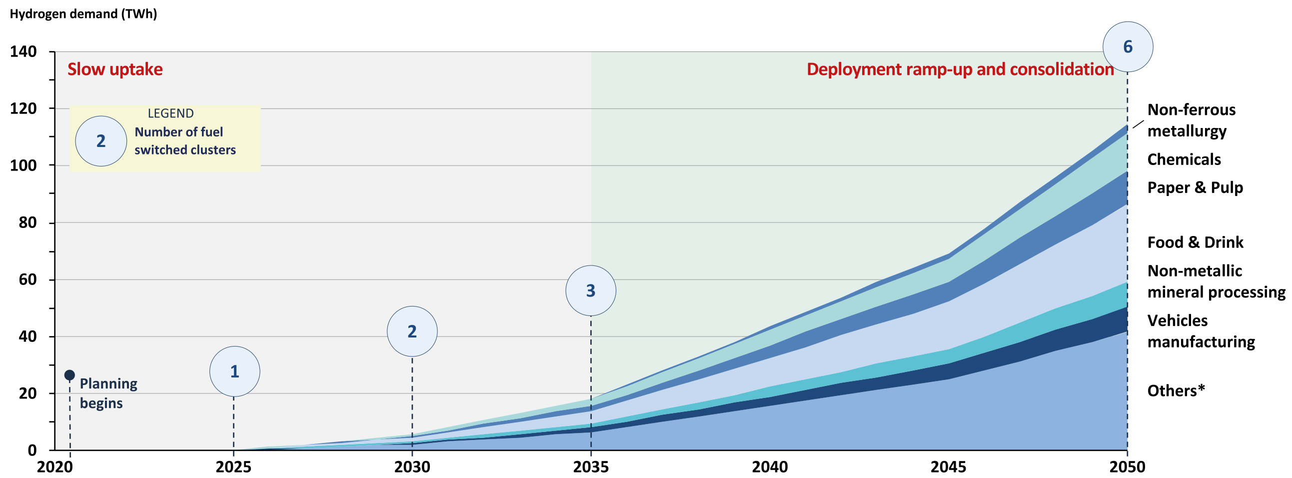
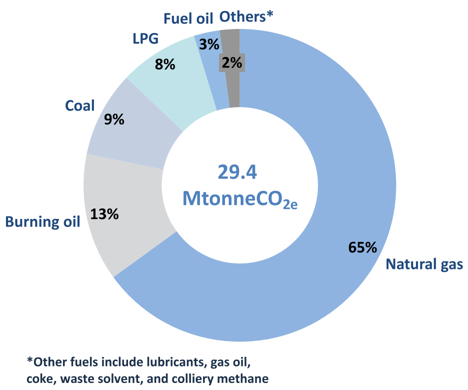


Figure 5: Industrial blue hydrogen demand across industrial sectors[17]

16 Based on Element Energy work for the Committee on Climate Change in regard to the "Net Zero: The UK's contribution to stopping global warming" study (2019)

17 Conversion of other industries may pose challenges if industrial facilities are outside of the industrial clusters. Full-scale conversion could be achieved more feasibility by the conversion of the gas grid to hydrogen, as explored in later scenarios.

The deployment of blue hydrogen in industry will follow the same schedule as the deployment of CCS and will occur on a hub-by-hub basis, exhibiting a slow uptake followed by a rapid ramp-up and consolidation as previously detailed. This would require a wide-scale conversion of industrial appliances, at an estimated cost of £19.7 billion between now and 2050 and will avoid around 29.4 $MtCO_2$/year emissions at 2016 levels (Figure 6).



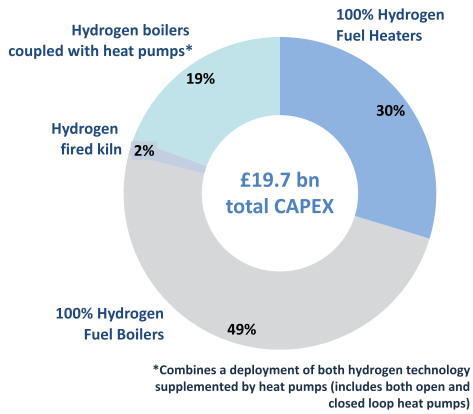


Figure 6: Industrial GHG emissions by fuel type in 2016 (left) and CAPEX required by 2050 for UK industrial equipment conversion to hydrogen (right)[16]

Geographic deployment

Given the aggregation of several industrial sites in large industrial areas (clusters), this study assumes that the deployment of industrial decarbonisation will take place cluster by cluster. The location of these clusters and their proximity to both carbon capture sites and feedstock for hydrogen production (in the form of natural gas or biomass) will play a crucial role in the timeframe of the deployment.

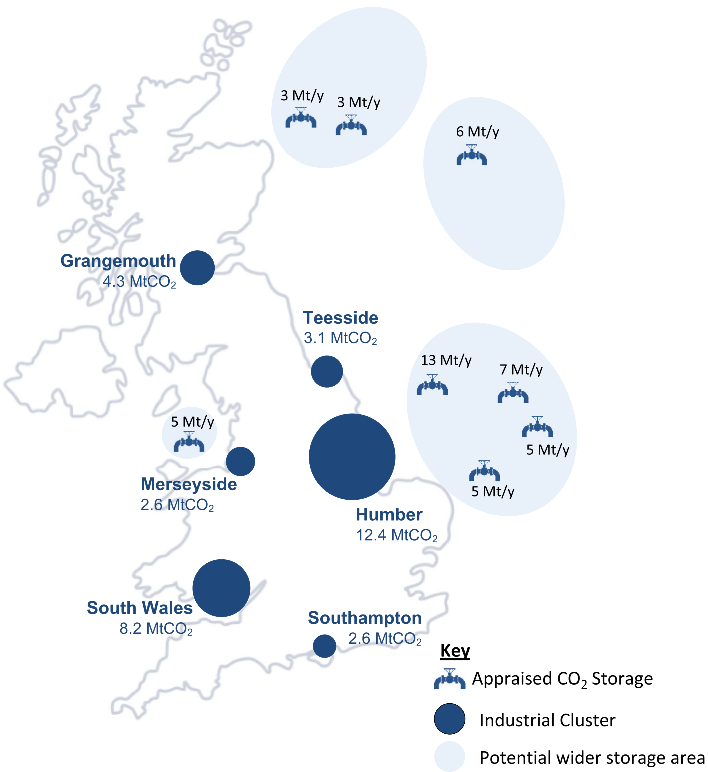


Figure 7: Map of the largest industrial clusters by emissions (based on high-emissions sites in scope of the EU ETS – may not be exhaustive)and appraised CO_2 storage fields – annual injection rate shown underneath blue taps.[18] Contours around storage fields show a wider potential storage area, with other existing smaller fields.

18 Industrial Strategy, Grand Challenge, "What is the Industrial Cluster Mission?" Infographic, 2019

As shown in Figure 7, there are 6 main industrial clusters in the UK. Access to CO_2 storage facilities will be crucial for the deployment of the first industrial CCS cluster. It is impossible to predict which clusters will deploy CCS infrastructure first. However, it is likely that the four clusters with more easily accessible storage sites in the North Sea (Grangemouth, Teesside, Humberside) and the Irish Sea (Merseyside) will deploy CCS by 2040. Due to storage limitations, the South Wales and Southampton clusters may rely on CO_2 transport to other clusters by ship, so CCS operations may begin later.

By 2050, it is expected that the infrastructure at the four early-deployment sites will be consolidated, whilst Southampton and South Wales clusters will have already deployed, to some extent, CCS (Figure 8).

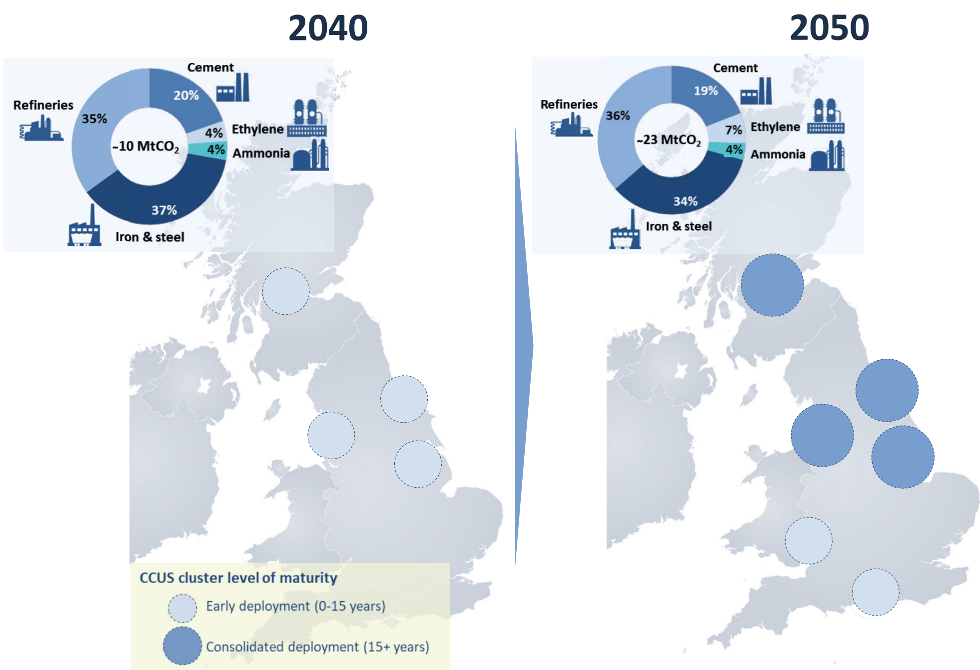


Figure 8: Overview of industrial CCS deployment in two key years and the captured emissions across the largest six industrial clusters

Hydrogen production infrastructure is likely to be located in close proximity to the industrial clusters. This will allow shared use of CO_2 transport and storage infrastructure as well as shorter delivery distances of hydrogen to industrial sites. In the longer term, industrial clusters could be connected by hydrogen pipelines, developing the foundation for a UK-wide hydrogen transmission system.

The investment required, both in terms of capital expenditure and operations costs, to achieve decarbonisation in the industrial sector is presented in section 3.1, along with the benefits to the UK economy.

2.2 Scenario 2: Economy-wide UK decarbonisation

2.2.1 Context

Blue hydrogen, defined as hydrogen generated from natural gas with the CO_2 emissions from production captured, represents great potential for decarbonising multiple sectors, such as heating, industry, power generation, and transport (including passenger vehicles and vans, buses, trucks, and trains). In addition to capturing emissions associated with hydrogen generation, CCS can also be used to further decarbonise other sectors, particularly power generation and industry.

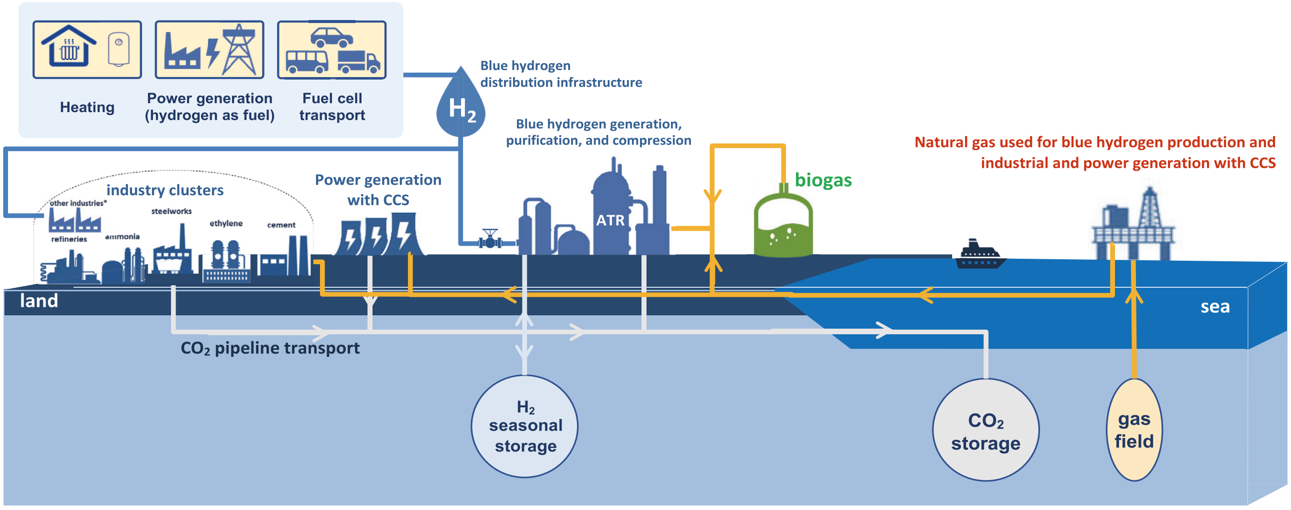


Figure 9: Overview of the economy-wide UK decarbonisation

This section describes how the roll-out of both technologies could help reach environmental targets by 2050, what scale of infrastructure roll-out and domestic hydrogen and power demand is expected.

2.2.2 Decarbonisation trends

A wide-scale decarbonisation of the UK economy will require decarbonisation of all sectors. This section addresses the four sectors (heating, industry, power generation, and transport) that could be decarbonised by the use of blue hydrogen and CCS.

Heating

In order to fight climate change and reach carbon targets, the heating sector must undergo extensive decarbonisation. Whilst there are several possible approaches and technologies available to decarbonise heat, this scenario envisages a transition from a grid carrying natural gas to one carrying hydrogen, with several parts of the current natural gas network, particularly the distribution network, reused and repurposed to hydrogen, reducing the overall deployment costs and times.[19] In addition, heating appliances, such as boilers, will require upgrades. In many cases such upgrades may only involve refitting the gas burner unit,

19 This could include one or a combination of the following options: demand reduction, switch to low-carbon gas (including hydrogen), electrification, heat networks (e.g. district heating), and small-scale onsite renewables (e.g. biomass boilers or solar thermal panels).

whilst retaining the rest of the appliance. Hydrogen boilers are already part of research and development programmes of several appliance manufacturers. It could be possible for hydrogen-ready boilers, capable of running on natural gas and hydrogen, to be available on the market early and pre-installed in some of the dwellings, thus reducing the overall cost of the transition.

Industry

A similar approach to industry decarbonisation in the previous scenario is also considered here, considering five key industrial sectors that would deploy CCS: ammonia production, cement manufacturing, steelworks, ethylene and refineries. In addition, several industries will switch to blue hydrogen as previously described in the Decarbonised UK industry scenario. The only difference will arise from the supply of blue hydrogen to industry, which will utilise the wider national hydrogen transmission system, unlike a more localised approach as in the case of the previous scenario.

Power

This scenario considers a wide decarbonisation of the UK economy, including the power sector. To achieve this decarbonisation, the deployment of renewables will increase, however two key technologies that will replace aging and polluting generation assets and provide grid flexibility will also be required: power generation using blue hydrogen and power generation with post-combustion CCS.

With an installed capacity of renewables of 43 GW_e in 2018, investment in renewables is expected to continue, leading to an installed capacity of 72 GW_e, accounting for 211 TWh/year (~58%) of the 320 TWh/year of electricity generated in 2035, according to BEIS.[20,21] In addition to renewable sources, it is estimated that by 2035 the UK may have ~6 GW_e of hydrogen CCGT generation, and ~7 GW_e of natural gas CCGT coupled with post-combustion CCS.[22] An additional 4 GW_e of installed capacity could be based on hydrogen blending.

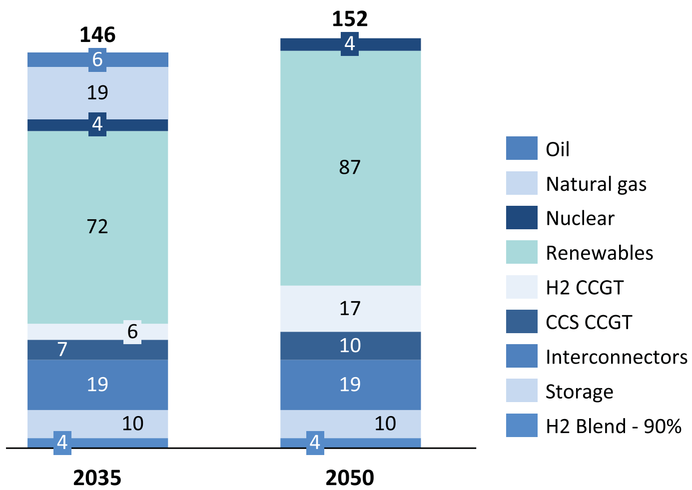


Figure 10: Installed power generation capacity (GW) in a hydrogen and CCS-centric decarbonised UK economy[24]

There is great uncertainty around the power demand and installed capacity between 2035 and 2050. In the recent Net Zero Report, the Committee on Climate Change (CCC) estimates a doubling of power demand in 2050 (594 TWh/year) from about 300 TWh/year in 2017.[23] This scenario is based on increasing demand due to electrification of buildings (e.g. heat generation using heat pumps). In the case of a hydrogen-centric scenario, where heating is decarbonised by blue hydrogen, we estimate a power demand of 450 TWh/year in 2050. Assuming a similar share of the power generated in 2050 coming from renewables as in 2035, an estimated 15 GW_e of renewables will be deployed after 2035.

