Deep Decarbonisation Pathways for Scottish Industries

A study for the Scottish Government

Final Report

December 2020

Scottish Government
Riaghaltas na h-Alba
gov.scot

elementenergy

Deep Decarbonisation Pathways for Scottish Industries

A study for
the Scottish Government

FINAL REPORT

December 2020

Scottish Government
Riaghaltas na h-Alba
gov.scot

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. The team of over 60 specialists provides consultancy services across a wide range of sectors, including the built environment, carbon capture and storage, industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon transport. Element Energy provides insights on both technical and strategic issues, believing that the technical and engineering understanding of the real-world challenges support the strategic work.

For comments or queries please contact:		ccusindustry@element-energy.co.uk
Emrah Durusut	Associate Director	emrah.durusut@element-energy.co.uk
Richard Simon	Senior Consultant	richard.simon@element-energy.co.uk
Elian Pusceddu	Senior Consultant	elian.pusceddu@element-energy.co.uk

Acknowledgements

We gratefully acknowledge the following stakeholders for the inputs provided during industry consultation:

- Alan Hunter, Owens-Illinois Inc.,
- Colin Pritchard, Ineos Chemicals,
- Douglas Grieve, Arjo Wiggins Fine Papers,
- Graham Birch, Petroineos,
- Peter Clark, Scotch Whisky Association,
- Tom Uppington, Alvance British Aluminium.
- Others who preferred to remain anonymous.

We would also like to convey our thanks to the teams of the Scottish Government and Zero Waste Scotland for their valuable input to the study.

Disclaimer

1 Executive summary

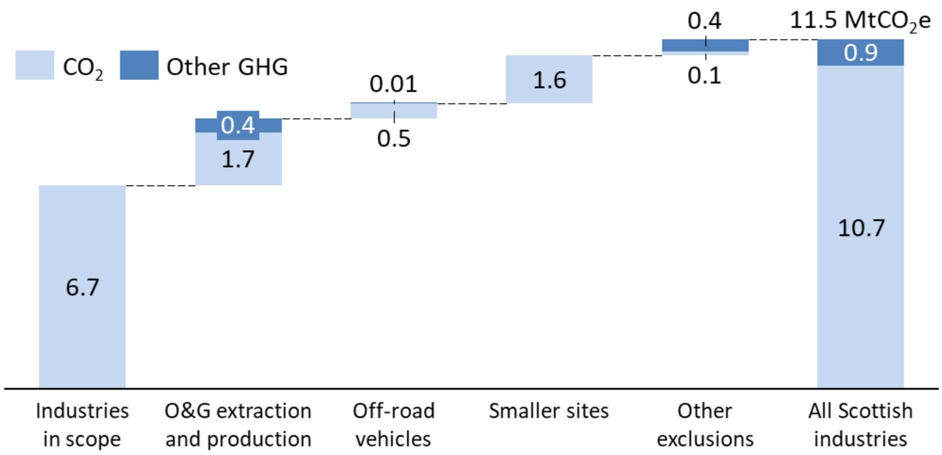
Pathways to deeply decarbonise industry and support the transition to net zero

The recent Climate Change (Emissions Reduction Targets) (Scotland) Act 2019 sets economy-wide targets for the reduction of greenhouse gas emissions to net zero by 2045 at the latest. Together with interim targets set for 2030 and 2040 mandating emission reductions of 75% and 90% against 1990 levels, respectively, this represents a divergence from the equivalent UK-wide target for 2050 and may introduce an imbalance between industries in Scotland and in the rest of the UK. Accordingly, Scotland's updated Climate Change Plan will set out actions to support achievement of the net-zero vision within the context of a Just Transition.

Work previously carried out by the Committee on Climate Change and others has shown that it would be technically feasible to meet a net-zero target in Scotland by 2045. Within this context, the Scottish Government commissioned Element Energy to assess viable pathways to deeply cut emissions from Scotland's industrial subsectors by improving energy efficiency, replacing fossil fuels with hydrogen, electricity, or in limited cases bioenergy (collectively termed 'fuel switching') and implementing carbon capture, utilisation, and storage (CCUS). This was done by assessing **three pathways informed by publicly available information on industry emissions and relevant decarbonisation technologies** and validating the analysis via **engagement with industry stakeholders.**

Emissions from industries in scope were 6.7 $MtCO_2e$ in 2018

This study focuses on emissions of carbon dioxide (**CO_2**) from existing energy-intensive industries that are categorised as '**scope 1**', i.e. occur on-site from the combustion of fossil fuels or directly from industrial processes. Specifically, emissions from industries in scope amounted to 6.7 $MtCO_2e$ in 2018, i.e. approximately 60% of all Scottish industrial emissions in the same year (11.5 $MtCO_2e$).



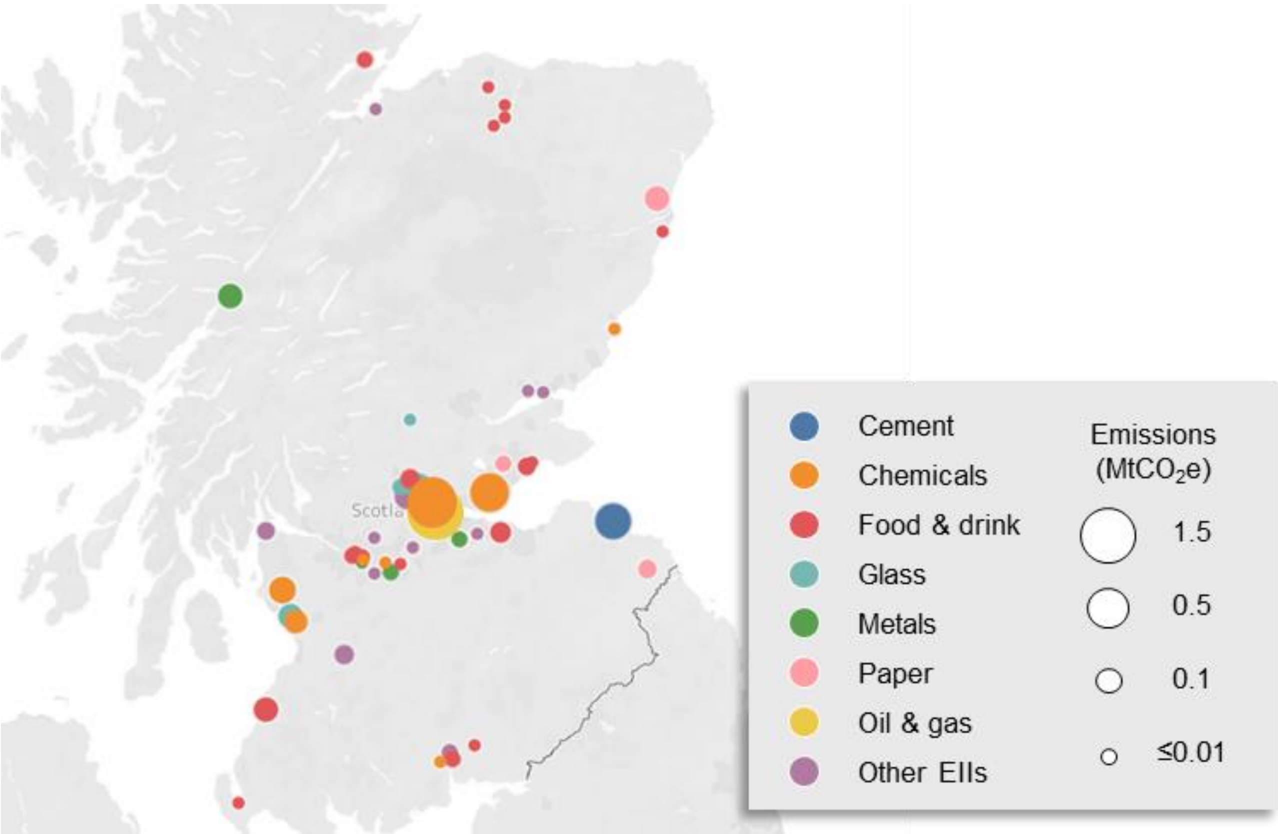
Greenhouse gas emissions from Scottish industry in 2018

Large sites that must report their emissions yearly were responsible for 95% of the emissions in scope, with the remaining 5% arising from smaller sites that are members of the Scotch Whisky Association.

The remaining emissions are out of scope as they are from non-manufacturing industrial subsectors or from sites or sectors for which data is unavailable. A small amount of non-CO_2 greenhouse gas emissions (0.02 $MtCO_2e$) that originates from sites in scope was excluded from the scope since they represent a very small portion of the overall emissions in scope (0.3%) and the available evidence does not allow detailed assessment of the corresponding emissions sources.

Emissions are highly concentrated in 3 sectors and within 50km from Grangemouth

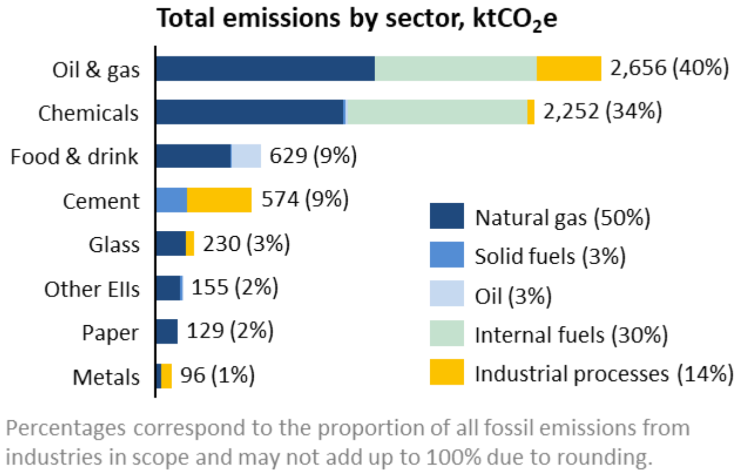
The industries in scope can be categorised into **eight energy-intensive sectors** in Scotland: chemicals, oil and gas, food and drink, cement, paper and pulp, glass, metals, and other energy-intensive industries (EIIs). **Emissions are highly concentrated** within a handful of sites and sectors: **75% of all emissions** from the industries in scope **occur within the seven highest-emitting sites** which themselves are found in just **three sectors** (chemicals, oil and gas, and cement). Furthermore, **6 out of the 7 largest sites are located within 50 km of Grangemouth**. This bears important implications for the geographical prioritisation of future decarbonisation efforts and for the corresponding infrastructure development plans.



Geographical distribution of emissions from sites in scope

Natural gas combustion is the biggest source of emissions, followed by the use of internal fuels within the oil and gas and petrochemical industries

The combustion of **purchased fossil fuels** (mostly natural gas) to supply heat and power to industry is responsible for **56% of all emissions** (from industries in scope, henceforth omitted), whereas the combustion of **internal fuels** (i.e. industry by-products generally burned on-site and with limited or no alternative use) accounts for **30%** of all emissions.



Fuel combustion and process emissions by sector

Several industrial processes emit CO_2 and other greenhouse gases as a result of the chemical reactions involved in the process themselves (e.g. the cement calcination reaction), leading to **process emissions** which combined contribute **14%** of all emissions.

Heating processes account for nearly three quarters of all industrial emissions

Heating processes are the leading driver for industrial emissions, accounting for **74% of all emissions**:

- Indirect high-temperature heating processes employed in the oil and gas and petrochemical industries are the single largest category of industrial emissions in Scotland, collectively contributing 33% of all emissions, most of which arise from internal fuel combustion.
- Indirect heating processes making use of steam are the second largest, accounting for 29% of all emissions.
- Direct heating processes are collectively responsible for 12% of all emissions, 90% of which relates to direct high-temperature processes such as furnaces and kilns.

Apart from a small portion of emissions arising from processes that could not be classified due to data limitations (2%), and process emissions (14%, already discussed above), the remaining (10%) is related to fuel combustion used to generate electricity in on-site combined heat and power (CHP) plants.

Three potential decarbonisation pathways were investigated

Three pathways were devised by combining energy efficiency measures, fuel switching, and CCUS, the last of which can be deployed to capture industrial emissions as well as those arising from the production of 'blue' hydrogen from natural gas reforming. Specifically:

- The **Efficiency** pathway assesses the maximum abatement that can be attained by implementing all – and only – energy efficiency measures.
- The **Electrification** pathway sees the electrification of all industrial processes for which it is technically viable and the deployment of **CCUS** on selected emissions sources not suitable for fuel switching.
- The **Hydrogen** pathway instead assumes that all fossil fuels are replaced by low-carbon hydrogen wherever this is technically viable. **CCUS** is also deployed here.

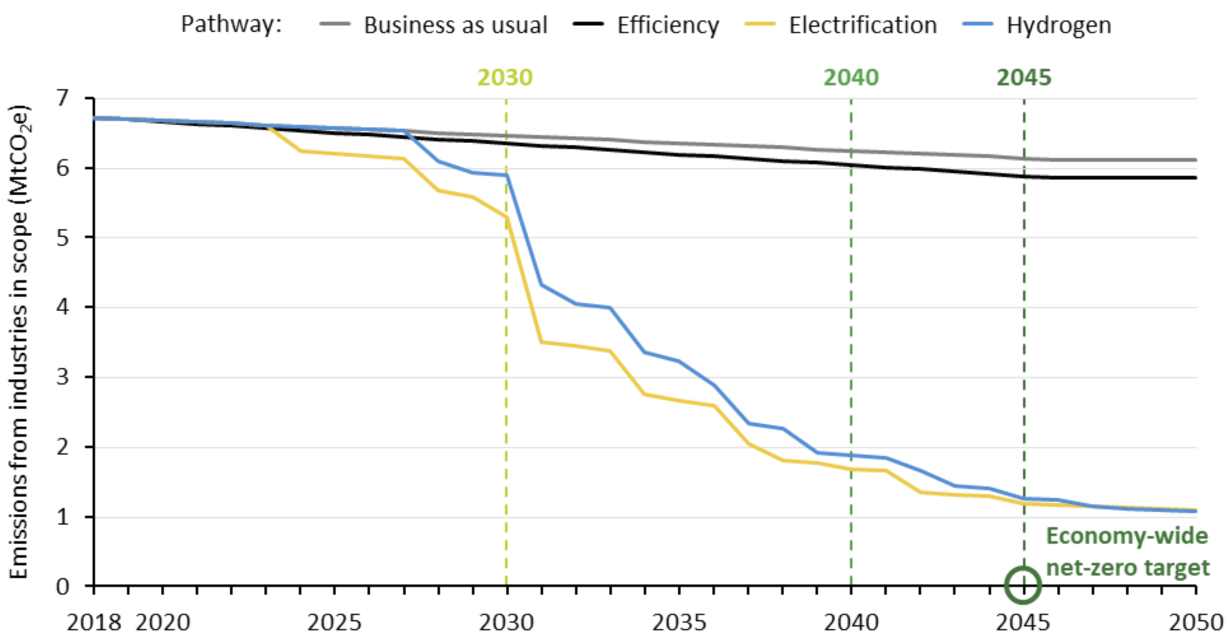
The research did not highlight any instances of fossil-fuelled appliances for which only electrification or only hydrogen fuel switching is viable, though industry stakeholders did indicate cases where one is likely to be costlier or more technically viable than the other. Hence, with the exception of the cement industry, no hydrogen is assumed to be used by industry in the Electrification pathway and no process electrification occurs in the Hydrogen pathway. In the cement industry, a mixed-fuel kiln that uses biomass, hydrogen and electricity is assumed to be used. It is also noted that hydrogen and electricity are assumed to be used to power CCUS in both pathways.

Two types of low-carbon hydrogen are considered: green hydrogen produced from the electrolysis of water powered by dedicated renewable energy sources, **and blue hydrogen** produced via the reforming of natural gas in combination with CCUS. In the Electrification pathway, only green hydrogen is assumed to be used. Instead, a mix of green and blue hydrogen is assumed to apply for the Hydrogen pathway, where the share of green hydrogen is assumed to grow from 10% in 2028 to 45% in 2045.

It is further assumed that neither the industrial products nor the processes used to manufacture them change over the 2020-2045 period. For this reason, the impact of demand-side measures such as product substitution, increased recycling – and more generally the transition to a circular economy – is not assessed here, although these may well have an important role to contribute in curbing industrial emissions in practice.

Emissions can be reduced by over 80% below 2018 levels by 2045

Emissions from the industries in scope are reduced by a similar amount in both the Electrification and Hydrogen pathways, collectively referred to as the deep decarbonisation pathways, reaching 1.2 $MtCO_2e$ and 1.3 $MtCO_2e$ by 2045, respectively. This represents a reduction of just over 80% from the 6.7 $MtCO_2e$ the same industries emitted in 2018.



Pathway emission trajectories

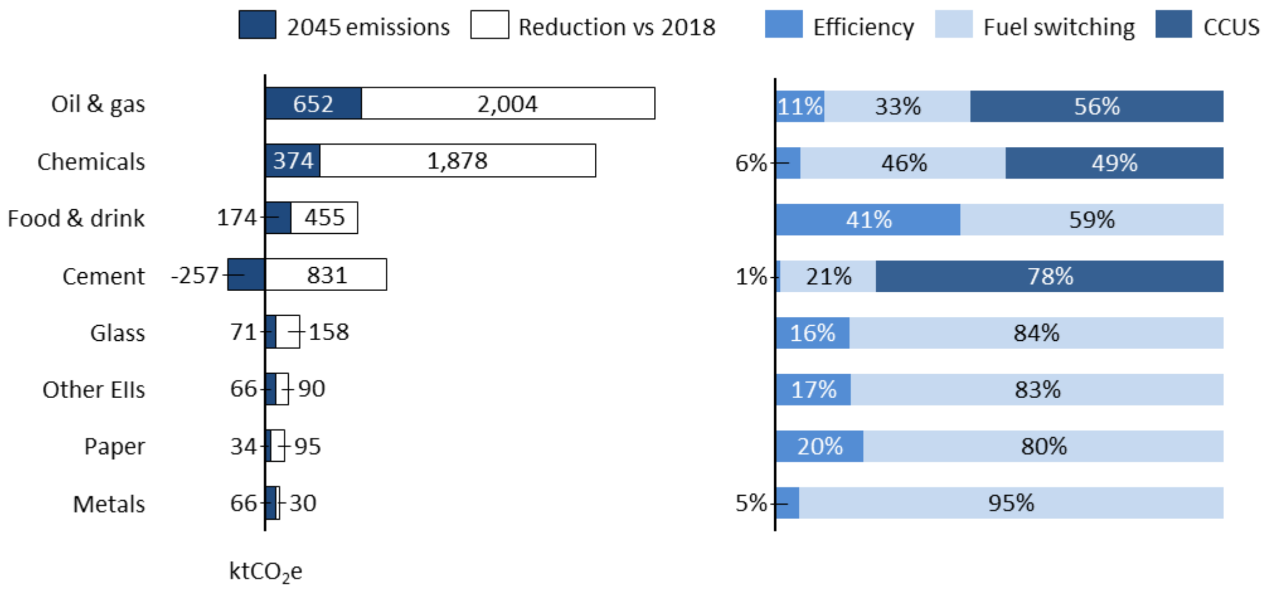
The similar decarbonisation potential of the two pathways results from the comparable feasibility and decarbonisation potential of fuel switching to electricity or hydrogen. This also implies that **a hybrid pathway,** where electrification occurs at certain sites and hydrogen fuel-switching at others, **would be able to deliver similar emission reductions as the pathways assessed here**, **possibly more rapidly and cost-effectively**. In the Efficiency pathway emissions in 2045 are only 12% below 2018 levels. This underlines the necessity to consider technologies able to deliver deeper emissions reductions for targeting net zero.

Emissions abatement for industries in scope in 2030, 2040, and 2045

	Electrification			Hydrogen		
	2030	2040	2045	2030	2040	2045
Residual emissions ($MtCO_2e$)	5.3	1.7	1.2	5.9	1.9	1.3
Net abatement vs 2018 levels	21%	75%	82%	12%	72%	81%
Cumulative abatement ($MtCO_2e$)	6	48	74	3	40	66

Both CCUS and fuel switching are essential for deep decarbonisation

Substantial decarbonisation occurs in all industrial sectors within both deep decarbonisation pathways. As shown in the chart below for the Electrification pathway (results for the Hydrogen pathway are shown in the appendix and are not repeated here due to their substantial similarity with the below), **nearly 60% of the overall abatement occurs within the oil and gas and chemical sectors**, which are the largest-emitting sectors today and are expected to remain so through to 2045.



Sectoral contributions to overall emissions abatement

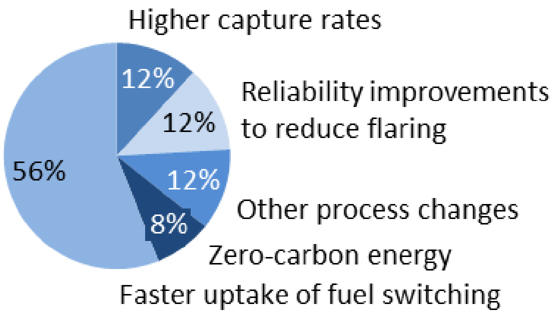
The abatement contributions of efficiency, fuel switching and CCUS to each sector's decarbonisation potential by 2045 are shown in the chart above:

- **CCUS is expected to be the main decarbonisation technology for the oil and gas, chemicals, and cement sectors**, delivering about 60% of the emissions abatement within these sectors. **Without CCUS, emissions would be 2.7 $MtCO_2e$ higher in 2045**. By combing bioenergy and CCS ('BECCS') within the cement industry nearly **0.3 $MtCO_2e$ of negative emissions** are also delivered. It is noted that other industries may also deploy BECCS, though this was not assumed to happen due to the relatively small emission levels of other likely bioenergy users.
- **Fuel switching accounts for about two thirds of the emission reductions in other sectors** and 41% of the overall abatement. **Switching fuels for steam generation should be of priority** in this context, given that over 80% of the abatement from fuel switching relates to indirect heating processes using steam. It is also worth noting that CCUS could also be considered *instead* of fuel switching, especially for large enough emission sources, since it would deliver comparable emission reductions.
- **Incremental improvements in energy efficiency offer a moderate overall contribution** (11% on average) but play a more important role in certain sectors (e.g. food and drink). Also, efficiency improvements can reduce the need for expensive new infrastructure by reducing energy demand, as well as reducing energy costs.

Residual emissions

It was noted above that over 1 $MtCO_2e$ remain unabated in 2045 in the deep decarbonisation pathways. These emissions could be tackled by:

- **Faster and fuller uptake of fuel switching technologies**, to ensure that all processes where fossil fuels can be replaced switch before 2045, and not after.
- **Increasing carbon capture rates** to 95% or higher, from the 90% assumed in this study.
- **Improving process reliability** and hence reducing flaring in the oil and gas and chemical industries.
- **CCUS and process changes** to reduce residual process emissions from the oil and gas, aluminium, and glass industries.



Tackling residual emissions

To completely eliminate all residual emissions, a higher level of negative emissions or the substitution of carbon-intensive products with low-carbon alternatives might be necessary.

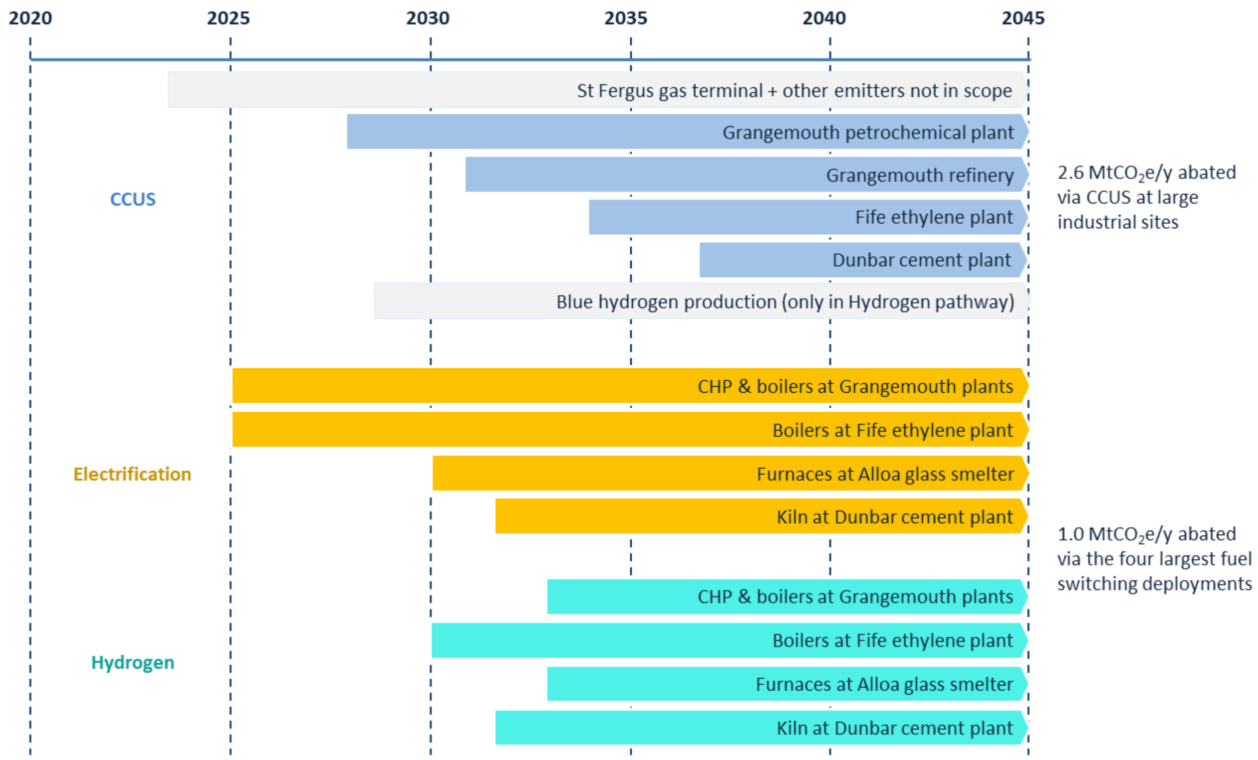
Four essential conditions to enable deep industrial decarbonisation by 2045

The achievement of the emission trajectories presented above is underpinned by the assumption that **four essential conditions** are met**:**

- **Significant economic incentives must be put in place via suitable policies**. Without these, no significant investment in deep decarbonisation is to be expected.
- **All decarbonisation options must be adopted promptly** when they become sufficiently mature from a technical and commercial point of view. This is a process which may also be brought forward with appropriate policy interventions.
- **Enabling energy assets and relevant infrastructure must be deployed in advance**, otherwise individual decarbonisation efforts might be delayed.
- **Site managers and investors need to have sufficient confidence in, and understanding of, the relevant technologies** and in the timescales for their commercialisation.

Failure to meet any of the above conditions would likely result in the delayed uptake of the key decarbonisation technologies, which may in turn make it even more challenging to achieve the accelerated net-zero targets.

Above all, **deep decarbonisation of the industries in scope hinges on the implementation of CCUS and fuel switching at the largest emission sources** (indicated in the timeline below), which would deliver two thirds of the overall abatement expected by 2045.

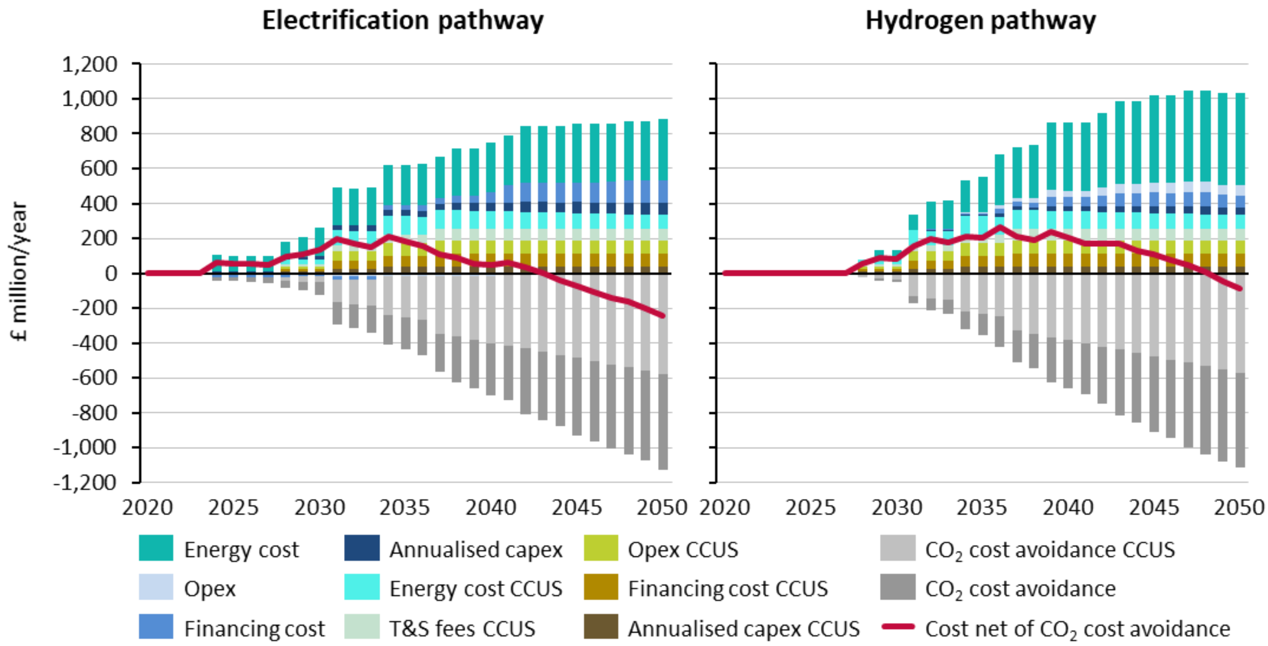


Timeline of key deployments

Efforts to make decarbonisation more affordable should focus on energy cost reductions

All industries in scope combined can be expected to incur additional costs of £0.8 to £1 billion per year by 2045, compared to the business-as-usual scenario where no fuel switching or CCUS are deployed. By 2045, it is estimated that this would add up to **a corresponding cumulative additional cost of £11.0 billion and £11.2 billion** in the Electrification and Hydrogen pathways, respectively.

The additional cost of low-carbon energy represents the greatest cost factor, due to hydrogen and electricity costing more than fossil fuels, **accounting for over £6 billion over the period in both pathways**. This is over 55% of the total additional cost of each pathway. Future efforts to make industrial decarbonisation more affordable should therefore focus on energy cost reductions. The **total financing requirement** to meet all capital expenditures until 2045 is **£3.0 billion and £2.5 billion in the Electrification and Hydrogen pathways** respectively.



Capex = capital expenditure; opex = operational expenditure; T&S fees = CO_2 transport and storage fees.
All cost factors not explicitly mentioning CCUS refer to fuel switching.

Additional cost of decarbonisation

If the cost of carbon is included it could instead be cheaper to decarbonise than to continue emitting greenhouse gases in the long term. It was estimated that **average carbon prices of £157/tCO_2e and £188/tCO_2e in the Electrification and Hydrogen pathways, respectively, could fully offset the additional cost of decarbonisation**. These carbon prices correspond to the **levelised cost of abatement** incurred within each pathway. Finally, it was found that fuel switching contributes a higher share of the costs yet offers lower carbon savings than CCUS, which implies a correspondingly higher cost of abatement.

Policy intervention is required to stimulate investment in deep decarbonisation, prevent carbon leakage, and promote a Just Transition to net zero

Policy is widely expected to have an irreplaceable role to play in making deep industrial decarbonisation happen. Above all, the interviewed representatives from the industries in scope believed **policy support** to be **critical for establishing a business case for investment in deep decarbonisation, while at the same time addressing the risk of carbon leakage**. Without policy intervention there is a risk that a strongly increasing carbon price could affect industrial competitiveness and induce certain industrial sites to shut down. In some cases, industrial sites may relocate to regions with a lower carbon price, which would not result in any carbon abatement.

Border Carbon Adjustment Measures (BCAMs) that adjust the price of carbon-intensive imports and exports to counteract any carbon price difference between different countries might be necessary **to address the risk of carbon leakage** in the absence of an international agreement on the price of carbon. Should BCAMs be implemented, which would entail UK-level policy action since Scottish Ministers do not have devolved competence for trade and import/export controls, it would then be possible to further increase the carbon price to incentivise decarbonisation, though this may nonetheless fail to generate an investable business case for fuel switching and CCUS.

Policy has two broad options to help create a business case for investment in deep decarbonisation: it could offer **direct financial support**, for instance by subsidising the cost of low-carbon energy through a Contract for Difference mechanism (so that the cost of electricity and hydrogen would be capped to that of natural gas) and providing investment grants or low-interest loans, or it could **stimulate demand for low-carbon products** via demand-side measures like green procurement. This last option could prove to be lower cost, but higher levels of market disruption could result from it, since disruptive innovations may also be favoured.

In light of the Scottish Government's commitment to pursue a 'Just Transition' to net zero, it is recommended that policy consider not just the technological and economic lens presented here also the broader societal and environmental dimensions within which the transition will take place. This approach might reveal ways in which the current workforce can benefit from disruptive innovation, rather than be adversely affected by it, and may also uncover relative merits of electrification or hydrogen fuel switching when environmental impacts other than climate change are simultaneously assessed.

Table of Contents

List of Figures

List of Tables

Acronyms

ATR	Autothermal reforming
AD	Anaerobic digestion
BAU	Business as usual
BCAM	Border Carbon Adjustment Measure
BTA	Border Tax Adjustment
BECCS	Bioenergy with CCS
BEIS	UK Department for Business, Energy and Industrial Strategy
CAPEX	Capital expenditure
CCC	Committee on Climate Change
CCGT	Combined cycle gas turbine
CCP	Climate Change Plan
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation, and storage
CfD	Contract for Difference
CHP	Combined heat and power
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DACCS	Direct air capture and storage
EII	Energy-intensive industry
ETS	Emissions trading scheme
FCC	Fluid catalytic cracker
GHG	Greenhouse gas
H_2	Hydrogen
NG	Natural gas
O&G	Oil and gas
OPEX	Operating expenditure
SIC	Standard Industrial Classification
SMR	Steam methane reforming
SWA	Scotch Whisky Association
T&S	Transport and storage

Note on hydrogen terminology

Blue hydrogen refers to hydrogen produced from a feedstock of natural gas by steam methane reforming (SMR) or autothermal reforming (ATR) coupled with carbon capture, utilisation and storage (CCUS) of the resulting carbon dioxide emissions. **Green hydrogen** refers to hydrogen produced through water electrolysis using renewable electricity. **Low-carbon hydrogen** refers to both blue and green hydrogen. **Grey hydrogen** refers to hydrogen produced via SMR or ATR, but *without* CCUS.

2 Introduction

2.1 Background

The Climate Change (Emissions Reduction Targets) (Scotland) Act 2019 sets **economy-wide targets for reducing emissions of all greenhouse gases to net zero by 2045** at the latest, with interim targets for 2030 and 2040 mandating emissions reductions of 75% and 90% against 1990 levels respectively.[1] These targets reflect Scotland's increased ambition for climate action and represent a divergence from the UK-wide net-zero target by 2050. This increased ambition could introduce an imbalance between industrial sites in Scotland and those in the rest of the UK. Accordingly, Scotland's updated Climate Change Plan (CCP), expected by the end of 2020, will set out a number of actions to support achievement of the **net-zero vision** within the context of a **Just Transition**.[2]

Substantial work has already been carried out in the UK and in Scotland specifically to assess decarbonisation options for industry, including:

- Roadmap development work that led to the 'Net Zero Technical Report' by the Committee on Climate Change (CCC),[3] the UK-wide 'Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050' for UK Department for Business, Energy, and Industry Strategy (BEIS),[4] and the 'Industrial Decarbonisation and Energy Efficiency Roadmaps: Scottish Assessment' summarised in the report by Zero Waste Scotland.[5]
- Sector-specific analyses investigating how individual industry subsectors can best decarbonise, which includes ongoing work on the review of the Scotch Whisky Industry Environmental Strategy, first launched in 2009 by the Scotch Whisky Association.[6]
- Multiple projects investigating ways to deploy low-carbon hydrogen (e.g. H2 Aberdeen)[7] and carbon capture and storage (e.g. Acorn project)[8] in Scotland.
- Work by the UK Government to establish suitable business models for CCUS.[9]

Such work has shown that it would be technically feasible to meet a net-zero target in Scotland by 2045 and possibly sooner, provided that the UK adopts an equivalent target for 2050.[10] **This will require deep decarbonisation within all sectors, including industry.**

Within this context, the Scottish Government commissioned Element Energy to **assess viable pathways to reduce emissions from Scotland's industrial subsectors in line with the accelerated net-zero targets** and interim milestones. The results are presented

1 https://www.gov.scot/policies/climate-change/reducing-emissions/.
2 https://www.gov.scot/policies/climate-change/.
3 https://www.theccc.org.uk/publication/net-zero-technical-report/.
4 https://www.gov.uk/government/publications/industrial-decarbonisation-and-energy-efficiency-roadmaps-to-2050.
5 https://www.resourceefficientscotland.com/sites/default/files/downloadable-files/Industrial Decarbonisation and Energy Efficiency Roadmaps Scottish Assessment.pdf
6 https://www.scotch-whisky.org.uk/insights/sustainability/environmental-strategy/2020-environmental-strategy-report/.
7 http://www.h2aberdeen.com/.
8 https://www.act-ccs.eu/acorn/.
9 https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-business-models.
10 https://www.climatexchange.org.uk/blog/net-zero-emission-by-2045-achievable-for-scotland-says-committee-on-climate-change/.

in this report. In parallel, the Scottish Government also commissioned Element Energy to establish and develop an understanding of industrial energy efficiency and decarbonisation projects that are currently in the pipeline, and to develop a database of such projects. That study focuses on the shorter-term development pathways of these projects, and how Scottish Government can aid and influence project sequencing.

2.2 Scope

Industries in scope

The analysis focuses on emissions from **existing energy-intensive industries** arising either from the on-site combustion of fossil fuels or directly from industrial processes, collectively defined as '**scope 1**' **emissions**.[11] According to the Scottish Greenhouse Gas Inventory, **emissions from all Scottish industries combined accounted for 28% of overall Scottish emissions in 2018, or 11.5 MtCO_2e out of 41.6 MtCO_2e** (million tonnes of carbon dioxide equivalent).[12] Within this total, the **scope of the quantitative analysis** presented below refers to two sets of industrial sites for which site- or sector-specific emissions data could be accessed:

- Large sites required to report their emissions on a yearly basis and whose emissions can be found on the National Atmospheric Emissions Inventory (NAEI) on large point sources,[13] which features **63 large sites** operating in industrial sectors within scope (sectoral focus defined below) that collectively emitted **6.4 MtCO_2e** in 2018.
- Members of the Scotch Whisky Association (SWA) (127 sites), whose emissions are analysed within a recent publication by Ricardo for SWA.[14] Net of the 11 large distilleries already included in the NAEI data, the **other SWA member sites** emitted an additional **0.3 MtCO_2e in 2018**.

Carbon emissions from industries in scope thus amounted to 6.7 MtCO_2e in 2018, which represents 58% of all greenhouse gas (GHG) emissions from Scottish industries in the same year.

11 Scope 2 emissions associated with purchased electricity or steam which is generated off-site by a third-party and scope 3 emissions to other parts of an industry's supply chain are beyond scope. For further detail on the differences between scope 1, 2, and 3 emissions see https://www.carbontrust.com/resources/what-are-scope-3-emissions.
12 A breakdown of all Scottish emissions (in and out of scope) is provided in Appendix 8.3. Emissions from all Scottish industries defined by the 'industry' CCP mapping. The original dataset can be accessed at https://www.gov.scot/publications/scottish-greenhouse-gas-emissions-2018/.
13 This includes combustion of all fossil fuels as well as process emissions, but not emissions from the combustion of bioenergy sources (e.g. biomass or biogas) which are known as 'biogenic' and are considered carbon neutral for accounting purposes.
14 Ricardo (2020).

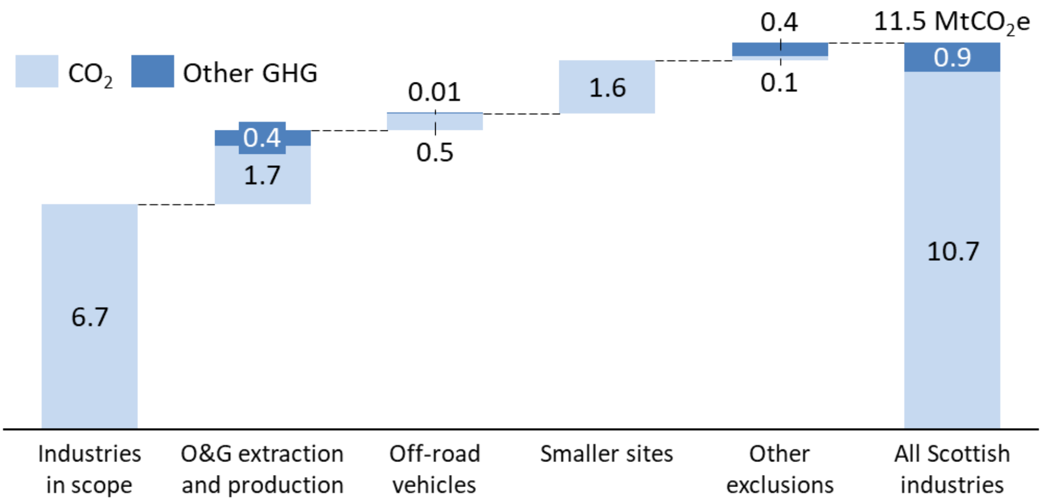


Figure 1 – Greenhouse gas emissions from Scottish industries in 2018

As detailed in Figure 1, the remaining out-of-scope emissions relate to oil and gas extraction and production,[15] off-road vehicles, a multitude of smaller sites for which emissions data is unavailable, and other subsectors which are not in scope for this study. It is worth noting that a small portion (0.02 $MtCO_2e$) of the emissions of GHGs other than CO_2 actually originates from sites in scope.[16] However, these were excluded from the scope since they represent a very small portion of the overall emissions in scope (0.3%) and the available evidence does not allow detailed assessment of the corresponding emissions sources. Further detail on out-of-scope emissions and, when relevant, how they were estimated is provided in Appendix 8.3.

Sectoral focus

This study groups Scotland's **most energy-intensive industries** into the **eight sector categories** and **22 subsectors** reported in Table 1. This categorisation clearly shows that emissions are highly concentrated within a handful of sites and sectors: **75% of all emissions** from industries in scope **occur within the seven highest-emitting sites** which themselves are found in just **three sectors**, i.e. chemicals, oil and gas, and cement.[17] Combined, these sites accounted for about 12% of all Scottish emissions in 2018.

15 The Kinneil Terminal within the Forties Pipeline System is the only site within this subsector which was kept within scope because of its tight connection to other sites within the Grangemouth complex.
16 Of these, 60% relates to nitrogen oxides (N_2O) and 40% to methane (CH_4).
17 Specifically, the 7 largest sites are: the Grangemouth refinery and chemical plant, the Fife ethylene plant, the Dunbar cement plant, the Kinneil Terminal within the Forties Pipeline System, and two large combined heat and power plants in Grangemouth.

Table 1 – Energy-intensive industries in scope and their subsectors

Industry sector	Subsector	# sites	2018 emissions[18] ($ktCO_2e$)
Cement	Cement	1	574
Chemicals and pharmaceuticals	Petrochemicals[19]	2	1,470
	CHP[20]	3	727
	Other chemical products	5	204
	Pharmaceuticals	2	42
	Other non-metallic mineral products[21]	1	5
Food and drink	Distilleries and breweries[22]	129	529
	Food products	9	100
Glass	Glass	4	230
Metals	Aluminium	1	67
	Steel finishing	2	16
	Forged products	1	13
Oil and gas	Refining	1	1,638
	CHP[20]	1	465
	Gas terminal	1	357
Paper and pulp	Paper	4	115
	CHP[20]	1	15
Other energy-intensive industries	Veneer sheets and wood-based panels	3	112
	Computers, electronics and optical products	1	17
	Other non-metallic mineral products[21]	4	14
	Rubber products	1	13
	Newspapers, magazines, & other publications	2	<1
Total		**179**	**6,721 $ktCO_2e$**

Geographical focus

Industrial emissions are highly concentrated not just sectorally but also geographically, as visually outlined in the map below. **Six out of the seven largest industrial emitters** as well a multitude of smaller sites are located **within 50 km of Grangemouth**[23] – the geographical heart of the refining and chemical industries – where approximately **75% of all emissions** from the industries in scope arise. Such geographical concentration of industrial activity and emissions carries three main implications:

18 Sums may not add due to rounding.
19 Petrochemicals mostly refers to olefins / ethylene.
20 Within the analysis, emissions from each CHP plant are re-allocated to industrial users of the heat and power which they produce.
21 The 'Other non-metallic mineral products' subsector exists both within the chemicals sector, where it refers to a manufacturer of flame retardant construction materials, and within the 'other EIIs' sector, where it refers to various asphalt producers and a brick manufacturer.
22 This includes 127 SWA member sites (>95% of subsector emissions) and 2 breweries.
23 I.e. all of the sites indicated in footnote 17 except for the cement plant.

- It provides a clear **geographical priority for future decarbonisation efforts** in Scotland since all pathways to net zero must substantially rely on the decarbonisation of the Grangemouth cluster.
- It offers an early insight into **potential synergies between neighbouring industries**, which could pool their demand for low-carbon energy and the corresponding infrastructure and thus spearhead the early development of low-carbon infrastructure at scale.
- It suggests that **decarbonisation options that may be economically viable for clustered sites may not be equally viable for more isolated sites** with more limited – and likely more expensive – access to the relevant infrastructure.

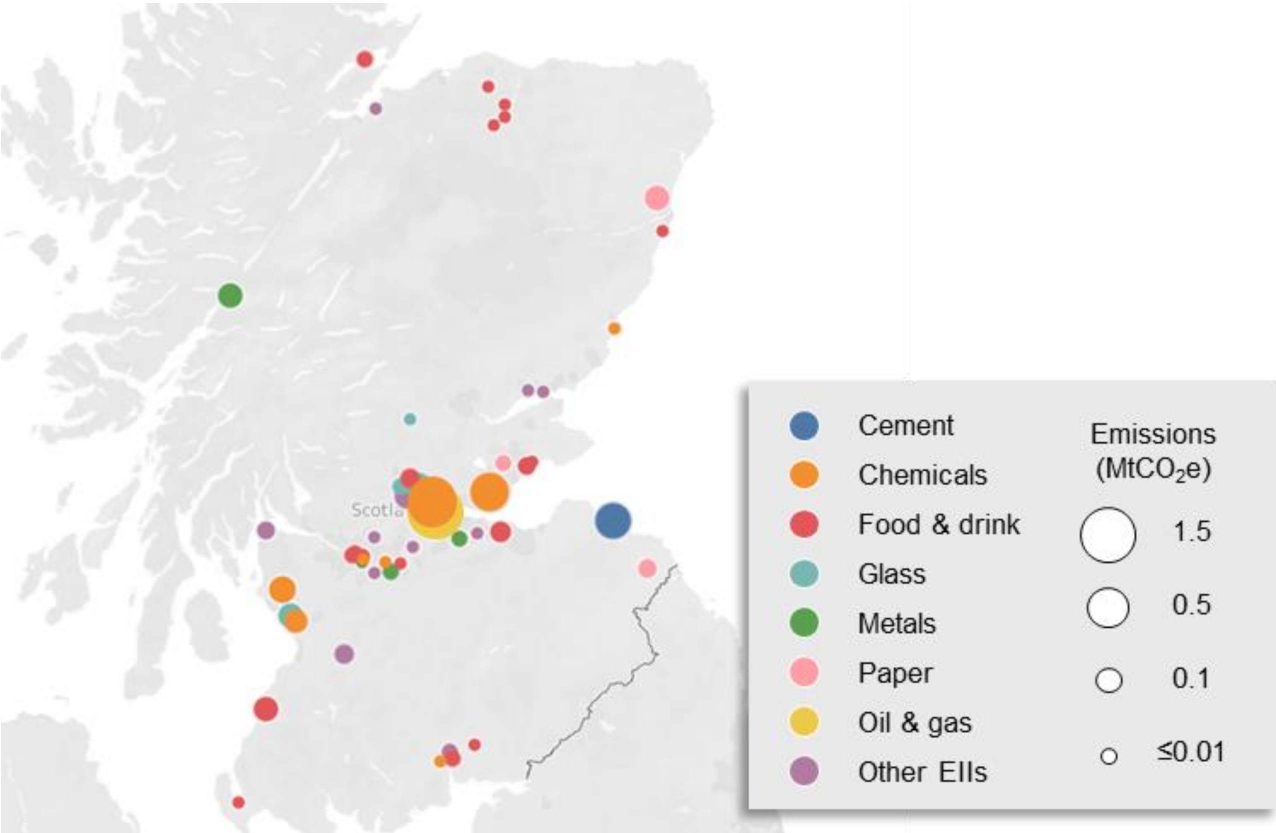


Figure 2 – Geographical distribution of emissions from sites in scope[24]

24 Note that some of the sites on the map are partly or fully hidden. For instance, the Grangemouth chemical plant (orange disc) partly hides the Grangemouth refinery (yellow disc), and completely hides the Kinneil gas terminal. Also, SWA member sites not included in the NAEI dataset are not mapped here.

2.3 Approach

Assessment of emissions, energy, and fuel use

As a first step, each industrial subsector was represented via simplified archetypes which enabled a close representation of the energy and fuel use across different industrial processes. Publicly available datasets and literature were used to inform the creation of each archetype. Specifically, site-level emissions of fossil CO_2 were obtained from the National Atmospheric Emissions Inventory (NAEI) on large point sources,[25] to which sector-level data from the Scotch Whisky Association was added.[26] Biogenic emissions were then estimated through the comparison of multiple datasets including the NAEI and the Scottish Pollutant Release Inventory (SPRI),[27] and complemented by information provided by industrial stakeholders.

The breakdown of energy and fuel use across different industrial subsectors was initially obtained from BEIS' 'Energy consumption in the UK' end-use tables.[28] These tables provide a UK-wide breakdown of energy and fuel use by process type for each subsector (as defined by its Standard Industrial Classification, or SIC), but do not offer a view around possible regional differences. In this study it was initially assumed that UK average values also apply at the Scottish level, but this assumption was later improved based on a previous model of industrial processes by Element Energy, and finally by validating the breakdown with industry stakeholders. Following this approach, all emissions from the industries in scope were mapped against sector-specific and cross-sectoral processes (see Appendix 8.4). The results from this analysis are presented in Chapter 3.

Analysis of relevant decarbonisation options

Relevant decarbonisation options for each emission source were defined via a review of publicly available literature.[29] **Three options were found to be pivotal to the deep decarbonisation of energy-intensive industries** and represent the core of the quantitative analysis proposed in this study:

- **Energy efficiency** measures to reduce energy use and hence abate emissions.
- **Fuel switching**, i.e. replacing fossil fuels with electrification, low-carbon hydrogen,[30] or, in selected cases, bioenergy (including waste biomass).
- **Carbon capture, utilisation, and storage (CCUS)** applied on combustion and process emissions from industrial sites as well as to decarbonise hydrogen production.

Other decarbonisation options which are only applicable to selected emission sources were reviewed in the context of addressing residual emissions from sources which cannot

25 This includes combustion of all fossil fuels as well as process emissions, but not emissions from the combustion of bioenergy sources (e.g. biomass or biogas) which are known as 'biogenic' and are considered carbon neutral for accounting purposes. It is also noted that some of the site-level data is estimated, rather than reported by site operators.
26 This data was published by Ricardo (2020) and was analysed as explained in Appendix 8.3.
27 https://www.sepa.org.uk/environment/environmental-data/spri/.
28 https://www.gov.uk/government/statistics/energy-consumption-in-the-uk.
29 A full bibliography of the sources reviewed for this task is provided in Appendix 8.1.
30 Including both blue and green hydrogen. See note on terminology on page 12 for definitions.

be decarbonised through the options introduced above. The applicability of each option within each sector was also reviewed with industry stakeholders, and their technical and economic characteristics are discussed in Chapter 4.

Design of viable decarbonisation pathways

Three decarbonisation pathways were designed by combining the above options:

- The first pathway relies on extensive deployment of energy efficiency measures but no fuel switching or CCUS. Accordingly, it is named the **Efficiency** pathway.
- The other pathways see progressive deployment of **fuel-switching technologies and CCUS** but a lower uptake of energy efficiency improvements. These pathways are solely differentiated by the deployment of *either* electrification *or* hydrogen fuel switching technologies.[31] For this reason, they are named the **Electrification** and **Hydrogen** pathways, respectively, and are jointly referred to as the **deep decarbonisation pathways**.

Since this study seeks to identify the potential impact of the decarbonisation pathways on the current industrial base, rather than to project what emissions will be like as a result of changes to their markets, **a core assumption underpinning all pathways is that the scale and type of industrial activity remains steady until 2050**. Further detail for each pathway is provided in Chapter 5.

Stakeholder engagement

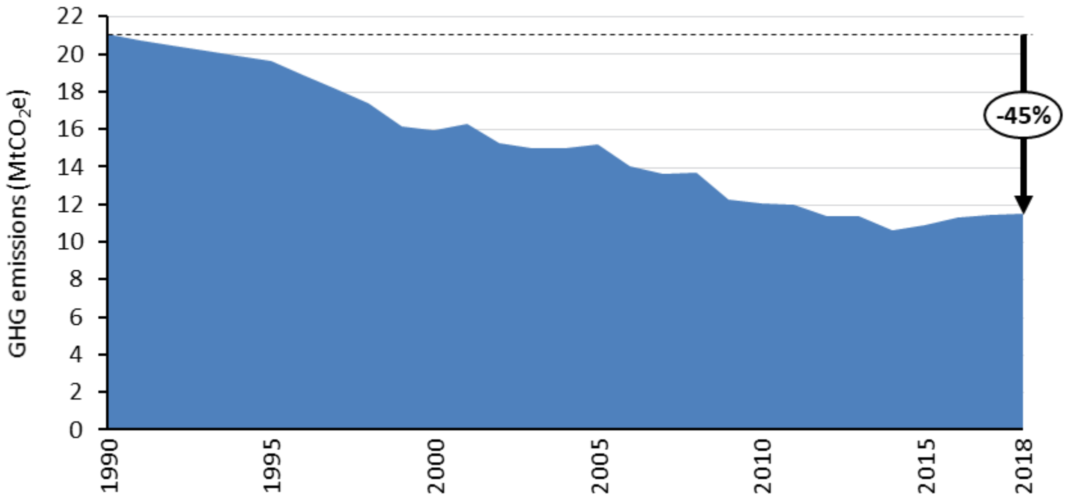
Stakeholder engagement played a central role in this study. Eight representatives[32] from some of the largest emitting sites within each sector were consulted via telephone interviews to validate the relevance and impact of each decarbonisation option and to understand the challenges they face on the way to implementing any deep decarbonisation pathway. These interviews helped increase the accuracy of the representation of industrial sites responsible for over 90% of in-scope emissions,[33] and were also instrumental to obtain information around the investment cycles and investment criteria that underpin all decarbonisation pathways outlined in this report. The insights gained through these interviews are included throughout the report where relevant, and they are also summarised in Section 6.4.

31 With the exception of the cement industry, where *both* are deployed in both pathways for reasons discussed in Section 4.2.1.
32 A list of the stakeholders who were happy to be named is shown in the Acknowledgments.
33 Sites directly interviewed were responsible for about 80% of all CO_2 emissions in 2018, and an additional 15% of the emissions arose from sites conducting activities similar to those of interviewed stakeholders.

3 Overview of emissions in scope

3.1 Historical emissions and reductions since 1990

Emissions from all Scottish industries amounted to 21.0 $MtCO_2e$ in 1990, the **baseline year** for both the Climate Change (Scotland) Act 2009 and the Paris Agreement. As shown in Figure 3, **emissions had fallen 45% by 2018, reaching 11.5 $MtCO_2e$**. Unfortunately, it is not known what percentage of the 1990 emissions refers to industries in scope, hence it is not possible to determine the baseline level of emissions from these.



Note: no emissions data are available for devolved administrations for 1991-1994 or 1996-1997. Hence, emission levels for these years have been interpolated from the available data. Source: NAEI (2019).

Figure 3 – Historical emissions from Scottish industries

Analysis from the Committee for Climate Change (CCC) however shows that the following have contributed the most to emissions reductions since 1990:[34]

- The closure of the Ravenscraig steelworks in 1992 reduced emissions by over 3.5 $MtCO_2e$.
- Emissions from paper, print and publications reduced by over 1.5 $MtCO_2e$.
- Fugitive emissions from fossil fuels reduced by about 2.5 $MtCO_2e$.

Combined, the above contributed nearly 80% of the emissions reduction from all Scottish industries, which indicates that emissions reductions from the other industries in scope must have been significantly lower than the 45% average and that emissions from certain sectors have in fact increased significantly in this time. It should also be noted that only part of the emissions reduction since 1990 resulted from decarbonisation of industrial processes. Indeed, the CCC highlights that “structural changes to the manufacturing

34 Committee on Climate Change (2019).

sector (i.e. faster growth for lower-carbon parts of the manufacturing sector)" significantly contributed to reducing overall emissions.[35]

Additionally, while UK *territorial emissions* reduced by 41% between 1990 and 2016, *consumption-based emissions* only reduced by 15% over the same period.[36] Although the current emissions targets only relate to territorial emissions, the smaller reduction in consumption-based emissions may represent an issue at a global level since it implies that a lower overall level of abatement has been attained since the baseline year. Furthermore, the divergence between territorial and consumption-based emissions also hints at the progressive relocation of energy-intensive industries away from the UK – an issue known as '**carbon leakage**' which is discussed further in the concluding chapter.

3.2 Emissions by sector and by source

Industrial emission sources can be categorised at a high level depending on whether they yield 'combustion' or 'process' emissions:

- **Combustion emissions** arise from the combustion of fuels to supply the energy required by the industrial processes and can be broken down according to the type of fuel used.
- **Process emissions** instead refer to the greenhouse gases produced within the chemical reactions involved in some industrial process (discussed below) and subsequently released to the atmosphere.

35 This statement applies to the UK as a whole, rather than to Scotland alone. However, the closure of the Ravenscraig steelworks in 1992 represents a clear example of how this applies to Scotland. Source: Committee on Climate Change (2018).
36 Owen *et al*. (2020). 'Territorial emissions' exclusively refers to emissions arising from activities *based* in the UK, whereas consumption-based emissions account for all emissions embedded in goods purchased in the UK.

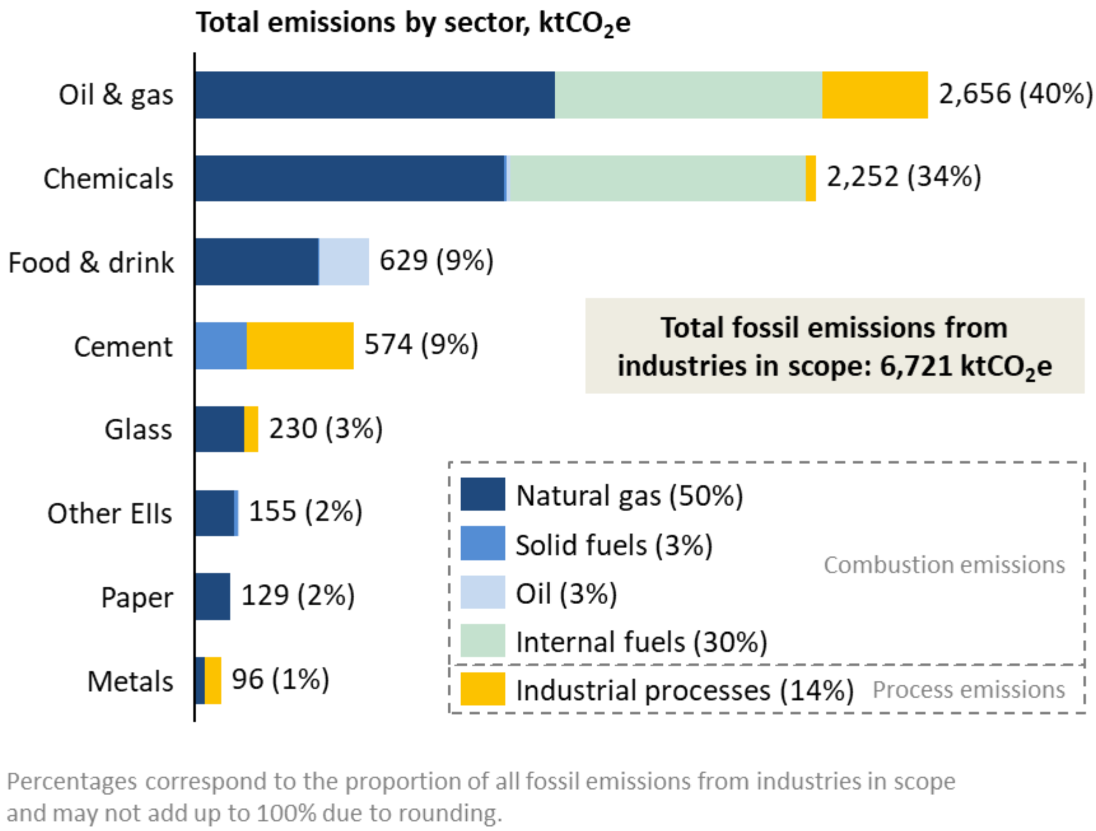


Figure 4 – Fuel combustion and process emissions by sector, 2018

As can be seen in Figure 4, which shows a breakdown of the sectoral emissions following the categorisation proposed above, **86% of all emissions from industries in scope can be classified as combustion emissions and 14% as process emissions**. It should be noted that only *fossil* emissions are analysed below, though some of the industries in scope also emit biogenic CO_2 from the combustion of biomass or biogas. In accordance with carbon accounting standards, biogenic emissions are treated as carbon neutral, hence the pathways assessed do not consider strategies to reduce them.[37] Since bioenergy sources constitute a sizeable share of the energy used by certain industries, biogenic emissions are discussed further in Box 1.

Emissions from the combustion of purchased fossil fuel

***Purchased* fossil fuel combustion** is the single largest category of emissions sources, responsible for **56%** of all emissions (from the industries in scope, henceforth emitted).[38] These relate chiefly to natural gas combustion, to which 89% of the corresponding emissions can be linked. Solid fuels[39] and oil are also used, for instance in processes where their use more efficiently generates the intense flames useful to achieve the high

37 This accounting standard arises from the assumption that all emissions relating to bioenergy use are offset by absorption of atmospheric CO_2 during plant growth through photosynthesis.
38 The term 'purchased' is used to differentiate these fuels from the 'internal fuels' discussed below.
39 Mostly coal but also other solid fuels, like the waste-derived fuels burnt in the cement kiln.

temperatures necessary for certain chemical reactions[40] or at sites not connected to the gas grid (e.g. in the food and drink sector).

Emissions from the combustion of internal fuels

Emissions from the combustion of 'internal fuels' account for 30% of all emissions. Internal fuels are industry by-products that cannot be sold or serve any other purpose and are therefore generally burned on-site. Specifically, the internal fuels relevant to Scottish industries are:

- fuel 'off-gases' co-produced within the refining and olefins steam cracking process,[41] and
- petroleum coke ('pet-coke') produced and consumed within the refinery's fluid catalytic cracker (FCC).

Since internal fuels are co-produced in fixed proportions to the main output product[42] and must always be burnt, **emissions from their combustion cannot be reduced without changing the process and can therefore only be captured**.[43] It could of course be possible for internal fuels to be sold to third parties instead of being burnt on site, but, since these third parties would most likely also have to burn them, no *net* emissions abatement is expected to occur via this route, hence this option is not considered further.

Process emissions

As mentioned above, **industrial processes contribute 14% of all emissions**. The main processes that give rise to direct emissions in Scotland include:

- The calcination reaction occurring within the cement kiln (42% of all process emissions).
- Steam methane reforming (SMR)[44] at the Grangemouth refinery (20%).
- Carbon anode degradation in the aluminium electrolysis process (7%).
- Raw material degradation during glass melting (5%).
- CO_2 separation and purging of the flare heads within the gas terminal (4% and 2%, respectively).
- The remaining (20%) is related to flaring at the Grangemouth refinery and gas terminal, and at petrochemical sites.

As in the case of emissions from internal fuel combustion, **process emissions are also unaffected by energy efficiency improvements and fuel switching**. Instead, their

40 This is for instance the case in the cement kiln. While gas-fired kilns also exist, these are generally considered less efficient.
41 This is the core process for olefins (e.g. ethylene) production and is found at the petrochemical plants in Grangemouth and Fife.
42 For instance, fuel gases and ethylene are produced at a fixed ratio for a given feedstock (e.g. naphtha). Slight differences in this ratio may arise due to changes in feedstock, and increased use of ethane can for instance slightly reduce the proportion of internal fuels that are co-produced with ethylene. When this happens, more natural gas must be purchased to offset the reduced internal fuel production, and this could in turn be fuel-switched to hydrogen.
43 Improvements in energy efficiency will however reduce the total amount of energy required, which can reduce the use of any purchased fossil fuels that is co-fired with the internal fuels (e.g. natural gas in the case of steam cracking, as discussed in the previous footnote). It is also noted that fuel switching could be part of the solution to reduce emissions from internal fuels, but only when it is combined with CCUS as discussed in Box 4.
44 Note that this is *grey* hydrogen, since CCUS is not currently installed.

abatement must rely on alternative methods like CCUS (not generally applicable to flaring emissions, as discussed below), product substitution, process change, or potentially on the development of breakthrough technologies. Among these options, this study performs a quantitative assessment of process emissions abatement via CCUS; other options, which are speculative at this stage and of limited applicability, are instead considered in the context of abating residual emissions (Section 6.1.4).

It is worth noting that flaring is not technically considered a source of process emissions, since the CO_2 is emitted following the combustion of hydrocarbon gases, which would suggest categorising flaring as a source of combustion emissions. Where flaring however diverges from all other combustion emission sources is in the fact that gases are not flared to supply energy to industrial processes. Rather, flaring is carried out for operational reasons, for instance to prevent the potentially explosive build-up of feedstock gases or to avoid the release of methane-rich gases with a global warming potential far higher than that of CO_2. Furthermore, **flaring-related emissions are unlikely to be suitable for CCUS due to safety and economic reasons**, though further work may find cases were this is applicable**.** [45]

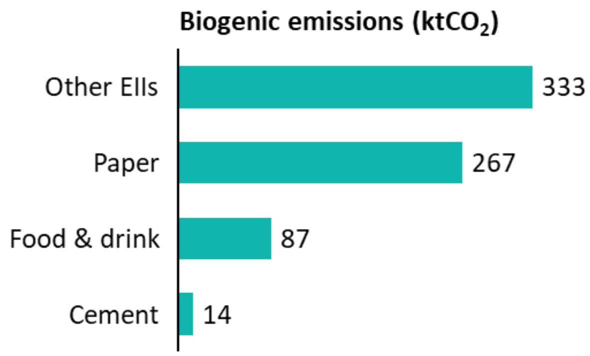
45 Options to reduce flaring emissions are assessed in Element Energy (2019a).