20 In terms of actual generation, the 2018 renewable mix was 51% wind (both onshore and offshore), 5% hydro, 12% solar PV, and 32% bioenergy – BEIS UK Energy Statistics, 2018 & Q4 2018, March 2019

21 Based on BEIS Emissions and Energy Predictions – 2018, (published April 2019); assuming a load factor of 34% for renewable generation and estimating that renewable generation covers 58% of the total electricity demand

22 Hydrogen for Power Generation: Opportunities for hydrogen and CCS in the UK power mix, Element Energy for Equinor, 2019

23 Net Zero – Technical report, Committee on Climate Change, May 2019

In the H21 NoE Study, the H21 XL scenario addressed the scaling-up of hydrogen generation capacity to satisfy demand from power generation, estimating that ~100 TWh/year electricity will be generated from blue hydrogen in 2050.[7] To reach this target, 9 GW_e of H2 CCGT powerplant capacity will have to be deployed between 2035 and 2050. Further electricity demand will be met by a combination of nuclear and natural gas power plants. Given the long lifetime of nuclear power stations, 4 GW_e nuclear capacity will be operational in 2050, with the rest of the demand covered by natural gas CCGTs with CCS. Figure 10 shows the installed generation fleet in the two key years. It must be noted that whilst the total installed capacity is shown as growing between 2035 and 2050, it is likely that the utilisation and load factor of interconnectors will decrease, especially as the UK will use some of this capacity for electricity exports.

Transport

UK transport is on a road towards decarbonisation, with the UK's government Road to Zero Strategy released in 2018 aiming to achieve at least 50% of new car sales as ultra-low emission vehicles (ULEVs) by 2030. This broad category includes various vehicle powertrains, such as plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs).

An ambitious uptake of hydrogen transport is expected in a decarbonised economy based on blue hydrogen and CCS. The hydrogen demand from cars, vans, trucks and buses is modelled in line with the work conducted by Element Energy in the Transport Energy Infrastructure Roadmap to 2050 for the Low Carbon Vehicle Partnership (LowCVP). [25] The following considerations must be taken into account:

- The uptake of fuel cell **passenger cars and vans** is highly dependent on the users' needs, total cost of vehicle ownership, and refuelling infrastructure availability. The direct competitors to these FCEVs are battery electric cars and vans and plug-in hybrids (for cars), which are generally cheaper (as of 2019) but have shorter ranges, due to constraints in terms of battery size.[26] A significant drop in the cost of fuel cell technology is expected in the 2020s, with BEVs and FCEVs becoming cost competitive. With manufacturing of PHEVs potentially halting in the mid-2030s, our scenario assumes that fuel cell and battery electric vehicles will share equal parts of the new cars and vans sales in 2050. At this rate, over 19 million fuel cell cars and vans will be on the roads in 2050, accounting for a combined hydrogen demand of approximately 73 TWh/year.

- **Buses** require the ability to drive long distances, usually during the day, allowing refuelling at night. Due to the high range requirements, long recharging times and the extensive and costly grid and depot upgrades, hydrogen fuel cell buses have a competitive advantage over battery electric buses, accounting for half of new bus sales in 2050. However, due to the high costs of fuel cell and electric buses, it is expected that ~10% of 2050 sales will be based on dedicated compressed natural gas (CNG) internal combustion engines, which provide similar ranges to hydrogen buses. It is estimated at around 46,000 fuel cell buses will be operational in 2050, leading to a hydrogen demand of almost 4 TWh/year.

24 Based on Element Energy analysis of the BEIS Emissions and Energy Predictions, 2018; grid storage is assumed at the same level as in 2035 BEIS forecast; further details provided in Appendix 1

25 Transport Energy Infrastructure Roadmap to 2050 – Hydrogen Roadmap, Element Energy for the Low Carbon Vehicle Partnership, 2015

26 The market of PHEV vans is rather small, with a limited number of models available

- **Trucks** have similar range requirements to buses, often needing to drive long distances with very short downtimes. Therefore, our scenario assumes a share of 20% of new sales being battery electric trucks, whist the remaining 80% will be covered by longer-range options, such as hydrogen, CNG, and hybrid powertrains. In terms of vehicle stock, around 86,000 fuel cell trucks will consume ~13 TWh/year hydrogen in 2050.

- A significant demand for hydrogen is envisaged to come from **trains**, given the limited number of options for decarbonising rail: electrification or switching to hydrogen. With over 58% of current UK rail infrastructure not electrified, large deployment of electrification is not expected to take place in the future due to a prohibitively-high cost and the unsuitability in areas where the natural landscape aesthetic may be affected.[27] Without mass electrification, two options remain possible for decarbonising rail: deployment of battery electric or fuel cell trains. Since battery-powered trains face the same range challenges as high-mileage heavy-duty trucks, we estimate that up to 7,000 trains may be powered by fuel cells in 2050, leading to a hydrogen consumption of 30 TWh/year.[28]

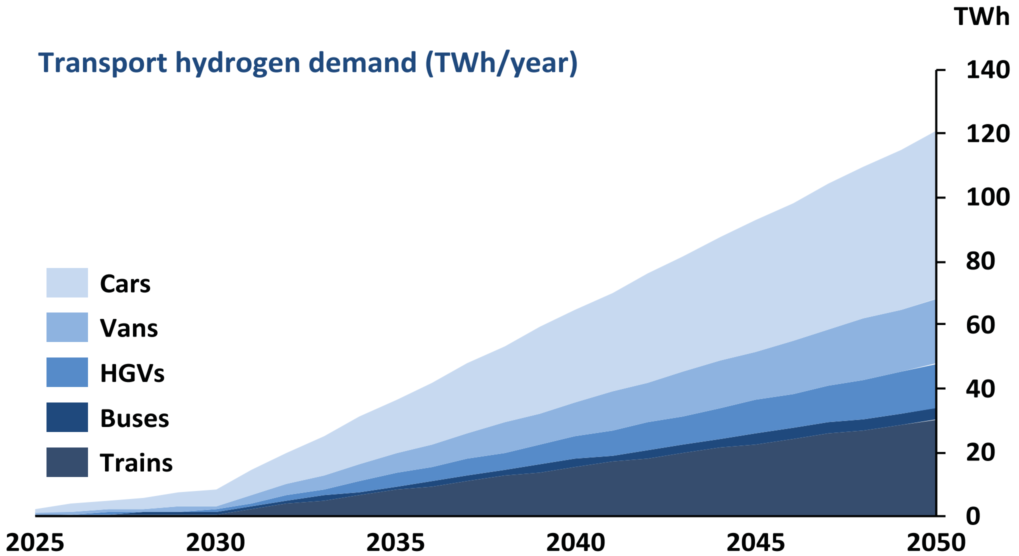


Figure 11: Annual hydrogen demand from the transport sector

Sectors other than hydrogen production, such as powertrain manufacturing and integration as well as refuelling infrastructure installation and operation, will be impacted from deploying a large fleet of hydrogen fuel cell vehicles. It is estimated that:

- Over 27 million fuel cell hydrogen vehicles of all sizes and uses will be sold by 2050, accounting for an equal number of hydrogen tanks being produced and a demand of 3.4 GW fuel cells to be installed.

- A potential annual demand of ~120 TWh/year hydrogen would be needed to power the fleet in 2050 (Figure 11).

- Considering the fuel cell vehicle roll-out, annual demand hydrogen demand, and the required hydrogen production and distribution infrastructure (discussed in the next section), it is estimated that a total of over 6,000 hydrogen refuelling stations (HRSs) will be installed by 2050.

27 https://www.railway-technology.com/features/will-uk-ever-get-electrification-back-track/

28 Element Energy analysis of the rail market

2.2.3 Rollout of decarbonisation across demand sectors

This section describes the deployment of the two key decarbonisation technologies, blue hydrogen and CCS, across different sectors, in terms of roll-out schedule, practical and logistical challenges, and demand estimates.

Blue hydrogen

Wide-scale deployment of blue hydrogen will require a whole network of infrastructure, starting at the production sites, each equipped with Autothermal reformers (ATRs). Hydrogen storage in close proximity will need to be implemented, as well as a cross-country pipeline system to achieve hydrogen transmission and distribution. End users will require hydrogen-suitable appliances (e.g. domestic and industrial users) or specific hydrogen infrastructure (e.g. hydrogen refuelling stations for transport). The roll-out of these pieces of infrastructure is detailed in this section.

Production

Several ATR (Autothermal Reforming) installations will have to be deployed across the UK in order to meet the hydrogen demand. With a total annual hydrogen demand of 735 TWh/year, a hydrogen production installed capacity of 89 GW would be required.[29] The production capacity roll-out will take place in line with the demand increase, and it is assumed to broadly follow the roll-out schedule of the H21 XL scenario. This approach assumes a seven-phase deployment, with planning for phase 1 starting as early as 2020.

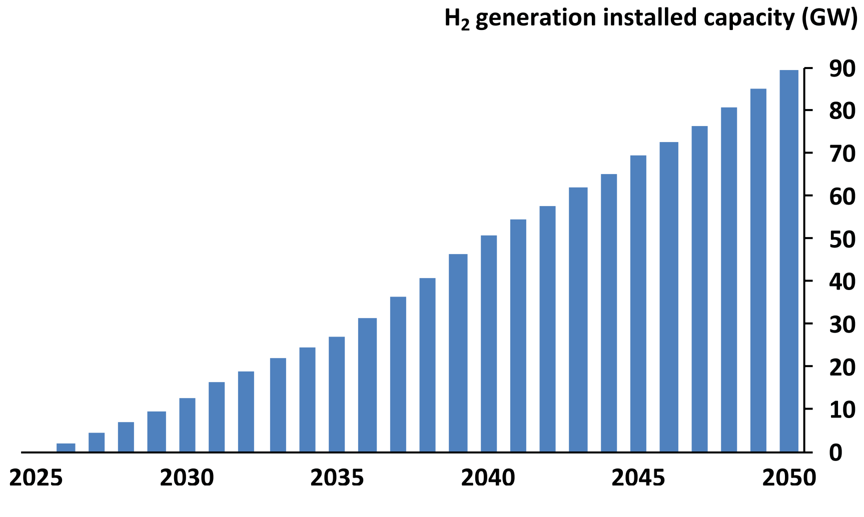


Figure 12: Cumulative H_2 production capacity required to decarbonised he UK economy

In terms of geography, the H21 Study and the associated scenarios assume an initial deployment (Phase 1) in North of England. By 2035 South Yorkshire and East/West Midlands, Scotland, and East London will have deployed hydrogen production and distribution facilities. By 2050, it is expected that South Wales and the South West , East Anglia and Home Counties, and the rest of London will have also been converted to hydrogen.[30]

29 Assuming a hydrogen availability – ATR utilisation factor of 95%. A full description of the hydrogen demand scenarios is provided in Table 1 in the Appendix.

30 Note that hydrogen production in South Wales and the South West is assumed to take place via cracking of low-carbon ammonia produced in Scotland, and not via ATR. The practical considerations of this production route are discussed later in this section.

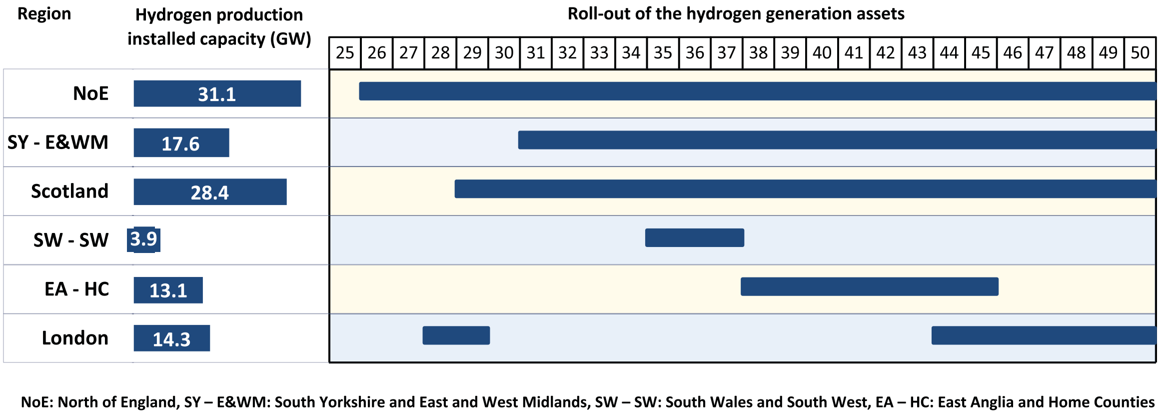


Figure 13: Roll-out schedule of the hydrogen generation capacity [31]

The ATR process utilises natural gas, which is oxidised to produce hydrogen and carbon dioxide. This process poses two additional challenges that must be overcome in order to decarbonise the UK economy: to secure a steady supply of low-emission gas feedstock (either natural gas or biomethane) and responsible management of the process carbon dioxide emissions.

The feedstock for the ATR installations deployed across the UK can be either natural gas or a blend of natural gas and biomethane.

- **Natural gas**, the current energy carrier used in several sectors of the economy, from domestic and industrial heat generation (through burners, cooking appliances, and boilers) to electricity generation in gas powerplants, could instead be used to generate hydrogen. Assuming that only natural gas is used to generate hydrogen, it is estimated that a consumption higher by ~33% relative to current levels will be required, after taking into account the ATR efficiency of around 75%. This incremental gas demand is taken into account when estimating the impact of hydrogen generation in the following chapter.

- **Biomethane**, generated from the anaerobic digestion of biomass, can be used to generate hydrogen. Due to the limited volumes of available biomass, biomethane by itself cannot be used to produce large volumes of negative-emission hydrogen. However, by mixing biomethane and natural gas and producing hydrogen by autothermal reforming coupled with CCS, blue hydrogen with low positive or even negative overall emissions can be produced, depending on the mixing ratio. A mix of 4% biomethane in the natural gas feedstock for hydrogen production is assumed in this study. This biomethane mix provides net zero emissions from the generated hydrogen.[1]

CCS will need to be used to manage the carbon dioxide emissions associated with hydrogen production. It is estimated that a total of 181 $MtCO_2$/year will need to be captured from the hydrogen production required to satisfy the total demand in 2050. It is assumed that the commissioning of the carbon dioxide storage fields will take place at the same rate as deployment of other hydrogen infrastructure (e.g. ATR installation, transmission and distribution).

Hydrogen interseasonal storage is required in order to secure hydrogen supply during periods of seasonal peak (e.g. increased heat demand in winter). Two types of hydrogen storage are assumed in this scenario:

- **Salt caverns**, underground cave-like structures have historically been used for storing natural gas and hydrogen and provide a well-established and relatively cheap way of storing hydrogen. Salt caverns account for most of the hydrogen stored inter-seasonally – around 13 TWh/year.[32] The roll-out of storage facilities is assumed to be aligned with the deployment of other hydrogen production and distribution assets. Salt cavern hydrogen storage is available on the East Coast of the UK, but is limited or non-existent in Scotland, South Wales and the South West.

- **Ammonia as storage** provides a practical, though more expensive solution for areas that lack salt cavern storage, such as Scotland, South Wales and the South West. Hydrogen produced during the summer (using spare capacity not utilised due to low heating demand) is converted to ammonia and stored in tank facilities. At times of demand, ammonia is converted back to hydrogen, using an ammonia cracker. In this scenario it is assumed that ammonia is produced in Scotland, from locally-sourced hydrogen. Ammonia is then stored locally and used for hydrogen production at times of peak in Scotland and also exported to South Wales, by ship.[33] It must be noted that whilst Scotland's hydrogen production is mainly based on ATR hydrogen, with seasonal supply from ammonia cracking, the hydrogen production in South Wales and the South West is assumed to be entirely based on cracking low-cost ammonia imported from Scotland. All additional infrastructure associated with ammonia production (~ 7 TWh/year in 2050), storage (20 storage tanks, each of 60,000 tonnes, in 2050), and use is considered in the economic impact assessment. The use of ammonia as storage in both regions is driven by the lack of salt caverns and lack of easy access to CCS in south Wales. However, the different sourcing of hydrogen in both regions is based on the supply of natural gas. Scotland has direct access to natural gas from the North Sea and is thus able to produce hydrogen via ATR, whilst the South Wales deployment has more limited access to hydrogen storage. This combined with the existence of a cluster producing ammonia in Scotland that will have already opened, this deployment will rely on ammonia shipments. Such shipment is likely to take place via the Milford Haven port, taking advantage of established port logistics and existing infrastructure, a direct result of the existing LNG terminal.