Box 1 – Biogenic emissions

The combustion of biomass and biogas (collectively 'bioenergy') for energy generation leads to emissions of CO_2 (an estimated 0.7 $MtCO_2$ in the case of the industries in scope). **In accordance with typical carbon accounting standards**, biogenic emissions are considered carbon neutral. The reason for this assumption is that the carbon stored within all bioenergy sources was previously extracted from the atmosphere by the source trees or other vegetation. It is however acknowledged that the existence of emissions from the bioenergy supply chain (e.g. transportation) as well as emissions related to 'land use and land use change' (LULUC) may imply that **not all biogenic emissions are carbon neutral**.

Since biogenic emissions are considered carbon neutral, this study does not consider ways to reduce them. Nevertheless, their inclusion in the analysis is useful to obtain a more accurate assessment of the energy and fuel requirements across the different industrial process in Scotland. Specifically, biogenic emissions originate from the following processes:

- Biomass combustion at some of the paper manufacturing and wood processing sites (listed under 'other EIIs'), from which 86% of all biogenic emissions arise.
- Appliances that combust biogas and biomass residues from some of the Scotch Whisky distilleries. The biogas is itself often produced on-site from the anaerobic digestion of organic distillery by-products.[46] This is a fuel-switching option not quantitatively assessed within this study but reviewed in Box 2.
- A proportion of biomass contained in the waste-derived fuels burnt in the cement industry.



Emission values are not expressed in CO_2-equivalent terms since biogenic emissions are treated as carbon neutral.

Figure 5 – Biogenic emissions

For clarity, all references to industrial emissions in this report are to be interpreted as referring to fossil CO_2 arising from fuel combustion or from other processes, unless otherwise specified.

3.3 Emissions by cross-sectoral process

Combustion emissions can be broken down according to whether fuels are burnt to generate heat or electricity (the latter of which mostly happens within on-site combined

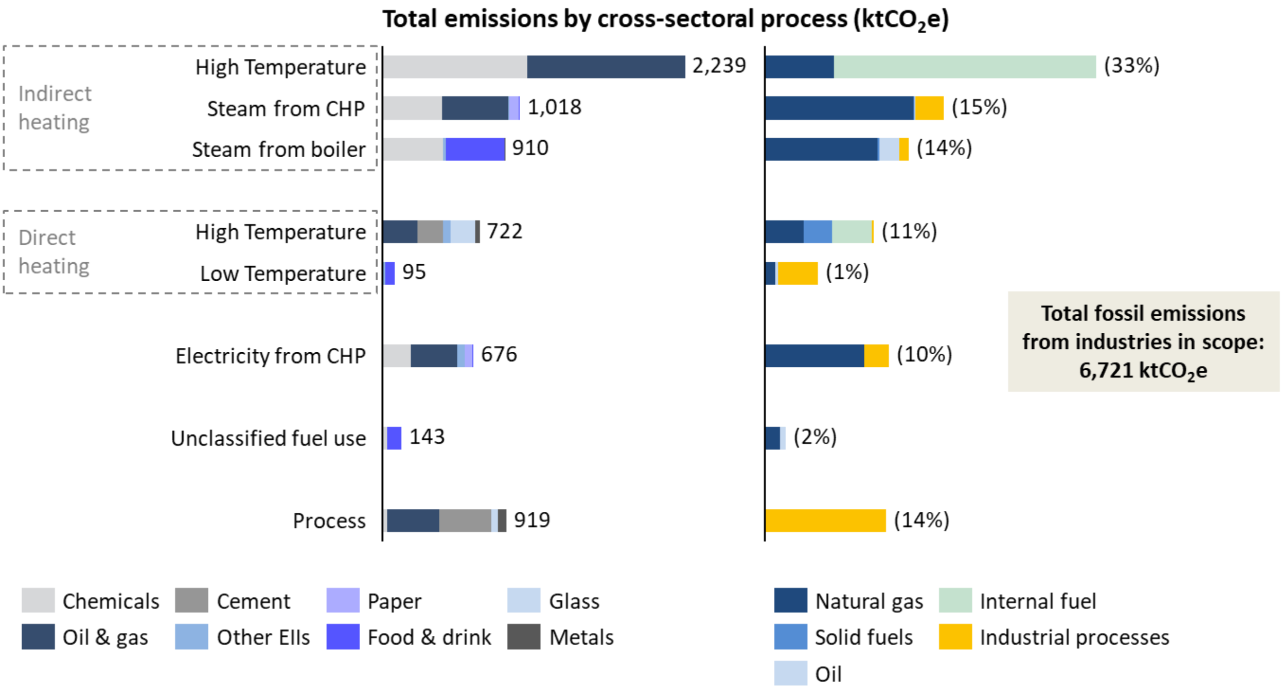
46 For further detail see Brownsort (2018).

heat and power, or CHP, plants). Furthermore, heating processes can be categorised according to four cross-sectoral processes differentiated by whether the process materials are directly exposed to combustion gases or not (direct vs indirect heating), and depending on whether steam, high- or low-temperature heat are needed, as summarised in Table 2. (A comprehensive list of all sector-specific processes and their cross-sectoral counterparts is provided in Appendix 8.4.)

Table 2 – Direct and indirect heating processes

Cross-sectoral heating process		Representative technology	Main sectors or subsectors relying on these processes
Indirect heating	High temperature	Furnaces (up to 850°C)	Refining, petrochemicals
	Steam-driven	Boilers and CHP plants (up to 240°C)	Food & drink, paper, chemicals, other EIIs
Direct heating	High temperature	Kilns, smelters, and other furnaces (up to 2000°C)	Glass, cement, other non-metallic minerals
	Low temperature	Dryers, ovens	Food & drink, veneer sheets and wood-based panels

The emissions breakdown shown in Figure 6 (see Appendix 8.5 for the breakdown in table format) was obtained by dividing the 6.7 MtCO_2e emitted by industries in scope according to the cross-sectoral process and fuel from which they are estimated to arise. Here, emissions are also broken down by sector (on the left-hand side) or fuel type/process (on the right-hand side).



Percentages correspond to the proportion of all fossil emissions from industries in scope and may not add up to 100% due to rounding.

Figure 6 – Emissions by cross-sectoral process

This breakdown highlights that **indirect and direct heating processes collectively account for nearly three quarters (74%) of all emissions**, that electricity generation in on-site CHP plants contributes 10% of all emissions, and that about 2% of all emissions arise from processes that could not be classified due to data limitations. As previously noted, industrial processes are responsible for the remaining 14% of emissions.

Heating related emissions

These results highlight the importance of decarbonising industrial heat to achieve deep emissions reductions, which warrants further investigation into the corresponding emission sources:

- **Indirect high-temperature heating processes employed in the oil and gas and petrochemical industries** are the single largest category of industrial emission in Scotland, collectively contributing **33% of all emissions**.[47] This category brings together processes where temperatures of up to 850°C are attained by passing process gases through furnace coils. **Nearly 80% of the energy demand for these processes is met via internal fuel combustion**, which underlines the importance of CCUS or process changes to decarbonise these processes.
- **Indirect heating processes making use of steam account for 29% of all emissions**. Steam of up to 240°C is the most often used energy carrier[48] for indirect heating processes and can be generated via boilers or CHP plants, assessed separately as they may be decarbonised in different ways. Hot water can also be used at lower temperatures, but that is more often used by non-industrial users.
- **Furnaces, kilns, and other direct, high-temperature processes are collectively responsible for 11% of all emissions**. These processes expose process materials to naked flame and combustion gases reaching very high temperatures of up to 2000°C, required to trigger the core reactions for clinker production, glass smelting, and metal processing.
- **Direct low-temperature heating processes like dryers and ovens account for just over 1% of all fossil emissions**. These are mostly employed in the wood processing and food and drink sectors, and air is the usual energy carrier within these processes.

Power related emissions

As mentioned, 10% of the emissions relate to electricity generation in on-site CHP plants, which is *additional* to those emissions related to the generation of grid electricity (not assessed here as they are classified as scope 2). While this indicates that electricity generation is a relatively small contributor to scope 1 industrial emissions, it is noted that electricity can in some cases constitute a high share of the energy used by industrial sites;

47 The main processes include steam cracking for olefins production and various furnaces at the refinery.
48 The 'energy carrier' carries the heat from where fuels are combusted (e.g. the boiler) to one or multiple processes requiring heat.

in the paper and pulp industry, for instance, approximately 60% of all energy used is electricity.[49] Electricity also plays an important role in larger Scottish industries like olefins production, refining, and cement manufacturing, but it represents a far smaller share of the overall energy demand.[50]

The quantitative analysis presented above exclusively focuses on carbon dioxide emissions from the sites within the scope defined in Section 2.2. As previously noted, this is because emissions from smaller sites as well as emissions of other greenhouse gases could not be attributed to specific sites or sectors due to data limitations. These two emissions sources are briefly reviewed in the appendix.

49 The percentage is expressed on an energy-content basis (i.e. based on the MWh of the various energy sources). Source: analysis of energy consumption statistics by BEIS, https://www.gov.uk/government/statistics/energy-consumption-in-the-uk.
50 Stakeholder interviews suggested that the share of energy use linked to electricity is around 5-15% in these sectors.

4 Decarbonisation options

The three main options for emissions abatement that are generally applicable across multiple industrial subsectors are energy efficiency measures, fuel switching, and carbon capture, utilisation, and storage (CCUS). Each of the three is discussed in detail within the next three sections, which cover the specific options considered within each high-level category, their abatement potential, and the key enablers and barriers relevant to their implementation. Specific uptake assumptions for each decarbonisation option are presented in Section 5.3.

4.1 Energy efficiency measures

4.1.1 Options considered

The first category of decarbonisation options considered here is that of 'energy efficiency measures', an umbrella term which refers to all improvements that enable an industrial site to reduce emissions by lowering the amount of energy and fuel used per unit of output. A comprehensive list of energy efficiency measures was determined through a literature review for each industrial sector. Following feedback from industry stakeholders, it was deemed appropriate to group these according to the level of disruption that their implementation implies:[51]

- **Incremental improvements**, including measures such as waste-heat recovery,[52] energy-use optimisation, improvement in the generation of steam, and other (relatively) non-disruptive measures listed in Table 3 that can generally be implemented without having to interrupt operations for prolonged periods.
- **Major overhauls**, which includes the implementation of state-of-the-art processes or Best Available Techniques.[53] Implementation of these projects implies a significant rebuild of the industrial sites affected and/or the overhaul of large portions of the site setup, and extended downtime can be expected for their implementation.

It is also noted that the distinction between the categories above can be blurry, since even the implementation of measures here classified as incremental improvements can sometimes be highly disruptive. Nonetheless, the distinction proposed here holds approximately and serves as a useful proxy for the *likelihood* that a given efficiency measure is implemented (all else being equal). Reflecting this distinction, only the first of the decarbonisation pathways assessed in this study – i.e. the Efficiency pathway, presented in Section 5.2.1, which assesses the maximum abatement that can be attained via full implementation of all energy efficiency measures – includes the implementation of major overhauls to improve energy efficiency. By contrast, the other pathways only see

51 See Appendix 8.1 for the complete Bibliography and Section 6.4 for a summary of the feedback received from the interview ed stakeholders. It is noted that this study does not make use of confidential site data.
52 The w aste-heat recovery options considered here refer to on-site use of the recovered heat. How ever, it is noted that it is also possible to use the recovered industrial heat off-site, e.g. in district heating.
53 It is noted that, the EU-defined list of Best Available Technologies may not apply after Brexit, and that only BATs relevant to increasing energy efficiency are considered here.

deployment of incremental improvements in energy efficiency (next to fuel switching and CCUS, as outlined in Sections 5.2.2 and 5.2.3).

Table 3 – Energy efficiency measures and their abatement potential

Sector *(key sources)*[54]	Abatement potential: Incremental improvements only	Abatement potential: All measures considered	Key decarbonisation options[55]
Chemicals and pharmaceuticals *(1, 2, 3, 4, 5)*	5%	5%	*Incremental measures*: improved heat recovery and reuse. Note that the high level of heat integration already present and the substantial use of internal fuels limit the improvement potential.
Oil and gas *(2, 5)*	10%	20%	*Incremental measures*: waste heat and energy recovery; advanced control and improved monitoring. High level of heat integration already present limits improvement potential. *Major overhauls*: crude unit upgrades; design improvements; integration of crude and vacuum units.
Cement *(2, 5, 6, 7)*	<5%	<5%	The dry kiln with pre-heaters and pre-calciner installed already constitutes state-of-the-art technology, hence the limited residual improvement potential.
Food and drink *(5, 8)*	31%	31%	*Incremental measures*: energy management; good maintenance practice; improvements to steam production, distribution, and end-use; waste heat recovery. Note that several of the large distilleries included in the NAEI already meet a high proportion of their energy needs via CHP plants fuelled by biogas produced on-site via anaerobic digestion.
Iron, steel and aluminium *(2, 5)*	5%	5%	*Incremental measures*: waste heat recovery. Already known to be used in some cases. Residual heat tends to be of low temperature and limited value.
Paper and pulp *(2, 5)*	15%	15%	*Incremental measures*: improved energy management; focus on maintenance; improved process control; heat recovery. A high proportion of heat requirement for this sector is already met with CHP plants or biomass combustion.
Glass *(2, 9, 10)*	15%	35%	*Incremental measures*: waste heat recovery. *Major overhauls:* Improvements to furnace construction; oxy-fuel combustion.
Other EII *(stakeholder interviews)*	10%	10%	*Incremental measures*: Optimising heat use; waste heat recovery. Note that a high proportion of heat requirements already met via biomass, largely in the wood panels industry, which represents 70% of the emissions from this sector.

In the case of the petrochemical industries, one way to increase efficiency would be to use of naphtha as feedstock to the steam cracking process instead of ethane and other gases. Feedback from industry stakeholders however highlighted that such a process change can hardly be classified as an energy efficiency measure due to its far-reaching implications: such feedstock switch would require a different supply chain, would result in different

54 The key sources for this analysis are: (1) Benner *et al* (2011); (2) ICF & Fraunhofer ISI (2019); (3) IEA, ICCA, & DECHEMA (2013); (4) Griffin *et al* (2018); (5) WSP & DNV GL (2015); (6) Mineral Products Association (2013); (7) ETC (2018); (8) Brownsort (2018); (9) British Glass (2014); (10) British Glass (2017). The full references as well as a complete list of all other sources consulted for this task are included in Appendix 8.1.

55 Major overhauls were only specifically listed for sectors where stakeholders indicated that their implementation would be not be considered an 'incremental' improvement.

output products (e.g. a wider range of high-value chemicals, the exact composition of which depends on the specific feedstock), and could only be implemented through complete overhaul of the production plant, since the cracking process is fully integrated. For this reason, conversion to naphtha steam cracking would likely only be plausible in the context of a greenfield project, whereas conversion of existing plants could only realistically be expected if a strong strategic motivation exist beyond the desire to improve energy efficiency.

4.1.2 Abatement potential

To accurately estimate the abatement potential of the implementation of energy efficiency measures one would need to possess site-specific information on:

- The initial energy efficiency as measured by the amount of energy used per unit of finished product (e.g. MWh of input energy per tonne of output product).
- The emissions intensity of the energy used, which in turn depends on the source of energy (generally electricity or a fossil fuel).
- The potential reduction in energy demand (for a fixed quantity of finished product) that can be attained through the implementation of energy efficiency measures.

Unfortunately, this information is generally commercially sensitive and therefore not available in the public domain. Hence, a simplified approach was followed here whereby the average abatement potential from each category of efficiency measure was estimated for each industrial sector through literature review and later validated with stakeholders. This approach relies on estimations that abstract from the (unknown) efficiency levels present today within Scottish sites and will therefore not be precise in the quantification of the potential benefits. However, in the absence of site-specific data this approach provides a good indication of the overall decarbonisation potential of energy efficiency measures, especially considering that the picture emerging from this study is that they have a limited – though not negligible – role to play in the transition to net zero for Scotland's industrial sites.

4.1.3 Barriers and enablers

Obstacles to commercialisation

The primary obstacles to the uptake of energy efficiency measures are centred on the fact that many of these measures are not commercially viable, with the ones that are commercially viable having already been implemented, in many cases. Hence, economic drivers and incentives need to change to make any additional ones viable. In fact, whenever site operators increase energy efficiency they do not just reduce combustion emissions but also save on energy costs. Since energy generally represents a sizeable share of the manufacturing cost in energy-intensive industries, it is perhaps unsurprising that most of the industry stakeholders engaged for this study indicated that they have already implemented all commercially viable measures to increase energy efficiency. Some also mentioned that their companies had already signed Climate Change

Agreements (CCAs) that compel them to achieve previously agreed targets in order to pay a reduced rate of the Climate Change Levy.[56] This explains why **the residual decarbonisation potential of energy efficiency measures may be limited unless the economic drivers substantially change**, for instance if the cost of energy (or carbon) increases.

It is worth noting that 'commercial viability' – defined as the ability of a project to be backed by a business case that meets the relevant investment requirements (e.g. on the payback period) – is a relatively strict requirement compared to 'economic viability', which simply implies that the project's annualised costs are lower than the annualised savings. A previous study by Element Energy, Ecofys, and Imperial College London investigated the differences in the context of industrial waste-heat recovery, determining that just under half of the technically viable heat-recovery options were also commercially viable without further incentives.[57] **In the decarbonisation pathways assessed in this study it is assumed that sufficient incentives will be made available by government to justify investment in all decarbonisation measures, including energy efficiency**.[58]

Technical challenges

Certain energy efficiency measures might not be fully adopted due to their potential impact on the final product quality. In the Scotch Whisky industry, for instance, the character and flavour of the spirit produced may be affected by the implementation of measures such as thermal vapour recompression, which could reduce steam demand and hence energy consumption in the distillation process. Further work is required to assess the extent to which adoption might be affected.

Potential synergies with fuel switching

Fuel switching could strengthen the business rationale for investing in energy efficiency, since the cost of low-carbon hydrogen and electricity is expected to be higher than that of fossil fuels (see Section 4.2.3). This would increase the economic value and commercial viability of any measure that can reduce energy use, including some that may not be considered viable with current energy prices. For this reason**, all decarbonisation pathways assessed below assume that all of the incremental improvements in energy efficiency which are considered technically viable today are implemented by 2045**. Major overhauls are instead assumed to only be implemented in the first pathway, as noted above. This is because it is assumed that CCUS would be implemented *instead* of major overhauls in the other pathways, hence their additional implementation would not lead to further emissions abatement though it would still cause major disruption. Lastly, it is noted that, since it is possible that at least some of the efficiency measures will not be implemented, these assumptions may be considered optimistic. However, new ways to

56 See https://www.gov.uk/guidance/climate-change-agreements--2.
57 Element Energy, Ecofys, & Imperial College London (2014).
58 For modelling purposes, it is further assumed that investments in efficiency measures can achieve a 5-year payback, on average, also thanks to the assumed incentives (not modelled explicitly). Note that this does not imply that commercial viability could be attained without the incentives.

improve energy efficiency may also be discovered before 2045, which would increase the technical potential of energy efficiency.

4.2 Fuel switching

4.2.1 Options considered

This assessment primarily focuses on electrification and hydrogen fuel switching as potential substitutes to fossil fuels. Both 'green' and 'blue' hydrogen, collectively referred to as 'low-carbon hydrogen', are considered to be part of the energy mix.[59] Hydrogen produced via biomass gasification coupled with CCUS is also considered an option to produce low-carbon (possibly carbon-negative) hydrogen. However, with a limited supply of sustainable biomass available, it may be the case that hydrogen from biomass would be unlikely to constitute a large share of the overall hydrogen supply in the long term, therefore this option is not explored further.

Switching to bioenergy is assessed for the cement industry, which already burns some biomass contained within waste-derived fuels and is assumed to increase its use (while also deploying CCUS, which results in negative emissions – see Section 4.3.2).[60] Other options for switching to bioenergy which may be considered by some Scottish industries but are not evaluated here are discussed in Box 2.

Key technologies that will need to undergo fuel switching include boilers, furnaces, driers and the other appliances indicated in Table 4. In a few selected cases the characterisation of the fuel-switching counterparts to existing fossil-fuelled appliances warrants further explanation:

- Following stakeholder consultation, the cement kiln is assumed to be converted to co-firing biomass (up to 70% of the heat demand), with the remaining heat generated by a mix of hydrogen combustion (20%) and electric plasma gas (10%).[61] Due to the characteristics of the mixed-fuel kiln, fuel switching could take place in phases: biomass use could be maximised right away (provided suitable economic incentives existed), whereas the residual energy use could be switched later on when the relevant technologies become available. For simplicity it is conservatively assumed here that fuel switching occurs at the same time once all the required technologies become available.
- In the electrification pathway, the heat demand currently met via CHP plants is assumed to be replaced by a mix of electric steam boilers and heat pumps powered via the grid, whereas electricity produced with CHP plants is substituted by electricity from the grid.[62]

59 See note on terminology on page 12 for definitions of green and blue hydrogen.
60 The presence of biomass in waste-derived fuels was reported by the Dunbar cement plant operator at https://www.tarmac.com/dunbar-plant/fuels/.
61 The characterisation of the mixed-fuel kiln was informed by stakeholder consultation. The corresponding cost was calculated as the weighted average cost of the individual technologies (i.e. the kiln co-firing biomass, hydrogen furnace, and electric plasma gas, see Table 4 for individual costs), with weights corresponding to the percentages quoted above.
62 Specifically, it is assumed that 45% of the energy *output* current derived from CHP plants is provided by electric boilers, 15% by heat pumps, and 40% by the grid. Heat pumps are mostly used in the context of waste-heat recovery (rather than from ground or air source).

Technology costs and efficiencies for each appliance were derived from publicly available sources and are also reported in Table 4. When considering these **it is important to acknowledge the uncertainty that surrounds the technical and economic characteristics of all fuel-switching technologies**, most of which have not yet been demonstrated in an operational environment.

Grid connection requirements

A further assumption employed in this study is that 1 MW of new grid connections is required for each megawatt of electrical appliance installed, at a cost of £350/kW.[63] Since it is likely that existing connections would suffice to cover part of the additional power demand, the extent to which new grid connections are required is therefore overestimated through this approach, and future work could refine this assumption by assessing the local grid constraints on a site-by-site basis. It is also worth noting that no corresponding cost is computed for hydrogen fuel switching (e.g. for connection to a future hydrogen grid); rather, it is assumed that the cost of hydrogen fuel presented in Section 4.2.3 already includes all infrastructure-related costs.

Replacements vs retrofits

It should also be noted that, although it is here assumed that all fossil-fuelled appliances must be *replaced*, it is expected that, when switching to hydrogen, a portion of these would in practice be suitable for *retrofitting*, which represents a potential advantage of the Hydrogen pathway over the Electrification alternative (discussed in Section 6.5). An extensive discussion of retrofitting industrial natural gas appliances to hydrogen can be found in previous work by Element Energy, Advisian, and Cardiff University.[64]

Box 2 – Fuel switching to bioenergy

Fuel switching to bioenergy is particularly **relevant to industries that generate organic process residues**, like the food and drink, paper and pulp, and wood processing sectors. Organic residues are either combusted in their solid form or can be fed to anaerobic digesters to produce biogas, which can replace natural gas and hence directly reduce *fossil* CO_2 emissions. To evaluate the **overall level of emissions abatement, however, one must also consider the relative carbon intensity of the fuel supply chains as well as the alternative potential uses of the biomass feedstock**.

In the case of **Scotch Whisky distilleries**, for instance, several of them already produce biogas through the **anaerobic digestion of draff** – an organic residue from the mashing process – **and/or pot ale** – a viscous liquor which is left in the pot still after the first distillation stage in malt distilling.[65] Analysis by Ricardo showed that using draff and pot ale in such systems **can indeed deliver substantial climate benefits**, especially when

63 Based on network cost calculations from Ricardo (2019), including civil and installation costs.
64 See Element Energy, Advisian, & Cardiff University (2019).
65 For examples of anaerobic digestors used in combination with biogas CHP plants at Whisky distilleries see Scotch Whisky Association (2012).

heavy fuel oils commonly used in remote distilleries are replaced (instead of natural gas).[66] However, the same study also showed that **if these biomass feedstocks are diverted from animal feed uses, the additional climate benefit of converting them to bioenergy would reduce significantly**.

The approach followed in this study with respect to fuel switching to bioenergy is that recommended by the Committee on Climate Change,[67] who only consider bioenergy in combination with CCUS (i.e. bioenergy CCS, or BECCS) or for sites where it is already in use.

Technology maturity and date of first deployment

The maturity of electrification technologies is generally higher than that of hydrogen technologies, **as** can be deduced by considering their technology readiness level (TRL, see Box 3), also reported in Table 4. Accordingly, the estimated date of first deployment of technologies in the former group generally occurs earlier than that of technologies in the latter group. To estimate this date it was assumed that the first deployment of each technology among the industries in scope would occur 2 years after a technology reaches TRL 9,[68] which was in turn calculated starting from the technology's current TRL, assuming that it will take 1-3 years to progress from one TRL to the next.[69] However, it is also assumed that the uptake of hydrogen technologies can proceed faster, since the process of substituting natural gas with hydrogen can be less disruptive than that of electrifying heat.[70]

66 Ricardo (2018).
67 Committee on Climate Change (2018).
68 The 2-year delay is an estimate of the time it would take a newly demonstrated technology to become more broadly available commercially. It is noted that Scottish sites could potentially deploy these technologies sooner if strong incentives existed, and indeed they could be among those sites who pilot new technologies even before they have reached TRL 9.
69 Thus, for example, a technology that is at TRL 5 in 2020 could be expected to reach TRL 9 in 2028.
70 The possibility of retrofitting certain hydrogen technologies also helps with their uptake (see corresponding feedback from industry stakeholders in Section 6.4 and uptake assumptions in Section **Error! Reference source not found.**).

Box 3 – Technology readiness level: the TRL scale

The maturity of any technology can be approximately defined by the technology readiness level (TRL), defined by the European Commission as:[71]

- TRL 1 – basic principles observed
- TRL 2 – technology concept formulated
- TRL 3 – experimental proof of concept
- TRL 4 – technology validated in lab
- TRL 5 – technology validated in industrially relevant environment
- TRL 6 – technology demonstrated in industrially relevant environment
- TRL 7 – system prototype demonstrated in operational environment
- TRL 8 – system complete and qualified
- TRL 9 – actual system proven in operational environment

Two additional constraints were set on the date of first deployment:

- **No hydrogen technology is deployed before low-carbon hydrogen becomes available**.[72]
- Technologies that are already at TRL 9 today are not deployed until 2023 at the earliest since earlier deployment would likely be limited by infrastructure constraints and/or by the lack of economic incentives.

Given the uncertainty surrounding the timeline of development of each technology, the first deployment dates quoted in Table 4 represent an informed estimate based on current TRLs. Regardless of the exact year in which each technology is first deployed, **all fuel-switching technologies are estimated to become available at the required scale by 2030** – although this expectation is conditional on the implementation of suitable policies and economic incentives to support the development and commercialisation of the required technologies.

71 See https://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf.
72 i.e. from 2028, see Section 4.2.3.

Table 4 – Modelling assumptions on fuel-switching technologies

Fuel	Technology (source)[73]	Suitable for	Lifetime (years)	TRL	Date of first deployment	Capex (£/kW)	Opex (£/kW/y)	Efficiency
Electricity	Electric boiler (1)	Steam-driven processes	15	9	2023	120	4.0	95%
	Electric oven (1)[74]	Direct low-temperature heating	15	9	2023	120	2.4	95%
	Electric process heater (1)	Indirect low-temperature heating	15	9	2023	120	2.4	95%
	Electric plasma gas furnace (1)	High-temperature heating	15	5	2028	262	3.0	90%
	Heat pump (1)	Low-temperature heating (inc. steam)	20	8	2023	450	9.0	150-350%
	Grid connection (2)	See assumption on page 36.	N/A	9	2023	350	N/A	N/A
Hydrogen	Hydrogen boiler (1)	Steam-driven processes	25	7	2028	199	4.0	92%
	Hydrogen oven (1)[74]	Direct low-temperature heating	15	5-6	2028	232	4.6	92%
	Hydrogen heater (1)	Direct low-temperature heating	25	5	2028	232	4.6	92%
	Hydrogen furnace (1)	High-temperature heating	25	4-5	2028-2030[75]	232	4.6	92%
	Hydrogen CHP (3)[76]	Replacing gas-fired CHP	25	7	2028	489	35.0	80%
Mixed fuel	Kiln co-firing 70% biomass (1)	Cement kiln	25	7-8	2025	83	1.3	84%
	Kiln co-firing 70% biomass, hydrogen, & plasma gas (1)[77]	Cement kiln	25	4	2030	156	2.5	84%
Fossil fuels	Steam boiler (1)	Steam-driven processes	25	9	<2020	166	3.3	92%
	Oven (1)	Direct low-temperature heating	15	9	<2020	193	3.9	92%
	Dryer (1)	Direct low-temperature heating	25	9	<2020	193	3.9	92%
	Furnace (1)	High-temperature heating	25	9	<2020	193	3.9	92%
	CHP (3)[76]	Steam- & electricity-driven processes	25	9	<2020	406	24.0	80%

73 Sources: 1) Element Energy & Jacobs (2018); 2) Ricardo Energy & Environment (2019); 3) Parsons Brinckerhoff (2011).
74 The characteristics of electric and hydrogen ovens were assumed to be comparable to those of process heaters (except for their lifetime, assumed to be equal to that of natural gas ovens).
75 The later date refers to furnaces for glass smelting.
76 Natural gas and hydrogen CHP costs based on the "medium" and "high" estimates for "NOAK Small GT based CHP", respectively.
77 See page 28 for a description of the mixed-fuel kiln.

4.2.2 Abatement potential

Hydrogen and electricity can be far less carbon intensive than fossil fuels and their use does not yield any scope 1 emissions.[78] **However, neither option is necessarily carbon neutral**. Fuel use along other segments of the respective value chains (e.g. in electricity generation or hydrogen production), may reduce the net decarbonisation benefit of fuel switching. To avoid overstating the emissions abatement that can be achieved through electrification and hydrogen fuel switching, this study also accounts for the emissions associated with hydrogen production and electricity generation.[79]

Grid carbon intensity

The carbon intensity of grid electricity is assumed to decrease linearly from 173 gCO_2e/kWh in 2017 to 41 gCO_2e/kWh in 2035,[80] later reducing at a slower rate of 10% year-on-year and reaching an assumed 14 gCO_2e/kWh in 2045, as shown in the figure below. Notably, **the average carbon intensity of the electricity generated in Scotland in 2018 was already 48gCO_2e/kWh**,[81] which is similar to the level expected for Great Britain as a whole in 2035. Hence, it could be argued that Scottish industries that use electricity generated in Scotland could decarbonise even more rapidly than is estimated here.

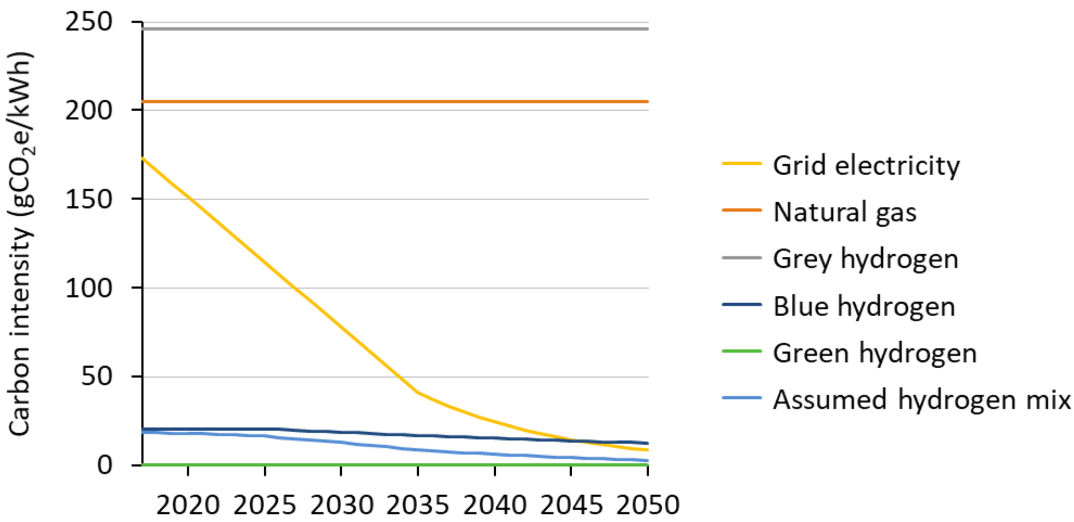


Figure 7 – Carbon intensity of the energy sources

Hydrogen carbon intensity

Residual emissions from blue hydrogen depend on the rate of carbon capture and net energy efficiency of the hydrogen production process. Due to the high CO_2 purity of the flue gases from the steam methane reforming (SMR) and auto-thermal reforming (ATR) processes, it is expected that high carbon capture rates can be achieved regardless

78 Since neither the use of electricity nor hydrogen combustion release greenhouse gases.
79 Only those emissions associated with the generation of the additional electricity demanded by the electrification of industrial processes are considered here. Scope 2 emission related to the baseline level of electricity demand are instead not considered.
80 2017 data and 2035 projection from BEIS updated energy and emissions projections (2018).
81 https://scotland.shinyapps.io/sg-scottish-energy-statistics/?Section=RenLowCarbon&Subsection=RenElec&Chart=GridEmissions.

of which method is selected for hydrogen production. In this study we acknowledge that there are relative merits to the SMR or ATR routes but do not make any assumptions around which is preferable or more likely to be implemented. Regardless, blue hydrogen's embedded emissions are **assumed to be 10% of those from natural gas in 2025, decreasing to 6% by 2050** following more efficient hydrogen production and increased capture rates.[82]

Green hydrogen is assumed to be carbon neutral, which implies that hydrogen must be produced *exclusively* from renewable energy sources (either from excess renewable energy that would otherwise be curtailed, for instance due to network constraints, or from dedicated off-grid renewable generation). Further information on embedded, scope 3, emissions relating to the manufacturing of equipment for hydrogen production and renewable electricity generation can be found in previous work by E4Tech.[83]

Although the carbon intensity of natural gas is assumed to remain constant (at 205 gCO_2e/kWh), it is possible that some hydrogen (or biomethane) could in the future be blended into the gas grid, which is expected to be able handle blends of up to 20% hydrogen by volume (or 8% by energy content) without significant challenges.[84] Hydrogen injections into the gas grid could thus offer an additional way for reducing emissions from gas use.