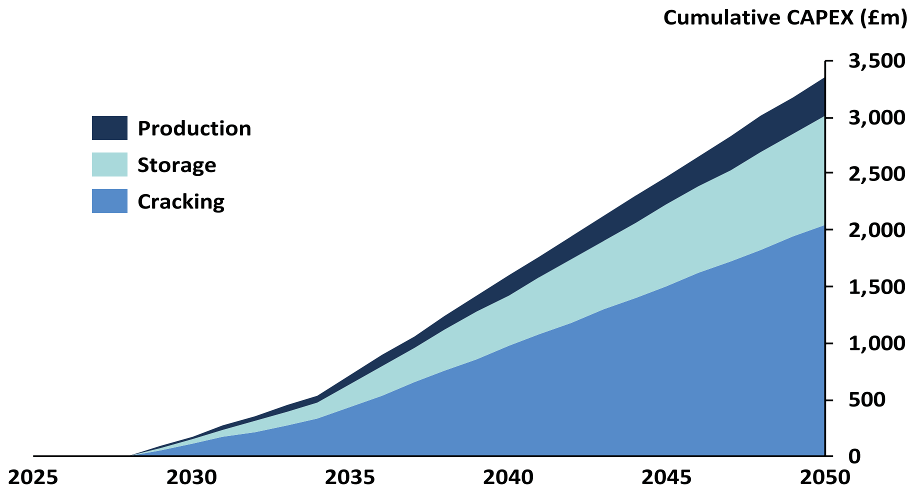


Figure 14: Cumulative CAPEX required for developing the ammonia supply chain[34]

32 Based on the hydrogen storage demand assumed in the NGN and Equinor's H21 North of England Report – H21 XL Scenarios

33 Based on the NGN and Equinor's H21 North of England Report

34 Based on Element Energy analysis of the ammonia production, storage, and cracking infrastructure in line with the deployment scale and costs assumed in the H21 North of England study (2018)

Transmission and distribution

A new transmission system will need to be built to transport the hydrogen from the ATR sites across each region and feed it into a distribution system. The conversion of the distribution system will take place region by region. During this transition, some industrial and power generation users will be early adopters of hydrogen within a geographic area, connecting directly to the transmission system. Others (residential and small commercial users) will still use natural gas until their local distribution network and appliances have been converted to hydrogen. As a result, a newly built system for hydrogen will be needed as the existing natural gas transmission system will still be required to provide natural gas to the ATR sites and to industrial, power, and domestic users before the full completion of the network and appliance conversion.

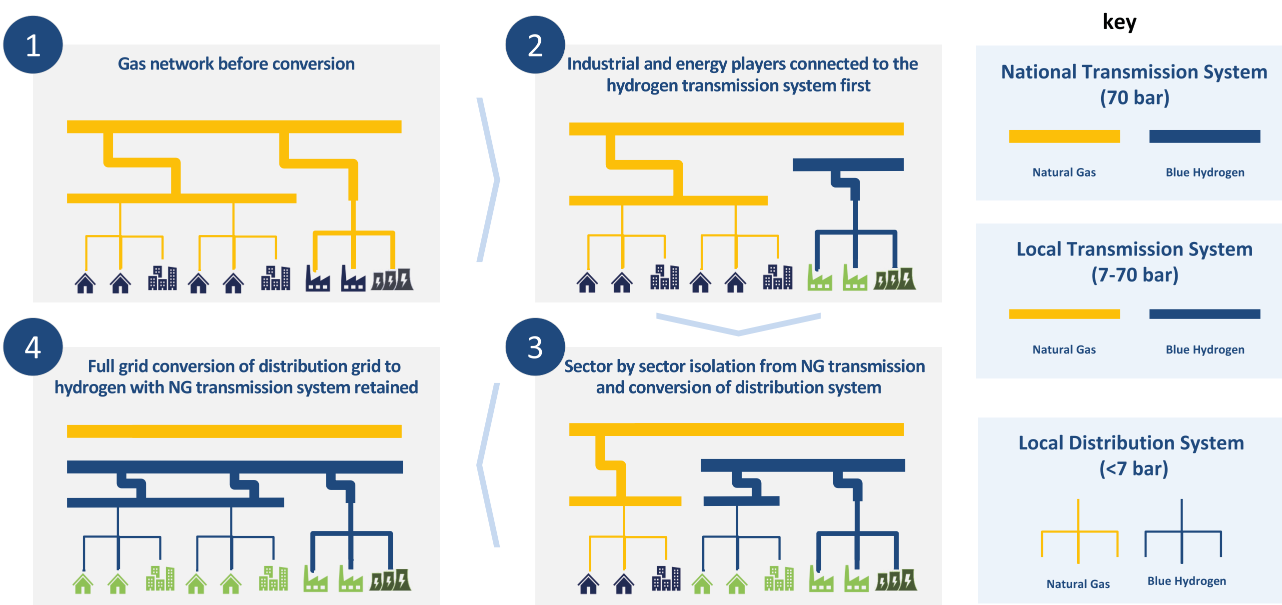


Figure 15: Gas grid conversion to hydrogen approach: sectorised isolation of the distribution network from the gas grid and conversion to hydrogen with the conservation of the Natural Gas NTS

Distribution system

The natural gas distribution system will be converted to hydrogen in line with the roll-out of the hydrogen production infrastructure. According to the H21 studies, the conversion will require both strategic network reinforcement (required to maintained peak demand capacity) and isolated sector conversion, in which areas of the distribution networks are isolated, purged of any remaining natural gas, and made hydrogen-ready (Figure 15).

End users

In order to satisfy the needs of different hydrogen end users, work in four areas will be required and is included in this **Decarbonised UK Economy** scenario:

- Domestic appliance conversion will take place as the isolated sector conversion of the natural gas network occurs. Hydrogen boilers will represent the largest share of replaced appliances, with other smaller appliances making up the remainder (e.g. cooking appliances). The length and costs of the appliance conversion could vary significantly depending on several factors. Governmental policies increasing the degree of electrification of cooking appliances could reduce conversion times and costs as those appliances would not be affected by the hydrogen transition. Hydrogen-ready boilers, which can operate on both natural gas and hydrogen with little modification, would allow preparation to begin early. In this scenario, the costs of conversions, shown in the next chapter, are in line with the H21 NoE projections, adjusted for delays in starting the FEED (Front End Engineering Design).

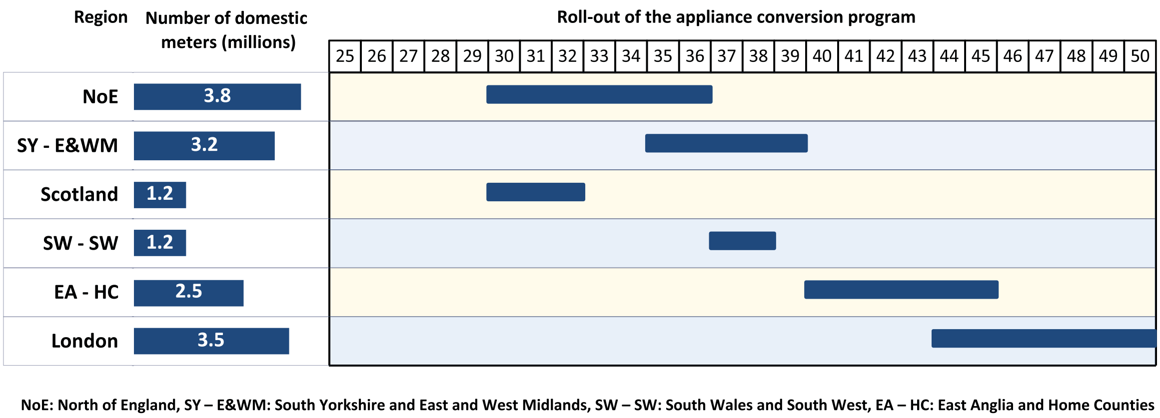


Figure 16: Timetable and scale of the appliance conversion across six UK regions

The other main hydrogen users will be converted to hydrogen as summarised below:

- **Industrial appliances** will follow a similar replacement schedule as the replacement of domestic appliances and the localised grid network conversion.

- **Power generation** is expected to increase from current levels to about 450 TWh/year in 2050, leading to an increase and diversification of the installed generation capacity. Power stations will likely be among the first users to convert to hydrogen and in the majority of cases will be connected directly to the hydrogen transmission system and not the distribution grid.

- **Hydrogen vehicle refueling infrastructure** will be installed as the demand from hydrogen vehicles increases. It is expected that most private hydrogen vehicles will be adopted in two areas: those already served by refuelling infrastructure and in areas where blue hydrogen is deployed, in line with the seven phases of national deployment. On the other hand, fleet operators within hydrogen deployment areas are likely to convert to hydrogen vehicles once the hydrogen supply in those areas has been established.

Carbon capture, utilisation, and storage

CCS will play an important role in decarbonising the UK economy. In addition to capturing CO_2 emissions from hydrogen production using ATRs, CCS will be deployed in the power sector and industry. The following uptakes of CCS are included in this scenario:

Power generation

CCS is required to ensure wide-scale decarbonisation of 10 GW_e power generation installed capacity. This scenario assumes that future power generation technologies using natural gas are either built equipped with CCS or hydrogen powered CCGTs. However, as the replacement of existing aging power plants is already underway, our economic impact analysis only considers the incremental investment (e.g. CCS premium) relative to the counterfactual technology, as explained in the next chapter.

2.3 Scenario 3: UK's position as a world leading decarbonised economy

2.3.1 Context

This scenario is an extension of the Economy-wide UK decarbonisation scenario which, in addition to an extensive roll-out of hydrogen in the UK, also assumes a scale-up of the blue hydrogen production capacity in order to satisfy external demand for low-carbon hydrogen and electricity from continental Europe. Blue hydrogen is directly exported to Europe via pipeline whilst electricity is produced from hydrogen and exported via existing interconnector infrastructure.

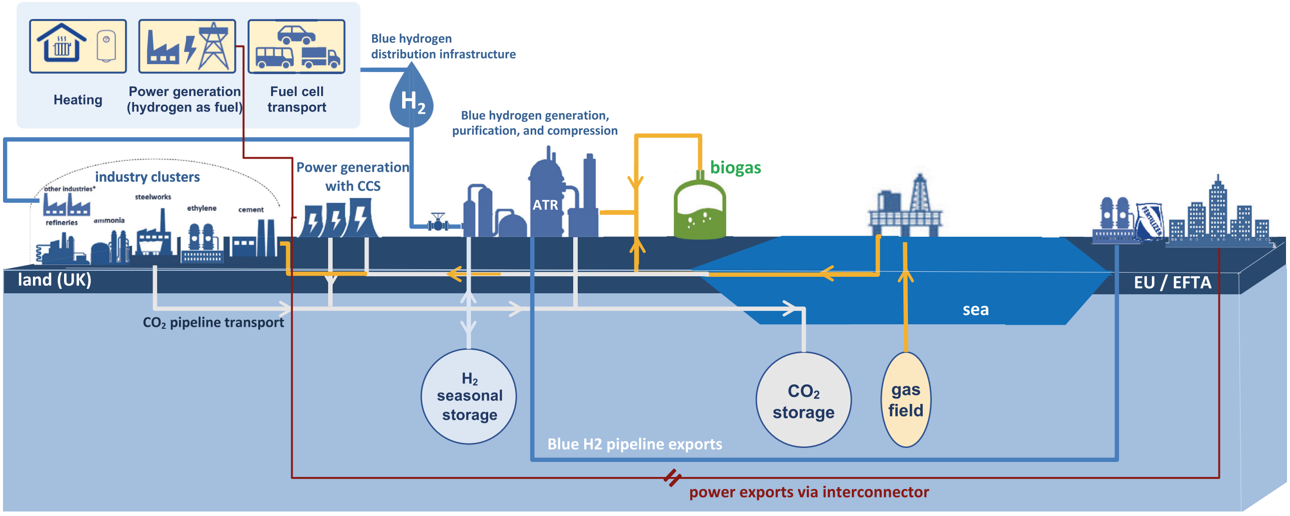


Figure 17: Overview of the infrastructure deployed to decarbonise UK economy and achieve maximum export potential

2.3.2 Demand for low-carbon energy carriers outside the UK

The **World leading decarbonised economy** scenario contains the same level of UK domestic hydrogen demand as the Economy-wide UK decarbonisation scenario, but requires additional hydrogen generation capacity to allow hydrogen export. The additional hydrogen production capacity is quantified in this section, along with any constraints and bottlenecks. Exporting low-carbon energy carriers, both hydrogen and electricity, based on blue hydrogen represents an even more ambitious goal than decarbonising the UK economy alone. It is expected that such exports will not start until the UK has deployed hydrogen production and distribution facilities across several geographical regions. As a result, 2040 is assumed as the year exports start in this scenario.

Blue hydrogen

It is possible that the UK will be able to start exporting blue hydrogen once the hydrogen production facilities (ATRs) have been deployed in several regions.

It is unclear what the demand for hydrogen would be in Europe in 2050. To date several countries have published plans to decarbonise different sectors (e.g. heat, transport, industry, etc) using hydrogen, however hydrogen demand scenarios are available for only France and Germany.

- **France:** The hydrogen council estimates that hydrogen demand will grow across six sectors (power generation, storage, industry fuel, heating and industry feedstock). France's current 40 TWh/year baseline hydrogen demand is expected to reach 180 TWh/year by 2050.[35]

- **Germany:** has no hydrogen demand projections published by the Hydrogen Council to date. Following the review of several studies, it was decided that the demand scenario shown in Figure 18 below provided the most comprehensive estimation of potential demand (165 TWh/year in 2050). This considers future mobility designed around electricity and hydrogen (in contrast to other scenarios relying on synthetic fuels.[36]

- **Post 2050-demand:** No data is available regarding the hydrogen demand in France and Germany after 2050. However, it is expected that by 2050 both France and Germany will have reached decarbonisation goals in most sectors and thus the estimated 2060 hydrogen demand will be similar to that in 2050.

- **Other countries:** It is envisaged that the UK will be able to meet hydrogen demand from other Western European countries, particularly those with access to current and future gas pipelines in the North Sea (e.g. Belgium, Denmark, and the Netherlands). However, as there are no hydrogen demand projections available for these countries, we have excluded hydrogen exports to other European countries from our analysis. To compensate for this, we have included an ambitious hydrogen demand from France and Germany.

- **Supply from the UK:** It is expected that hydrogen exports will start after 2040, once the UK has installed hydrogen generation capacity and the related infrastructure covering most of its territory and domestic demand. Due to lack of data in other Western European markets (e.g. Belgium, Denmark, and the Netherlands), it is assumed that the UK will be able to supply 75% of the French and German demand by 2060. Thus, total supply of British blue hydrogen will reach almost 260 TWh/year in 2060, as shown in Figure 18 as red diamonds.[37]

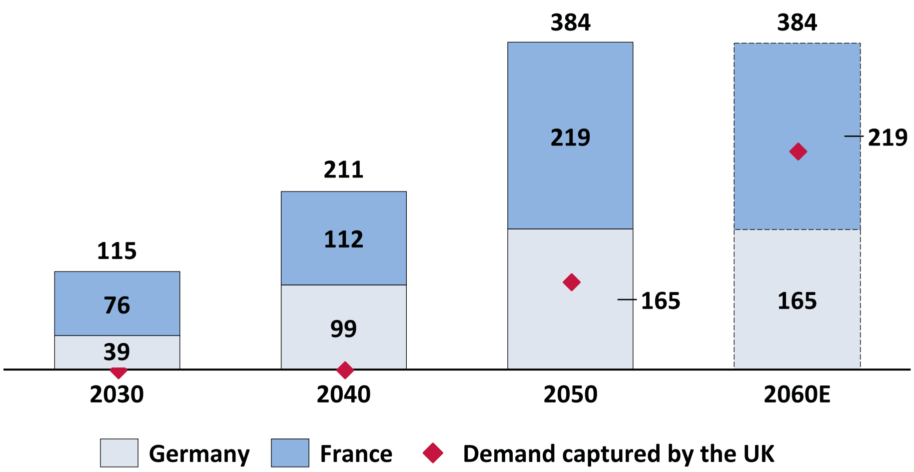


Figure 18: France and Germany demand of hydrogen and UK's supply (TWh/year) in key years

35 Hydrogen Council, Developing Hydrogen for the French Economy, A perspective study, 2018

36 Demand for hydrogen in decarbonizing European energy markets - The case of Germany, ewi Energy&Scenario, Nov 2018

37 Assuming demand in France and Germany remain constant between 2050 and 2060 (as both countries reach their climate goals), and the UK captures 75% of this demand due to being one of the first players to adopt blue hydrogen itself, having the skills and capacity to also export it.

Power

In addition to direct exports of blue hydrogen, exports of low-carbon electricity to Europe generated using hydrogen are possible. Blue hydrogen exports will require the development of a new transport infrastructure across the English Channel, however power exports could utilise current and projected interconnector infrastructure. It is projected that by 2050, the UK will have 20 GW_e of installed interconnector capacity.[38] Even if all this capacity could be used for power exports, subject to sufficient demand from continental Europe, it is expected that demand will be volatile and seasonal. Exports of electricity will start in 2040 and increase gradually as more hydrogen generation capacity is installed. As the UK is decarbonising its electricity grid and focusses power generation on blue hydrogen, the interconnector infrastructure could be fully used at times of peak demand from continental Europe in 2060. However, considering demand volatility, an average of about 30% of the full interconnector capacity will be utilised annually (Figure 19).[39]

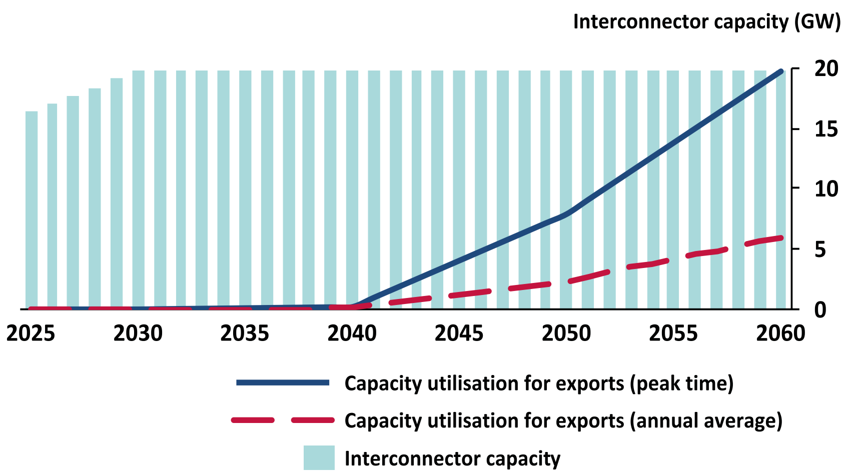


Figure 19: Deployment of interconnector capacity and utilisation for power exports[40]

A total of 21 TWh/year electricity would be exported in 2050, and 52 TWh/year in 2060 respectively. Assuming an efficiency factor of 58% for the H2 CCGT plants, this would require an additional 36 TWh/year hydrogen being produced in 2050, and 89 TWh/year in 2060. In terms of installed capacity, analysis show that increasing the load factor on the deployed hydrogen CCGT should allow enough power generation to satisfy export needs.

2.3.3 Additional infrastructure requirements

Hydrogen production

In order to meet the power demand, about 89 TWh/year of blue hydrogen will need to be produced in 2060. Alongside the ~260 TWh/year of hydrogen exported directly to Europe, this will require an increase of 41 GW_{H2} in hydrogen generation capacity over the decarbonised UK economy scenario. As the hydrogen exports are expected to start in 2040, the roll-out of the export-dedicated hydrogen production capacity and the associated infrastructure (e.g. CCS, pipeline upgrades etc.) will commence in the 2030s.

38 National Grid, Future Energy Scenarios, 2017

39 Based on Element Energy analysis of the BEIS Emissions and Energy Predictions, 2018 (published April 2019)

40 Based on Element Energy analysis of the National Grid Future Energy Scenarios and announced planned consolidation of interconnector capacity

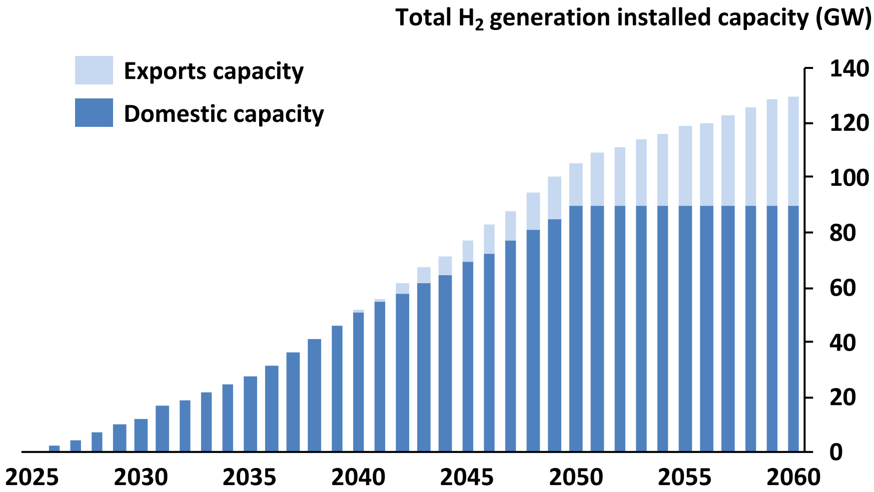


Figure 20: Overview of the purpose of the installed hydrogen generation capacity

A total hydrogen generation capacity of 105 GW would be installed in 2050, increasing to 130 GW in 2060. This deployment should be achievable within the proposed timeframe. For example, the H21 North of England Study investigated a wide-scale conversion to hydrogen in the H21 Max Scenario, projecting that a deployment of 131 GW hydrogen production capacity could be achieved by 2050 assuming realistic deployment rates. In the case of the World Leading Decarbonised Economy scenario, a lower deployment is assumed by 2050, reaching the hydrogen production capacity of the H21 Max Scenario detailed in the H21 NoE report.

A comparison of the costs of the infrastructure roll-out in the two scenarios, Economy-wide UK decarbonisation and UK's position as a world leading decarbonised economy, is shown in the next chapter. However, as the diagram above shows, the hydrogen production capacity for domestic usage is assumed to remain flat post-2050, as the UK will have already decarbonised most of its domestic demand by then.

Power generation

As the electricity will be generated from hydrogen, an additional 21 TWh/year electricity would have to be produced for exports in 2050, and 52 TWh/year in 2060, as mentioned in the previous section.[41] However, in terms of installed capacity, our analysis shows that increasing the load factor (from 65 to 79%) of the deployed H2GT should allow enough power generation to satisfy export needs. For this purpose, the economic impact analysis detailed in the next chapter only accounts for the incremental OPEX due to exports and does not consider any additional capital expenditure.

As the increased load factor will reduce spare capacity, the electricity demand should be closely monitored (and forecast) to ensure demand increases can still be accommodated. Thus, the UK would require managing internal demand first, during peak times, and only utilise spare capacity during times of low-demand. Additional grid storage infrastructure may be required to provide adequate flexibility, however, such requirements were not examined in this study.

41 Electricity demand is estimated based on interconnector constraints. As hydrogen-generated electricity exports are assumed to start in 2040, a full interconnector utilisation would be reached in 2060 at peak times.

Direct benefits to the UK economy

3 Direct benefits to the UK economy

A large investment will be needed for the UK to decarbonise different areas of the economy. However, there are a number of benefits of this energy transition beyond meeting emissions targets. This chapter examines the costs associated with each deployment scenario, both the capital investment and operational expenditure. It also assesses the impact of the investment in terms of domestic output, gross value added (GVA), job creation and international trade of goods and services.

In order to understand the impacts, a techno-economic analysis of the investment was conducted, spanning hydrogen production, distribution and end-use equipment, as well as CCS infrastructure. The annual costs were mapped to over 20 different standard industrial classifications (SIC) of economic activities, ranging from infrastructure construction to support activities. A macroeconomic model was built to understand the impacts, using statistical data, such as the UK input-output analytical tables and the Annual Business Survey provided by the UK Government's Office for National Statistics (ONS). A full description of the modelling approach, key data sources, and investment mapping on industrial classifications is provided in an appendix.

This chapter contains a section for each of the three decarbonisation scenarios, showing a high-level presentation of the required undiscounted costs and the economic impacts. A full comparison of the three scenarios, both in terms of costs and benefits, is presented in the Chapter 4.

3.1 Scenario 1: Decarbonised UK industry

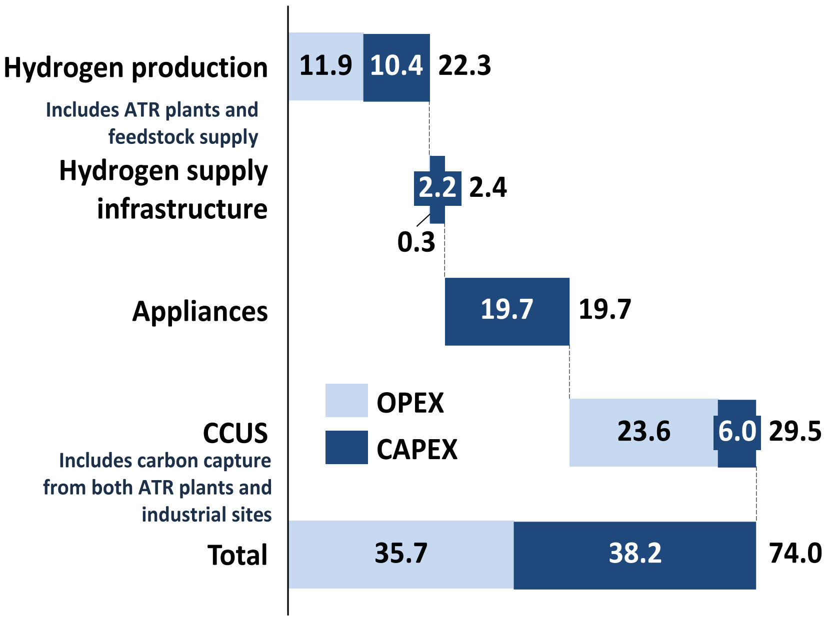


Figure 21: Expenditure by 2050 on industry decarbonisation

In order to achieve an industry-wide decarbonisation target, a total of £74 billion will be invested in the UK by 2050. Around 48% (£35.7 billion) of this amount will consist of capital expenditure in building the necessary CCS and hydrogen infrastructure. The remaining £38.2 billion will consist of operational expenses in the period to 2050. The total OPEX will be £3.5 billion/year in 2050. A large proportion of the OPEX is due to CCS (Figure 21) as this modelling considers transport and storage of industrial CO_2 to be charged as a fee (variable cost) for industrial players.

£0.7 billion will be spent as capital investment in decarbonising industry in 2035, with this figure reaching almost £3 billion in 2050. This will translate to a domestic output of £2.2 billion/year in 2050 with the remainder coming from imports. The increased output will create a total gross value added (GVA) of £1.6 billion and will sustain a total of 13,700 direct jobs (mainly in industries related to manufacturing of industrial machinery and appliances, construction, and oil and gas support activities), as well as some 9,700 indirect jobs in the associated supply chains.[42]

Operational expenditure of £3.5 billion/year is estimated for hydrogen and CCS facilities and infrastructure by 2050. Operating facilities will create 9,000 direct jobs in 2050 and will contribute to a £1.3 billion GVA growth.

An overview of the investment required in 2050, the impacts on trade, GVA, and jobs is provided in figure 22.

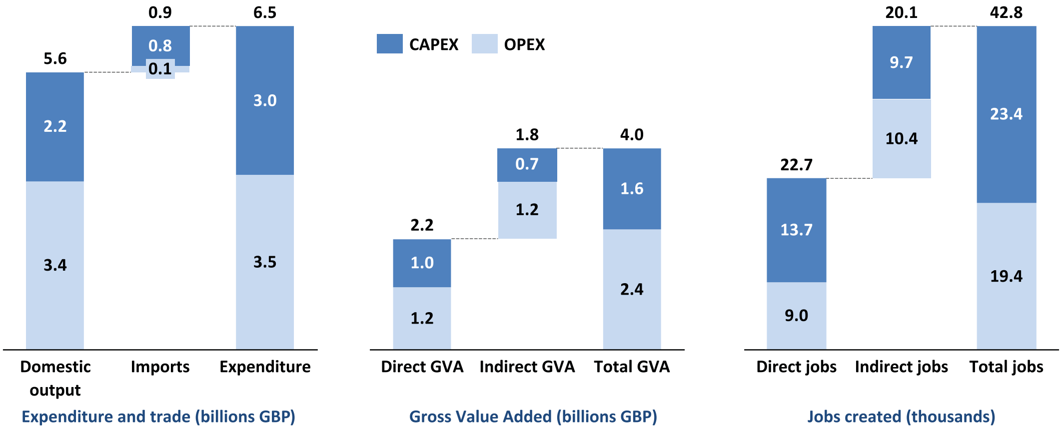


Figure 22: Summary of economic impacts of the decarbonised UK Industry scenario in 2050

Industry decarbonisation could generate almost 1,500 jobs as early as 2035, 10 years after the opening of the first industrial cluster, with the employment growing rapidly onwards, in line with the rapid ramp-up phase described in section 2.1.3.

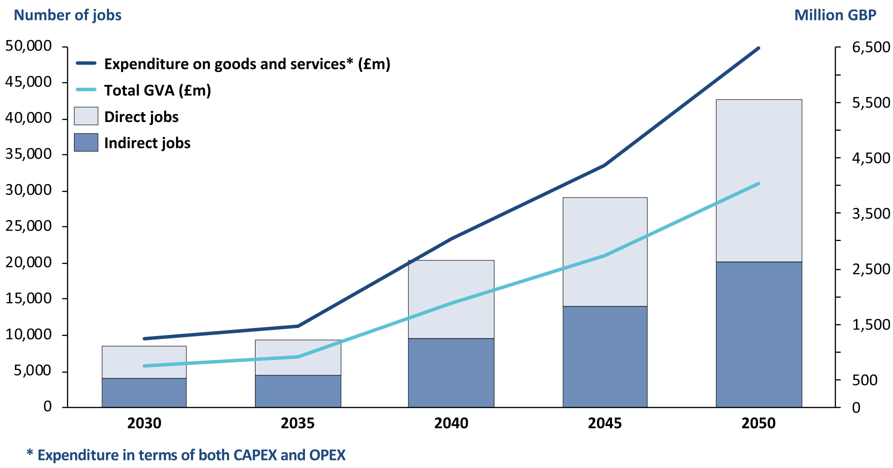


Figure 23: Expenditure on goods and services, GVA (£ million), and number of jobs generated under Scenario 1

42 Due to the similarities between CCS and O&G extraction, it is expected that storing CO_2 in depleted hydrocarbon wells would require similar skills and labour intensities as the opposite process (extraction of O&G).

3.2 Scenario 2: Economy-wide UK decarbonisation

Decarbonising the whole UK economy will require investment in multiple key areas: hydrogen generation (production and capture and storage of the resulting CO_2 emissions), interseasonal storage, hydrogen supply infrastructure (building a hydrogen transmission system and the conversion of the distribution grid alongside with upgrades of domestic, commercial and industrial appliances), electricity generation (installation of CCS systems at natural gas powerplants), industrial CCS, and transport (through the deployment of hydrogen refuelling stations).[43] In addition, considerable expenditure will be oriented towards purchasing hydrogen fuel cell vehicles, which will proliferate in this decarbonised economy.

£36.7 billion is required to decarbonise UK industry and £123 billion will be required to cover other sectors of the UK economy such as hydrogen for power generation and transport. This gives a total of £160 billion invested between now and 2050, as shown in Figure 24.

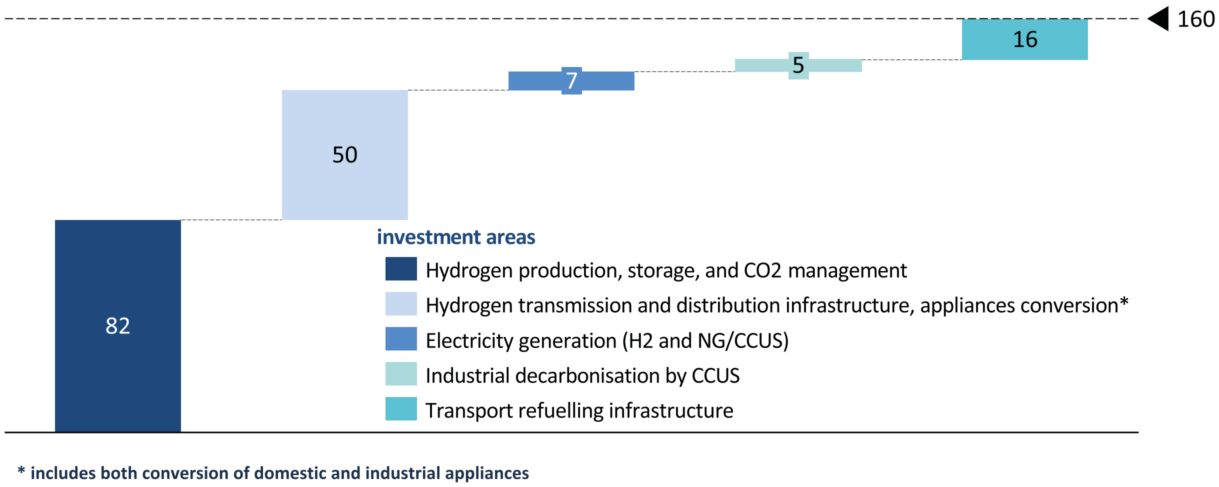


Figure 24: Hydrogen and CCS-related infrastructure CAPEX spent by 2050 (£ billions)

It is estimated that at its peak 73,000 people will be working in activities directly and indirectly related to the construction and deployment of the blue hydrogen and CCS infrastructure. The construction alone will require an investment of £8.2 billion in 2050 and generate a domestic UK output of £6.2 billion and a gross value added (GVA) of £4.7 billion in 2050.