Green and blue hydrogen mix

Considering that neither blue nor green hydrogen is commercially available today, the following assumptions were made around the sources of low-carbon hydrogen for industry:

- Within the Hydrogen pathway, the hydrogen used by the Scottish industries is assumed to be **90% blue and 10% green in 2028**.[85] Over time, the penetration of **green** hydrogen is assumed to increase, reaching a **45% share of the hydrogen market** by 2045.
- Only **green** hydrogen is used in the **Electrification** pathway, where it is exclusively used within the cement industry or for CCUS.

Based on the assumptions discussed above, emissions from hydrogen use are estimated to be 17 gCO_2e/kWh in 2028 and 7 gCO_2e/kWh in 2045 in the Hydrogen pathway and 0 gCO_2e/kWh in the Electrification pathway. Given the fact that the carbon intensities of both hydrogen and electricity are expected to be below 10% of those of natural gas in the long term, it can be deduced that switching to either hydrogen or electricity can result in

82 These assumptions are broadly in line with *low-end* estimates from van Cappellen *et al.* (2018) and Mohd *et al.* (2019).
83 A discussion on these embedded emissions related to green hydrogen is provided by E4Tech (2019).
84 The Health and Safety Laboratory (2015) reports that "the differences in the behaviour of methane mixed with up to 20% hydrogen and that of pure methane are small and unlikely to present a significantly greater hazard in practical situations" and that gas appliances are "capable of operating safely (at least in the short term) with a hydrogen content of ≤ 20%", although some of the long-term impacts are not well understood, including the effect of burner heating due to higher flame speeds. Likewise, Ofgem's summary of the HyDeploy project states that "All appliance sold post 1993 must comply with the 1990 Gas Appliance Directive 90/396/CCE (GAD), which demonstrates that they can operate on a wider range in gas quality than specified in the GS(M)R". http://www.ofgem.gov.uk/ofgem-publications/107831.
85 Produced via the reforming of natural gas in combination with CCUS, which assumes that CCUS is deployed as indicated in Section 5 and that one or more green hydrogen projects are also commissioned by then.

comparable emissions abatement, a feature which is evident in the results concerning emissions trajectories within each pathway presented in Section 6.1.

4.2.3 Barriers and enablers

Higher energy costs affecting competitiveness

Even though several of the fuel-switching technologies considered in this study have already been demonstrated, few are used in industry today due to the **higher cost of low-carbon energy sources, compared to natural gas**. Cost estimates for hydrogen range widely:

- The Hydrogen Council place the production cost[86] of green and blue hydrogen at 12.7 p/kWh and 4.5 p/kWh, respectively.[87]
- A review by Spears *et al.* finds production costs in the range of 4-9 p/kWh for green hydrogen and 2-5 p/kWh for blue hydrogen.[88]
- A recent report on the first phase of the Gigastack project calculates a cost for green hydrogen in the range of 10.7-17.5 p/kWh, depending on the project configurations.[89]

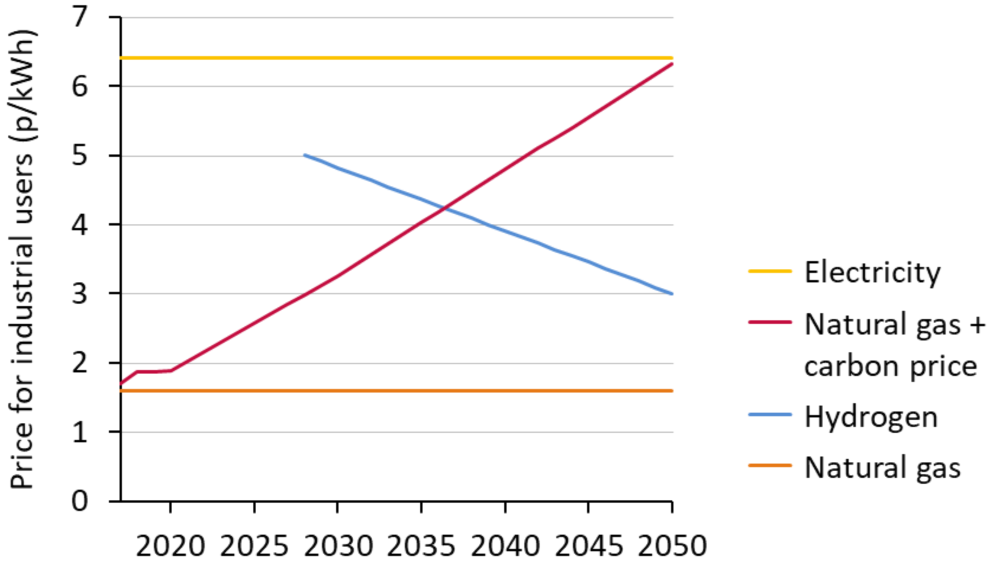
Considering that low-carbon hydrogen is still a pre-commercial fuel, it is generally expected that its cost will substantially reduce with time. By 2030, the cost of green and blue hydrogen production in Europe could reduce to 5.3 p/kWh and 3.8 p/kWh, respectively, according to the Hydrogen Council, and Bloomberg NEF predicts that the cost of green hydrogen delivered to industrial users (i.e. not just the production cost) could reduce to 4.2 p/kWh in 2030 and 2.1 p/kWh in 2050.[90]

In light of the wide spread in the cost estimates reported above, **it is assumed in this study that hydrogen will cost 5.0 p/kWh when first deployed in 2028**, **linearly reducing to 3.0 p/kWh by 2050**, whereas no assumption is made regarding its cost pre-2028, hence the gap for the corresponding years in the figure below. While in practice the hydrogen price may be different for blue and green hydrogen, also due to their potentially different characteristics (e.g. purity), the price assumptions employed here refer to the *mix* of blue and green hydrogen described previously.

As for **electricity and gas**, the CCC calculates that large industrial users in the UK paid an average of **6.4 p/kWh and 1.6 p/kWh** in 2016, respectively – values which are here assumed to apply throughout the timeline of interest.[91] According to these energy price estimates – and **before accounting for the cost of carbon – gas will remain cheaper than hydrogen and electricity through to 2050 at least**. Hence, switching from natural gas to electricity or low-carbon hydrogen would cause a substantial increase in the cost of

86 Note that the production cost does not include transportation and distribution costs, billing costs, taxes and levies.
87 Hydrogen Council (2020).
88 Speirs *et al*. (2017).
89 Element Energy (2020). Project configurations assessed include hydrogen production from a high voltage grid connection, from direct connection to a wind farm, from non-exclusive connection to a wind farm (i.e. some electricity is fed to the grid), and from offshore electrolysis. Factors like the electricity price, levies, and connection costs vary depending on the configuration.
90 Mid-range values by Bloomberg NEF (2020) calculated with a levelised cost of electricity of $28/MWh in 2030 and $17/MWh in 2050. For the best locations (e.g. Australia) they instead estimate a price of 3.2 p/kWh in 2030 and 1.8 p/kWh in 2050.
91 Electricity price for 'Large manufacturing sites (low-carbon support compensation)', gas price for 'Large (ETS) manufacturing'. Source: CCC (2017).

energy that would be hard to justify from a commercial perspective unless the economic incentives change.



Hydrogen is assumed to only become commercially available from 2028, hence the lack of price estimates before then. A single hydrogen price is assumed for green and blue hydrogen.

Figure 8 – Energy price assumptions

It is of course possible that the price of the various energy forms will differ from what is assumed here, also considering that the publicly available sources from which the relevant energy price data were sourced do not clearly state their assumptions (e.g. around network costs, or on taxes). This could affect the business case for fuel switching. However, **it is the difference between the price of gas, electricity, and hydrogen, rather than their absolute levels, that affects the cost of decarbonisation** (see corresponding results in Section 6.3). Since the price of blue hydrogen is linked to that of natural gas[92] and that of green hydrogen depends on the cost of renewable electricity generation, it can be argued that the different price levels are going to be tightly coupled in the long term, with any difference between them imputable to energy conversion technologies and taxation regimes. Hence, rather than developing complex energy price projections that would necessarily be subject to high uncertainty it was preferred to employ simple assumptions that enable a transparent comparison of energy costs in the different pathways.[93]

If the cost of carbon is included, fuel switching could be justifiable on economic grounds alone. With a projected carbon price of £193/tCO_2 in 2045,[94] the total cost of unabated natural gas (inclusive of the carbon cost) would approach 6 p/kWh – a value that is higher than that assumed for hydrogen and comparable to that assumed for electricity,

92 To which one must add the costs and energy losses related to conversion from gas to hydrogen, as well as CO_2 compression, transport, and storage. Note that carbon capture is expected to cost relatively little in the case of blue hydrogen due to the high CO_2 concentration in the flue gases.
93 A reader interested in assessing the impact of different energy prices can simply scale the results on the additional cost of energy (see Table 15) by the updated difference in energy prices to obtain an approximate result.
94 See Appendix 0 for the carbon cost assumptions based on projections by BEIS.

as evidenced by the converging lines in Figure 8. Should the carbon price in the UK increase at the rate modelled in this study, a different concern would however arise; local industries facing higher energy costs than their counterparts abroad (who have lower carbon costs) might struggle retain competitiveness, an issue discussed in the concluding chapter. Finally, it should also be noted that new technologies for producing low-carbon hydrogen at cost lower than is assumed here may also emerge. Indeed, already today there are companies claiming to be able to offer hydrogen at less than 10% of the costs assumed here.[95]

Availability of low carbon energy and infrastructure

As already noted, no low-carbon hydrogen is available in Scotland today at the scale required to support the decarbonisation of industry, although roadmaps and feasibility studies have been assessing ways to initiate this as indicated in Section 2.1. This poses a barrier to industrial decarbonisation via hydrogen fuel switching. The **limited availability of low-carbon hydrogen** is one of the **main barriers to the deployment of hydrogen technologies.** In this study it is assumed that low-carbon hydrogen becomes commercially available in 2028 (see Section **Error! Reference source not found.**).

A similar challenge affects industrial electrification efforts since the current capacity of **the electricity network may not be sufficient to meet the increased demand for electrical power**. Hence, electrification of large heating processes such as those in the petrochemical industry may only be possible after major upgrades to the grid infrastructure (and potentially large-scale deployment of energy storage).

Technical challenges

Several technologies considered in this section **are not yet commercially available**, and it is possible that some of them never will be. Early-stage technologies that are not yet technically mature are particularly susceptible to this risk, since they may encounter obstacles on their way to market.

A key challenge that may affect the technical – and therefore commercial – viability of certain fuel-switching technologies includes the **strict requirement to meet specific heating profiles demanded by some industrial processes**. This is especially a challenge when the heating profile directly impacts product quality, as is sometimes the case in the food and drink industry. Unfortunately, it is not possible to rule out the possibility that some of the fuel-switching technologies considered may turn out to be unsuitable because of this. It is however also possible that the increased societal focus on decarbonisation may accelerate the development of new technologies that were not considered by this study. Hence, despite the risk that some of the technologies may never be deployed, it is assumed that others will be used in their stead.[96] It is worth mentioning that this challenge **does not apply to indirect heating processes that make use of**

95 https://www.bloomberg.com/news/articles/2020-08-13/home-of-the-oil-sands-eyes-cleaner-future-as-hydrogen-superpower.
96 This may also include deployment of electrification options instead of hydrogen fuel-switching technologies, or vice-versa.

steam, which represent the largest single type of heat demand that is suitable for fuel switching (see Section 3.3).

Disruptiveness of switching and other operational challenges

Significant changes to the plant configuration may be required to make fuel switching possible, especially in the case of integrated processes (e.g. in petrochemical plants) where changes to the energy source cause other system impacts.

The core processes within each industrial subsector are often designed to operate uninterrupted to avoid costly down-time. Not only can interruptions lead to missed revenue due to reduced output, but they can also adversely impact CO_2 emissions (for instance in the case of event-related flaring, which is caused by unwanted interruptions). This is especially true for high-temperature processes (e.g. those in the petrochemical industry) that require precise control of the heat load and that may need time to be fully operational following an interruption – during this time, large amounts of energy and low-quality product can be wasted, causing unnecessary emissions and process waste. For these reasons it is common practice to have back-ups in place to guarantee continued operations in case of faults with the primary equipment, e.g. back up steam generators in case the primary boilers fail.

Pathways that rely extensively on electrification expose industrial users to the reliability risks facing the grid. To mitigate this risk, clean alternatives to back-up diesel generators could include battery storage or, if hydrogen is already used on site, hydrogen fuel cells. **Back-up hydrogen equipment would similarly be required**. Considering that back-up equipment generally has low load factors and consequently marginal impact on carbon emissions, investment to replace it with alternative back-up appliances would likely be deferred to a later date, when the cost of fuel-switching technologies may be similar to that of current natural gas appliances. For these reasons, the impact of back-up equipment on the overall additional cost of the deep decarbonisation pathways is considered negligible.[97]

Space availability is also considered a challenge, for instance in the case of installations of heat pump systems at existing distilleries, where space constraints are likely to limit their uptake as noted by Ricardo.[98]

Retrofitting opportunity for hydrogen technologies

It was already mentioned above that fossil-fuelled appliances may in some cases be retrofitted to operate with hydrogen (see Section 4.2.1). This represents a potential advantage for the Hydrogen pathway, since the possibility to retrofit appliances that may have a long residual lifetime without having to replace them could enable prompter uptake of hydrogen technologies. In this study it is conservatively assumed that appliances are instead replaced at the end of their useful life.

97 Note that the replacement cost for fossil-fuelled appliances is also incurred in the BAU scenario.
98 Ricardo (2020).

4.3 Carbon capture, utilisation, and storage

4.3.1 Options considered

Sites implementing carbon capture

A wide range of factors must be considered when developing a CCUS project, a few can help pre-select which sites are most likely to implement this on some or all of their emissions sources:

- The absolute amount of carbon that must be captured, important to reach sufficient economies of scale.
- Geographical factors, and in particular proximity to relevant CO_2 infrastructure for transport and storage, or to users of the captured CO_2.
- Availability of alternative pathways for deep decarbonisation.[99]

Far from being an exhaustive list, the above provides a first set of criteria for deciding whether CCUS is likely to be relevant for a site. Based on these criteria, it was assumed that the following Scottish sites would be most likely to take part in CCUS projects before 2045:

- The refinery and petrochemical plant in Grangemouth, which make substantial use of internal fuels and also feature a source of process emissions (i.e. the refinery SMR).
- The Dunbar cement plant, which also features substantial process emissions.

The selected sites are the largest emitters among those which cannot be deeply decarbonised by fuel switching, whether because of internal fuel use or due to the presence of process emissions. Other large emitters in the area, like the Grangemouth CHP plants, are instead assumed to decarbonise via fuel switching. Other sites with unavoidable process emissions also exist (i.e. the aluminium smelter and the glass manufacturing sites), but these are considered too small and/or remote to justify CCUS implementation or, in the case of flaring, are deemed unsuitable for capture (see page 26). It is expected that process changes might be the more likely option to decarbonisation these emissions sources, as discussed in Section 6.1.4.

The selected sites are also located in an advantageous geographical area. Except for the Dunbar cement plant, the other sites are clustered around Grangemouth, where it is envisioned that the initial shared CO_2 capture infrastructure will be created. Later on, this infrastructure could also be extended to reach sites that are further away, like the cement plant itself. The timeline for the deployment of CCUS at these sites is discussed in Section 5.3.

Carbon capture and compression: technology and cost assumptions

Various technologies exist to extract CO_2 from a flue gas stream, differing in technology maturity, energy requirements (discussed in the next section), and ultimately cost. The

99 As was discussed in the previous chapter, process emissions and those from the combustion of internal fuels cannot be abated by fuel switching and are therefore prime candidates for CCUS.

most commonly used technology relies on amine scrubbing, in which CO_2-containing flue gas passes through vats containing amino compounds (i.e. amines), which absorb most of the CO_2. Considering that the accelerated emission targets place Scotland among the most ambitious countries in the pursuit of net zero, it is assumed that the Scottish industrial sites that implement carbon capture will be among the first of their kind to do so in a commercial setting. In light of the limited time available for capture technologies other than (first generation) amines to reach commercial maturity, **it is assumed that amine-based technology will be adopted by all sites where CCUS is deployed**. This is intended as a *conservative* assumption since the cost of capture would likely reduce if other technologies like advanced amines, calcium looping, or oxy-fuel combustion with carbon capture were used.[100]

The complete set of assumptions underpinning the analysis of CCUS is reported in Appendix 8.7, but some of the key factors with a significant impact on the cost of capture include:

- The **CO_2 concentration** in the flue gases, which depends on the emission source. Specifically, it is easier and cheaper to capture CO_2 when it is not excessively diluted (the limit case is that where atmospheric CO_2 is captured).
- The **capture rate**, i.e. the proportion of CO_2 contained by the incoming gas stream which is captured (which also affects the abatement potential; a capture rate of **90%** is assumed though higher rates are also possible, as discussed in the next section).[101]
- The **fuel** used to meet the significant heat demand from the capture process, **assumed to be low-carbon hydrogen**, rather than natural gas, so as to enable the maximum emissions abatement (see discussion in the next section).
- The **absolute emission level**, which determines scale economies.
- **The pressure to which the captured CO_2 must be compressed** before it is transported. It is assumed the CO_2 is always captured at atmospheric pressure (0.11MPa) and must be compressed to 10MPa.

The cost of carbon capture and compression can be calculated by summing up the lifetime expenditures (capital, operational, and energy-related) and dividing the total by the cumulative amount of captured CO_2.[102] This yields an **average** levelised **cost of capture of around £100/tCO_2**, about 60% of which is imputable to the cost of energy, and an **average** levelised **cost of compression of around £5/tCO_2.**[103] It should be noted that **the net cost of abatement is slightly higher** than that presented here due to the fact that the energy used for CCUS is not fully carbon neutral. In conclusion, Box 4 reviews two alternative ways for CCUS to tackle emissions from the combustion of internal fuel gases.

---

100 A thorough review of all capture technologies can be found in Element Energy, Carbon Counts, PSE, Imperial College, & University of Sheffield (2014).
101 A capture rate of 100% is assumed for the refinery SMR and for the cement process emissions since they both result in high CO_2 purity streams.
102 Levelised values were calculated using a social discount rate of 3.5%.
103 Cost estimates based on the assumptions reported in Appendix 8.7, an assumed energy price of 4.9 p/kWh and 6.4 p/kWh for hydrogen and electricity, respectively, and a project lifetime of 20 years. A substantially lower cost of capture applies to high CO_2 purity streams (see footnote 101).

Box 4 – CCUS to tackle emissions from internal fuel combustion

There are two options for CCUS to abate emissions from internal fuel combustion in the refining and petrochemical subsectors:

- The first option sees **post-combustion capture applied to the flue gases** resulting from combustion of internal fuels.
- In the second option, **internal fuel gases**[104] **are diverted to a natural gas reformer** (SMR or ATR) to produce blue hydrogen and capture is applied onto the flue gases from the reforming process. This hydrogen in turn replaces internal fuels in the furnaces leading to zero combustion emissions.

There are pros and cons to both options. **The second has the advantage that carbon capture is only needed at the natural gas reformer**. **However, this route incurs a higher energy penalty** due to the losses occurring when natural gas is converted to hydrogen, which would reduce the net decarbonisation benefit of CCUS. In this study **the first option is assumed to be implemented**. It is however acknowledged that, ultimately, the choice depends on the relative cost and on other strategic considerations. It is worth highlighting in this context that the substantial demand for blue hydrogen in hydrogen-centred decarbonisation pathways may make it preferable to accept higher conversion losses in light of the considerable economies of scale that would be achieved by only capturing CO_2 from very large standardised reformers, which it is assumed would also be installed within the Grangemouth cluster.

Transport and storage

The captured CO_2 can be transported to its destination in multiple ways. Options for onshore transport include pipelines (e.g. the Feeder 10 pipeline which the Acorn project aims to convert to transport CO_2 from Grangemouth), trucks, and trains. Conversely, options for offshore transport include underwater pipelines or shipping. It was already noted that a site's **distance from the CO_2 infrastructure** (e.g. from CO_2 pipelines or from the storage site) and the characteristics of the storage site itself can have a marked impact on the cost of storage. A recent assessment of the UK's CO_2 storage resource carried out by Pale Blue Dot, Axis Well Technology and Costain indicates that the levelised cost for offshore transport and storage across different UK sites ranges between £11-18/tCO_2 stored,[105] and the upper end of the range is selected for the modelling here. The additional cost of onshore transport (inclusive of the cost of transport in the Feeder 10 pipeline as well as any connection to it)[106] is assumed to be:

- £5/tCO_2 for the Grangemouth sites, assumed to be connected via pipeline to the Feeder 10.
- £10/tCO_2 for the petrochemical plant in Fife, also assumed to be connected via pipeline (either to the Feeder 10 directly or to the Grangemouth infrastructure).

104 Note that the second option does not apply to petcoke combustion in the refinery's fluid catalytic cracker (FCC).
105 Pale Blue Dot, Axis Well Technology, & Costain (2016). Excludes capture, compression, and onshore transport.
106 As an alternative, CO_2 could be shipped from Grangemouth directly to the Acorn Storage site.

- £15/tCO_2 for the Dunbar cement plant, assumed to be connected to the Grangemouth infrastructure via truck or, considering that the site is already rail connected, via train.

The cost of CO_2 transport and storage is therefore assumed to range between £23/tCO_2 and £33/tCO_2, modelled as a fee (T&S fee) paid to third parties assumed to operate the CO_2 transport and storage infrastructure.

It is noted that the only scenario discussed so far is that where CO_2 is permanently stored underground (and specifically offshore, in the case of the Acorn project). However, the captured CO_2 could also be used as feedstock by industries willing to pay for it, which would transform CO_2 from a potentially very large liability (especially for sites far from the storage infrastructure) into an asset, thus significantly improving the business case for CCUS.

4.3.2 Abatement potential

Permanent CO_2 sequestration vs utilisation

Since this study specifically investigates pathways for deep industrial decarbonisation, **the only CCUS options of interest here are those able to deliver emissions savings comparable to the case of permanent storage** (i.e. CCS). It is highlighted in this context that not all CO_2 utilisation routes satisfy this criterion. Indeed, if the CO_2 is released to the atmosphere again after capture (as might be the case when it is used to create synthetic fuels or when it is used in greenhouses to accelerate plant growth), the climate benefit from CCUS would be significantly lower.

Capture rates

The capture rate is one of the factors that most directly affects the abatement potential of CCUS since any CO_2 that remains in the flue gases after the capture process is released to the atmosphere. As mentioned above, **capture rates of 90% are assumed to apply** in this study,[107] though higher rates (e.g. 95-99%) are deemed possible and are considered in the context of tackling residual emissions (see Section 6.1.4). Higher costs are to be expected when increasing the capture rate, given that CO_2 would need to be removed from flue gases containing ever lower CO_2 concentrations (since CO_2 has already been stripped from them). A recent report by the IEA Greenhouse Gas R&D Program (IEAGHG) however indicates that the additional cost of increasing capture rates to 95% could be negligible in the case of gas and coal power plants (per unit of CO_2 captured),[108] though it is not clear from this study whether the increased energy demand and the corresponding emissions intensity were accounted for. It is also noted that the *size* of the capture plant increases with higher capture rates, hence space constraints would need to be considered when deciding on the capture rate.

107 Exceptions the refinery SMR and for the cement industry are discussed in footnote 101.
108 IEAGHG (2019).

Emission intensity of the energy needed for CCUS

The **high energy requirements for CO_2 capture** are a known limitation to the net abatement achievable through CCUS. If the heat demand is met via natural gas, as would be most likely be the case today, it would therefore be expected that capture technologies with higher energy requirements (e.g. first generation amines) would deliver the lowest level of abatement, strengthening the case for using more advanced technologies instead. **To ensure that CCUS delivers the greatest amount of abatement possible for the selected Scottish industries it is assumed that hydrogen will be used to meet the heat requirements for carbon capture**. This assumption is considered realistic since low-carbon hydrogen is envisioned to be produced in Grangemouth more or less at the same time as CCUS deployment starts, and it could be possible that natural gas is temporarily be used to bridge any delay in its availability with negligible impact on the overall decarbonisation pathway.

Negative emissions with BECSS

No discussion on the abatement potential of CCUS would be complete without a mention of **the potential for negative emissions which could be unlocked by combining CCUS with bioenergy combustion** (known as bioenergy CCS, or BECCS)**. This possibility is assessed in this study only in the context of the cement industry** for two reasons. First, this industry already uses a small share of biomass (contained in waste-derived fuels) and it is assumed that the share will increase to 70% of the total energy required by the kiln when implementing fuel switching (see Section 4.2.1) – which would make the cement plant the single largest industrial user of bioenergy in Scotland. Second, CCUS is assumed to be necessary to abate process emissions within the cement industry, hence the additional cost of capturing emissions from the kiln (as well as from the calcination process) would likely be reduced compared to that of a standalone installation.

This does not imply that other industries cannot also contribute negative emissions. For instance, the whisky distilleries and the wood panel manufacturers that already use organic residues could in theory also implement BECCS. Their limited size and often remote location – potentially far from CO_2 transport and storage infrastructure – however suggest that CCUS will be costlier to implement at these sites. Additional possibilities for achieving negative emission with CCUS are discussed in Box 5.

Box 5 – Additional possibilities for negative emissions

Some negative emissions are achieved within the deep decarbonisation pathways by implementing CCUS on the cement kiln, where substantial amounts of biomass can be combusted. More extensive implementation of **BECCS** within the industries in scope could potentially be proposed, for instance, if the refinery or petrochemical sites were to co-fire biogas within their furnaces.

Alternatively, negative emissions could be attained by **mixing biogas** in the natural reformer used **for blue hydrogen production**. According to a previous study by Element Energy,[109] a gas mix with just under 10% biogas could lead to a negative emission intensity for blue hydrogen of -10 gCO_2/kWh. Speirs *et al.* instead find that hydrogen produced via **biomass gasification**[110] could deliver hydrogen with an emission intensity of -371 gCO_2/kWh.[111] While there are a number of bioenergy routes to the production of negative-emissions hydrogen, it is important to reflect on the scarcity of sustainable bioenergy sources and on the fact that their optimal use may be found in other sectors.[112]

Direct air carbon capture and storage (DACCS) – i.e. the capture of the highly diluted CO_2 contained in the atmospheric air – could also become commercially available at a price that is competitive with other options for deep decarbonisation. DACCS might in fact be a cheaper solution, if implemented at scale, compared to the capture of CO_2 from many small emission sources, in spite of their higher CO_2 concentration. Cost savings could in this case arise from economies of scale and from the possibility to locate DACCS close to the relevant CO_2 transport and storage infrastructure.

4.3.3 Barriers and enablers

Key barriers which may hinder CCUS deployment include:

- The high cost and consequent impact on competitiveness.
- The low maturity of capture technologies which have never been commercially deployed within certain sectors, which would entail deployment of first-of-a-kind (FOAK) technologies.
- The commercial complexity of CCUS projects, which must bring together emitters, transport infrastructure developers and storage operators in the context of what is often FOAK projects for the parties and regions involved.
- Exposure of each party to ‘counter-party risk’, i.e. the risk that another party may at some point withdraw with disastrous consequences for the overall project economics, is also considered an important commercial barrier.

109 Element Energy (2019b).
110 This process converts carbonaceous materials into hydrogen (and oxygen, carbon monoxide, and carbon dioxide) at high temperatures (>700°C) and without combustion. A complete description of the process can be found at https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification.
111 Speirs *et al*. (2017).
112 Committee on Climate Change (2018).

- Distance from the CO_2 infrastructure (CO_2 pipelines and storage sites) increases cost and hence is often an obstacle to the development of CCUS. For the Scottish industries on which CCUS is assumed to be deployed in this study, however, this is not expected to be an important challenge considering the possibility to connect to the Acorn CCS project via pre-existing pipelines.
- Availability of sufficient space on site for the installation of the (large) capture equipment.
- Planning constraints.
- Exposure to uncapped liability in case CO_2 leaks from the storage site.

A detailed review of the main barriers to CCUS deployment can be found in a previous study by Element Energy for IEAGHG,[113] where one of the main enablers is specifically investigated: i.e. to pool demand for CO_2 by *clustering*, which could make it more economical and less risky to develop a CCUS project.

113 Element Energy (2017b).

5 Pathways

A baseline and three decarbonisation pathways were devised by combining the decarbonisation options introduced above, as illustrated in Figure 9. These **pathways are *possible*** – rather than optimal – **ways for Scottish industries to abate their emissions**. Therefore, while the two deep decarbonisation pathways are evaluated independently to better assess the relative merits and infrastructure requirements of each fuel-switching option more transparently, it is likely that a hybrid pathway that includes both electrification and hydrogen fuel switching (as well as CCUS, efficiency improvements, and other decarbonisation options), could be preferable. This hybrid pathway is qualitatively reviewed in Section 6.5.

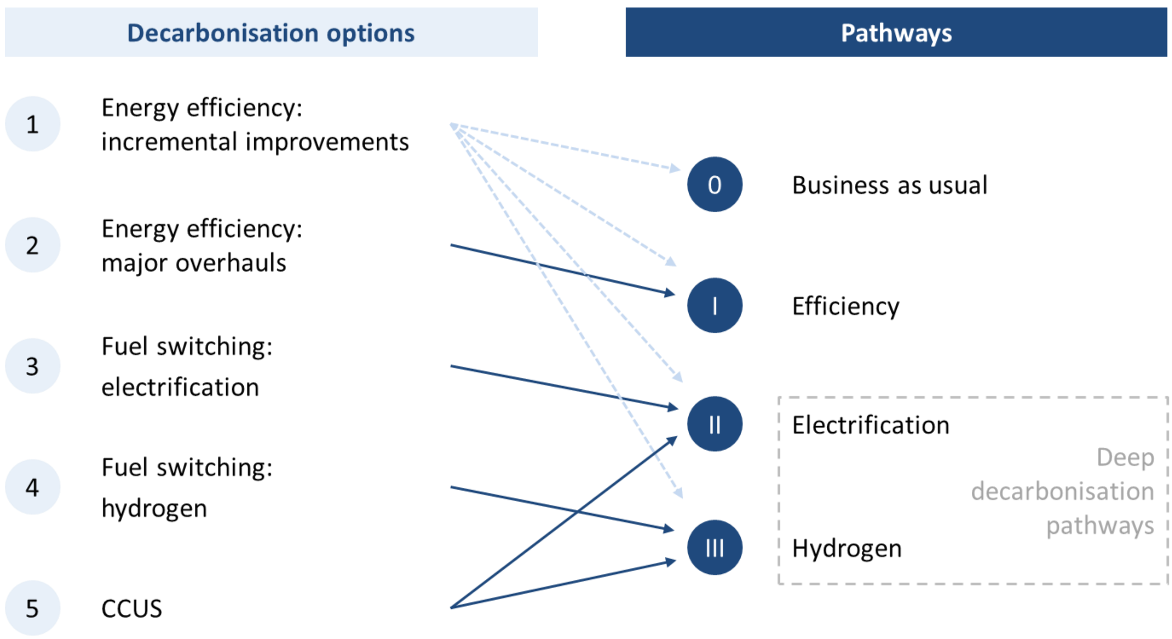


Figure 9 – Decarbonisation options and pathways

5.1 Business as usual scenario

The net impact of each decarbonisation pathway is assessed against a baseline or business-as-usual (BAU) scenario representative of the case where none of the conditions necessary to invest in deep decarbonisation materialise. Neither fuel switching nor CCUS are deployed in this scenario, and the only decarbonisation measures implemented are the incremental improvements in energy efficiency listed in Section 4.1.

As was already noted in the introduction, **the scale and type of industrial activity is assumed to remain steady** over the timeline of interest (i.e. to 2050) and equal to 2018 levels. It is acknowledged that this assumption is not likely to hold in practice, especially in view of the current downturn induced by the COVID-19 pandemic, briefly addressed in **Error! Reference source not found.**. This simplifying **assumption applies to all athways** and is specifically made to clearly isolate the impacts of the decarbonisation options and avoid blurring the insight with uncertain assumptions around the future evolution of industrial markets.

It is further assumed that neither the industrial products nor the processes used to manufacture them change over the 2020-2045 period. For this reason, the impact of demand-side measures such as product substitution, increased recycling – and more generally the transition to a circular economy – is not assessed here, although these may well have an important role to contribute in curbing industrial emissions in practice. Given their similar, highly uncertain nature, a detailed review of the breakthrough technologies that may revolutionise how industrial products are made is out of scope.

Box 6 – The COVID-19 downturn

At the time of writing the COVID-19 pandemic is still unfolding and its impact on the UK economy is not yet fully known. Interim estimates by the Bank of England are that the UK GDP could reduce by 14% in 2020 compared to 2019,[114] and PwC estimates a 9-16% reduction in gross value added from the manufacturing sector in the same period.[115] Should these predictions turn out to be correct, the UK will face in 2020 an unprecedented contraction of the economy which may also have long-term repercussions on industries in Scotland.

To accurately assess how industry emissions will be affected by COVID-19 over the timeline assessed in this study one would need to know how each industrial subsector was affected as well as when and how it will recover. However, there are substantial unknowns:

- The timeline and 'shape' for the recovery is not known. If the sharp economic decline is followed by quick and strong recovery there may be virtually no long-term impact on the scenarios assessed here. If however the recovery is slower (as was the case with the 2008 downturn, after which it took over a decade to return to pre-crisis levels)[116] it is possible that industrial activity may not return to the previous level for several years.[117]
- Policy could affect the long-term viability of certain industries, also depending on whether future business support packages will support emission-intensive sectors as much as others.