In terms of operational expenditure, this will increase from the commencement of operations in the mid-2020s, as more hydrogen and low-carbon power is generated. OPEX is expected to reach a total of £12.2 billion/year in 2050, with the largest proportion (70%) relating to hydrogen production and its feedstock (Figure 25).

43 The economic impact analysis only considers incremental costs from a business as usual (BAU) scenario. In the BAU case, aging natural gas CCGT plants would be replaced by newer Natural Gas CCGTs, however the high hydrogen uptake assumes replacement by H2 CCGT. Element Energy's analysis estimates no incremental cost between Natural Gas and H2 CCGT technology, and thus those costs are not considered when assessing the economic impact.

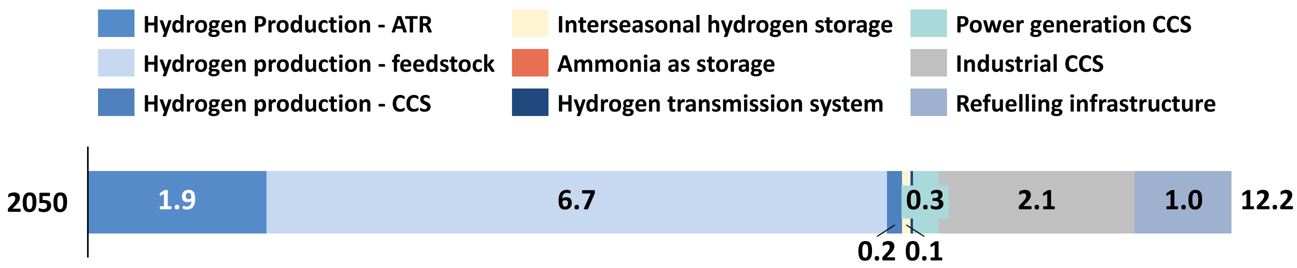


Figure 25: Split of OPEX required to sustain the decarbonised UK economy in 2050 (£ billion)

The long-term OPEX will sustain an estimated 38,200 direct jobs and 39,500 jobs in the supply chain and will generate a GVA of £8.3 billion in 2050 alone.

As shown in Figure 25, the numbers mentioned in this section so far include include the costs and operation of the hydrogen refuelling infrastructure but do not contain any impact from the increased sales of hydrogen vehicles, since these costs would be covered by the citizens switching to fuel cell vehicles.

However, it is estimated that 1,830,000 fuel cell vehicles will be sold in 2050. This number multiplied by the cost difference between fuel cell and internal combustion engine vehicles, leads to £10.4 billion of such goods would be required in 2050.[44] Whilse manufacturing of such technologies is mainly localised overseas (the UK sector sourcing almost 60% of its materials from imports), a UK gross output of £4.2 billion would be expected. This would contribute to a total GVA of £2.8 billion and 45,200 jobs, out of which 30,400 would be direct jobs.

The diagram below provides a summary of all opportunities created by such a deep decarbonisation of the UK economy as examined in Scenario 2.

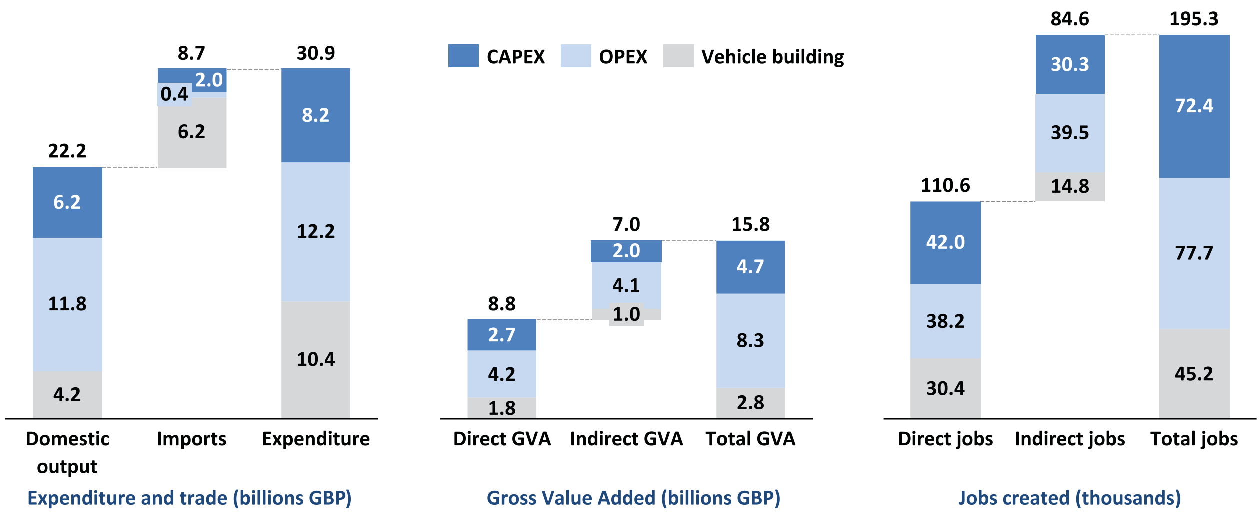


Figure 26: Summary of economic impacts of the decarbonised UK economy scenario in 2050

44 Details relating to the costs of fuel cell technologies are provided in the Appendix 1

Jobs related to both construction and operations will have a great impact in revitalising parts of the UK that rely heavily on industrial output and that see high levels of unemployment and benefits claims. Since the ATR and CCS facilities will be concentrated around industrial clusters (e.g. Humberside, Teesside, Liverpool area, South Wales, Grangemouth etc), over 110,000 direct jobs in 2050 will be created in these areas with half of these jobs being created as early as 2035 (see Figure 27). These jobs will not be limited to actually deploying the relevant infrastructure in the field (e.g. laying down pipelines and installing machinery) but will also create additional demand for processed metal goods and specialised machinery and appliances,that are generally produced by factories in these industrial areas.

Jobs in the gas industry will still be maintained as natural gas is the primary feedstock for blue hydrogen production. In addition, this transition will facilitate the retraining of personnel involved in subsea retraining of the personnel involved in undersea oil and gas exploration and support activities to provide services for seabed injection and storage of captured carbon from hydrogen production and industrial activities. This will prevent oil and gas jobs becoming redundant in a decarbonised economy and provide significant expertise and cost synergies.

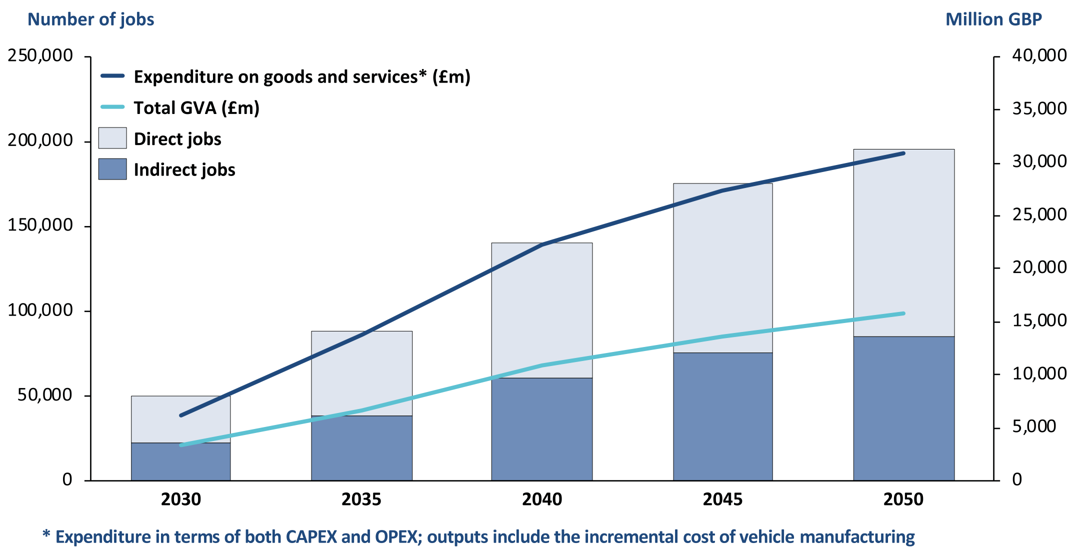


Figure 27: Expenditure on goods and services, GVA (£ million), and number of jobs generated under Scenario 2

The energy industry will continue to transition, even after the deployment of blue hydrogen and reaching net-zero emissions by 2050. Green hydrogen will be manufactured from renewable electricity sources via large-scale electrolysers. This transition will require both the deployment of renewable assets, electrolysers, and the associated network connections, as well as a decommissioning of some of the aging blue hydrogen assets. Depending on the deployment rate of green hydrogen, decommissioned blue hydrogen facilities may be either replaced by new blue hydrogen technology or demolished and replaced by electrolysers. All this skilled workforce similar to the one used to roll-out the initial blue hydrogen infrastructure.

It is also possible that the blue hydrogen economy will proliferate, with more hydrogen generation being deployed even after the UK has reached its climate goals. This could be achieved by scaling-up capacity to provide decarbonised energy carriers to other markets in Europe. The effects of this scale-up are detailed in the following section.

3.3 Scenario 3: UK's position as a world leading decarbonised economy decarbonised economy

The second scenario showed that a decarbonised UK economy could generate around £15.8 billion in total GVA and 195,000 jobs. The UK could additionally become a leader in decarbonisation, exporting 258 TWh/year of blue hydrogen and 52 TWh/year of electricity by 2060. Achieving these export targets would require an additional £17 billion in investment between 2040 and 2050 compared to Scenario 2, and an extra £24 billion between 2050 and 2060 (Figure 28).

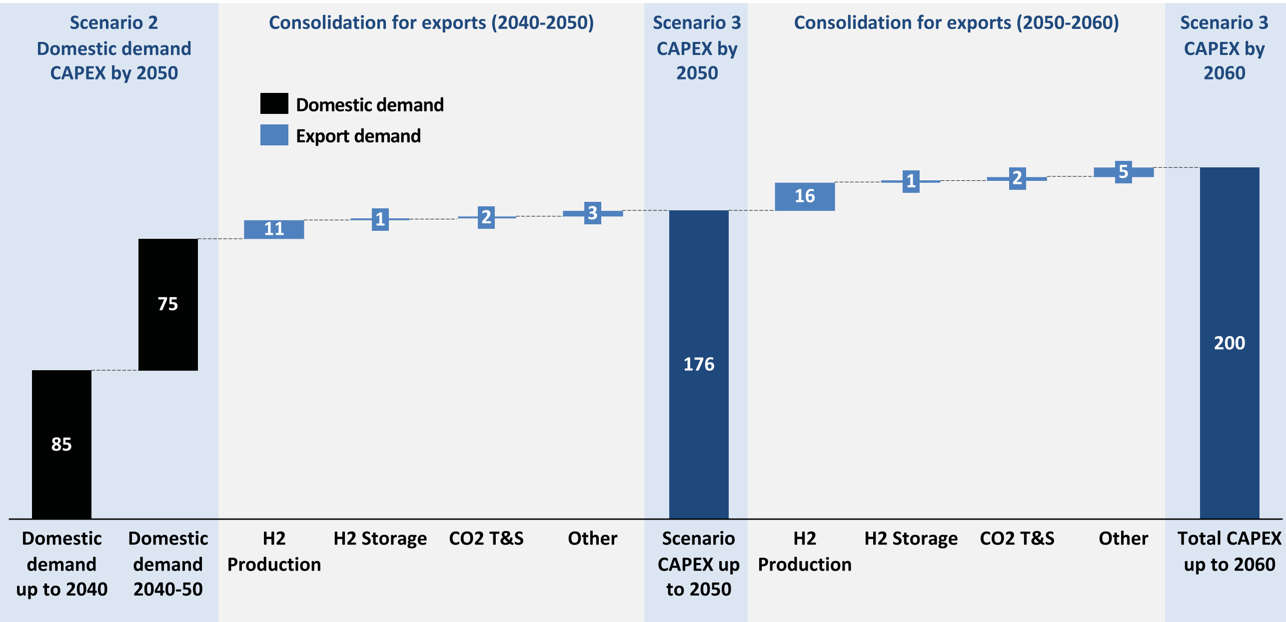


Figure 28: CAPEX (£ billion) spent to satisfy domestic and export demand

The investment profile considered in this scenario will not only increase UK's hydrogen generation capacity and strengthen its regional and global position. With the exports beginning in 2040, this investment will also translate into £5.6 billion total GVA related to infrastructure development in 2050 and around 7,100 direct jobs and 6,200 indirect jobs in between the late-2030s and 2050. Following 2050, additional hydrogen production capacity dedicated to exports will be constructed.

An increase in OPEX of £1.7 billion (11%) compared to the operational expenditure of domestic decarbonisation alone will be expected in 2050, escalating to £4.2 billion in 2060 (Figure 29). Although it is uncertain what infrastructure deployments will take place post-2060, it is estimated that this OPEX will create 51,000 permanent jobs directly related to operation of the consolidated infrastructure, 6,000 more than in the previous scenario, showing the long-term direct benefits of leveraging skills and infrastructure to satisfy exports demand.

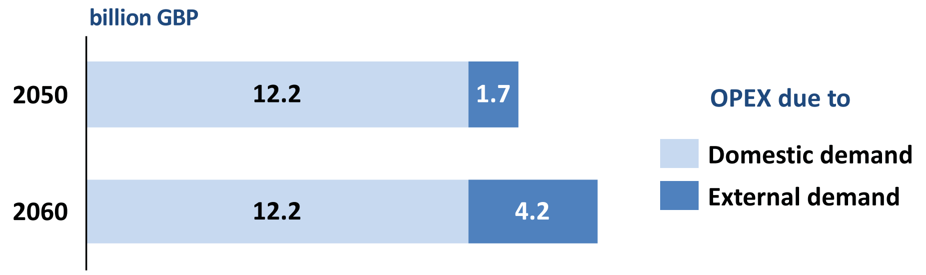


Figure 29: The effect of hydrogen demand for exports on the OPEX profile in two key years

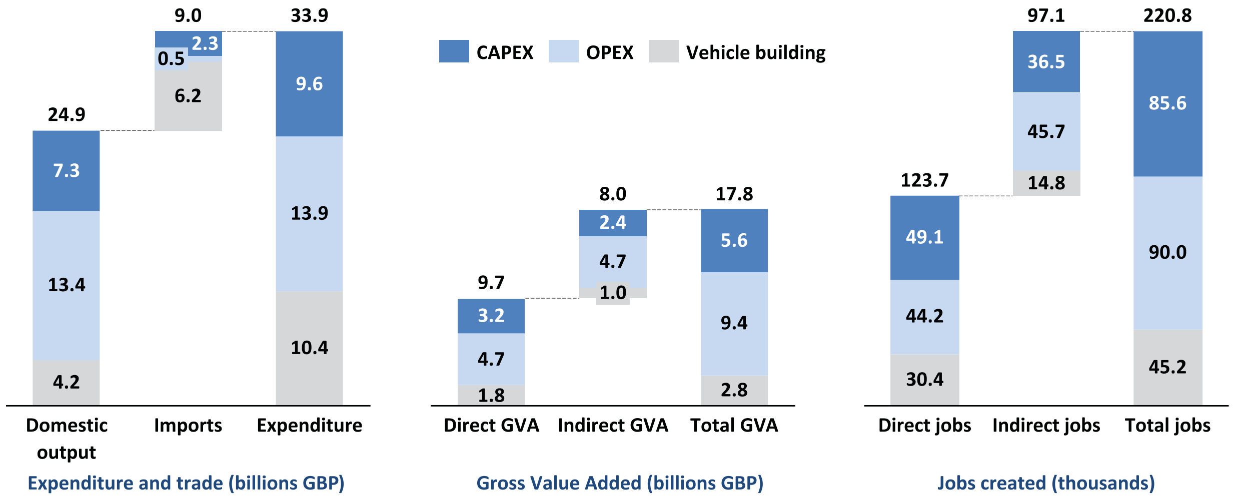


Figure 30: Summary of economic impacts of the world-leading decarbonised UK economy scenario in 2050

The diagram below shows the annual capital and operational expenditure, including manufacturing of fuel cell technologies in key years. The workforce will double over 15 years reaching a total of 220,800 jobs in 2050. The bulk of the workforce will be sourced from within the UK, through retraining from other industries, however the UK will need to ensure that appropriate training programs are in place for future workers.