Acknowledging the great uncertainty surrounding future developments as the world recovers from COVID-19 and recognising the impossibility of making accurate predictions about such an uncertain future, **this study assumes that all industries will return to pre-COVID-19 levels** in due time, and the likely short- to medium-term deviations are estimated to be negligible over the long-term.

114 https://www.bankofengland.co.uk/report/2020/monetary-policy-report-financial-stability-report-may-2020.
115 COVID-19: UK Economic Update on 29 April.
116 ONS Manufacturing sector performance, UK: 2008 to 2018.
117 Certain economists predict "long-lasting negative effects on unemployment […] because the lockdown disproportionately disrupts the employment of workers who need years to find stable jobs" in the USA (https://www.marketwatch.com/story/why-these-economists-say-the-recovery-will-be-l-shaped-2020-05-11). Similar conclusions were drawn by a study looking at the Chinese economy (https://www.wsj.com/articles/china-economic-data-indicate-v-shaped-recovery-is-unlikely-11589257260.

5.2 Decarbonisation pathways

5.2.1 #1: Efficiency pathway

The Efficiency pathway assesses the maximum abatement that can be attained by implementing all energy efficiency measures presented in Table 3, and it is the only pathway that assumes implementation of efficiency measures classified as major overhauls (whereas only incremental improvements are implemented in the other pathways – the difference is only relevant to the oil and gas and glass sectors). Since the implementation of each individual efficiency measure has a relatively marginal impact on the overall trajectory of the emissions from Scottish industries, a simplifying assumption is made that the implementation of efficiency measures reduces emissions at constant rate until 2045.

This pathway represents the case where the policy and regulatory environment does not justify investment in fuel switching or CCUS. It is however expected that additional policy incentives would be required for implementation of measures classified as major overhauls, which may otherwise be considered hard to justify commercially.

5.2.2 #2: Electrification pathway

The Electrification pathway is characterised by the electrification of all industrial processes for which this is considered to be technically viable. Since the analysis presented in Section 4.2 highlighted the cement kiln as the *only* process for which full electrification or full hydrogen conversion is not assumed to be possible, **all sectors other than cement see no uptake of hydrogen technologies in this pathway.**[118] As discussed Section 4.2.1, a mixed-fuel kiln using bioenergy, hydrogen and electricity is assumed to be used in the cement industry in both deep decarbonisation pathways.

Considering that fuel switching cannot tackle emissions from internal fuel combustion or industrial process,[119] **CCUS is also deployed** on selected sites (see Section 4.3.1).

The Electrification pathway is representative of a world in which cheap renewable energy sources are rapidly deployed, meaning that grid decarbonisation can progress at the rate shown in Section 4.2.2 in spite of the additional demand for electricity from industry. A few other developments are expected to happen for this decarbonisation pathway to be possible:

- **Ways are found to manage the increased volatility in electricity supply** due to the high penetration of variable energy sources. For instance, this could happen through technological developments that substantially reduce the cost of 'flexibility measures' like energy storage and demand-side response.
- **Alternatively**, substantial deployment of **CCUS or hydrogen in the power sector** could also help address said volatility through flexible thermal generation.

118 It is however important to reiterate once more that other reasons (e.g. economic or logistics) may make it strongly preferable to choose hydrogen over electrification (or *vice versa*) for certain processes, as discussed in the next chapter in the context of a possible hybrid pathway.
119 See Section 3.2.

- Major electricity **grid upgrades** are carried out to enable large-scale electrification.
- **Changes in the policy and/or regulatory framework** mean that investment in deep decarbonisation is commercially viable. This scale of the policy and regulatory change necessary to support these pathways **cannot be understated**, since the mechanisms required to encourage deep decarbonisation have not even been designed yet, and a considerable lead time might be expected before these are implemented and decarbonisation can start.

5.2.3 #3: Hydrogen pathway

The Hydrogen pathway is characterised by the deployment of Hydrogen in all industrial processes for which it is considered to be technically viable, and no electrification happens outside of the cement industry.

While the Electrification pathway can partly leverage existing infrastructure and electricity generation assets and can hence start sooner, **the start of the Hydrogen pathway is dependent on the development of new infrastructure for the production and distribution of low-carbon hydrogen**.[120] A few other conditions must be met for this pathway to be viable:

- The hydrogen technologies presented in Section 4.2.1 must **demonstrate technical and commercial viability**. While a similar condition applies also for the Electrification pathway, it is noted that the earlier stage of development of a few hydrogen technologies indicates a bigger risk that they may never become commercially available. On the other hand, there is also the possibility the hydrogen technologies could progress to commercialisation faster than electrification technologies due to their greater similarity to fossil-fuelled systems.
- **Low-carbon hydrogen is assumed to be first available from 2028**. This is when the blue hydrogen production facility in Grangemouth is assumed to become operative, with hydrogen production progressively ramping up to meet the growing demand.

This pathway not only includes CCUS, just like the Electrification pathway, but it is also highly dependent on it**,** since CCUS is also necessary for blue hydrogen production.

5.3 Uptake assumptions

The pathway trajectories arise out of the bottom-up technology uptake assumptions since no industry-specific targets have been defined by policy to date. A different approach was employed to model the uptake of each type of decarbonisation option, as outlined below.

5.3.1 Efficiency

As noted in Section 5.2.1, the implementation of each individual efficiency measure has a relatively marginal impact on the overall emissions envelope from Scottish industries. This

120 Although it was noted above that partial reconversion of the gas infrastructure is thought to be possible, this is not considered to be a likely option for initiating fuel switching at large industrial sites, also due to the difficulties in managing varying levels of hydrogen in the gas blend highlighted by Navigant (2020). Instead, it is expected that new hydrogen-only infrastructure would need to be developed.

is because most measures would only reduce emissions by a few percentage points at the individual site level, and far less than that at the overall industry or sector level. For this reason, a simplifying assumption is made in all pathways that efficiency measures are implemented at a constant rate until 2045. This rate is different for each sector, since the maximum abatement potential that can be achieved with energy efficiency measures also varies sector by sector.

5.3.2 CCUS

The first CCUS project deployed at one of the industries in scope is assumed to become operational in 2028. This timeline is ambitious and could possibly represent the earliest time that such a project could reasonably be expected to become operational. For this to happen, feasibility studies would need to start promptly and supporting policies would need to be put in place to justify the business case. If these conditions are met, it is believed that this timeline could be achievable. A final investment decision could then be taken by early 2024, leaving 3-4 years for the engineering, procurement, and construction (EPC) phase. This timeline would also enable the Grangemouth CCUS project to connect to the Acorn CCS Project, which plans to start CO_2 injection at St. Fergus from 2023 and aims to be ready to import CO_2 from Grangemouth via the Feeder 10 pipeline starting 2027.[121]

A steady, stepwise deployment of CCUS across industry is assumed:

- The first industrial site to implement CCUS is the Grangemouth petrochemical plant, in 2028.
- The Grangemouth refinery starts capturing CO_2 from its furnaces and SMR in 2031.[122]
- The Fife ethylene plant, situated not far from Grangemouth, is assumed to connect to the Grangemouth CO_2 pipeline network in 2034.
- The Dunbar cement plant, furthest away from Grangemouth, is assumed to join last in 2037.
- No other industrial site deploys CCUS for the reasons outlined in Section 4.3.

CCUS is also assumed to be deployed for blue hydrogen production in Grangemouth in 2028,[123] i.e. at the same time as the first Grangemouth CCUS project, progressively ramping up production based on the increasing demand from industry (and potentially from other hydrogen users).

It is noted that, if suitable CO_2 utilisation applications can be found, the development of certain CCUS projects could potentially be sped up. Likewise, the substantial uncertainty surrounding the dates assumed above should not be underestimated. Earlier or later dates are possible depending on future developments around CCUS technology and the

121 ACT Acorn Consortium (2019). The import capacity of the Feeder 10 pipeline is of up to 3 $MtCO_2$ per year. It is noted that CO_2 shipping could potentially offer a faster route to the completion of the Grangemouth CCUS project, should the availability of the Feeder 10 pipeline be a bottleneck.
122 Note that this SMR is used to produce hydrogen for internal refining processes but it is not assumed that the same reformer will become the blue hydrogen production hub to serve local industries. Rather, a new reformer is assumed to be developed.
123 The study does not make assumptions around who would develop the blue hydrogen production facilities. It is however noted that the Grangemouth refinery already produces (grey) hydrogen within its SMR.

establishment of measures to prevent carbon leakage and of financial support mechanisms.

5.3.3 Fuel-switching

The adoption of fuel-switching technologies is assumed to increase steadily over time, at the same rate for each technology but with a different starting date, reflecting the differences in the estimated commercialisation dates (see Section 4.2.1). Specifically, it was assumed that:

- In the **Electrification pathway**, each technology reaches a level of **uptake of 80% within 20 years** from its first deployment date, and **100% uptake within 35 years**.
- For the **Hydrogen pathway**, the **80% uptake** level is reached after **10 years**, and **100% uptake** is achieved within **25 years**. The assumption that uptake occurs faster in this pathway (though it starts later, due to lower technology maturity) reflects feedback from stakeholders who indicated that the implementation of hydrogen technologies would be less disruptive, also considering that this can often happen via retrofits.

It was further assumed that larger sites are the first to decarbonise. While this may not be the case in practice, considering that larger sites may have stricter requirements when judging the maturity of a new technology or the reliability of its supply chain, this approach maximises the decarbonisation attained by the interim (economy-wide) targets and minimises the overall amount of emissions from industry within all future carbon budgets. This approach therefore provides an indication of the *maximum* abatement which could be achieved via the pathways assess in this study. It is stressed that the **rate of deployment** assumed here is considered **ambitious**, and only thought to be possible provided sufficient policy support is put in place. Additional conditions which are essential to making this ambitious deployment possible are discussed in Section 6.2.1.

Counterfactual appliance replacement

Even if no fuel-switching technology were deployed, industrial sites would still be required to replace fossil-fuelled appliances at the end of their useful lifetime. When considering the cost incurred within each decarbonisation pathway, **the cost of the counterfactual appliance replacement (also incurred in the BAU scenario) is netted off**.

To model this precisely, the age of current appliances would need to be known, but this generally represents commercially sensitive information that is not available in the public domain. In a few cases, however, relevant information is publicly available. For instance, it was announced in 2019 that a new CHP plant will be built in Grangemouth to replace a 40-year old power station.[124] Assuming that the new plant would become operational in 2022 and allowing for a minimum lifetime of 20 years, it was assumed that fuel switching would not be carried out until 2042. In all other cases it was instead assumed that the

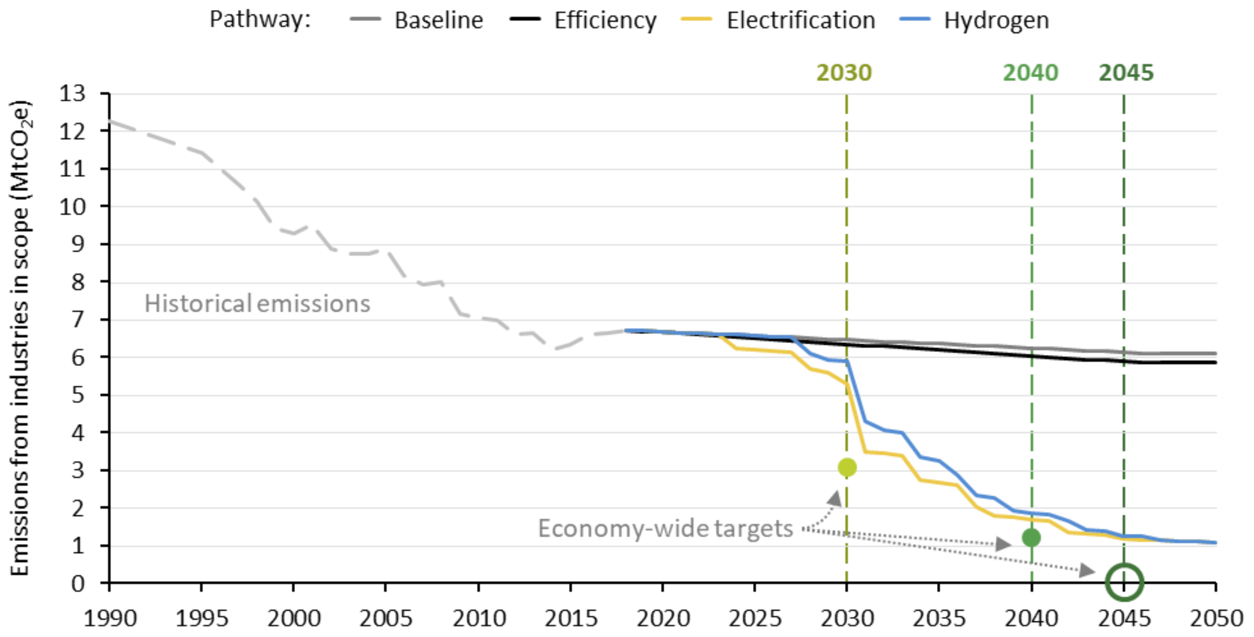
124 https://www.ineos.com/sites/grangemouth/news/ineos-is-investing-350m-in-a-new-state-of-the-art-energy-efficient-power-plant-at-its-grangemouth-site/.

counterfactual appliance replacement in the BAU scenario occurs in the same year in which fuel switching happens in the decarbonisation pathways.

6 Results

6.1 Decarbonisation potential

The three pathways introduced in the previous chapter were evaluated until 2050, and emission reductions from the reference year (2018, when emissions from industries in scope amounted to 6.7 $MtCO_2e$) were calculated for 2030, 2040, and 2045, i.e. the years for which economy-wide emission targets apply (or 75%, 90%, and 100% reduction against the 1990 baseline, respectively). It should be noted in this context that no industry specific targets have been set, and that the pathways studied here are not constrained to meet any economy-wide or other emission reduction targets, but rather build on the bottom-up uptake assumptions presented in the previous chapter.



Economy-wide targets: -75% by 2030, -90% by 2040, -100% by 2045. These are only shown for reference since no industry-specific targets exist.
Historical emissions estimated by assuming that emissions from all industries followed a similar trajectory after 1990.

Figure 10 – Pathway emission trajectories

6.1.1 Deep decarbonisation pathways

The first finding of this study is that **emissions from the industries in scope decrease by over 80% below 2018 levels by 2045 in both deep decarbonisation pathways,** reaching 1.2 $MtCO_2e$ in the Electrification pathway and 1.3 $MtCO_2e$ in the Hydrogen pathway, as summarised in Table 5. The similar decarbonisation potential of the two pathways is first of all explained by the fact that no fossil-fuelled appliance was found to be replaceable by only hydrogen or only electrical appliances and, second, by the comparable carbon intensities of electricity and hydrogen fuel when compared to fossil fuels.

These considerations also imply that **a hybrid pathway,** where electrification occurs at certain sites and hydrogen fuel-switching at others, **would be able to deliver similar**

emission reductions as the pathways assessed here, **possibly more rapidly and cost-effectively**. Section 6.5 discusses what such a pathway may look like.

The main difference in the emission trajectories of the two deep decarbonisation pathways is in *how rapidly* they decarbonise, which determines their performance against the economy-wide interim target years as well as the cumulative abatement they deliver (8 $MtCO_2e$ higher for the Electrification pathway, by 2045), also reported in Table 6. This can be explained by two factors:

- The **greater maturity of electrification technologies** means that they can be deployed sooner.
- Only a handful of sites are expected to have switched to hydrogen by 2030, since **no low-carbon hydrogen is assumed to be available before 2028**.

Despite this, the two pathways deliver comparable yearly emissions reductions by 2045 owing to the assumption that hydrogen technologies can be deployed more rapidly when they become available (see Section 5.3.3). It is also noted that a slightly lower carbon intensity is assumed for hydrogen in 2045 in comparison to electricity, which partly counteracts the slightly greater uptake of electrification options by that same year.

Table 5 – Emissions from industries in scope in 2030, 2040, and 2045

Pathway emissions ($MtCO_2e$)	2030	2040	2045
Baseline	6.5	6.2	6.1
Efficiency	6.3	6.0	5.9
Electrification	5.3	1.7	1.2
Hydrogen	5.9	1.9	1.3

Table 6 – Emissions abatement for industries in scope in 2030, 2040, and 2045

	Electrification			Hydrogen		
	2030	2040	2045	2030	2040	2045
Net abatement vs 2018	21%	75%	82%	12%	72%	81%
Cumulative abatement since 2018 ($MtCO_2e$)	6	48	74	3	40	66

Emissions reductions from 1990 levels

To assess what these results would mean for the contribution from all Scottish industries to the achievement of net zero targets, an assumption must be made around the emission reductions achieved by industries not in scope. Two alternative assumptions are proposed here as the likely range of emissions reductions for all Scottish industries by 2045 (note that baseline emissions from all Scottish industries are 21.0 $MtCO_2e$, and that they were already 45% lower than this by 2018, as noted in Section 3.1):

- If it is assumed that industries out of scope decarbonise at the same rate as industries within scope, overall emissions from all Scottish industries would amount to 2.0-2.2 $MtCO_2e$ in 2045, i.e. 90% lower than in 1990.
- Conversely, if industries out of scope do not decarbonise at all (i.e. the worst-case scenario), overall emissions would be 6.0-6.1 $MtCO_2e$ in 2045, or about 70% lower than 1990 levels.

Table 7 – Residual emissions and estimated abatement from all Scottish industries

Residual emissions in $MtCO_2e$ and % reduction from 1990 levels	Electrification			Hydrogen		
	2030	2040	2045	2030	2040	2045
If industries not in scope decarbonise at the same rate as industries in scope	9.1 (-57%)	2.9 (-86%)	2.0 (-90%)	10.1 (-52%)	3.2 (-85%)	2.2 (-90%)
If industries not in scope do not decarbonise	10.1 (-52%)	6.5 (-69%)	6.0 (-72%)	10.7 (-49%)	6.7 (-68%)	6.1 (-71%)

6.1.2 Efficiency pathway

While emissions are seen to substantially reduce in both deep decarbonisation pathways, they **only reduce by 12% below 2018 levels in the Efficiency pathway**. This means that the implementation of all efficiency improvements is estimated to reduce emissions by only 4% more than what can be achieved with the sole implementation of incremental efficiency improvements in the BAU scenario. Despite the relatively small role that efficiency improvements play *on average* within the context of the transition to net zero, the analysis presented in the next subsection shows that sectors like food and drink can cut their emissions far more substantially by improving efficiency.

There are also broader benefits of increasing energy efficiency – the reduced energy demand reduces fuel costs and also reduces the need for deploying additional energy infrastructure, for instance – it can therefore be understood why improving energy efficiency retains an important role within industrial decarbonisation plans. Nevertheless, since it clearly appears that **increasing energy efficiency alone is insufficient to deliver substantial emissions reductions**, the Efficiency pathway will not be analysed further.

6.1.3 Sectoral and technology contributions

It was noted above that the two deep decarbonisation pathways hold a similar potential to reduce overall emissions from the industries in scope by 2045, and since this similarity also applies at the level of each individual sector only the numerical results for the Electrification pathway are reported in the remainder of this section (results for the Hydrogen pathway are shown in Appendix 8.8). By analysing sector-level emission reductions and the corresponding contribution from efficiency improvements, fuel switching and CCUS, shown in Figure 11, it can be noted that:

- **Nearly 60% of the overall abatement occurs within oil & gas and the chemical industries**, which are the largest-emitting sectors today.

- **CCUS is expected to be the main decarbonisation technology for the oil and gas, chemicals and the cement industries**, delivering about 60% of the emissions abatement within these sectors.[125]
- **BECCS can deliver nearly 0.3 $MtCO_2e$ of negative emissions within the cement industry**. Without it, residual emissions from the industries in scope would be 22% higher in 2045.
- **Fuel switching is essential to all other sectors** where CCUS is not assumed to be deployed, accounting for about two thirds of their emission reductions.
- **Incremental efficiency improvements offer a more moderate overall contribution** (11% on average) but are far more important for the decarbonisation of certain industries, specifically food and drink. It is also worth noting that similar emission reductions could also be achieved *without* improving energy efficiency, though this would increase the amount of low-carbon energy needed for fuel switching and therefore increase the cost of decarbonisation.

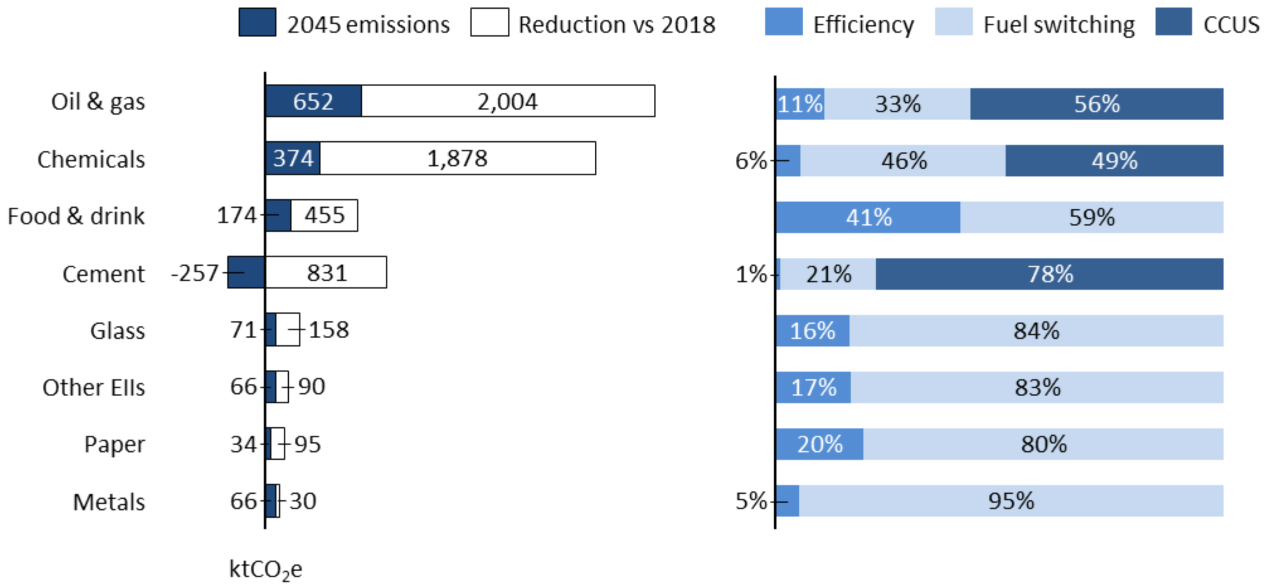


Figure 11 – Sectoral contributions to overall emissions abatement (Electrification)

When looking at the cross-sectoral contributions from individual decarbonisation technologies, shown above for the Electrification pathway (results are broadly similar for the Hydrogen pathway), it can be observed that:

- CCUS delivers **49%** of the emissions reductions, abating 2.7 $MtCO_2e$.
- All **fuel-switching** technologies combined are responsible for **41%** of the overall reduction (2.1 $MtCO_2e$).
- As noted above, energy efficiency improvements account for the remaining share (0.6 $MtCO_2e$).

125 Emissions embedded in the low-carbon energy used for CCUS operations are netted off from its abatement potential.

Furthermore, the fact that switching fuels in boilers and CHP plants accounts for 81% of the emission reductions related to fuel switching highlights the critical need to focus on **low-carbon steam as a key target for fuel switching**.

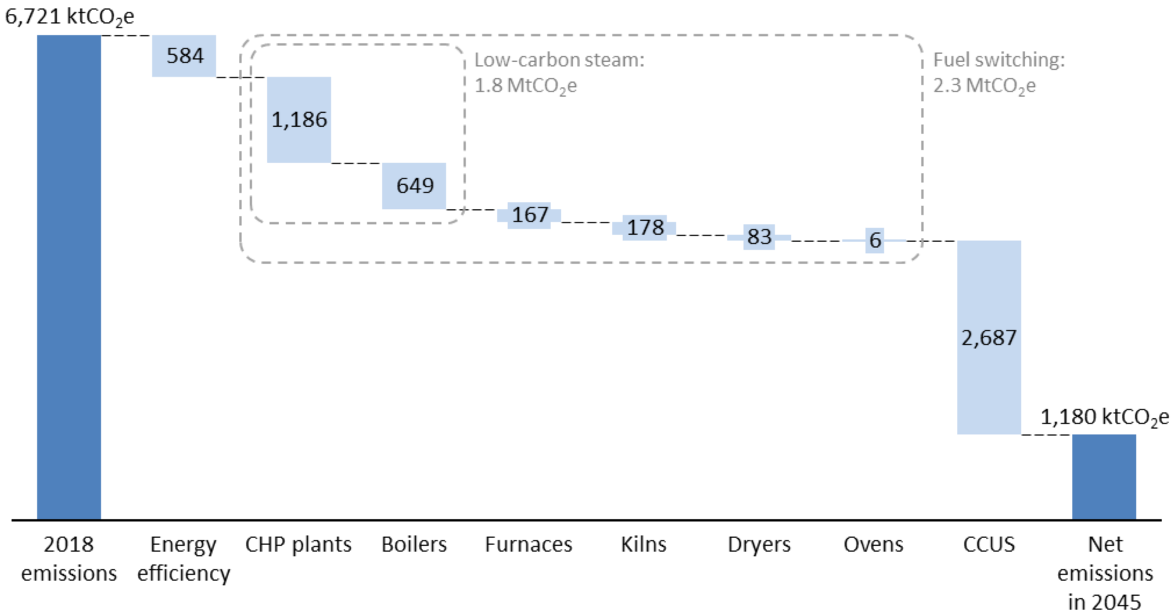


Figure 12 – Technology contributions to emissions abatement (Electrification)

6.1.4 Tackling residual emissions

To address those emissions sources that are not decarbonised within the pathways considered before 2045, additional measures must be considered. Leaving aside the negative emissions from the cement sector for this analysis, it can be seen from Figure 13 that the nearly 2 $MtCO_2e$ of residual emissions in the Electrification pathway are attributable to the following sources (results for the Hydrogen pathway are shown in Appendix 8.8 and are not repeated here due to their substantial similarity with the below):

- CO_2 that escapes capture because of the assumed 90% capture rates (171 $ktCO_2e$), which could partly be avoided if plants with **higher capture rates** were to be installed – a decision which ultimately depends on cost.
- Flaring-related emissions from the oil and gas and chemical industries (178 $ktCO_2e$), which may be tackled by **improving process reliability and hence reducing the need to flare**. Such improvements also bring other economic benefits and are actively being pursued by the interviewed stakeholders. There is a possibility that at least some flaring emissions may also be addressed via CCUS, but further work would be required to assess this possibility and its cost.[126]
- Other **process emissions from aluminium and glass manufacturing and from the Kinneil gas terminal** (167 $ktCO_2e$ distributed in similar proportions across the three industries). **CCUS or process changes** could be considered to lower these, as discussed in Box 7.

126 To capture flaring emissions, it would be necessary to invest in equipment that mostly sits idle, and which may be utilised even less if the reliability issues are resolved. This is likely to imply a very high abatement cost for CCUS on flaring-related emissions.

- **Emissions embedded within low-carbon energy sources** (147 $MtCO_2e$), which could in theory be eliminated if only renewable energy sources were used to produce it.
- The remainder (809 $ktCO_2e$) results from residual combustion of fossil fuels used in appliances which have not been replaced, or in appliances which could not be classified and are conservatively assumed to be unsuitable for fuel switching (see Section 3.3). **If the uptake of all fuel switching technologies were to be completed by 2045, emissions could be reduced by a further 0.6 $MtCO_2e$**.

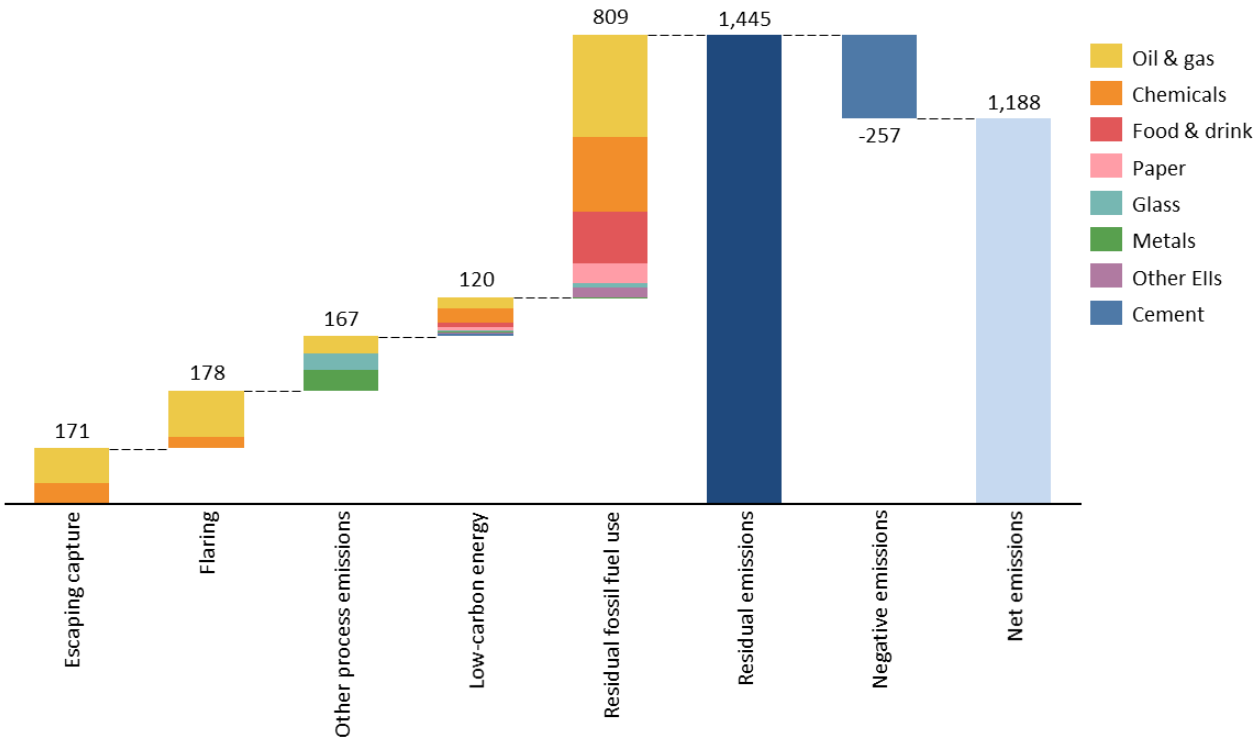


Figure 13 – Breakdown of residual emissions (Electrification)

Two further possibilities exist to abate industrial emissions further than is achieved by the deep decarbonisation pathways:

- **Higher levels of negative emissions** can be achieved from combining bioenergy with CCUS (i.e. BECCS) in other industries, and possibly also in the context of negative-emissions hydrogen production, which was discussed in Box 5.
- **Demand-side measures such as the substitution of carbon-intensive products** with others that are less carbon-intensive can also reduce industrial emissions, though this may also affect industrial activity. A common example of product substitution is to use electricity instead of petrol in the transport sector.

Product substitution could occur due to changes in consumer preference or because of the impact of demand-side policies. This possibility is not addressed here as it violates the assumption that underpins this study, i.e. that industrial products and processes do not change. The potential implications from product substitution and demand-side policies specifically are discussed in the concluding chapter.

Box 7 – Abating residual processes emissions

The deep decarbonisation pathways considered here are unable to abate all process emissions occurring in the glass, aluminium, and oil and gas industries; however, options to reduce – if not eliminate – such emissions exist.

CCUS could be applied to these processes, although it was assumed that this would not happen due to the relatively small size of the corresponding sites, as judged by emissions level. The case of the Kinneil gas terminal may present an exception in this regard, especially if CCUS is implemented at some of the Grangemouth plants: about 18 $ktCO_2e$ of high-purity CO_2 is separated from the feedstock gases already today and could be captured with relative ease.

Alternatively, **process changes** could be considered. Process emissions from glass can be fully abated if **recycled glass** (cullet) is used instead of virgin materials in the glass melting process. For this to happen, current supply constraints – especially affecting white flint glass – would need to be overcome. Glass manufacturers across the UK already use 35-40% cullet in their feedstock, but further increases are *limited by feedstock availability* (especially for flint glass),[127] which is why this option is considered of limited applicability.

In the case of aluminium, use of carbon anodes in the smelting process results in process emissions. It is acknowledged that the Elysis project, originating from the joint venture of aluminium manufacturers Rio Tinto and Alcoa, claims to have devised a solution for **carbon-free smelting**,[128] but not enough detail is available in the public domain to assess the possible relevance of their technology to tackle Scotland's aluminium manufacturing emissions. Substitution of virgin aluminium with **recycled aluminium** would also prevent process emissions since it altogether removes the need to use carbon anodes, however this is not considered to be a probable route for the Lochaber smelter since it would require a completely new facility. Further work would also be required to assess what proportion of the existing demand for aluminium could be met with recycled aluminium.[129]

Finally, emissions occurring when purging the flare heads at the Kinneil gas terminal (~35 $ktCO_2e$) could potentially be averted by replacing the current hydrocarbon-based purged gas, for instance with nitrogen.

6.2 Enablers

6.2.1 Essential conditions

The achievement of the emission trajectories shown in Figure 10 is underpinned by the assumption that **four essential conditions** are met**:**

127 British Glass (2017).
128 See https://www.elysis.com/.
129 Due to differences in product quality.

- **Substantial economic incentives must be put in place via suitable policies**. Without these, no significant investment in deep decarbonisation is to be expected.
- **All decarbonisation options must be adopted promptly** when they become sufficiently mature from a technical and commercial point of view. This is a process which may also be brought forward with appropriate policy interventions.
- **Enabling energy assets and the relevant infrastructure must be deployed in advance**, otherwise individual decarbonisation efforts might be delayed.
- **Site managers and investors need to have sufficient confidence in, and knowledge of, the relevant technologies** and in the timescales for their commercialisation, which will likely originate via the successful deployment of relevant demonstration projects within each industrial sector.

Failure to meet any of the above conditions would likely result in the delayed uptake of the key decarbonisation technologies, which will make it even more challenging to achieve Scotland's accelerated net zero targets. Considering that a certain proportion of the industrial sites will likely need to replace their current appliances within the next decade – potentially before suitable fuel-switching options are sufficiently mature to be considered as a viable option – a risk exists that these sites will be forced to choose fossil-fuelled appliances. This possibility, known as the risk of '**technology lock-in**', is the most likely outcome unless the abovementioned conditions are met. Should this happen, the long investment cycles dictated by useful appliance lives in excess of 20 years mean that, for many sites, **there might be only one chance to fuel-switch before 2045**; and it also means that, unless the four conditions above are met, the opportunity of a low-carbon replacement could be missed (unless appliances are scrapped before the end of their useful life, which could potentially be mandated by policy). It is worth noting **two potential advantages that hydrogen fuel switching may present over electrification** in mitigating the risk of technology lock-in:

- Sites requiring to replace their appliances before low-carbon hydrogen is available could install **'hydrogen-ready' appliances**, i.e. appliances that are optimally designed to run on pure hydrogen but are initially configured to run on natural gas, with minimal work required at the point of switchover. This would enable operators to switch to hydrogen as soon as it becomes available.
- **Retrofits** could convert appliances fuelled by natural gas to working with hydrogen, though this may not be applicable to all processes and further technology developments may be necessary.[130]

Conversely, it should be noted that electrification may be the only fuel switching option available to many sites within the next 5-10 years, hence the risk of technology lock-in could also be prevented by enabling site operators to invest in electrification as soon as they are ready to do so, which would also require suitable economic incentives.

130 See Element Energy, Advisian, & Cardiff University (2019).

6.2.2 Key deployments

Whenever fuel switching or CCUS are implemented on the largest emission sources, clear downward **steps in the emissions trajectories** in Figure 10 can be seen.[131] The **key deployments** from which the most evident steps arise – and which **deliver approximately two thirds of the overall abatement expected by 2045**[132] – are included in the timeline shown in Figure 14 (detailed information is summarised in Table 8 and Table 9).

The fact that fuel switching starts sooner with Electrification explains why the downward steps are seen to occur earlier for this pathway. As a reminder, the delayed start of the Hydrogen pathway is due to the assumption that **low-carbon hydrogen only becomes available in 2028**, when:

- The **first phase of the Grangemouth CCUS project becomes operational** and carbon capture starts at the petrochemical plant and at a new natural gas reformer dedicated to the production of blue hydrogen.
- The captured CO_2 is assumed to be transported via the **Feeder 10 pipeline to the Acorn CO_2 Storage site**, currently under evaluation.[133]
- In the same year, smaller-scale production of **green hydrogen** is also assumed to begin.[134]

It should however be noted that **hydrogen could contribute to decarbonising industry sooner than is modelled here** since, as it was noted above, **gas blends** with up to 20% hydrogen by volume should be compatible with the current gas infrastructure and equipment.[135] Thus, even assuming blue hydrogen production cannot start sooner, some green hydrogen could in theory be injected into the gas grid to help Scottish industries decarbonise sooner, though it is unlikely that green hydrogen production could meet more than a small portion of the energy demand supplied via the gas grid. Alternatively, some of the hydrogen produced at St Fergus within the Acorn project or produced abroad and imported to Scotland may also be available to a few of the industries in scope. Finally, it can also be seen from the tables below that **the largest emission sources are assumed to decarbonise by 2045**, which explains why the pathways converge by then.

131 The fact that the steps appear smoother in the Electrification pathway is due to the fact that the carbon intensity of the electricity grid is assumed to significantly reduce over time, whereas that of hydrogen only reduces marginally (see Figure 7). This in turn causes a steady reduction in the emissions trajectory of the Electrification pathway even in years where no fuel switching deployments occur.
132 The key fuel-switching deployments abate approximately 1.0 $MtCO_2e$ and the four CCUS deployments abate 2.6 $MtCO_2e$. Combined, this represents just under two thirds of the total abatement achieved by 2045 in both the Electrification and Hydrogen pathways (5.6 and 5.5 $MtCO_2e$, respectively).
133 This is when the Acorn project expects to be able to receive up to 3 $MtCO_2$/year from Grangemouth through Feeder 10.
134 See 4.2.2 for assumptions on the share of blue and green hydrogen.
135 See footnote 84.

Table 8 – Carbon capture deployments

Site and process	Deployment year	CO_2 captured[136] ($MtCO_2$/year)
Grangemouth olefins plant: furnaces[137]	2028	0.4
Grangemouth refinery: furnaces and SMR	2031	1.1
Fife ethylene plant: furnaces[141]	2034	0.5
Dunbar cement plant: kiln and calcination process	2037	0.5
Natural gas reformer for blue hydrogen production[138]	2028	2.1[139]
Total from industry		**2.6**
Total inc. blue hydrogen production in the Hydrogen pathway		**4.7**

Table 9 – Main fuel switching deployments

Site and processes	Deployment year		Estimated energy demand (TWh)[140]
	Electrification	Hydrogen	
Grangemouth refinery & olefins plant: CHP plants & other boilers[141]	2025, 2031, 2032, 2039, 2043	2033, 2037, 2043, 2044	4.3
Fife ethylene plant: boilers	2025	2030	0.9
Alloa glass plant: furnaces	2030	2033	0.5
Dunbar cement plant: kiln[142]	2032	2032	0.5
All main deployments			**6.2**

136 Sums may not add due to rounding.
137 Includes the steam crackers.
138 Assumed to be in Grangemouth, only in the Hydrogen pathway.
139 Based on an estimated 0.25 $MtCO_2e$ of emitted for each TWh of blue hydrogen produced. Source: Mohd *et al.* (2019).
140 Energy demand calculated from site emissions and assuming average fuel emission factors. Note that energy demand slightly reduces over time due to efficiency improvements and that it is lower for the Electrification pathway, due to the higher efficiency of electrical appliances.
141 Fuel switching is assumed to be rolled out progressively across the Grangemouth sites.
142 The cement industry could begin fuel switching to 70% biomass sooner with the right support in place. Here it is conservatively assumed that switching to the mixed-fuel kiln occurs all at once.

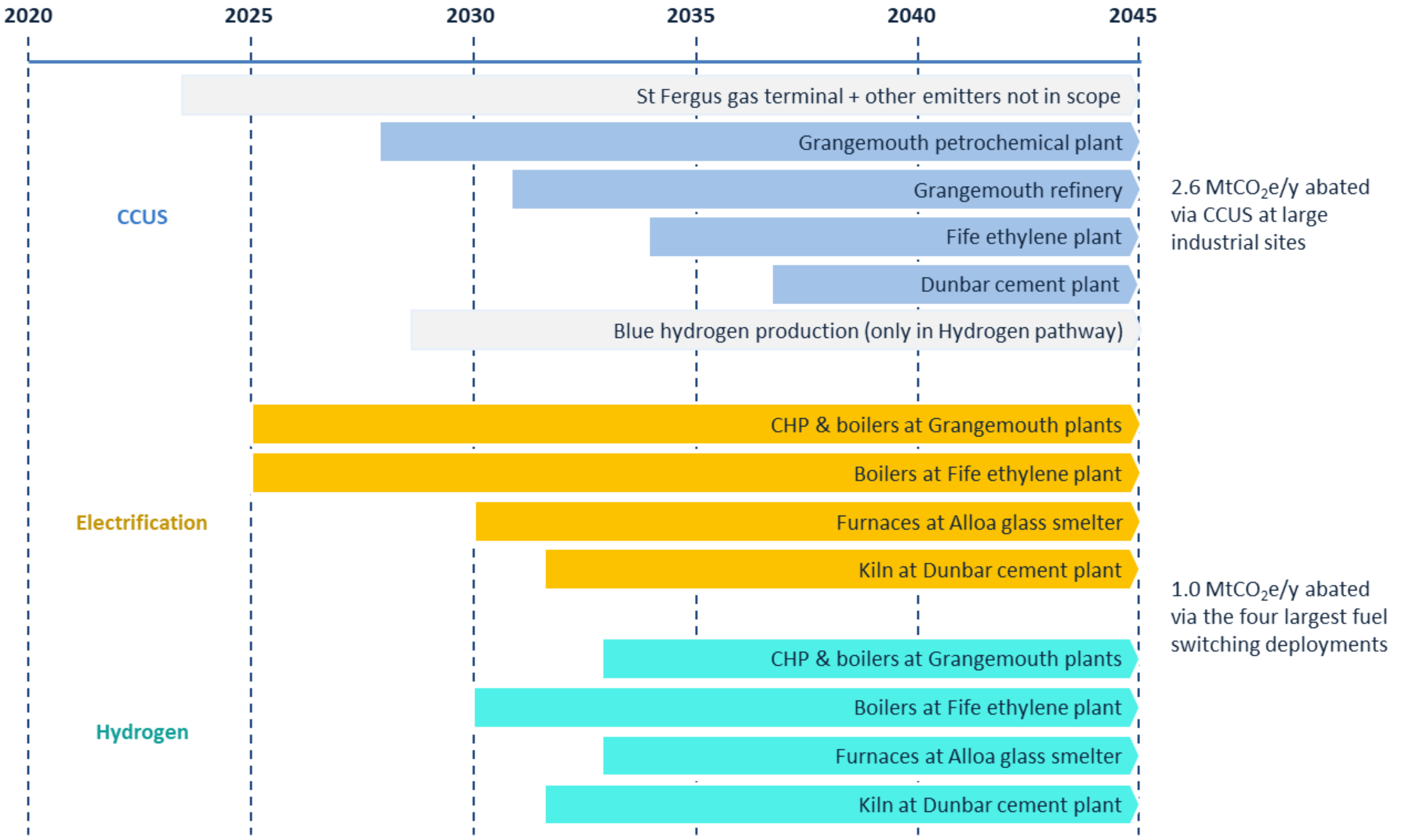


Figure 14 – Timeline of key deployments

6.2.3 Energy assets and infrastructure requirements

The results presented in the previous section are underpinned by the assumption that substantial growth in the supply of low-carbon energy can occur, which in turn requires the deployment of numerous assets broadly categorised here as **infrastructure**. Three assets categories are further defined:

- Assets for the **generation** of electricity from renewable energy sources.
- Energy **conversion** assets for producing hydrogen from natural gas or renewable electricity.
- **Other infrastructure**, which includes all other assets necessary to access low-carbon energy as well as those related to CCUS for blue hydrogen production and at industrial sites.

Table 10 – New low-carbon energy assets required[143]

Energy end use form	Primary energy source	Generation assets	Conversion assets	Other infrastructure	Focus of quantitative assessment
Hydrogen (blue)	Natural gas[144]	-	Natural gas reformers	CO_2 transport, CO_2 storage[145]	Amount of CO_2 processed in 2045 [MtCO2/year] Natural reforming capacity in 2045 [TWh/year]
Hydrogen (green)	Renewable energy sources[146]	Wind farms, solar farms etc.	Water electrolysers	Hydrogen distribution	Water electrolysis capacity in 2045 [TWh/year] Renewable generation capacity in 2045 [TWh/year]
Electricity	Renewable energy sources[146]	Wind farms, solar farms etc.	-	Grid upgrades	Renewable generation capacity in 2045 [TWh/year] Grid upgrade needs by 2045 [GW]

143 Curly braces indicate assets not quantitatively assessed in this study.
144 The possibility of combining natural gas with biogas and/or biomass gasification is discussed in Box 5. The quantitative analysis presented here assumes that only natural gas is used.
145 CO_2 could potentially be utilised instead of stored; this does not affect the quantitative analysis presented below.
146 It is expected that nearly all of the electricity generated in 2045 will be from renewable sources, which is why non-renewable generation sources were omitted from the table.

Depending on the *end use* and *primary* forms of the low-carbon energy used, different sets of assets are needed. 'End use energy' refers to what end users see, i.e. hydrogen and electricity, which can in turn be produced via a multitude of routes and from different (primary) energy sources. For instance, hydrogen can either be produced via natural gas reforming or from water electrolysis powered by renewable energy sources, and it is easy to see why the infrastructure requirements strongly depend on the choice of primary energy form, as summarised in Table 10. At the same time, certain infrastructure needs only depend on the end use form: hydrogen fuel switching for instance hinges on the development of new hydrogen distribution channels regardless of whether blue or green hydrogen is used.

An additional infrastructure-related assumption which was implicitly made when developing the decarbonisation pathways is that sufficient distribution infrastructure is developed in due time so as not to constrain uptake of hydrogen technologies from industry. Finally, no assumption is made around which technology is used to generate renewable electricity or to produce green hydrogen, or as to where these assets are located.

End use energy demand

To assess the infrastructure requirements within each decarbonisation pathway it is first necessary to quantify how much low-carbon energy is needed in both its end use form and in its primary form. **End use energy demand totalled just over 27 TWh before 2020**, as estimated by breaking down emissions by fuel type (see Figure 4) and accounting for the average emission factors for each fuel type. The demand for hydrogen and electricity[147] was then calculated after accounting for the assumed energy efficiency improvements (see Table 3) and for the different efficiencies of fossil-fuelled and fuel-switching appliances (see Table 4). Energy requirements for CCUS deployments at industrial sites were also evaluated (see page 50), since these significantly affect the total demand for low-carbon energy as is easily seen from Figure 15.[148]

147 The electricity demand calculated here is *additional* to that for renewable electricity drawn from the grid already today.
148 Energy demand related to CCUS at the blue hydrogen production facility is not included here as its contribution is accounted for in the context of the primary energy discussion when estimating the natural gas demand for CCUS (see next sub-section).

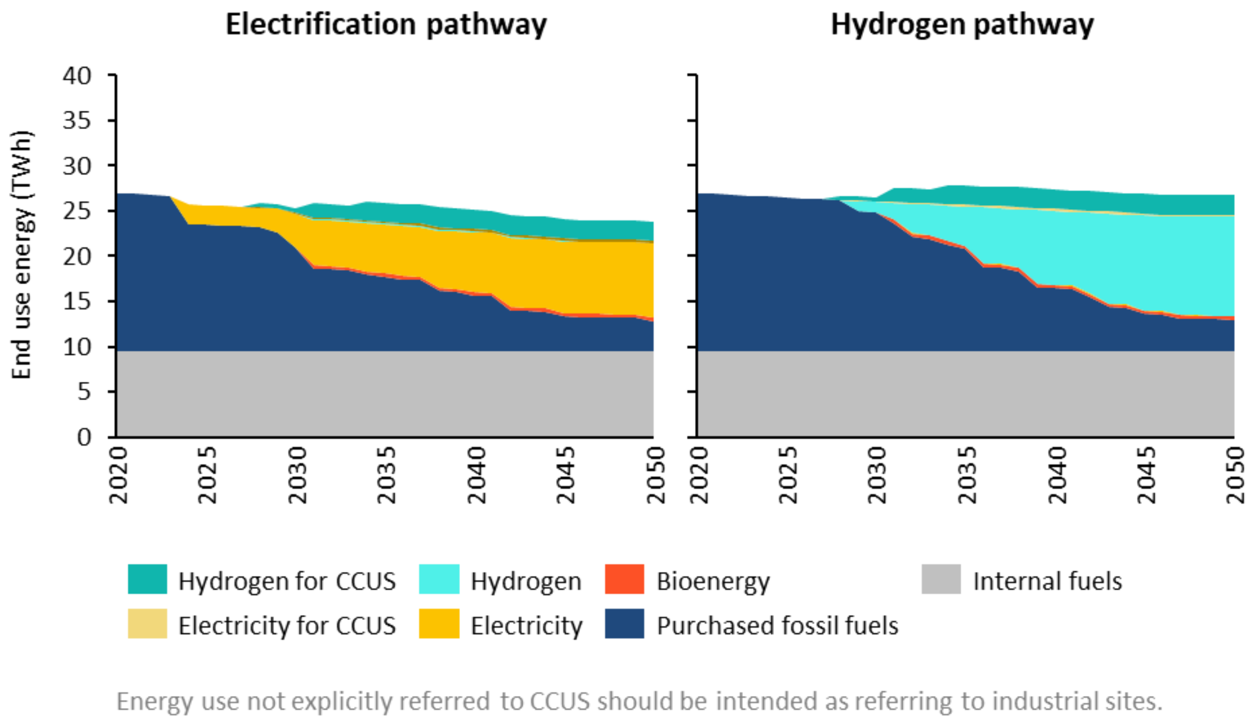


Figure 15 – End use energy demand

Following the approach outlined above it was estimated that **the overall amount of end use energy required within the Electrification pathway will be 3.1 TWh lower in 2045 than it is today, whereas it will only be 0.3 TWh lower in the Hydrogen pathway**, as shown in Table 11. Since it is assumed that industrial output remains steady, the fact that energy demand reduces is mostly due to the incremental improvements in energy efficiency, which reduce the demand by 2.7 TWh in both pathways. The higher energy efficiency of electrification appliances (specifically heat pumps) compared to both fossil-fuelled and hydrogen appliances however contributes to reducing energy demand by a further 2.4 TWh in the Electrification pathway. The combined energy demand from all industrial CCUS deployments (over 90% of which is heat for carbon capture), which require 2.1 TWh of hydrogen and 0.2 TWh of electricity in both pathways, partly offsets the effect of all efficiency improvements. Analysis of this table also helps quantify the impact of the later deployment of hydrogen technologies, which implies a residual use of fossil fuels in 2045 that is 0.2 TWh greater in the Hydrogen pathway. Conversely, internal fuel use is assumed to remain constant in both pathways for the reasons explained in Section 3.2.

Table 11 – Breakdown of end use energy demand in 2045

Energy vector	Initial demand (TWh)	Electrification (TWh)	Hydrogen (TWh)
Internal fossil fuels	9.5	9.5	9.5
Purchased fossil fuels	17.7	3.9	4.1
Electricity	-	8.1	0.3
of which for industry	-	*7.9*	*0.1*[149]
of which for CCUS	-	*0.2*	*0.2*
Hydrogen	-	2.3	12.6
of which for industry	-	*0.1*[149]	*10.5*
of which for CCUS	-	*2.1*	*2.1*
Biomass149	-	0.4	0.4
Total	**27.2**	**24.1**	**26.9**

Primary energy demand

The demand for primary energy plotted in Figure 16 was calculated from that for end use energy after accounting for the energy losses along the supply chain (specifically those in the hydrogen conversion step and in electricity transport and distribution) according to the net efficiency values reported in Table 12.

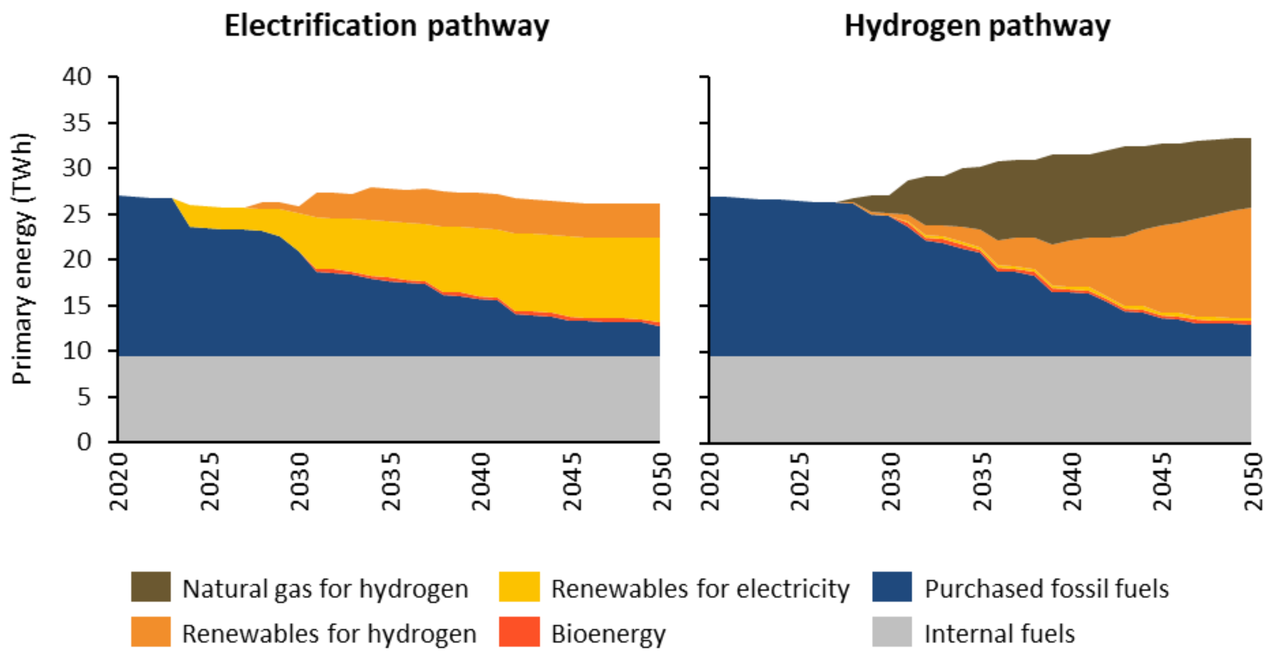


Figure 16 – Primary energy demand

149 The mixed-fuel kiln assumed to be used by the cement industry (see page 28) is responsible for all biomass use, all electricity for industry in the Hydrogen pathway, and all hydrogen for industry in the Electrification pathway.

Table 12 – Efficiencies and load factors of generation and conversion assets

Generation asset	Load factor	Net efficiency
Renewable electricity	27%[150]	92% (generation-to-use)[151]
Water electrolyser for green hydrogen	27%[152]	60% (power-to-H_2)[153]
Natural gas reformer for blue hydrogen	85%	77% (gas-to-H_2)[154]

The following assumptions were also made:

- **Dedicated renewable electricity generation is assumed to be used for green hydrogen production**, which implies that that green hydrogen is only produced when the generation assets are operating (which explains why the respective load factors match) and that 1 GW of generation capacity is needed for each GW of installed electrolyser capacity.
- **Only green hydrogen is used in the Electrification pathway, whereas a 50:50 mix of blue and green hydrogen is used in the Hydrogen pathway by 2045** (the cases where only green or only blue hydrogen are used are also discussed below).

Three significant differences between the two pathways emerge when comparing the detailed breakdown of primary energy requirements provided in Table 13:

- **Primary energy demand in 2045 is 5.9 TWh higher in the Hydrogen pathway** than it is in the Electrification pathway.
- **Even though electricity demand is 8.6 TWh higher in the Electrification pathway, the overall need for new renewable generation is only 2.7 TWh higher than in the Hydrogen pathway**. This is because of the large demand for new renewable electricity for green hydrogen production.
- **The demand for natural gas as feedstock to produce blue hydrogen (+8.9 TWh) partly offsets the reduction in the demand for purchased fossil fuels (-13.6 TWh),** most of which is natural gas.

The first point above warrants further explanation. The higher efficiency of electrical appliances, already discussed in the context of end use energy, partly explains the difference in primary energy demand, but another reason which impacts demand to a similar extent can be found in the lower end-to-end energy efficiency of the hydrogen

150 Load factor refers to Scottish average for wind power. Source: BEIS (2020) Table 6.1c Renewable electricity capacity and generation: Scotland.
151 Accounts for 8% transmission and distribution losses. Source: Written evidence submitted by Citizens Advice (NTC0019), http://data.parliament.uk/writtenevidence/committeeevidence.svc/evidencedocument/energy-and-climate-change-committee/networkcosts/written/8275.html.
152 Assumes that the electrolysers are directly connect to a dedicated wind farm, hence the load factors coincide.
153 Although electrolysers can achieve higher efficiencies (closer to 70%), the value assumed here is considered more representative in light of the fact that electrolysers powered by dedicated renewable generation will not always be operating at peak performance.
154 Representative of an average hydrogen production efficiency according to Antonini *et al.* (2020).

supply chain, compared to that for electricity. Specifically, over a third of the renewable energy that powers the water electrolyser is lost in the processes, whereas less than 10% of the electricity is lost while transported along the electricity grid. Incidentally, this also explains why **the demand for new renewable generation is still substantial in the Hydrogen pathway and would in fact be even higher than in the Electrification pathway if only green hydrogen was used**.

Table 13 – Primary energy demand in 2045

Energy source	Initial demand (TWh)	Electrification (TWh)	Hydrogen (TWh)
Internal fossil fuels	9.5	9.5	9.5
Purchased fossil fuels	17.7	3.9	4.1
Bioenergy	-	0.4	0.4
Renewables		12.6	9.9
of which for electricity use	-	*8.9*	*0.3*
of which for green hydrogen	-	*3.8*	*9.6*
Natural gas for blue hydrogen	-	-	8.9
Total primary energy	**27.2**	**26.4**	**32.8**

New asset and infrastructure requirements

Building on the analysis presented above, the new asset and infrastructure requirements can finally be quantified using when relevant the load factor assumptions listed in Table 12. The results reported in Table 14 (referring to 2045, like the rest of the discussion below) highlight several differences between the new asset and infrastructure requirements of the two pathways, some of which are best highlighted when considering two sensitivities for the hydrogen pathway, i.e. the case where only green or only blue hydrogen (H_2) are used.

Both deep decarbonisation pathways will likely require significantly higher levels of renewable electricity generation, with the exception of a Hydrogen pathway that mostly relies on blue hydrogen. Looking for instance at the Electrification pathway, the 5.3 GW of new renewable capacity required to decarbonise industry would represent a 45% increase over the current level of renewable generation in Scotland.[155] This increase is *on top* of the additional renewable generation capacity necessary to meet increasing clean electricity demands from other parts of the energy system (for electric vehicles and domestic heat pumps, for example). The requirement for new renewable generation would not be much

155 According to BEIS (2020), Scotland had 11.8 GW of renewable generation capacity in 2019, of which 9.3 GW was wind power.

lower in the Hydrogen pathway: if more than 60% of the hydrogen used by industry were to be produced from water electrolysis, it would indeed be higher.

Table 14 – New assets and infrastructure required by 2045

Asset category	Description	Electrification pathway	Hydrogen pathway		
			Default	*100% green H2*	*100% blue H2*
Generation	Renewable generation capacity [GW]	5.3	4.2	9.0	0.1
Conversion	Water electrolyser capacity [GW]	1.6	4.0	8.9	-
	Natural gas reforming capacity [GW]	-	1.2	-	2.2
Other infrastructure	Grid upgrades [GW]	2.3	0.01	0.01	0.01
	Hydrogen distribution [TWh/year]	2.3	12.6	12.6	12.6
	CO_2 transport [MtCO_2/year]	2.6	4.8	2.6	6.7
	Cumulative CO_2 storage [MtCO_2]	36	67	36	79

Substantial deployment of water electrolysis and/or natural gas reforming (plus CCUS) will be necessary to decarbonise industry with hydrogen fuel switching: **up to 8.9 GW of electrolysers or up to 2.2 GW of natural gas reformers would be needed by 2045 if only green or only blue hydrogen were used respectively**. For context, a UK company is currently building an electrolyser manufacturing facility in Sheffield with the aim to manufacture up to 1 GW of electrolysers per year by 2025.[156]

A minimum of 2.6 MtCO_2/year would also need to be transported and stored in both pathways, with up to a further 4.1 MtCO_2/year related to blue hydrogen production in case no green hydrogen is available. This would in turn imply that 36-79 MtCO_2 would need to be stored (or utilised) by 2045. For reference, saline aquifers in Scotland have an estimated storage capacity of 4,600-46,000 MtCO_2).[157]

156 https://theenergyst.com/hydrogen-itm-power-to-open-worlds-biggest-electrolyser-factory-in-sheffield/.
157 University of Edinburgh (2009).

The required **grid upgrades** were conservatively estimated to be **2.3 GW in the Electrification pathway** (assuming that deployment of electrical appliances always requires an upgraded grid connection).[158] Grid upgrade requirements for the Hydrogen pathway are instead minimal as they only relate to the mixed-fuel kiln used by the cement industry.

Finally, **hydrogen distribution infrastructure able to process 2.3-12.6 TWh/year of hydrogen will be needed by 2045**. While this does not change depending on whether blue or green hydrogen is used, it may be that the *characteristics* of such infrastructure will differ depending on whether *centralised* blue hydrogen production or *decentralised* green hydrogen production are more prevalent.

It should be noted that although it is often thought that the existing gas network might at least in part be repurposed to handling hydrogen, this is neither completely certain nor sufficient to handle the hydrogen volumes (if all gas is replaced with hydrogen). Speirs *et al.* indeed note that "[t]here is limited real-world evidence on the capability of low-pressure gas networks to transport 100% hydrogen gas streams effectively",[159] hence there is a possibility that the hydrogen distribution infrastructure will need to substantially rely on new build. Even if the existing gas grid can be converted to carry hydrogen, the significantly lower energy density of hydrogen[160] implies that substantial grid expansions would be nonetheless required to enable hydrogen to replace natural gas in full. For remote sites not connected to the gas grid it may be more likely that hydrogen distribution will occur via land, e.g. by lorry or by train, a solution which may also be temporarily implemented for sites wishing to fuel switch before the hydrogen infrastructure is ready.

6.3 The cost of decarbonisation

The cost of decarbonisation was calculated as the *additional* cost incurred in the decarbonisation pathways compared to that incurred in the BAU scenario. Four cost factors were quantified by utilising the cost assumptions presented in Chapter 4:[161]

- Capital expenditure (**CAPEX**), also known as 'upfront cost' or 'investment cost'. This was broken down into an annualised CAPEX plus a financing cost.[162]
- Operational expenditure (**OPEX**), which includes fixed and variable operations and maintenance costs but excludes the cost of energy.
- **Energy costs**, calculated as a variable cost per unit of fuel or electricity used.
- CO_2 transport and storage fees (**T&S fees**) for sites that implement CCUS.

A further cost factor which does *not* affect the cost of decarbonisation but was calculated because of its relevance to the business case for investing in deep decarbonisation is the

158 Assumption on grid upgrade requirements discussed on page 29.
159 Speirs *et al.* (2017).
160 Volumetric energy densities: 12.7 MJ/m^3 for hydrogen; 40.0 MJ/m^3 for gas. Source: Bossel and Baldur (2003).
161 Other costs which might be incurred in the decarbonisation pathways include one-off costs related to the disruption to site operations when switching fuels or installing CCUS as well as potentially increased operational complexity once the systems are operating. These hard-to-estimate costs are assumed to be negligible compared to the cost factors quantified in this study.
162 Key financing assumptions: assets financed over their entire lifetime, at a 10% weighted-average cost of capital (WACC). Methodology reported in Appendix 8.9.

carbon cost, i.e. the policy cost induced by the carbon price, assumed to increase over time in line with what is specified in the guidelines by BEIS (see Appendix 8.6). More specifically, it was the **carbon cost avoidance** resulting from deployment of the different decarbonisation measures which was calculated, and this is plotted in Figure 17 alongside the other cost factors, assessed separately for industry and for CCUS so to provide a clearer view of how and why the two deep decarbonisation pathways differ (note that CCUS is deployed to the same extent and at the same time in both pathways). As for the incremental improvements in energy efficiency, they have no impact on the additional cost of decarbonisation. This is because the efficiency measures implemented in the deep decarbonisation pathways are also assumed to be implemented in the BAU scenario, hence their cost contributions cancel out.

6.3.1 Additional cost compared to business as usual

By analysing Figure 17, which shows how the cost of decarbonisation evolves over time as the uptake of fuel switching and CCUS progresses, two important results become apparent. The first is that **the industries in scope can be expected to incur additional costs of around £0.8-1 billion per year by 2045** in the Electrification and Hydrogen pathway, respectively (neglecting carbon cost avoidance). For context, the Scottish manufacturing industry turned over £35 billion in 2017.[163]

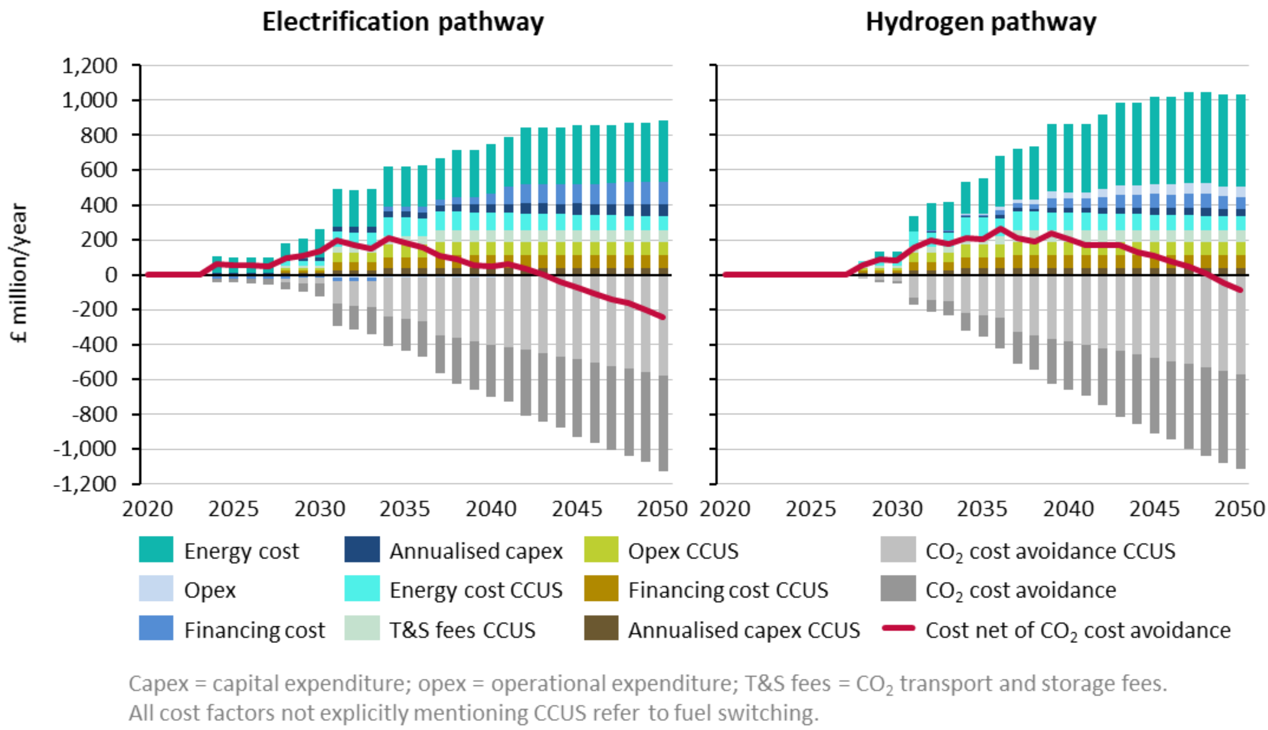


Figure 17 – Additional cost of decarbonisation

The second key result is that **carbon cost avoidance can significantly offset the cost of decarbonisation**. If this is counted as a saving, annual decarbonisation costs reach a

163 Scottish Annual Business Statistics (2017). Note that the scope of this study largely (but not fully) overlaps with the 'manufacturing industry' definition used in the referenced statistics.

peak of around £200 million per year in the 2030s and slowly decrease afterwards due to the assumed increase in carbon price. (The next chapter however discusses why carbon cost avoidance is not a reliable basis for investment). **In both pathways there comes a point when the cost of decarbonisation becomes negative**, i.e. decarbonisation becomes cheaper than paying for unabated emissions. This inflection point occurs earlier in the Electrification pathway (2043, vs 2048 in the Hydrogen pathway) because of the considerably lower cost of energy in this pathway.