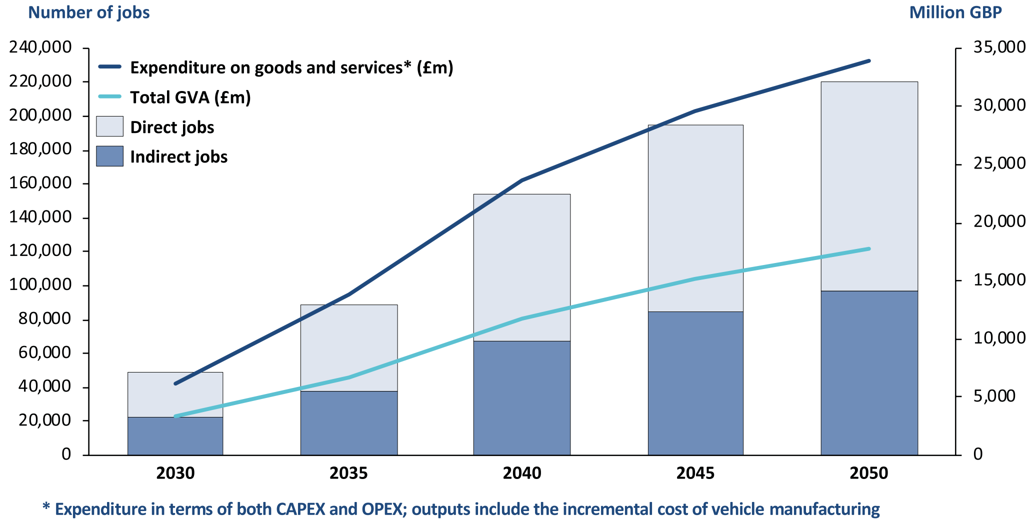


Figure 31: Expenditure on goods and services, GVA (£ million), and number of jobs generated under Scenario 3

As previously discussed, these job opportunities will be created in areas of the UK which heavily rely on industrial activities and will represent a revitalisation of communities historically affected by the UK's transition from industry to services. In addition, the large hydrogen generation capacity installed in this scenario will ensure a sustainable job incubator, both during the building and operation of the infrastructure, as well as during further decommissioning and the ultimate transition to green hydrogen.

Discussion and summary

4 Discussion and summary

4.1 Investment and direct benefits

Decarbonising the UK economy is a challenging task, both financially and in terms of logistics, regardless of the chosen technologies and approach.

Scenario 1: Industrial decarbonisation using blue hydrogen (~89 TWh/year in 2050) and CCS (capable of removing 23 $MtCO_2$/year in 2050), will require an estimated of £35.7 billion of CAPEX to be spent between 2020 and 2050, across all six main industrial clusters.

Scenario 2: Decarbonising the UK economy is a greater challenge, requiring a total of £160 billion in capital expenditure by 2050, excluding the cost of fuel cell vehicles. This transition will include an additional focus on:

- Scaling-up the hydrogen production and storage infrastructure, including an installed ATR generation capacity of 89 GW (735 TWh/year hydrogen availability), interseasonal storage (including both salt caverns and ammonia), infrastructure related to ammonia production and cracking, and the construction of a new hydrogen transmission system.
- Decarbonisation of heating will require developing a supply of hydrogen, a conversion of the local gas grid (15.4 million domestic meters converted taking 27 years), and a full conversion of domestic appliances.
- The power sector will have to invest £7.2 billion in CCS technology for its natural gas powerplants, currently in operation or planned for the future.[45]
- In a hydrogen-centric economy, hydrogen transport will play a significant role, with a wide vehicle deployment requiring an annual of ~120 TWh/year dispensed over 6,000 hydrogen refuelling stations, at a total capital cost of £15.6 billion.

Scenario 3: Expanding the hydrogen production capacity to satisfy exports and securing the **UK's position as a world leading decarbonised economy will** require an additional investment of £17 billion by 2050, adding up to a cumulative CAPEX of £176 billion deployed between 2020 and 2050. This investment will mainly focus on building the additional hydrogen production infrastructure, covering an additional hydrogen demand for exports of ~140 TWh/year in 2050, of which around 25% will be indirectly exported as electricity. Power generation will not require further capital investment as the powerplants deployed in the second scenarios will be able to deliver the additional ~21 TWh/year of electricity per year for exports by increasing load factors.

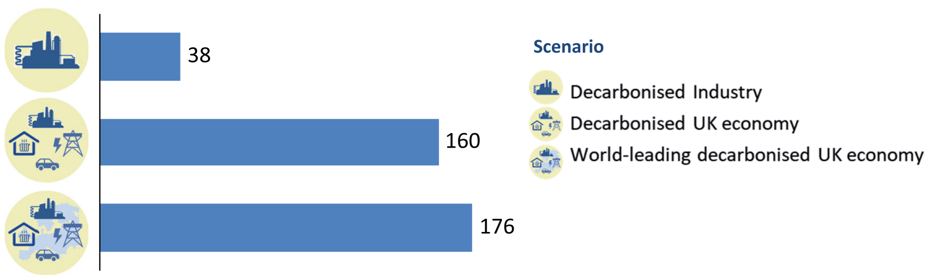


Figure 32: Comparison of CAPEX deployed by 2050 across different scenarios (billion GBP)

45 Due to similarities in the cost of natural gas CCGT and hydrogen CCGT, especially past the first of the kind deployment, no additional cost is assumed for the replacement of aging gas powerplants by hydrogen.

In addition, £155bn will be spent on fuel cell vehicle technologies between now and 2050 in both UK-wide decarbonisation scenarios.

Operational costs vary in line with the scale of deployment, ranging from £3.5 billion per year in 2050 to decarbonise industry to £13.9 billion in 2050 for a fully decarbonised economy capable of exporting low-carbon energy carriers. A comparison of the scale of OPEX and its breakdown in 2050, across the three scenarios, is presented in the Figure 33.

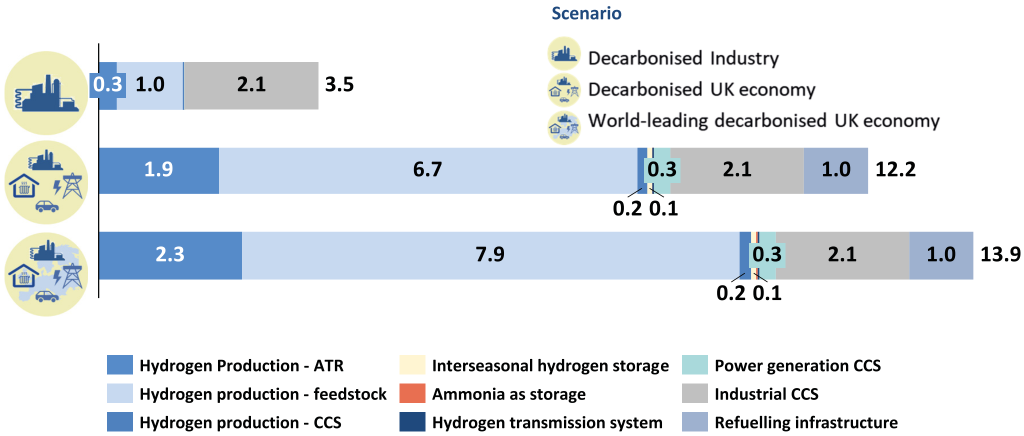


Figure 33: Comparison of the operating expenditure in 2050 (£ billion)

Given the difference in the scale of investment required in each scenario, the macroeconomic impacts vary significantly. For example, decarbonising industry alone would generate £4 billion of gross value added, whilst a wide-scale economy decarbonisation will lead to £18 billion in 2050. In addition, the hydrogen economy could employ between 43,000 and 221,000 people in 2050.

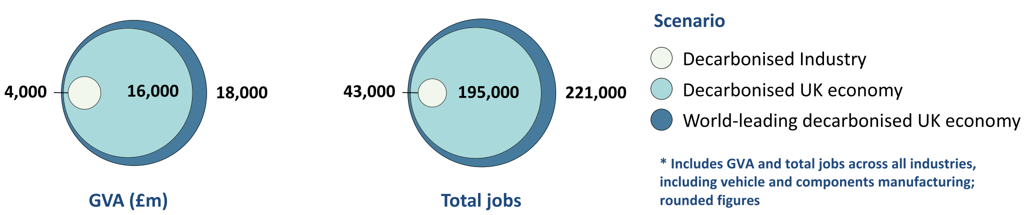


Figure 34: Comparison of macroeconomic impacts of the three scenarios in 2050

In addition to creating over 220,000 jobs and 18 billion pounds in GVA, this roll-out will create direct employment opportunities in the areas where hydrogen generation and capture infrastructure is located. Some of these areas are characterised by one of the highest benefit claimant counts (Figure 35), thus creating real opportunities and significant benefits for the regions and the UK as a whole. Given that much of the workforce will become available either through retraining or direct training, additional benefits related to increasing education in disadvantaged communities could bring long-term benefits, both at a local level and nationwide.

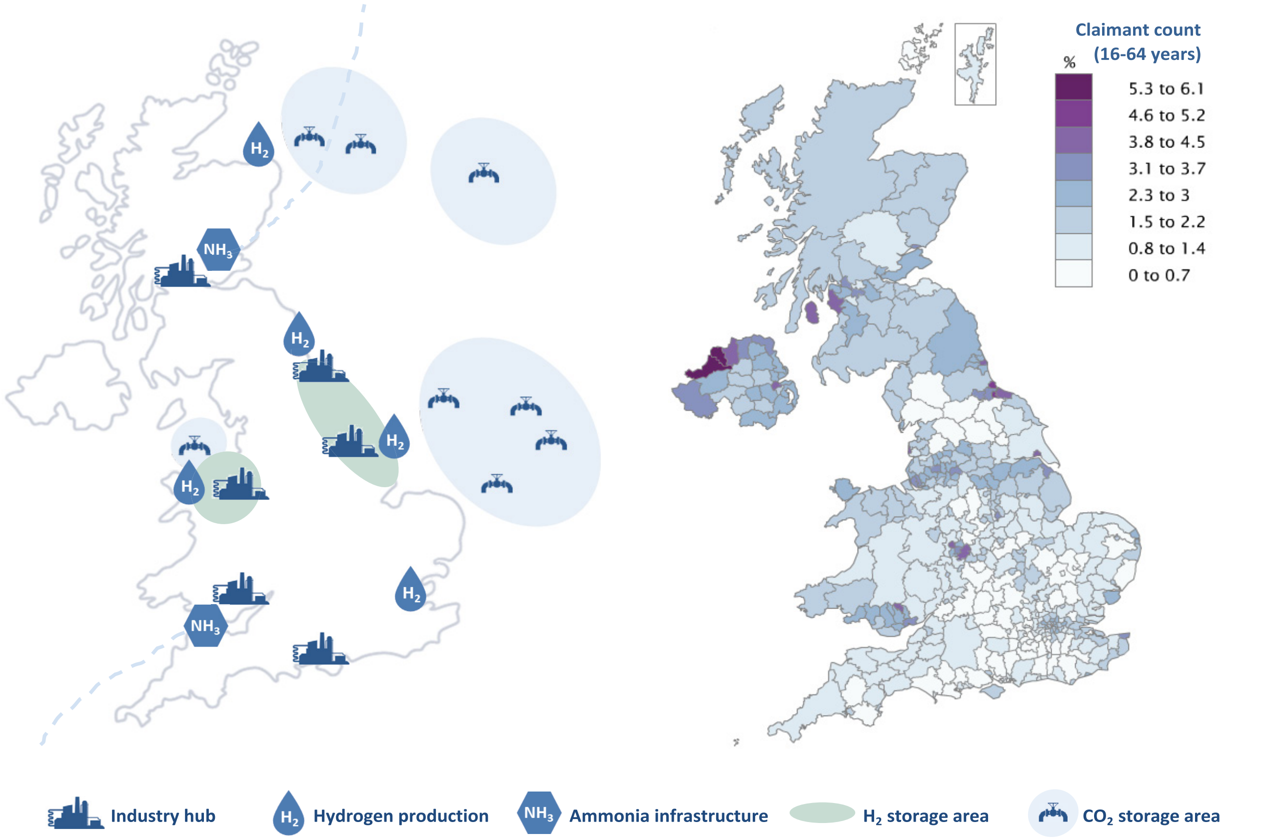


Figure 35: Geographic deployment of blue hydrogen and CCS infrastructure (left) and the benefit count percentage by local authority (May 2016) [46]

4.2 Other benefits for the UK

It is expected that the UK will have several opportunities to benefit from its leading position as one of the first European countries to deploy large-scale blue hydrogen and CCS.[47] These opportunities will be both in terms of technology and skills related to hydrogen deployment and infrastructure transition that could be exported (e.g. as British-built hydrogen appliances or consultancy services), as well as provision of services related to CCS. Since the UK will develop significant expertise in transporting carbon dioxide and storing it underground safely, reliably, and cost effectively, there is the possibility that the UK will allow shipments of CO_2 from continental Europe to UK injection and storage regions.

Carbon dioxide shipping

Carbon dioxide can be liquified, by pressurisation and cooling, similarly to liquified petroleum gas (LPG), and transported by ship to capture clusters that have pipeline connections, transferred and injected into storage fields. The first large-scale project is already underway in Norway, thanks to the collaboration of Equinor, Shell and Total, and is aiming to develop CO_2 storage on the Norwegian shelf. The Northern Lights project's goal is to collect emissions from an incineration chimney in Oslo, transport these emissions by ship close to the Øygarden municipality in Hordaland, and inject the CO_2 up to 3,000 meters below sea level.[48]

46 Regional labour market statistics in the UK, Office for National Statistics, 2016 (data from Department for Work and Pensions)

47 These opportunities were not numerically quantified in the scenarios developed due to uncertainty around demand from other countries.

48 https://www.equinor.com/en/magazine/carbon-capture-and-storage.html

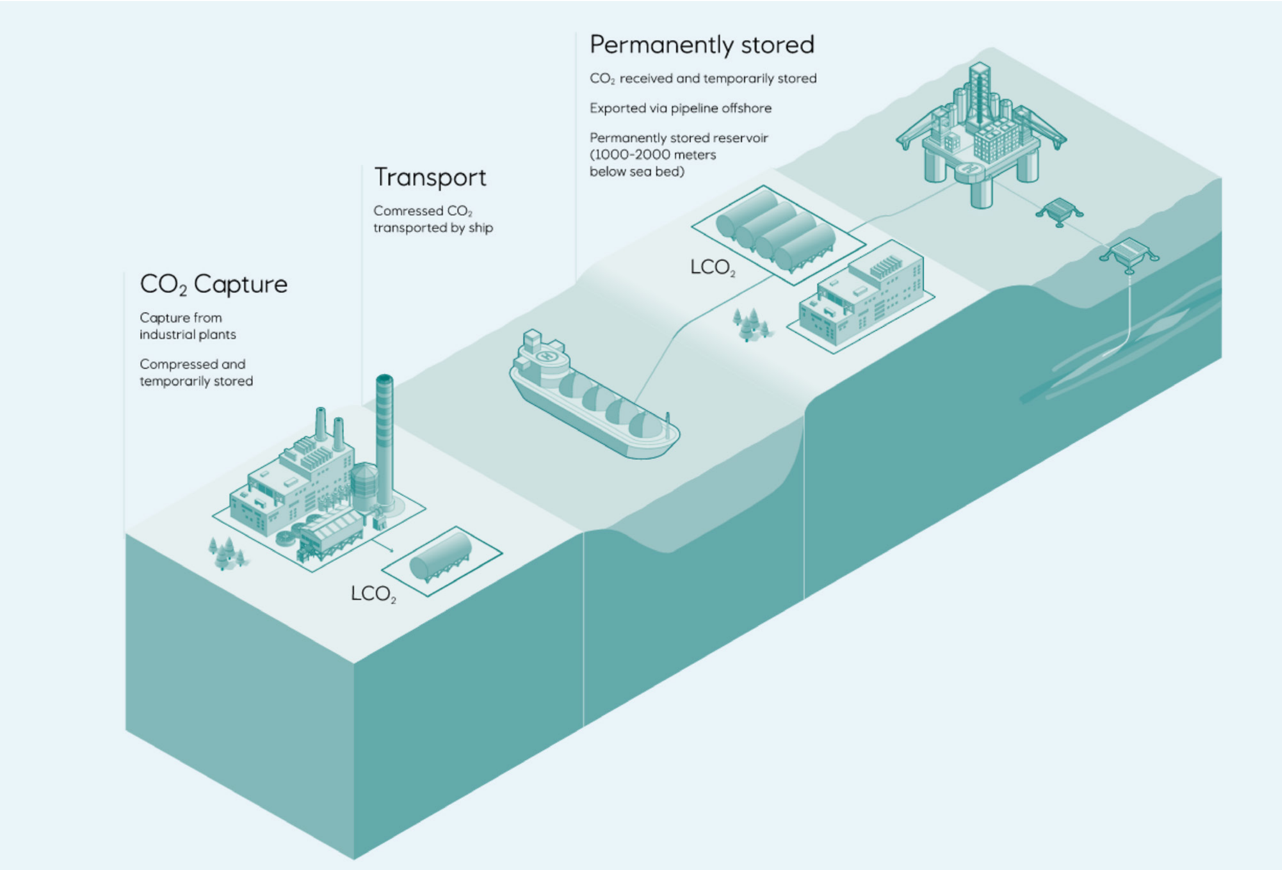


Figure 36: Overview of the Equinor Northern Lights CCS project

Shipping by boat could emerge as an intermediate low-cost CO_2 shipping solution before the finalisation of the transport pipeline infrastructure or in areas where pipeline construction is unfeasible (areas not in the proximity of storage fields, e.g. industry in the South Wales cluster).[48] As a result, the UK could either use some of the shipping fleet and/or its hubs suitable for receiving CO_2 shipments from the continental Europe. This can connect UK ports with potential early movers (such as Norway and Rotterdam) and other key industrial hubs with limited offshore CO_2 storage potential (e.g. France and Germany). Fees associated with this import solution could help cover some of the investment required to develop both the transport and storage infrastructure and the modernisation and upgrade of existing ports (for example improving maximum ship length, berth availability and storage space).