The **cumulative cost of decarbonisation**, i.e. the sum of all costs incurred up to and including 2045, was estimated to be **around £11 billion** (discounted net-present values are shown in Table 15).[164] The analysis of the contribution from each cost factor highlights that:

- **The additional cost of low-carbon energy compared to fossil fuels represents the greatest cost factor for both pathways**. The low-carbon energy used in industrial appliances in fact bears an overall additional cost of £4.7 billion (Electrification) and £4.9 billion (Hydrogen), a value which grows by a further £1.5 billion when the energy used for CCUS is included. **This underlines the importance of reducing the cost of low-carbon energy.**
- **Capital expenditures related to industrial appliance replacement account for £1.4 billion in the Electrification pathway but only £0.9 billion in the Hydrogen case**. The cost of grid upgrades (~£0.4 billion, only in the Electrification pathway) largely explains the difference between the pathways. Also, a slightly larger share of fossil-fuelled appliances is electrified by 2045 (see Table 11).
- **A total financing requirement of £3.0 billion (Electrification) and £2.5 billion (Hydrogen)** can be estimated when also including the CAPEX on carbon capture.[165]
- Operating costs (OPEX plus CO_2 transport and storage fees) contribute a further £1.7 billion (Electrification) and £2.4 billion (Hydrogen). It is worth noting that the expenditure relating to operating electrical appliances is expected to be lower than that referring to fossil-fuelled appliances, which explains the negative OPEX shown in Table 15 for the Electrification pathway.

164 Using a 3.5% social discount rate and referred to 2018 pounds.
165 Note that this excludes any financing requirements related to investment in the infrastructure discussed in Section 6.2.3.

Table 15 – Breakdown of the cumulative cost of decarbonisation

Cost factor	Electrification pathway			Hydrogen pathway		
	Undisc. £ billion	*Disc. £ billion*	*% of total*	*Undis. £ billion*	*Disc. £ billion*	*% of total*
Capex (industrial appliances)	1.4	0.7	13%	0.9	0.4	8%
Opex (industrial appliances)	-0.3	-0.2	-3%	0.4	0.2	3%
Energy cost (industry)	4.7	2.5	43%	4.9	2.3	43%
Capex (CCUS)	1.6	0.8	14%	1.6	0.8	14%
Opex (CCUS)	1.1	0.6	10%	1.1	0.6	10%
Energy cost (CCUS)	1.5	0.8	14%	1.5	0.8	14%
T&S fees (CCUS)	0.9	0.5	8%	0.9	0.5	8%
Total cumulative cost	**11.0**	**5.6**	**100%**	**11.2**	**5.5**	**100%**

The results above indicate that both pathways face a significant additional cost which will need to be addressed for deep decarbonisation to take place. It is in this context useful to consider the substantial cost savings that industry could benefit from by reducing carbon emissions and the related charges. Indeed, **cumulative costs reduce by 83% (Electrification) or 73% (Hydrogen) if carbon cost avoidance is accounted for**, as shown in Table 16.

Table 16 – The cost of decarbonisation net of carbon cost avoidance

Cost factor	Electrification pathway			Hydrogen pathway		
	Undisc. £ billion	*Disc. £ billion*	*% of total*	*Undisc. £ billion*	*Disc. £ billion*	*% of total*
Total cumulative cost of decarbonisation	11.0	5.5	100%	11.2	5.5	100%
Carbon cost avoidance	-9.1	-4.4	-83%	-8.2	-3.9	-73%
Total cumulative cost net of carbon cost avoidance	**1.9**	**1.2**	**17%**	**3.0**	**1.6**	**27%**

In interpreting these results it is important to note the **uncertainty surrounding future energy and technology costs**, which implies that the values shown here can only be approximate estimates of the true cost of decarbonisation.

'Optimism bias' could be affecting the technology cost estimates utilised in this study, since as HM Treasury reports "[t]here is a demonstrated, systematic, tendency for project appraisers to be overly optimistic", especially in the absence of robust primary evidence.[166] There are also reasons to believe that certain costs could turn out to be lower than was assumed here. It is for instance possible that the cost of low-carbon electricity will reduce

166 HM Treasury: Green Book supplementary guidance: optimism bias.

substantially over time due to the large-scale penetration of renewables with zero marginal cost of generation. Likewise, unpredictable technological advancements and economies of scale could lead to technology cost reductions.

6.3.2 Carbon cost avoidance and abatement cost

To evaluate the relative merits of fuel switching and CCUS it is possible to analyse their individual contributions to the cumulative cost within each pathway as well as the decarbonisation benefit they provide, as measured by the reduced carbon charges. A review of the results in Table 17 shows that **fuel switching is responsible for a higher portion of the overall cost, compared to CCUS, but offers lower carbon savings**. Indeed, the net cost of CCUS is relatively small, meaning that investment in CCUS could nearly pay off on the basis of carbon cost avoidance alone, provided the carbon price increases as per the assumptions in Appendix 8.6. In contrast, fuel switching is expected to incur a net cost of £1.6 billion (Electrification) and £2.7 billion (Hydrogen). However, it is unlikely that the increasing carbon price alone would trigger the required investment in decarbonisation due to the impact that it would have on industrial competitiveness and the consequent risk of carbon leakage, discussed in the next chapter.

Table 17 – Relative costs and benefits of fuel switching and CCUS

Cost contribution	Electrification pathway			Hydrogen pathway		
	Undisc. £ billion	*Disc. £ billion*	*% of total pathway cost*	*Undisc. £ billion*	*Disc. £ billion*	*% of total pathway cost*
Total cost of fuel switching	5.9	3.0	53%	6.1	2.9	54%
Carbon cost avoidance from fuel switching	-4.2	-2.1	-39%	-3.4	-1.6	-30%
Net cost of fuel switching	**1.6**	**0.9**	**15%**	**2.7**	**1.3**	**24%**
Total cost of CCUS	5.1	2.6	47%	5.1	2.6	46%
Carbon cost avoidance from CCUS	-4.8	-2.3	-44%	-4.8	-2.3	-43%
Net cost of CCUS	**0.3**	**0.3**	**3%**	**0.3**	**0.3**	**3%**

Another way to think about the cost of decarbonisation is to consider the levelised cost of abatement (LCOA), which represents the carbon price that would make each pathway cost neutral when accounting for the avoided carbon charges. The LCOA is calculated as the sum of the discounted additional costs of a pathway (independently for fuel switching and CCUS) over the sum of the discounted emissions savings arising from the pathway (see detailed methodology in Appendix 8.10). The results in Table 18 indicate that **the LCOA is lower in the Electrification pathway (£157/tCO_2e) compared to the Hydrogen pathway (£188/tCO_2e)**, a result which could have also been inferred by noting that, although the two pathways present comparable cumulative costs, the Electrification pathway offers greater cumulative abatement (see Table 6). The LCOA can also be evaluated separately for fuel switching and CCUS, which confirms that fuel switching would cost more than CCUS, per tonne of CO_2 abated, given the cost assumptions employed in this study. This is especially true for the Hydrogen pathway, where the LCOA of fuel switching (£255/tCO_2e) is 76% higher than that of CCUS (£145/tCO_2e) (whereas it is only 17% higher in the Electrification pathway); once again, this difference between the two pathways is due to the later start of the Hydrogen pathway and correspondingly lower cumulative decarbonisation potential.

Table 18 – Levelised cost of abatement

LCOA in £/tCO_2e	Electrification pathway	Hydrogen pathway
Fuel switching	169	255
CCUS	145	145
Overall	**157**	**188**

6.4 Feedback from industry stakeholders

The results presented above provide an indication of what financial resources will be needed to make the deep decarbonisation pathways investigated in this study possible. Out of the many challenges affecting these pathways, industry stakeholders highlighted the below as particularly difficult to mitigate.

Technical challenges

- **Achieving the required heating profiles with alternative fuels can be challenging** for certain processes. If the heat is applied indirectly via steam this would generally not be a problem since the quality of the steam would not change. In direct heating processes that are *quality critical*, however, the applicability of certain fuel-switching options might be restricted (which makes a hybrid pathway more likely, as discussed in the next section).
- In light of the above, the **greater similarities between hydrogen combustion and fossil fuel combustion** (both of which yield a flame), might make switching to hydrogen preferable to electrification.
- Although this study found that there is **no insurmountable obstacle to the uptake of either hydrogen or electrical appliances** in the industries considered, the two are not always equivalent. **Certain deployments are potentially more disruptive** to site operations – often designed to run uninterrupted – than others. In extreme cases it might be preferable to implement decarbonised processes in a greenfield project (i.e. at a new site), rather than to attempt decarbonisation of current processes.
- Investment in first-of-a-kind technologies was also mentioned as a risk which would likely persist for several years after a novel technology is first deployed and until its operational characteristics are well understood.

Infrastructure challenges

- Alternative fuels will be evaluated not just on cost and quality but also on the **reliability of** their **supply chains**. This is because operational downtime (which could be triggered by lack of fuel availability) is very costly. This could imply that fuel switching would start at smaller sites with easier-to-meet requirements, rather than at the larger sites as is assumed here.
- **New infrastructure is required before alternative fuels can even be considered**. Electrification may require costly electricity grid upgrades and hydrogen will require a novel infrastructure altogether. Delays in infrastructure deployment may therefore hold back the pathways considered here. Policy may have a role in ensuring that no such delays happen.
- A related challenge is that it might be hard to match the high **reliability** guaranteed by CHP plants (often backed-up by redundant steam boilers) **when connecting to the grid**. This may in turn mean that additional costs must be incurred, e.g. for behind-the-meter energy storage, in addition to the ones computed here.

Investment challenges

- It is expected that private investment in the technologies considered here will be challenging on solely commercial grounds. **Quick payback targets** (often around 2-3 years and sometimes as low as a 6 months) are considered hard to achieve via investment in decarbonisation. Longer payback periods (e.g. 5-10 years) were generally only considered possible for projects backed by demonstrated or 'bankable' revenue streams.[167]
- **Long investment cycles** – which are due to the long lifetime of industrial appliances, often lasting longer than 15 years, and in a few cases longer than 40 years – can cause a '**technology lock-in**' situation, where industrial sites are unable to decarbonise if this would mean writing off recent investments with long residual useful lives. The possibility to retrofit gas-fired technologies to work with hydrogen may represent an advantage for the Hydrogen pathway in this regard.
- **Competition for capital** in international businesses could further complicate the investment process.
- Above all, **the fact that both fuel switching and CCUS increase operating costs and hence adversely affect international competitiveness makes it hard to justify investment in these technologies**. Without policy support, the increasing carbon cost might cause industries to shut and, potentially, relocate, rather than to decarbonise. Hence, greater policy certainty could be essential in mitigating the risk of carbon leakage.

167 The term 'bankable' implies that a bank would be willing to offer debt financing against such a revenue stream. In other terms, the revenue stream is considered highly reliable and the risk of default on debt repayment is considered low.

Clean growth as driver for investment

Among the many challenges facing projects that aim at deep industrial decarbonisation, one potential opportunity was also highlighted by industry stakeholders: **if investment in decarbonisation could lead to increased market competitiveness and be associated with growth, this would be a more powerful driver for investment** compared to cost-cutting. This is especially so when the avoided costs originate from policy (e.g. the carbon cost) and is even more relevant in the context of mature industries facing limited growth prospects, or perhaps even operating in markets that are already contracting.

6.5 Considerations around a possible hybrid pathway

It was noted at the start of this chapter that a hybrid pathway, where certain sites electrify their processes while others switch to hydrogen, should deliver a similar level of decarbonisation to the Electrification and Hydrogen pathways. What is more, a hybrid has the potential do so more cost effectively. However, **it is not possible to determine *a priori* which pathway would be preferable for each site or sector**, since multiple factors that are beyond the scope of this study would need to be assessed (in addition to cost, which was previously discussed). **Some of the factors with the greatest impact on whether a site would opt to electrify or switch to hydrogen are**:

- **Infrastructure availability**: the availability of sufficient spare capacity at the local electricity substation could make electrification cheaper and faster than is considered here. The prior development of a suitable hydrogen distribution channel serving the area where a site operates would instead be essential for switching to hydrogen.
- **Technology availability:** there may not always be a choice for investment in low-carbon technologies, especially for investments made before the hydrogen supply chain ramps up; in this case electrification would be the only viable option, unless site operators and investors have a high confidence that relevant hydrogen appliances are going to be available within a reasonable timeframe.
- **Technical characteristics**: it was already noted in Section 4.2.3 that certain technologies may be more operationally disruptive than others, and the full impact that emerging technologies have on the quality of industrial products may only become clearer in the next stages of development. If so, this might strongly influence whether a site chooses hydrogen or electrification.
- **Retrofitting potential**: the possibility of retrofitting natural gas appliances to work with hydrogen might not only reduce the cost of fuel switching[168] but it might also allow it to happen more rapidly, since site operators need not wait until the end of an appliance's useful life to convert it.

It is clear that analysis of these and other factors on a site-by-site basis would be necessary to judge the relative merits of different decarbonisation pathways. However, the analysis and stakeholder feedback presented above contain several important possibilities around the likely feature of a future hybrid pathway:

168 It was conservatively assumed here that complete appliance replacement would be necessary, as discussed in Section 4.2.1.

- Some sites will use a mix of technologies. This is likely going to be true for the cement industry (see page 35) and is also considered to be the preferred pathway for the Scotch Whisky subsector, where hydrogen could have an essential role in meeting the peaks in energy demand which heat pumps would find hard to meet.[169]
- Electrification can in many cases start now. For appliances needing replacement in the next 5-8 years, electrification would represent a safe way to decarbonise. For this to happen, policy support would need to be offered ahead of time to make this a cost-effective, competitive option.
- In the context of CHP plants, electrification implies that these plants would be dismantled and replaced by a mix of grid connection, electric boiler, and heat pumps (see Section 4.2.1). Hence, the only way for the CHP plant to continue operating would be to switch to hydrogen or deploy CCUS.
- A preference for hydrogen was expressed by operators of processes with very high heat demands who are sceptical around the ability of the electricity grid to meet their demands. More analysis would be required to assess this.

In conclusion, it is noted that the results presented in the preceding sections provide sufficient information to evaluate the cost and infrastructure requirements for a potential hybrid pathway, which will necessarily lie somewhere in-between those estimated for the Electrification and Hydrogen pathway.

169 This is due to the high cost and low utilisation of sizing heat pumps for peak demand, considering that 80% of the energy needs could already be met via heat pumps that are only 1/3rd of the size. Source: Ricardo (2020).

7 Conclusions and policy recommendations

7.1 Summary of key findings

Within the context of the updated decarbonisation targets for Scotland, which aim for economy-wide net zero emissions by 2045 at the latest, this study sought to investigate how emissions from energy-intensive industries in Scotland can be substantially reduced via the implementation of selected deep decarbonisation measures, chiefly fuel switching and CCUS.

Two deep decarbonisation pathways combining fuel switching with CCUS were investigated. A third pathway that only relied on improvements in energy efficiency was also initially considered but, given its inability to deliver significant reductions in carbon emissions, this was not analysed in depth. The results from the two deep decarbonisation pathways demonstrated that:

- **It should be possible to reduce emissions from the industries in scope by over 80% compared to 2018 levels by 2045**. Different ways to tackle residual emission and devise a path to net zero in industry were also reviewed, though further work is needed to evaluate their feasibility and cost.
- Combined, the industries in scope can be expected to incur **additional costs of up to £1 billion per year and of just over £11 billion cumulatively, by 2045**, when including capital, operational, and energy-related expenses but excluding the reduction in carbon costs.
- **Substantial infrastructure as well as new energy generation and conversion assets will need to be developed** before fuel switching and CCUS can be deployed on a large scale.

Industry stakeholders who were consulted for this study highlighted critical challenges that hinder investment in deep decarbonisation. There are three specific issues where policy may help:

- **Addressing the lack of a business case**. This is seen as the primary obstacle to investment. To address this issue, policy could offer a range of financial support mechanisms or enact measures that stimulate demand for low-carbon products.
- **Ensuring a level playing field with international competition.** Even though the inclusion of carbon cost avoidance was found to reduce the net additional cost of both deep decarbonisation pathways by over 80% (provided the price of carbon increases over time as per BEIS assumptions), this is not considered a solid basis for the business case. Indeed, increasing costs would adversely affect industrial competitiveness whether fuel switching or CCUS are deployed or not (i.e. either due to the cost of decarbonisation or due to the increasing carbon price). As a response, industries might be induced to relocate to regions were environmental regulations are looser – an issue known as **carbon leakage**. Policies that establish a level playing field with international competition will be required to address this.

- **Mitigating the technology lock-in risk.** This corresponds to the possibility that site operators may not be looking to replace their fossil fuelled appliances again until after 2045, especially if they have recently invested in fossil-fuelled appliances. This risk is exacerbated by the fact that site operators and investors have low confidence in, and/or knowledge of, new, carbon reduction technologies that have not yet been proven in their subsector, which could lead to a rate of uptake which is lower than that envisioned for the pathways here. Policy support is expected to play a role in ensuring prompt development of the required technologies and deployment of the enabling infrastructure.

The remainder of this chapter describes how government action – from the Scottish Government whenever possible, though intervention from the UK government is likely to be required in some cases – can help act to address these important challenges.

7.2 Policies to encourage investment in decarbonisation

7.2.1 Preventing carbon leakage

To mitigate the risk of carbon leakage while preserving the incentive to decarbonise that an increasing carbon price would offer, the ideal option would be to ensure that no regulatory asymmetries existed in the first place. If all industries across the world faced the same carbon price, which could be achieved by the implementation of an **international agreement concerning the price of carbon**, there would be no incentive to relocate. Political challenges in reaching such an agreement and the expected difficulties in its enforcement make its implementation unlikely, at least in the short term.

A more likely alternative is offered by a **Border Carbon Adjustment Mechanism (BCAM)**, which would adjust the import and export prices of products exposed to different carbon pricing regimes. This could for instance take the form of Border Tax Adjustments (BTAs),[170] where import fees are issued on goods manufactured in countries with a lower carbon price and carbon charges paid on exports to the same countries can be claimed back.

It should be recognised that BCAMs are complex and that their effectiveness in combating carbon leakage might depend on their detailed design features; BCAMs would also need to be compatible with World Trade Organisation (WTO) rules and Government policy on free trade arrangements. Lastly, **UK-level policy action would be required to establish BCAMs** given that Scottish Ministers do not have devolved competence for trade and import/export controls.

170 Also known as Border Adjustments or Border Tax Assessments.

Box 8 – Carbon leakage
The term 'carbon leakage' refers to the risk that industries facing environmental regulations stronger than those borne by their international competitors may relocate to less regulated regions. If they were to do so, their carbon emissions would also relocate, or 'leak', with them. When assessed from a global point of view, **carbon leakage represents a policy failure since it does not lead to any net emissions abatement**, and although it does lead to reduced territorial emissions in the country where industries are mothballed, this could come at the expense of a corresponding loss of jobs and output. Also, it is possible that global emissions might in fact *increase* if industries relocate to regions with looser regulations around GHG emissions. **This risk of carbon leakage is particularly acute for industries that are both energy-intensive and trade-intensive**, since they have higher emissions, are exposed to greater competitive pressures from international markets and are less able to pass on additional costs, e.g. from an increased carbon price, without losing market share.

Both an internationally coordinated carbon price and suitably designed BCAMs would enable policymakers to increase the price of carbon without risking carbon leakage. In this scenario, industries would have to face the full cost associated with their greenhouse gas emissions and would therefore feel an increasing pressure to decarbonise (though the important challenges to decarbonisation discussed above would remain). However, **prices for decarbonised industrial products would necessarily be higher** than those of today's carbon intensive products unless ways to decarbonise industry are found which do not increase the manufacturing cost base. **Price increases would negatively affect market demand for industrial products and would simultaneously incentivise innovation in disruptive, low-carbon *alternative* products** considered too costly today, but which may become cost-competitive with more expensive decarbonised products (the difference between the two categories of low-carbon products is further explored in Box 9).

Previous research also highlighted that the narrow framing of climate change as a 'market failure' and of carbon pricing as its primary solution oversimplifies the scale of the challenge and hence hinders its resolution. If climate change is instead understood as a system problem, it becomes apparent that the transition to net zero will likely "entail profound and interdependent adjustments in socio-technical systems that cannot be reduced to a single driver, such as shifts in relative market prices".[171] Hence, it should be expected that multiple policy measures will need to be deployed to successfully incentivise the decarbonisation of industry, and drive the path to net zero.

171 Rosenbloom *et al*. (2020).

Box 9 – Low-carbon industry: decarbonised or alternative products?

There are two types of low-carbon products that should be differentiated for the purposes of policy making:

- **Decarbonised products** produced in equivalent ways to those produced today, except for the use of low-carbon fuels or for the addition of carbon capture.
- **Low-carbon alternative products**, which are *intrinsically* lower carbon than those used today. Examples include bio-based plastics, cement-less concrete, and recycled materials.

There are two key differences between the two types.

- First, while decarbonised products can be manufactured using current industrial facilities, **low-carbon alternatives may require radically different processes**. This has obvious implications on the different level of disruption to incumbent industries (and to their supply chains) that would arise from the uptake of one or the other type.
- Second, **while decarbonised products are necessarily more expensive than current products**, since both fuel switching and CCUS increase costs, **low-carbon alternatives may become cheaper once produced at scale**.

These differences are relevant to policy making because certain policies may incentivise the uptake of one but not the other type of product. The clearest example of this would be if subsidies were offered for the implementation of deep decarbonisation measures. These may make decarbonisation cost-neutral for industry but would do little to stimulate demand for low-carbon alternatives.

7.2.2 Financial support mechanisms

The results in Section 6.3 demonstrated that although the financial requirements for deep decarbonisation are significant and diverse in nature, **the single most important policy focus should be in offsetting the increase in energy costs**, which is due to hydrogen and electricity costing more than fossil fuels. Increased energy costs not only account for over 55% of the additional cost of decarbonisation in both deep decarbonisation pathways but also directly impact the marginal cost of production and hence adversely affect industrial competitiveness. A **Contract for Difference (CfD)** mechanism could lock the **price of low-carbon energy to that of natural gas** (or other fossil fuels where relevant) and ensure that industries that decarbonise are not disadvantaged against competitors who use fossil fuels.

The second goal of policies aimed at supporting investment in decarbonisation should be to reduce the absolute magnitude of the capital expenditures, which represent the second largest cost factor. **Grants** and **low-interest financing** would be obvious ways for policy to intervene in this direction, though **direct equity investments** (where the state obtains company shares and receive the corresponding dividends, instead of receiving an interest on the amount loaned) could also be considered. The latter approach could be especially relevant to investments in shared low-carbon energy infrastructure, which hold far larger value to society than can be accrued to any individual site operator. This might justify more direct state intervention.[172]

For CCUS in particular, the scale of the investment and the complexity of the commercial framework is such that substantial government intervention will most likely be required to mitigate the multiple project risks and justify the business case, at least for the initial project phases. The inclusion of a "CCS Infrastructure Fund of at least £800 million" within the UK Government's 2020 budget is a promising development in this direction.[173] A recent Element Energy report for BEIS on industrial carbon capture business models identified potential business models and policies that are applicable to wider industrial decarbonisation:[174]

- **Contract for Difference** on the CO_2 price (relative to the market price of CO_2, e.g. from the UK ETS) to provide a payback on investment which reduces emissions.[175]
- **Cost plus**: all properly incurred costs are reimbursed through taxpayer funding.[176]
- **Regulated asset base**: public regulation allows decarbonisation costs to be recovered through product prices.
- **Tradeable tax credits**: a tax credit is awarded for each unit of CO_2 stored (or simply abated, which could make this mechanism relevant to fuel switching as well), and this reduces a firm's tax liability. The credit can also be traded with other firms.
- **Decarbonisation certificates**: certificates representing the amount of CO_2 abated (through CCUS or other technologies) which can be traded, and towards which emitters have an obligation.

It is recommended that any financial support offered be technology neutral. The findings of this study in fact highlighted that even though some decarbonisation measures are going to be central to the transition to net zero – CCUS and fuel switching for steam raising above all – different industries are likely to benefit from a different technology mix. Policy could reduce uncertainty by '**picking winners**' (e.g. supporting electrification instead of hydrogen, or *vice versa*), but considering that both pathways deliver substantial decarbonisation and that there is high uncertainty around the future price of hydrogen and electricity and around the viability of the corresponding fuel-switching technologies, it would be hard to justify a choice of winners that could close off other options which may later turn out to be more effective.

7.2.3 Ensuring prompt deployment of the key technologies

The pathways outlined in this study assume that investments in fuel-switching technologies take place at the end of the current life of fossil-fuelled appliances,[177] since

172 Mazzucato (2013) discusses the conditions under which direct equity investments might be preferable.
173 https://www.gov.uk/government/publications/budget-2020-documents/budget-2020.
174 Element Energy (2018).
175 The emitter is paid (or refunded) the difference between a CO_2 strike price contractually agreed (in £/tCO_2 abated, fixed for the duration of the contract), and the prevailing CO_2 market certificate price (or carbon tax). The quantity of CO_2 abated is determined relative to an industry benchmark.
176 'Properly incurred' refers to costs that are consistent with, and were negotiated freely in, the market.
177 Except for the cement kiln, which is retrofitted.

this minimises the overall cost of decarbonisation. However, **if the uptake of fuel switching technologies were to be delayed** by slower development timelines, infrastructure unavailability, or by the lack of economic incentives, **the number of sites finding themselves 'locked-in' with fossil-fuelled technologies until after 2045 could be significant**. This could make it challenging to meet the economy-wide net zero target by this date. To mitigate this risk policy could:

- **Support the creation of pilot projects and demonstrators** useful to validate the technical and economic viability of each technology (within each subsector, if required) and help industry stakeholders acquire confidence in novel technologies.
- **Finance feasibility studies** for the deep decarbonisation of all subsectors (e.g. for one or a few sites within each subsector). It is recommended that a specific focus on *deep* decarbonisation (ideally net zero) is required, as well as extensive knowledge sharing. A key priority in this regard could be to support feasibility studies for projects which could start decarbonising immediately (predominantly in the context of process electrification).
- **Ensure that the required infrastructure is developed well ahead of time**, so that fuel switching and CCUS can be implemented without delay when the business case is established. To maximise the climate benefits, policy could prioritise the key deployments indicated in Section 6.2.2, since they are responsible for a large share of the overall abatement from industries in scope.
- If technology lock-in cannot be avoided for all sites, **early decommissioning of fossil-fuelled appliances** might need to be encouraged or mandated for cases where retrofitting is not an option.

7.2.4 Demand-side policies

By relaxing the constraint that demand for industrial products remains fixed until 2045, several additional pathways could be conceived. While the pathways investigated in this study only looked at ways to decarbonise *existing* industrial processes, the analysis of pathways to reduce emissions across entire supply chains (or perhaps across the whole economy) could reveal that it is in some case cheaper to *replace* carbon-intensive products with lower-carbon alternatives, rather to decarbonise them. There are several examples of how **product substitution has already started affecting the industries considered here**:

- The uptake of electric vehicles is already affecting the demand for refined fuels in developed countries.
- Increased plastic recycling could reduce demand for basic chemicals and for the petrochemical feedstock.
- Low-carbon alternatives to cement are being considered for concrete manufacturing.

And while most of these alternative products only hold negligible market shares today, an increasing carbon price might make them more cost competitive and widespread. Moreover, **policy could also intervene by implementing demand-side measures that**

foster demand for low-carbon products (at the expense of carbon-intensive products) and thus indirectly incentivising industry to decarbonise. Relevant measures include:

- Mandating **green procurement**, which implies that low-carbon products would be preferred to carbon-intensive ones in procurement processes (especially within the public sector), even if they cost more.
- Implementing **product standards**, e.g. requiring that certain fraction of the concrete used for public infrastructure must be low carbon.
- Supporting the adoption of **'green labels'** that transparently communicate a product's environmental credentials to consumers, which may trigger an increased market demand for such products.

Considering that the cost of deep decarbonisation is often more substantial on the price of *intermediate* products, rather than on that of final products, it is also possible that demand-side measures could represent a more cost-effective way to incentivise industrial decarbonisation. For example, a 1% increase in the cost of a soda bottle is less noticeable than a 50% increase in that of ethylene.[178]

Further work would be required to assess the most effective ways to stimulate demand for low-carbon products in the context of Scottish industry, and whether this could indeed be more cost-effective than financially supporting investment in deep decarbonisation. In light of the stakeholder feedback summarised in Section 6.4, it is however worth noting that **demand-side measures able to create significant new markets for low-carbon industrial products could help turn the decarbonisation challenge into an opportunity for clean growth**, and this could be a far more compelling driver for investment in deep decarbonisation compared to cost cutting.

7.3 Supporting a Just Transition to net zero

The Scottish Government is committed to a net zero pathway that fulfils the principles of a 'Just Transition', summarised by the Just Transition Commission as:[179]

- "plan, invest and implement a transition to environmentally and socially sustainable jobs, sectors and economies, building on Scotland's economic and workforce strengths and potential.
- create opportunities to develop resource efficient and sustainable economic approaches, which help address inequality and poverty.
- design and deliver low carbon investment and infrastructure, and make all possible efforts to create decent, fair and high value work, in a way which does not negatively affect the current workforce and overall economy."

In light of this commitment, it is useful to reflect on the different impact that alternative policy measures could have on the markets in which incumbent industrial sites operate. On the one hand, subsidies and other financial support mechanisms would help minimise

178 The illustrative example of ethylene (used in soda bottles) is extracted from a recent report by the Energy Transitions Commission (2018). Both price increases correspond to the added cost of decarbonisation.
179 https://www.gov.scot/groups/just-transition-commission/.

disruption and help preserve Scottish industry in its current form. If, however, these mechanisms solely benefited incumbent industries (e.g. by only incentivising the decarbonisation of current industrial processes, but not other low-carbon innovations) there might be a risk that, in the long term, the Scottish industrial sector would become ill-equipped to compete internationally. On the other hand, demand-side measures that could potentially reduce the overall cost of transitioning to net zero are also likely to force more extensive structural changes upon industry.

Fortunately, there are ways to ensure that the transition to net zero is both cost effective and fair. While a detailed analysis of the best policy approach to achieve this objective is beyond the scope of this study, it is noted that there are multiple ways to "design policies in a way that ensures the benefits of climate change action are shared widely, while the costs do not unfairly burden those least able to pay, or whose livelihoods are directly or indirectly at risk as the economy shifts and change", among which:[180]

- **Public investment in research, technology development, and more generally in education** can help ensure that, if innovation happens, its disruptive impact is not necessarily negative. If the local workforce can actively participate in the industries of the future, disruption of the old ones will be perceived as a smaller problem (or perhaps even as a good thing). Establishing relevant **retraining programs** for the workforce affected by potential site closures would be essential to ensure that everyone can find work in the new industries.
- **Financial support to individuals and families that find themselves without a source of income**, if industries close, could likewise help to mitigate the social cost of disruptive innovation. If the support is guaranteed and unconditional (as it would for instance be in the case of a universal basic income) this could also empower workers to realign their career towards the new demands of the net-zero economy before disruptive events happen.
- **Careful consideration of the locally available skills and knowledge could provide an additional way to evaluate different pathways and select relevant policy priorities.** For instance, Scotland has one of Europe's most developed wind sectors, and its extensive offshore know-how is likely to be relevant to the delivery of the substantial new renewable generation expected in both deep decarbonisation pathways. Likewise, the Scottish oil and gas sector is well-versed with hydrogen production, carbon capture, and in dealing with high pressure fluids and undersea gas storage.[181] These are just two examples of local industries that could stand to benefit if the pathways assessed here materialise.

180 Just Transition Commission Interim Report (2020). https://www.gov.scot/publications/transition-commission-interim-report/.
181 The Grangemouth refinery currently produces (grey) hydrogen with an SMR, though without capturing the related carbon emissions. Carbon capture is already implemented at the Kinneil gas terminal (and likely at other gas terminals), where CO_2 is separated from other feedstock gases before being released to the atmosphere. (Note that even though this is technically CO_2 separation and not capture, the two share the same core technology.)