49 Shipping CO_2 – UK Cost Estimation Study, Element Energy for BEIS, 2018

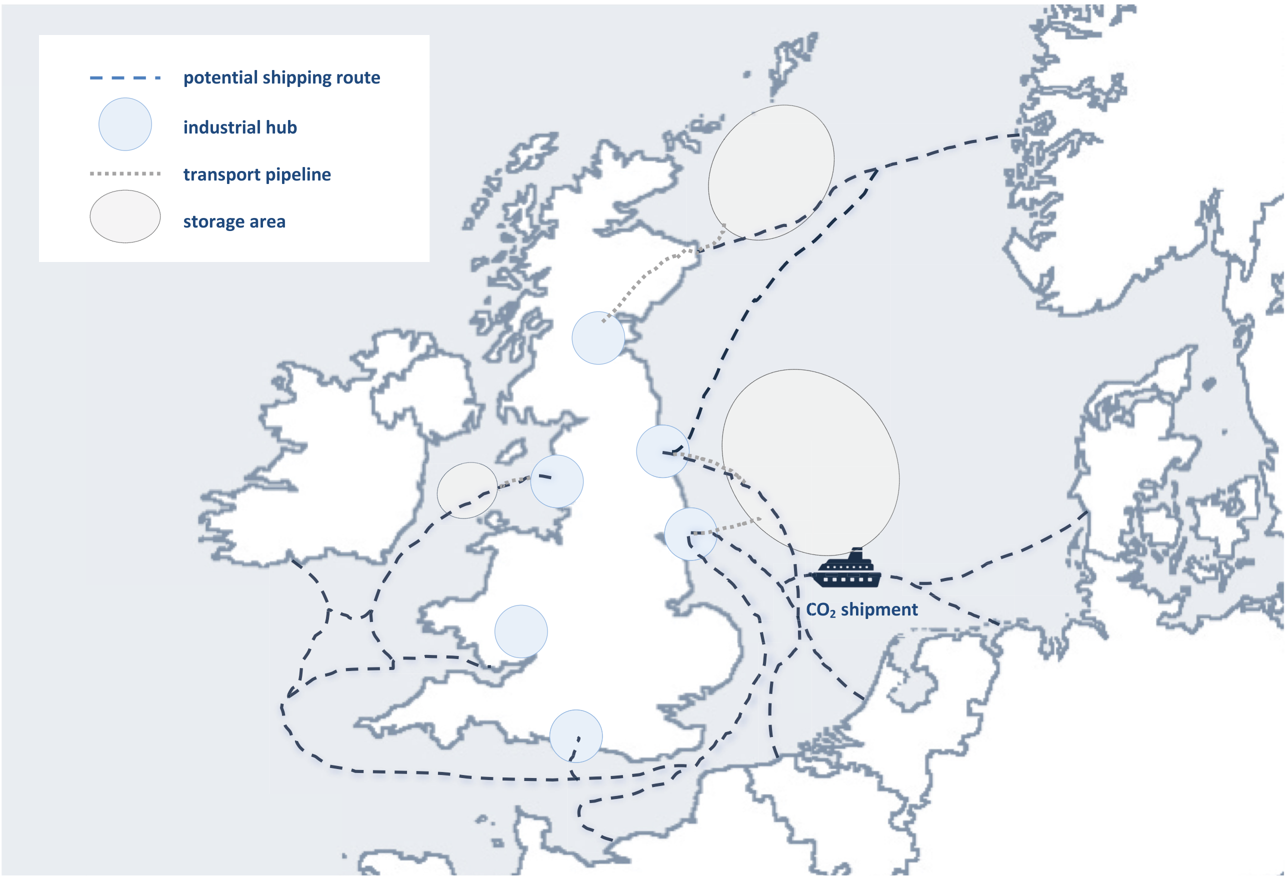


Figure 37: Potential carbon dioxide shipping routes (illustrative)

Storage as a Service (SaaS)

Several countries and oil and gas companies already offer Storage as a Service (SaaS), selling carbon dioxide underground storage to private customers or other countries. SaaS could be exploited by the UK, especially following the expertise gain and transport and storage infrastructure consolidations associated with large-scale deployment of blue hydrogen and CCS. The UK has an estimated CO_2 storage capacity of 1,645 $MtCO_2$ in appraised storage sites, with an additional ~7,170 $MtCO_2$ in other sites currently documented.[50] Based on the emissions associated with Scenario 2, it is estimated that the UK will have stored ~2,800 $MtCO_2$ by 2050, with approximately 6,000 $MtCO_2$ spare storage capacity. Injection rates across future storage sites are not well known, however, by assuming a maximum injection rate of 500 $MtCO_2$/year, approximately 50% of this capacity will be utilised by 2060. Thus, the UK has the potential to provide additional CO_2 storage of at least 200 $MtCO_2$/year to other countries in close proximity to the North Sea (e.g. Germany, Denmark, the Netherlands etc). This will facilitate a wider decarbonisation at a European level and will also generate additional income, jobs, and opportunities for the UK.

50 Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource, Energy Technologies Institute, 2016

51 Strategic UK CCS Storage Appraisal Project, Energy Technologies Institute, 2016

Exports of ammonia

Ammonia production and usage as a low-carbon source of hydrogen will play a key role in the transition to a blue hydrogen economy, For example, the H21 NoE study envisages ammonia produced in Scotland and South Wales. However, it is envisaged that in time, the UK will increase its ammonia production facilities, both in conjunction with utilising any spare ATR capacity as well as curtailed renewable electricity generation coupled with electrolysis. Such a scale-up will not only improve UK's energy security at times of high demand, but will also use some of the expertise developed for the domestic ammonia market to enable exports of ammonia to global markets. This will strengthen the UK's position as a world-leading decarbonised economy and the revenue will support the financing of infrastructure, such as port facilities. It is expected that the use of ammonia will grow in later years to play an important role in the second half of the 21st century, so its impacts were not modelled as part of this study.

Other long-term benefits

The thousands of workers involved in the construction, installation, and operation of the blue hydrogen and CCS infrastructure will build considerable skills and knowledge. Such intellectual assets could be leveraged by the UK by providing both consultancy and construction services to other countries looking to decarbonise their economy.

The UK manufacturing industry will also prosper. The UK is already home to several manufacturers of domestic appliances, particularly boilers. The deployment of blue hydrogen and the required conversion of industrial appliances will require considerable R&D. However, given the UK's leading position in European and international decarbonisation, it is expected that boiler manufacturers will be able to export a considerable number of appliances to other markets which are following the UK's decarbonisation pathway, increasing the market share of British boilers significantly.

In short, the UK could easily establish a leadership position in decarbonisation technology by diversifying its skills and technologies portfolio. It is worth noting that Scotland alone exports renewable technologies and expertise to over 70 countries, employing 17,700 people and having a turnover of £5.5 billion in 2017.[52] Whilst the potential value of such a diversification was not explored in this study, the UK's exports of low-carbon products and services could reach several times the value of the current renewable Scottish industry.

The development of a hydrogen economy in the UK will enable the production of low-carbon (green) products, such as ammonia and other chemicals. The UK will be able to trade these products internationally, adding value to its economy.

52 The Scotsman: More than 70 countries benefit from Scottish renewable energy, May 2019

4.3 Towards and beyond blue hydrogen

Towards a green hydrogen horizon

Early deployment of blue hydrogen and CCS will have a key role in leading a potential long-term transition to green hydrogen in the second half of the century (green surface, Figure 38 below). This transition to green hydrogen could utilise some of the infrastructure deployed for blue hydrogen, such as the transmission and distribution network. Green hydrogen expansion would also require an increased share of renewable power generation and large-scale water electrolysis in the UK.

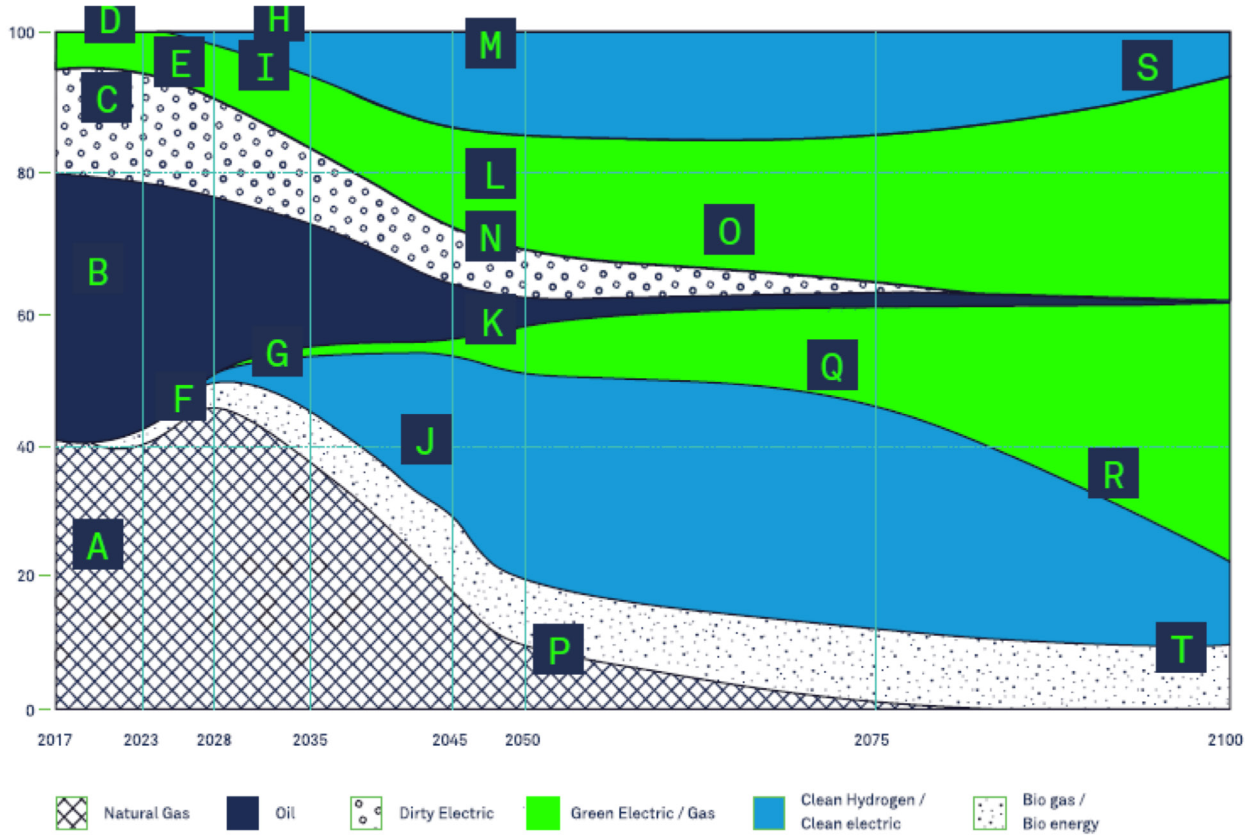


Figure 38: Key energy sources and the onset of a hydrogen economy in the second half of the century - based on H21 2100 Vision[53]

53 Reproduced from the H21 NoE Report (2018), page 497 – please refer to the original report for full details, including a detailed walked through

Just like natural gas today, green hydrogen, in the form of ammonia, could be traded internationally. As a result, the UK will be required to develop its ammonia storage and cracking assets in order to accept imports of green ammonia. Australia, a continent of only 24 million people, has a wide renewable hydrogen potential. The country has already invested over 500 million Australian dollars in hydrogen-related projects and is envisaged to become a leader in exporting blue hydrogen and ammonia, with exports starting as early as 2030.[54, 55] The transition from blue to green hydrogen will also mean additional jobs being created between 2050 and 2100 in the construction of the additional required infrastructure (renewable deployment, electrolysers, ammonia storage and crackers), as well as the decommissioning and/or repurposing of some of the aging blue hydrogen facilities (e.g. aging ATR facilities).

Unleashing blue hydrogen's potential

To ensure the benefits of blue hydrogen and CCS are fully exploited, investment in the sector must start immediately. Early investment will ensure successful roll-out, validating the concept and increasing awareness and acceptance of the technology. These pilots will address any remaining barriers, and demonstrate safety, taking the UK closer to reaching its ambitious net-zero goal by the middle of the century.

54 Green Tech Media: How Australia Is Looking to Develop a Hydrogen Economy, December 2018

55 Australia's Hydrogen Future, Energy Transition Hub, December 2018

Appendix 1: Key modelling assumptions

5 Appendix 1: Key modelling assumptions

This study builds up on several assumptions used to derive the hydrogen demand and the associated deployment costs. The hydrogen demand in 2050 is based on well-referenced sources, as shown in the table below.

Table 1: Hydrogen demand (TWh/year) across different sectors and scenarios in 2050

Demand sector		Industry decarbonisation	Decarbonised UK Economy	World leading decarbonised economy	Notes
Industry		115	115	115	Based on EE work for the CCC.
Heat		-	303	303	H21 XL Scenario demand
Electricity		-	202	202	H21 XL Scenario demand
Transport		-	115	115	EE work in line with the LowCVP H2 Infrastructure roadmap
Exports	Hydrogen via pipeline	-	-	202	EE analysis of European hydrogen demand
	For power generation intended for exports	-	-	103	EE analysis of interconnector capacity, assuming a utilisation for power export of 21 TWh/year electricity in 2050, and a H2 CCGT efficiency of 58%

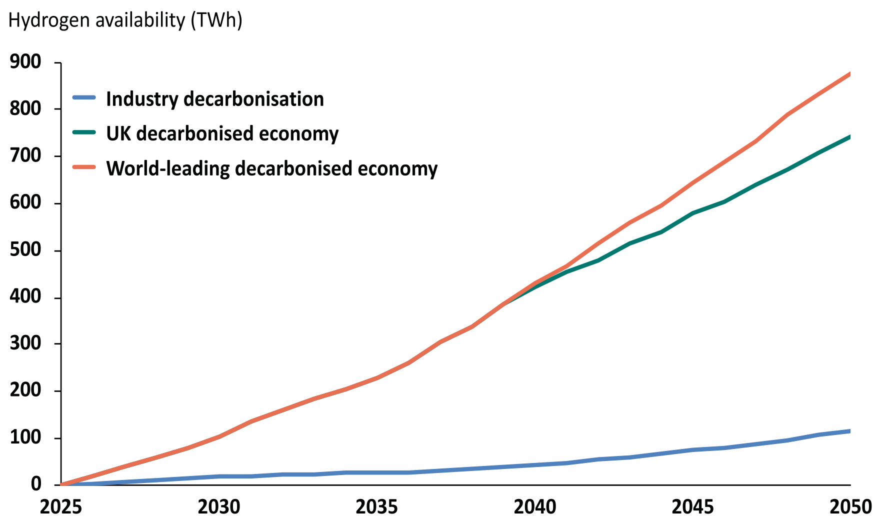


Figure 39: Hydrogen availability (hydrogen capacity) roll-out

A hydrogen availability of 95% is assumed in all three scenarios when converting the hydrogen demand (TWh/year) to installed capacity (GW). To achieve this demand in 2050, a demand roll-out curve was developed in line with the assumptions in the H21 study.

The hydrogen demand and installed capacity are used in calculating the costs of deploying and operating the hydrogen supply infrastructure, using the cost multipliers shown in Table 2.

Table 2: Overview of key cost assumptions related to the hydrogen infrastructure

Level	Component	Cost type	Units	Value	Contribution to economic impact	Notes
Hydrogen Production	ATR plant and air separation unit	CAPEX	£m/TWh prod. capacity	80.00	100%	EE modelling using assumptions based on the H21 NoE study. For the supply of natural gas and biogas for hydrogen production, only 25% of the costs are counted towards economic impact modelling, corresponding to an ATR efficiency of ~75% relative to business as usual demand in a gas-centric UK economy.
		OPEX	£m/TWh/year	2.60	100%	
ATR Feedstock	Electricity	OPEX	£m/TWh/year	3.35	100%	
	Natural gas			20.60	25%	
Biogas supply chain	Anaerobic digestion plants	CAPEX	£m/TWh prod. capacity	40.00	25%	
		OPEX	£m/TWh/year	2.20	25%	
Inter-seasonal H_2 storage	Hydrogen storage facility	CAPEX	£m/TWh prod. capacity	3.85	100%	
		OPEX	£m/TWh prod. capacity	0.11	100%	
Blue H_2 - CO_2 T&S	CO_2 transport and storage	CAPEX	£m/TWh prod. capacity	12.20	100%	
		OPEX	£m/TWh prod. capacity	0.22	100%	
Hydrogen transmission system	Hydrogen transmission system	CAPEX	£m/TWh prod. capacity	14.94	100%	EE work for the UK Infrastructure Commission
		OPEX	£m/TWh/year	0.03	100%	Analysis of H21 NoE HTS OPEX
Network conversion	LP reinforcement	CAPEX	£ / connection	18.87	100%	Based on H21 assumptions
	LP isolations	CAPEX	£ / connection	9.06	100%	
	MP Isolations	CAPEX	£ / connection	4.23	100%	
	District Governors and connections	CAPEX	£ / connection	5.66	100%	
Domestic appliances conversion	Labour costs	CAPEX	£ / meter	471.96	100%	
	Material costs - boilers	CAPEX	£ / meter	499.47	100%	
	Material costs - other appliances	CAPEX	£ / meter	249.74	100%	

The deployment of hydrogen power generation is based on Element Energy analysis of the BEIS Emissions and Energy Predictions, 2018, assuming the following roll-out of technologies by 2035 as a replacement for nuclear and natural gas CCGT assets planned by BEIS.[56] This case assumes a high uptake of hydrogen and CCS CCGTs.

Pre-development | Construction | Commissioning (GW) | FID

Power Plant Roll-out	Type	Replacing	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
CCS CCGT- 1	FOAK	Nuclear							1.7									
H2GT- 1	FOAK	Nuclear										1.5						
CCS CCGT- 2	SOAK	Nuclear												1.5				
H2GT- 2	SOAK	Nuclear													1.5			
CCS CCGT- 3	SOAK	CCGT														1.2		
H2GT- 3	SOAK	CCGT															1.7	
CCS CCGT- 4	NOAK	Nuclear															1.5	
H2GT- 4	NOAK	Nuclear																1.5
CCS CCGT- 5	NOAK	CCS CCGT																1.3
H2 Blending- 90%		CCGT													0.6	1.3	1.4	0.5

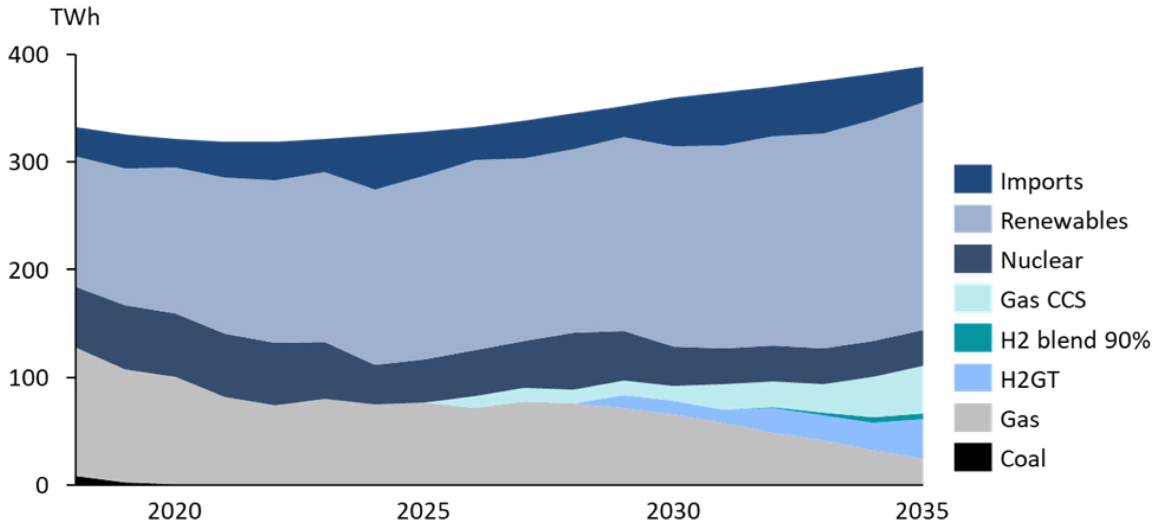


Figure 40: Roll-out schedule of hydrogen and CCS power generation (above) and technology transition in the electricity supply sourced (below)

56 Type of powerplants are: FOAK – First of A Kind, SOAK – Second of A Kind, NOAK – Nth of A Kind

Deployment of generation infrastructure by 2050 is based on an electricity demand of 594 TWh/year and assumes a growth of deployment of renewables and hydrogen generation as detailed on page 26. Broadly, this assumes that satisfying power demand will require:

- 58% of power coming from renewables in 2050. This assumes a constant share of renewable generation between 2030 and 2050.[57]
- ~100 TWh/year electricity will be generated from blue hydrogen in 2050, in line with the H21 NoE XL Scenario. This corresponds to a total of 9 GW_e of H2 CCGT powerplant capacity will have to be deployed between 2035 and 2050, assuming average load factors.
- Similar installed capacity of grid storage as in 2035.

The cost difference between internal combustion vehicles and fuel cells vehicles was calculated using the following technology costs and assumptions on sales of new FCEVs:

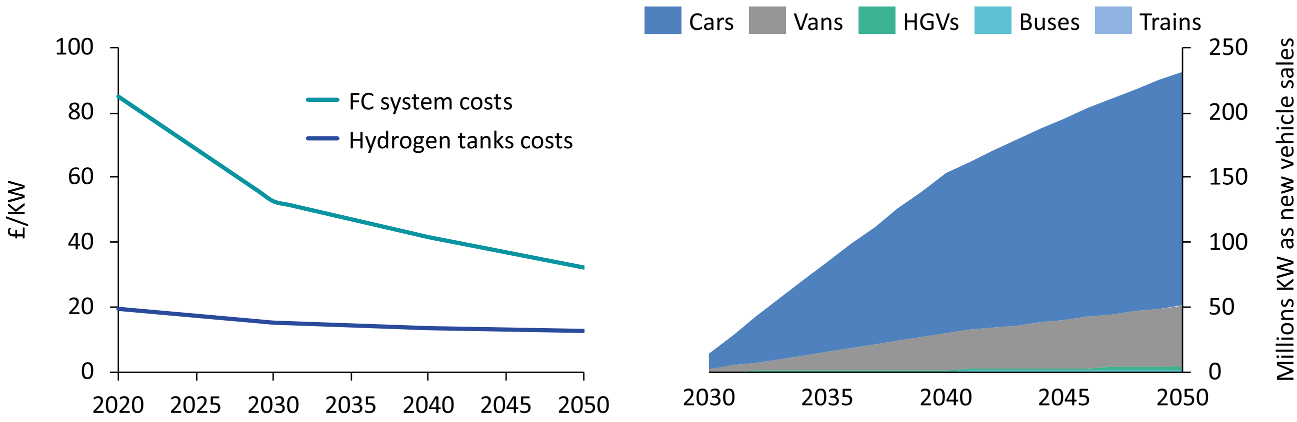


Figure 41: Left: Fuel cell technology cost curve; Right: New sales of vehicles in terms of FC capacity[58]

57 Whilst the share of renewables remains the same, the installed renewable capacity increased to the increase in power demand

58 Based on Fuelling Europe's Future, Element Energy for European Climate Foundation, 2018

Appendix 2: Macroeconomic assessment methodology

6 Appendix 2: Macroeconomic assessment methodology

6.1 Introduction

Consumption of goods and services drives industries, generate turnover, and jobs - both directly (in the producing industry) and indirectly (e.g. supply chain). It is for this reason that the demand for technologies, goods, and services under the form of investment and operational expenditure was quantified within all three scenarios of this study. These costs where further broken down into subcomponents which were attributed to different producing industries, as described below.

6.2 Industry classification mapping

The Standard Industrial Classification (SIC) is a system for classifying industries by a four-digit code. There are thousands of 4-digit codes, many of which correspond for similar industries. For this purpose, the SIC codes can be grouped into progressively broader industry classifications: industry group, major group, and division (2-digit code). The Office for National Statistics (ONS) produces datasets regarding the performance of industries, classified by their SIC, in the UK, their reliance on imports, and their contribution to GVA and job creation. These key outputs can be derived by understanding the demand that goes into each industry. This requires a mapping of the demand, namely all the incremental cost associated with the decarbonisation of the UK economy, relative to a business as usual case. For this reason, all costs generated in this study were mapped split into subcomponents and were mapped onto different industrial classifications. This includes both the CAPEX and OPEX components of the components (some of which are shown in Table 2) and was based on literature sources. This is shown illustratively in the example below, for the CAPEX of the hydrogen transmission system, based on the H21 NoE is split and mapped onto various industrial classifications:

Table 3: Example of industry classification mapping of the hydrogen transmission system based on the cost components in H21 NoE Report, table 8.5

CAPEX Item	Cost (£m)	Share	Industrial activity	4-digit SIC	Broad Industry Description	2-digit SIC
Design	231.8	7%	Engineering design activities for industrial process and production	71121	Architectural and engineering services;	71
Legal costs	94.1	3%	Construction of utility projects for fluids	42210	Construction	41-43
Project management	300	9%				
Commissioning	100	3%	Other specialised construction activities n.e.c.	43999	Construction	41-43
Pipeline materials	789.2	23%	Manufacture of tubes, pipes, hollow profiles and related fittings, of steel	24200	Basic iron and steel	24.1-3
PRS materials	544	16%	Manufacture of compressors	28132	Machinery and equipment n.e.c.	28
Pipeline build	664.4	19%	Construction of utility projects for fluids	42210	Construction	41-43
PRS build	391	11%				
HIPS pipeline	302.5	9%				
New district governors	10.1	0%				

ACTIVITY	COST (£M)	COMMENT
Design	231.8	Detailed design of the overall HTrS
Legal costs	94.1	Cost associated with land acquisition/wayleaves, etc.
Project management	300	Project management for the design, build and commissioning activity
Commissioning	100	Physical ties-in, connections and purging activity
SUB TOTAL HTRS (DESIGN/ PLANNING (CAPEX))	725.87	
HTS/LHTS		
Pipeline materials	789.2	Materials associated with the pipeline, e.g. steel pipe,linebends, valves, Pipeline Inspection Gauge (PIG) launch/reception facilities, etc.
PRS materials	544	Mechanical materials associated with Pressure Reduction Stations (PRS)
Pipeline build	664.4	Construction costs
PRS build	391	Construction costs
SUB TOTAL HTS/LHTS (CAPEX)	2,388.64	
HIP		
HIPS pipeline (lay rate including materials, install and reinstate, £0.5m/km)	302.5	Installation of hydrogen intermediate pressure pipelines/mains
New District Governors (DG) HIPS/MP/LP	10.1	Design and installation of DGs including all land and legal costs, etc.
SUB TOTAL HIPS (CAPEX)	312.6	N.B. CONTINGENCY IS INCLUDED WITHIN THE COST BUILD UP
OVERALL TOTAL CAPEX HTRS	3,427	

Table 8.5: HTrS CAPEX costs

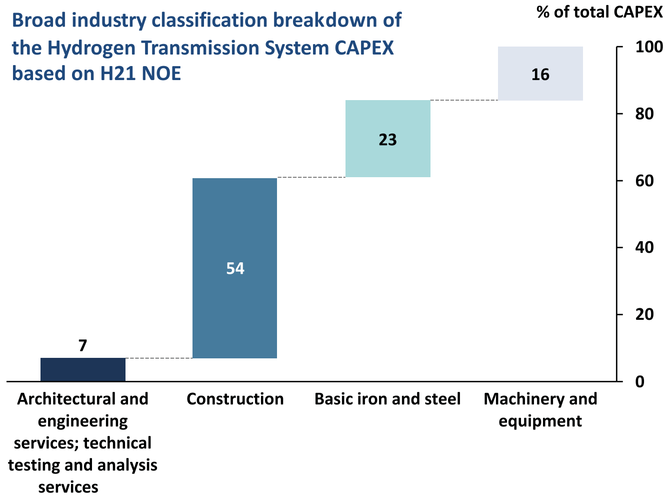


Figure 42: Visualisation of the H21 NoE cost data (left) and its mapping onto different industry classifications (2-digit SIC, left)

The table below shows the main broad industrial classifications onto which all 131 cost components and subcomponents in the UK-wide scenarios were mapped.

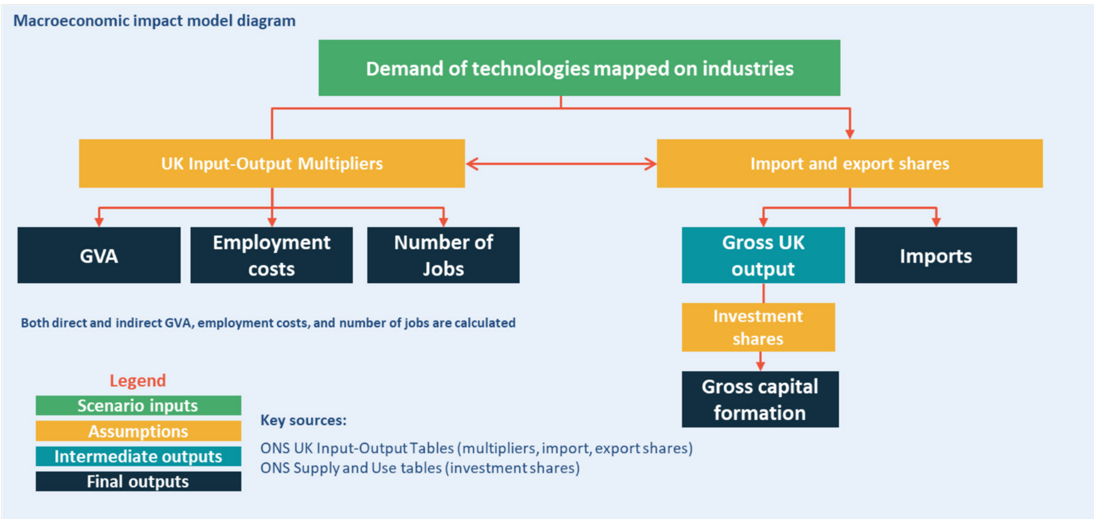
Table 4: Summary of industry classifications covering all cost components in the study

Broad Industry Description	2-digit SIC
Mining support services	09
Industrial gases, inorganics and fertilisers (all inorganic chemicals) - 20.11/13/15	20A
Basic iron and steel	24.1-3
Fabricated metal products, excl. machinery and equipment and weapons & ammunition - 25.1-3/25.5-9	25OTHER
Electrical equipment	27
Machinery and equipment n.e.c.	28
Gas; distribution of gaseous fuels through mains; steam and air conditioning supply	35.2-3
Electricity, transmission and distribution	35.1
Natural water; water treatment and supply services	36
Construction	41-43
Land transport services and transport services via pipelines, excluding rail transport	49.3-5
Water transport services	50
Insurance and reinsurance, except compulsory social security & Pension funding	65
Architectural and engineering services; technical testing and analysis services	71
Services to buildings and landscape	81

It is important to note that whilst there may be variation within the mapping at the 4-level SIC, with one component potentially being mapped on several very similar industrial activities, all of which falling within the same 2-digit SIC industry division, this does not influence the analysis as the domestic output and GVA are calculated based on ONS statistics, which only provide multipliers for the 2-digit SIC. The modelling approach behind these estimates is shown in the next section.

6.3 Economic impact modelling approach

A macroeconomic model was built for the purpose of this study. This model utilises inputs regarding the demand of different goods and services and statistical data to generate the following outputs: UK domestic output, imports, gross added value, and jobs.



- **The UK domestic output** is defined as the difference between demand and imports. The demand mapped on industries is used to calculate the UK domestic output, using historical import shares derived based on the UK's Office for National Statistics (ONS) Input-Output Analytical tables (IOTs).[59]
- **Imports** are calculated as the difference between the demand and UK domestic output
- **Gross Added Value (GVA)** is calculated based on the UK gross output, using industry specific multipliers provided by the UK IOTs, following the calculation methodology published by the ONS.[60]
- **The number of direct jobs** is calculated based on the relationship between UK gross output and the Labour Intensity for the relevant industries based on the ONS Annual Business Survey (ABS).[61] The labour intensity is defined as the number of employees required to generate £1 million turnover. The ABS provide information for all UK organisations, including number of organisations, the average number of employees and their turnover, allowing the calculation of the labour intensity. Indirect jobs are calculated based on the number of direct jobs and employment multipliers provided by the UK IOTs.

59 ONS UK input-output analytical tables, 2015 issue

60 Input-output analytical tables: methods and application to UK National Accounts, ONS, Oct 2017

61 Non-financial business economy, UK (Annual Business Survey) : 2017 provisional results

Authors: Element Energy www.element-energy.co.uk
Element Energy is a dynamic and growing strategic energy consultancy, specialising in the intelligent analysis of low carbon energy.

Report design | www.geniusandme.com