7.4 Recommendations for further work

This report investigated potential pathways to deeply decarbonise Scottish industry by 2045 and found that both fuel switching and CCUS are necessary to the achieve significant emissions cuts. Energy efficiency was found to offer more limited carbon savings, on average, though this should not hide the important role that efficiency improvements play in reducing future energy demand, and hence in mitigating the need (and cost) of developing new infrastructure. If these decarbonisation measures are deployed extensively, cumulative emissions from the industries considered can be reduced by over 90% compared to 2018 level. To go further, additional routes will need to be pursued; **further work could assess the most cost-effective way to bridge the gap to net zero emissions**.

The analysis presented in this study was underpinned by the assumption that industrial activity would remain steady through to 2045, which enabled a focused investigation of the decarbonisation potential of the selected decarbonisation options. **It would be insightful investigate alternative decarbonisation pathways where the improved material efficiency from a more circular economy and the development of new markets for green industrial products affect demand for industrial products**.

The scope of the analysis was also limited to sites and industries contributing 58% of all Scottish industrial emissions in 2018. **It is recommended that the boundaries of the analysis be expanded to encompass the totality of Scottish industry**, which is expected will require significant input from industry representatives to address current data limitations. The boundaries of the analysis can be expanded even further: **future work could study potential cross-sectoral and geographical synergies of electrification- and hydrogen-centred pathways**. This could reveal important reasons why, in spite of the seemingly broad equivalence between the two pathways which emerges from the present work, one or the other pathway may be preferrable in practice.

In conclusion, it is stressed that other factors will need to be considered for a complete evaluation of possible pathways for the deep decarbonisation of Scottish industries. Thus, the final recommendation is that **the results from this study should be evaluated in the context of a broader, more holistic assessment of the possible decarbonisation pathways**, where the technological and economic analysis offered by this study is complemented by the equally important analysis of how different pathways would affect the broader economy, society, and the environment. This approach might reveal ways in which the current workforce can benefit from disruptive innovation, rather than be adversely affected by it, and may also uncover relative merits of electrification or hydrogen fuel switching when environmental impacts other than climate change are simultaneously assessed.

8 Appendix

8.1 Bibliography for the literature review

Benner, J., van Lieshout, M., & Croezen, H. (2011). *Identifying breakthrough technologies for the production of basic chemicals*. https://www.scribd.com/document/342182520/CE-Delft-Identifying-Breakthrough-Technologies-for-the-Production-of-Basic-Chemicals.

British Glass. (2014). *A Clear Future: UK glass manufacturing sector decarbonisation roadmap to 2050*. https://www.britglass.org.uk/sites/default/files/A%20clear%20future%20-%20UK%20glass%20manufacturing%20sector%20decarbonisation%20roadmap%20to%202050_summary.pdf.

British Glass. (2017). *Recycled content of glass packaging.* https://www.britglass.org.uk/knowledge-base/resources-and-publications/recycled-content-glass-packaging.

Brownsort, P. (2018). *Negative Emission Technology in Scotland: carbon capture and storage for biogenic CO_2 emissions*. www.sccs.org.uk/images/expertise/reports/working-papers/WP_SCCS_2018_08_Negative_Emission_Technology_in_Scotland.pdf.

Committee on Climate Change. (2018). *Biomass in a low-carbon economy.* https://www.theccc.org.uk/publication/biomass-in-a-low-carbon-economy/.

Committee on Climate Change. (2019). *Net Zero Technical Report*. https://www.theccc.org.uk/publication/biomass-in-a-low-carbon-economy/.

Element Energy, Ecofys, & Imperial College London. (2014). *The potential for recovering and using surplus heat from industry*. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/294900/element_energy_et_al_potential_for_recovering_and_using_surplus_heat_from_industry.pdf.

Element Energy, & Jacobs. (2018). *Industrial Fuel Switching Market Engagement Study*. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/824592/industrial-fuel-switching.pdf.

Element Energy, Advisian, & Cardiff University. (2019). *Hy4Heat WP6: Conversion of Industrial Heating Equipment to* Hydrogen. https://www.hy4heat.info/reports.

Energy Transitions Commission. (2018). *Mission Possible: Reaching net-zero carbon emissions from harder-to-abate sectors by mid-century.* http://www.energy-transitions.org/mission-possible.

Griffin, P. W., Hammond, G. P., & Norman, J. B. (2018). *Industrial energy use and carbon emissions reduction in the chemicals sector: A UK perspective*. Applied Energy, 227, 587–602. https://www.sciencedirect.com/science/article/pii/S0306261917310255?via%3Dihub.

ICF Consulting Services Limited, & Fraunhofer ISI. (2019). *Industrial Innovation: Pathways to deep decarbonisation of Industry. Part 1: Technology Analysis*.

https://ec.europa.eu/clima/sites/clima/files/strategies/2050/docs/industrial_innovation_part_1_en.pdf.

IEA, ICCA, & DECHEMA. (2013). *Technology Roadmap Energy and GHG Reductions in the Chemical Industry via Catalytic Processes.* https://webstore.iea.org/technology-roadmap-energy-and-ghg-reductions-in-the-chemical-industry-via-catalytic-processes.

Lenaghan, M., & Mill, D. (2015). *Industrial Decarbonisation and Energy* Efficiency *Roadmaps: Scottish Assessment*. https://www.theccc.org.uk/2015/03/27/industrial-decarbonisation-and-energy-efficiency-roadmaps-to-2050/.

Mineral Products Association. (2013). *The UK cement industry 2050 roadmap.* www.sccs.org.uk/images/expertise/reports/working-papers/WP_SCCS_2018_08_Negative_Emission_Technology_in_Scotland.pdf.

WSP Parson Brinkerhoff, & DNV GL. (2015). *Industrial Decarbonisation and Energy* Efficiency *Roadmaps to 2050.* (Note: roadmaps for different sectors) https://www.gov.uk/government/publications/industrial-decarbonisation-and-energy-efficiency-roadmaps-to-2050.

8.2 Other references

ACT Acorn Consortium. (2019). *ACT Acorn Feasibility Study: D20 Final Report*. actacorn.eu/sites/default/files/ACT%20Acorn%20Final%20Report.pdf.

Antonini, C., Treyer, K., Streb, A., van der Spek, M., Bauer, C., & Mazzotti, M. (2020). *Sustainable Energy & Fuels Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis. Sustainable Energy Fuels*, 4, 2967–2986. https://doi.org/10.1039/d0se00222d.

BEIS. (2018). *Updated energy and emissions projections*. https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2018.

BEIS. (2020). *Renewable electricity in Scotland, Wales, Northern Ireland and the regions of England, Energy Trends.* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/875409/ET_6.1.xls.

Bloomberg NEF. (2020). Hydrogen *Economy Outlook*. https://about.bnef.com/blog/hydrogen-economy-offers-promising-path-to-decarbonization/.

Bossel, U., Eliasson, B. (2003) *Energy and The Hydrogen Economy.* http://www.methanol.org/pdf/HydrogenEconomyReport2003.pdf.

Committee on Climate Change. (2017). *Energy Prices and Bills.* https://www.theccc.org.uk/publication/energy-prices-and-bills-report-2017/.

Committee on Climate Change. (2018). *Reducing UK emissions: 2018 Progress Report to Parliament.* https://www.theccc.org.uk/wp-content/uploads/2018/06/CCC-2018-Progress-Report-to-Parliament.pdf

Committee on Climate Change. (2019). *Reducing emissions in Scotland 2019 Progress Report to Parliament*. https://www.theccc.org.uk/wp-content/uploads/2019/12/Reducing-emissions-in-Scotland-2019-Progress-Report-to-Parliament-CCC.pdf.

E4Tech. (2019). *H2 emissions potential: literature review*. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/798243/H2_Emission_Potential_Report_BEIS_E4tech.pdf.

Element Energy, Carbon Counts, PSE, Imperial College, & University of Sheffield. (2014). *Demonstrating CO_2 capture in the UK cement, chemicals, iron and steel and oil refining sectors by 2025: a techno-economic study.* http://www.element-energy.co.uk/wordpress/wp-content/uploads/2017/06/Element_Energy_DECC_BIS_Industrial_CCS_and_CCU_final_report_14052014.pdf.

Element Energy. (2017a). *Deployment of an industrial Carbon Capture and Storage cluster in Europe: A funding pathway*. www.i2-4c.eu/wp-content/uploads/2017/10/i24c-report-Deployment-of-an-industrial-CCS-cluster-in-Europe-2017-Final-.pdf.

Element Energy. (2017b). *Enabling the deployment of industrial CCS.* https://ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/960-2018-01-enabling-the-deployment-of-industrial-ccs-clusters.

Element Energy. (2018). *Industrial carbon capture business models*. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/759286/BEIS_CCS_business_models.pdf.

Element Energy. (2019a). *Assessment of Options to Reduce Emissions from Fossil Fuel Production and Fugitive Emissions*. https://www.theccc.org.uk/publication/assessment-of-options-to-reduce-emissions-from-fossil-fuel-production-and-fugitive-emissions/.

Element Energy. (2019b). *Hy-Impact Series* Hydrogen *in the UK, from technical to economic. A summary of four studies assessing the role of hydrogen in the UK net-zero transition.* http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Summary-Document.pdf.

Element Energy. (2019c). *Extension to Fuel Switching Engagement Study (FSES) – Assumptions log.* https://www.theccc.org.uk/publication/extension-to-fuel-switching-engagement-study-deep-decarbonisation-of-uk-industries-assumptions-log/.

Element Energy. (2020). *Gigastack: Bulk Supply of Renewable Hydrogen*. www.element-energy.co.uk/wordpress/wp-content/uploads/2020/02/Gigastack-Phase-1-Public-Summary.pdf.

Grubb, M. (2014). *Planetary Economics: Energy, climate change and the three domains of sustainable development.*

Health and Safety Laboratory. (2015). *Injecting hydrogen into the gas network – a literature search.* https://www.hse.gov.uk/research/rrpdf/rr1047.pdf.

HM Government, & Scottish Government. (2020). *The future of UK carbon pricing UK government and devolved administrations' response*. https://www.gov.uk/government/consultations/the-future-of-uk-carbon-pricing.

Hydrogen Council. (2020). *Path to hydrogen competitiveness: a cost perspective.* https://hydrogencouncil.com/en/path-to-hydrogen-competitiveness-a-cost-perspective/.

IEAGHG. (2019). *Towards zero emissions CCS in power plants using higher capture rates or biomass. (March), 1–128*. http://documents.ieaghg.org/index.php/s/CLIZIvBI6OdMFnf/download.

Lenaghan, M., & Mill, D. (2015). *Industrial Decarbonisation and Energy* Efficiency *Roadmaps: Scottish Assessment*. https://www.resourceefficientscotland.com/sites/default/files/downloadable-files/Industrial%20Decarbonisation%20and%20Energy%20Efficiency%20Roadmaps%20Scottish%20Assessment.pdf.

Mohd S., Hendrik, J., Cloete, S., & Amini, S. (2019). *Efficient hydrogen production with CO_2 capture using gas switching reforming*. Energy, 185, 372–385. https://doi.org/10.1016/j.energy.2019.07.072.

Navigant for the Energy Networks Association. (2020). *Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain.* https://www.energynetworks.org/assets/files/gas/Navigant%20Pathways%20to%20Net-Zero.pdf.

NAEI (2019) *Greenhouse Gas Inventories for England, Scotland, Wales & Northern Ireland: 1990-2017. https://naei.beis.gov.uk/reports/reports?report_id=1000.*

Owen, A., Ivanova, D., Barrett, J., Cornelius, S., Francis, A., Matheson, S., Redmond-King, G., & Young, L. (2020). *Carbon Footprint: Exploring the UK's Contribution to Climate Change*. https://www.wwf.org.uk/sites/default/files/2020-04/FINAL-WWF-UK_Carbon_Footprint_Analysis_Report_March_2020_%28003%29.pdf.

Parsons Brinckerhoff. (2011). *Electricity Generation Cost Model - 2011 Update - Revision 1.* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48126/2153-electricity-generation-cost-model-2011.pdf.

Pale Blue Dot. (2018). *CO_2 Transportation and Storage Business Models.* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/677721/10251BEIS_CO2_TS_Business_Models_FINAL.pdf.

Pale Blue Dot and Axis Well Technology. (2016). *Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource A Summary of Results from the Strategic UK CO_2 Storage Appraisal Project.* https://www.eti.co.uk/programmes/carbon-capture-storage/strategic-uk-ccs-storage-appraisal.

Ricardo. (2018). *Whisky by-products in renewable energy*. https://www.climatexchange.org.uk/media/3024/revised-february-2018-whisky-by-products-life-cycle-analysis-report-v02-03.pdf.

Ricardo. (2019). *Zero Emission HGV Infrastructure Requirements.* https://www.theccc.org.uk/publication/zero-emission-hgv-infrastructure-requirements/.

Ricardo. (2020). *Scotch whisky pathway to net zero*. https://www.scotch-whisky.org.uk/media/1733/net-zero-pathways-report-june-2020.pdf

Rosenbloom, D., Markard, J., Geels, F. W., & Fuenfschilling, L. (2020). *Why carbon pricing is not sufficient to mitigate climate change—and how "sustainability transition policy" can help.* Proceedings of the National Academy of Sciences of the United States of America, 117(16), 8664–8668. https://doi.org/10.1073/pnas.2004093117.

Scotch Whisky Association. (2012). *Scotch Whisky Industry Environmental Strategy Report 2012.* http://www.laphroaig.it/files/2012_swa_environmentalstrategy.pdf.

SLR. (2020). *Decarbonisation of heat across the food and drink manufacturing sector.* https://www.fdf.org.uk/publicgeneral/fdf-slr-report-decarbonising-heat-to-net-zero.pdf.

Speirs, J., Balcombe, P., Johnson, E., Martin, J., Brandon, N., & Hawkes, A. (2017). *A Greener Gas Grid: What Are the Options?* https://www.sustainablegasinstitute.org/wp-content/uploads/2017/12/SGI-A-greener-gas-grid-what-are-the-options-WP3.pdf

The Scottish Government. (2019). *The Scottish Greenhouse Gas Emissions Annual Target Report for 2017.* https://www.gov.scot/publications/scottish-greenhouse-gas-emissions-annual-target-report-2017/.

University of Edinburgh. (2009). *Opportunities for CO_2 Storage around Scotland; An Integrated Strategic Research Study.* https://era.ed.ac.uk/handle/1842/15718.

van Cappellen, L., Croezen, H., & Rooijers, F. (2018). *Feasibility study into blue hydrogen*. https://greet.es.anl.gov/publication-smr_h2_2019.

8.3 Emissions in and out of scope

Table 19 provides a breakdown of all GHG emissions in Scotland in 2018. Out of a total 41.6 $MtCO_2e$, 28% (11.5 $MtCO_2e$) is mapped to the 'Industry' sector (according to mapping for the Climate Change Plan, or CCP).

Table 19 – Breakdown of Scottish GHG emissions in 2018[182]

CCP Mapping	Source Sector	CO_2 ($MtCO_2e$)	Other GHG ($MtCO_2e$)	Total ($MtCO_2e$)[183]
Industry	Business and Industrial Process	6.45	0.42	6.87
	Energy supply	4.21	0.44	4.65
Total Industry		**10.66**	**0.86**	**11.53**
Agriculture	Agriculture and Related Land Use	1.03	6.44	7.47
Electricity Generation	Energy Supply	2.13	0.02	2.15
Land use	Agriculture and Related Land Use	1.79	0.32	2.11
	Development	1.90	0.15	2.05
	Forestry	-9.67	0.08	-9.59
Residential	Residential	6.01	0.22	6.23
Services	Business and Industrial Process	1.30	0.78	2.08
	Public Sector Buildings	1.10	0.00	1.10
Transport	International Aviation and Shipping	1.88	0.02	1.90
	Transport (exc. above)	12.76	0.14	12.91
Waste	Waste Management	0.01	1.67	1.68
Total Other		**20.23**	**9.85**	**30.09**
Total Scotland		**30.90**	**10.72**	**41.61**

Emissions from members of the Scottish Whisky Association

A recent report by Ricardo commissioned by the SWA and covering 127 sites (including 70 malt distilleries, 5 grain distilleries and 11 packaging sites) determined that emissions from these sites amounted to 529 $ktCO_2e$ in 2018. Of these, 5% relate to electricity use (scope 2, and hence not in scope), and 198 $ktCO_2e$ are from 11 large distilleries already

182 Source: Scottish greenhouse gas inventory 2018.
183 Sums may not add due to rounding.

accounted for within the NAEI data. Hence, it was estimated that emissions from the other 116 sites were 305 $ktCO_2e$.

Emissions from smaller sites

A previous report by Zero Waste Scotland indicated that, in 2012, the food and drink subsector included "over 800 companies, only 4% of which [...] defined as 'large enterprises'", which collectively generated nearly 1.7 $MtCO_2e$.[184] By comparison, the large food and drink sites included in the NAEI data only reported emissions of 0.3 MtCO2e in 2018, and even including SWA member sites the reported sector total barely exceeded 0.6 $MtCO_2e$ in 2018. For this reason, it is believed that a large share of the estimated 1.6 $MtCO_2e$ from smaller sites originates within this sector. Further information around possible decarbonisation pathways for the food and drink sectors can be found in a recent report by SLR for the Food and Drink Federation (FDF).[185]

Emissions of greenhouse gas other than CO_2

As indicated in Section 2.2, carbon dioxide (CO_2) is by far the most commonly emitted greenhouse gas (GHG) across all Scottish industries, contributing to 92% of all global warming potential.[186] There are however a few sources within industries out of scope which emit non-negligible amounts of other GHGs: [187]

- Industrial refrigeration systems, which emit 0.14 $MtCO_2e$ of hydrofluorocarbon (HFC) gases.
- Electronics and shoes manufacturing, which emit 0.14 $MtCO_2e$ of perfluorinated chemicals (PFCs).
- Foam blowing and fire protection equipment, which also emit a smaller amount of HFCs (0.05 MtCO2e).
- Electrical insulation equipment, from which 0.02 $MtCO_2e$ of sulfur hexafluoride (SF_6) are emitted yearly.
- Other sources, which combined emit a total of 0.09 $MtCO_2e$.

More substantial emissions of other GHGs occur in the upstream oil and gas operations, where 0.4 $MtCO_2e$ of methane (CH_4) was emitted in 2018 (see Figure 1).

184 Lenaghan, M., & Mill, D. (2015). Industrial Decarbonisation and Energy Efficiency Roadmaps: Scottish Assessment.
185 SLR (2020).
186 The global w arming potential of each GHG relative to that of CO2 is provided at https://www.gov.uk/guidance/assess-the-impact-of-air-emissions-on-global-warming#greenhouse-gases-impact-of-your-emissions.
187 Information about the different GHGs can be found at https://naei.beis.gov.uk/overview/ghg-overview.

Table 20 – GHG emissions other than CO_2

All values in $MtCO_2e$	HFCs	PFCs	SF_6	CH_4	N_2O	NF_3	Total
Industrial Refrigeration	0.14	-	-	-	-	-	0.14
Electronics and shoes	-	0.13	0.01	-	-	-	0.14
Firefighting	0.03	-	-	-	-	-	0.03
Foams	0.02	-	-	-	-	-	0.02
Electrical insulation	-	-	0.02	-	-	-	0.02
Other sources	0.03	0.02	0.01	0.01	0.02	0.00	0.09
Total	**0.22**	**0.14**	**0.04**	**0.01**	**0.02**	**0.00**	**0.43**

Other exclusions

Figure 18 provides a breakdown of the 0.1 $MtCO_2e$ classified as 'other exclusions in Figure 1.

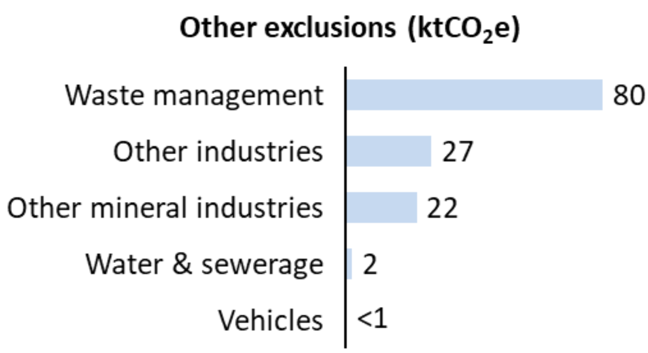


Figure 18 – Other exclusions

8.4 Sector-specific and cross-sectoral processes

Table 21 – Sector-specific and cross-sectoral processes[188]

Emissions source	Sector-specific process	Cross-sectoral processes	Applicable sector or subsector
Boiler or CHP	Drying, separation, space heating, other steam-based processes	Indirect – Steam-driven (from boiler or CHP)	All
CHP	Processes driven by electricity	Electricity-driven (from CHP)	
Dryer	Drying	Direct - Low Temperature Direct - High Temperature	Paper, food & drink, other EIIs
Fluid catalytic cracker	Fluid catalytic cracking	Direct - High Temperature	Oil and gas refining
Cement kiln	Cement kiln	Direct - High Temperature	Cement
Natural gas fired furnace	Casting, closed-die forging press, steel finishing, rolling	Direct - High Temperature	Metals
	Melting	Direct - High Temperature	Glass
	Other high-temperature process	Direct - High Temperature Indirect - High Temperature	Glass, refining, other EIIs
Natural gas oven	Baking and other direct fired processes	Direct - Low Temperature	Food & drink
Steam cracker	Steam cracking	Indirect - High Temperature	Olefins
Chemical reactions in industrial process	Calcination	Industrial Process	Cement
	Aluminium electrolysis		Aluminium
	Feedstock degradation		Glass
	Flaring		Olefins, oil and gas refining
	Steam-methane reactor		Oil and gas refining
Other	Other Direct Fire	Direct - Low Temperature	Food & drink
	Other	Other	Chemicals, food & drink, other EIIs

188 Adapted from Element Energy, Jacobs. (2018). Industrial Fuel Switching Market Engagement Study.

8.5 Emissions by cross-sectoral processes

The tables below report the numerical values of the emissions breakdown shown in Figure 6.

Table 22 – Emissions by cross-sectoral process and sector (ktCO$_2$e)

Cross-sectoral process	Chemicals	Oil & gas	Cement	Other EIIs	Paper	Food & drink	Glass	Metals
High Temperature	1,072	1,168	-	-	-	-	-	-
Steam from CHP	444	493	-	3	69	9	-	-
Steam from boiler	453	-	-	21	-	436	-	1
High Temperature	-	266	188	56	-	-	180	32
Low Temperature	-	-	-	22	4	69	-	-
Electricity from CHP	212	346	-	51	57	10	-	-
Unclassified fuel use	35	-	-	4	-	104	-	-
Process	37	383	385	-	-	-	50	64

Table 23 – Emissions by cross-sectoral process and fuel type (ktCO$_2$e)

Cross-sectoral process	Natural gas	Solid fuels	Oil	Internal fuel	Industrial processes
High Temperature	467	-	-	1,772	-
Steam from CHP	1,007	4	7	-	190
Steam from boiler	765	14	131	-	65
High Temperature	263	193	0	266	14
Low Temperature	73	2	20	-	269
Electricity from CHP	676	-	-	-	164
Unclassified fuel use	103	3	37	-	-
Process	-	-	-	-	819

8.6 Carbon cost assumptions

	Traded			Non-traded		
	Low	Central	High	Low	Central	High
2010	14	14	14	30	60	90
2011	13	13	13	30	61	91
2012	7	7	7	31	61	92
2013	4	4	4	31	62	94
2014	5	5	5	32	63	95
2015	6	6	6	32	64	96
2016	5	5	5	33	65	98
2017	5	5	5	33	66	99
2018	2	13	26	34	67	101
2019	0	13	26	34	68	102
2020	0	14	28	35	69	104
2021	4	21	37	35	70	106
2022	8	27	46	36	72	107
2023	12	34	56	36	73	109
2024	16	41	65	37	74	111
2025	20	47	74	38	75	113
2026	24	54	84	38	76	114
2027	28	61	93	39	77	116
2028	32	67	103	39	79	118
2029	36	74	112	40	80	120
2030	40	81	121	40	81	121
2031	44	88	132	44	88	132
2032	48	96	144	48	96	144
2033	52	103	155	52	103	155
2034	55	111	166	55	111	166
2035	59	118	178	59	118	178
2036	63	126	189	63	126	189
2037	67	133	200	67	133	200
2038	70	141	211	70	141	211
2039	74	148	223	74	148	223
2040	78	156	234	78	156	234
2041	82	163	245	82	163	245
2042	85	171	256	85	171	256
2043	89	178	268	89	178	268
2044	93	186	279	93	186	279
2045	97	193	290	97	193	290
2046	100	201	301	100	201	301
2047	104	208	313	104	208	313
2048	108	216	324	108	216	324
2049	112	223	335	112	223	335
2050	115	231	346	115	231	346

Source: BEIS modelling (2019). Further guidance on the use of carbon values is available from the appraisal guidance (Chapter 3) which can be downloaded from the Green Book supplementary guidance section of GOV.UK webpage.

8.7 Modelling assumptions for carbon capture and compression

This section summarises all modelling assumptions for carbon capture and compressor.

Capture costs

The CAPEX for a plant of size X $MtCO_2$/y and with CO_2 flue gas concentration Y is given by the following set of formulas:

*CAPEX for plant of size X = (CAPEX of reference plant) * (X / reference size) ^ (scaling exponent) **

** (Flue gas concentration of reference plant / Y) ^ (CO_2 exponent)*

The OPEX is instead calculated as percentage of CAPEX. All the relevant data is provided in the tables below where values for advance amines and calcium looping capture technologies is provided for reference (source: Element Energy, 2019c).

Table 24 – Characteristics of emission sources where carbon capture is deployed

Subsector	Emission source	Type	CO_2 stream purity (% volume)	Assumed capture rate
Cement	Calcination reaction	Process	95%	100%
Cement	Kiln	Combustion	10%	90%
Petrochemicals	Steam cracking	Combustion	10%	90%
Refining	Refinery furnaces	Combustion	10%	90%
Refining	SMR	Process	95%	100%

Table 25 – Cost assumptions for carbon capture

Capture technology	Reference CAPEX (£m)	Opex (% of CAPEX)	Reference size ($MtCO_2$/y)	Scaling exponent	Reference CO_2 stream purity (% volume)	CO_2 exponent
First generation amines	505.6	8%	2	0.67	11.5%	0.53
Advanced amines	388.9	5%	2	0.67	11.5%	0.53
Calcium looping	155.4	19%	2	0.67	13.0%	0.53

Energy requirements for capture

The heat and electricity requirements are inversely proportional to the CO_2 concentration of the exhaust stream. The formula for the heat input required per tCO2 is given by

*Heat input (kWh/tCO_2) = Reference heat input * Heat scaling coefficient **

** (CO_2 concentration (%) * 100) ^ Heat scaling exponent*

The formula for the electricity input required is analogous (swap 'heat' with 'electricity' in the above). All the necessary data is provided in Table 26.

Note that the energy costs are additional to those calculated above for capture and below for compression.

Table 26 – Energy requirements for carbon capture

Capture technology	Reference heat input (kWh/t CO_2)	Heat scaling coefficient	Heat scaling exponent	Reference electricity input (kWh/t CO_2)	Electricity scaling coefficient	Electricity scaling exponent
First generation amines	1056	1.42	-0.142	56.0	11.2	-0.99
Advanced amines	833	1.42	-0.142	56.0	11.2	-0.99
Calcium looping	444	1.42	-0.142	150.0	11.2	-0.99

Compression costs

It is assumed that CO_2 is always captured at atmospheric pressure (0.11MPa) and must be compressed to 10MPa for pipeline transport. The compressor is sized according to the following formula:[189]

$$\text{Compressor size (MW)} = CO_2 \text{ flowrate } (m^3/s) * 0.11 \text{ MPa} * \log(10\text{MPa}/0.11\text{MPa}) / \text{Compressor efficiency (\%)}$$

Where the CO_2 flowrate in m3/s can be calculated from the annual abatement and the (pressure-dependent) density of CO_2. The CAPEX and OPEX of the compressor are calculated in an analogous manner to the corresponding capture costs

Table 27 – Modelling parameters for CO_2 compression

Capex (£m/MW)	Opex (% of CAPEX)	Efficiency (%)	Reference size (MW)	Sizing exponent
1.64	5%	75%	10	0.29

[189] See https://physics.stackexchange.com/questions/37634/how-much-work-is-needed-to-compress-a-certain-volume-of-gas.

8.8 Additional results for the Hydrogen pathway

The figures below complement the those for the Hydrogen pathway presented in Chapter 6.

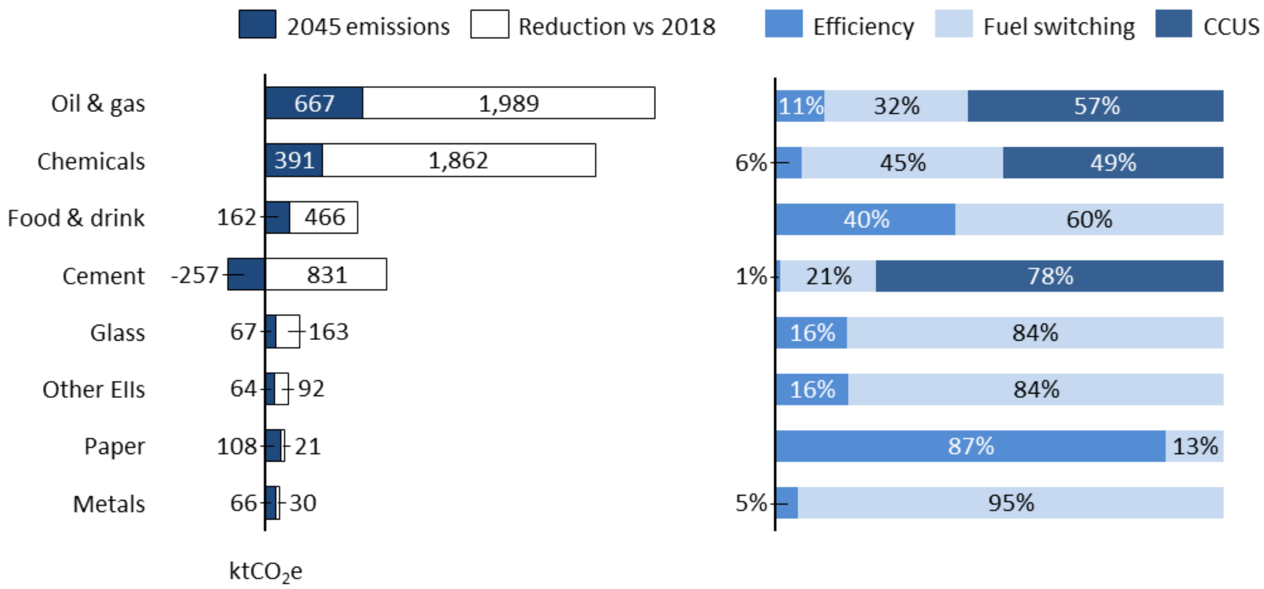


Figure 19 – Sectoral contributions to overall emissions abatement (Hydrogen)

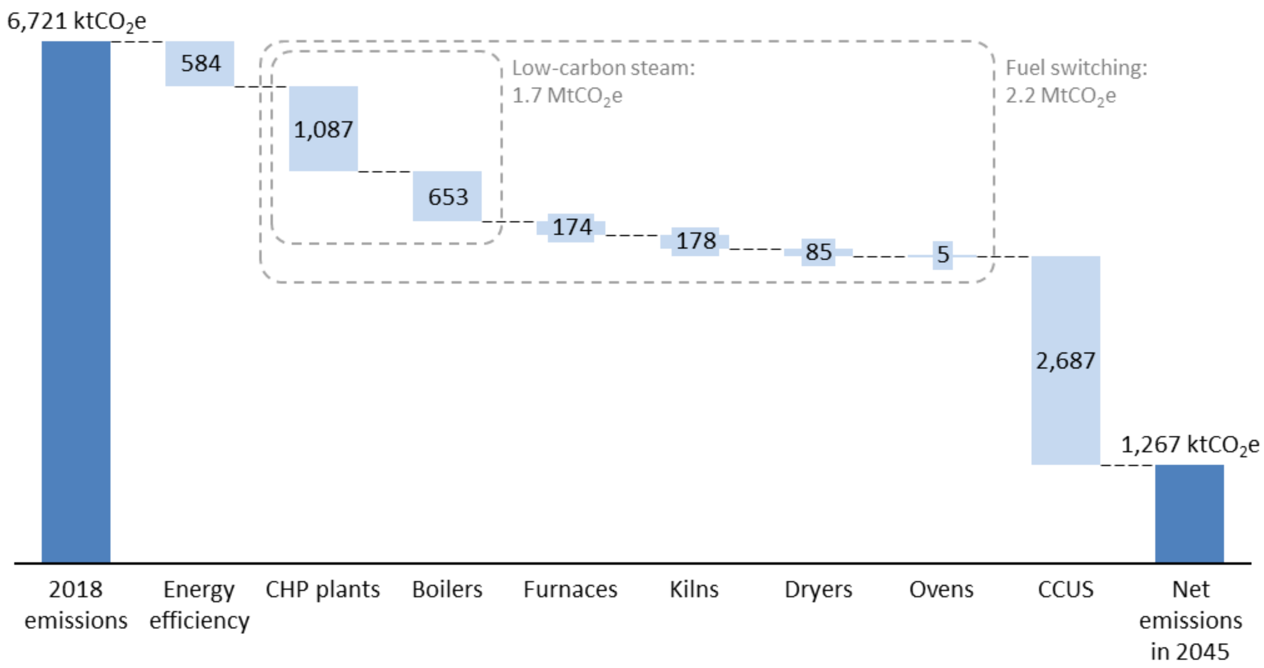


Figure 20 – Technology contributions to emissions abatement (Hydrogen)

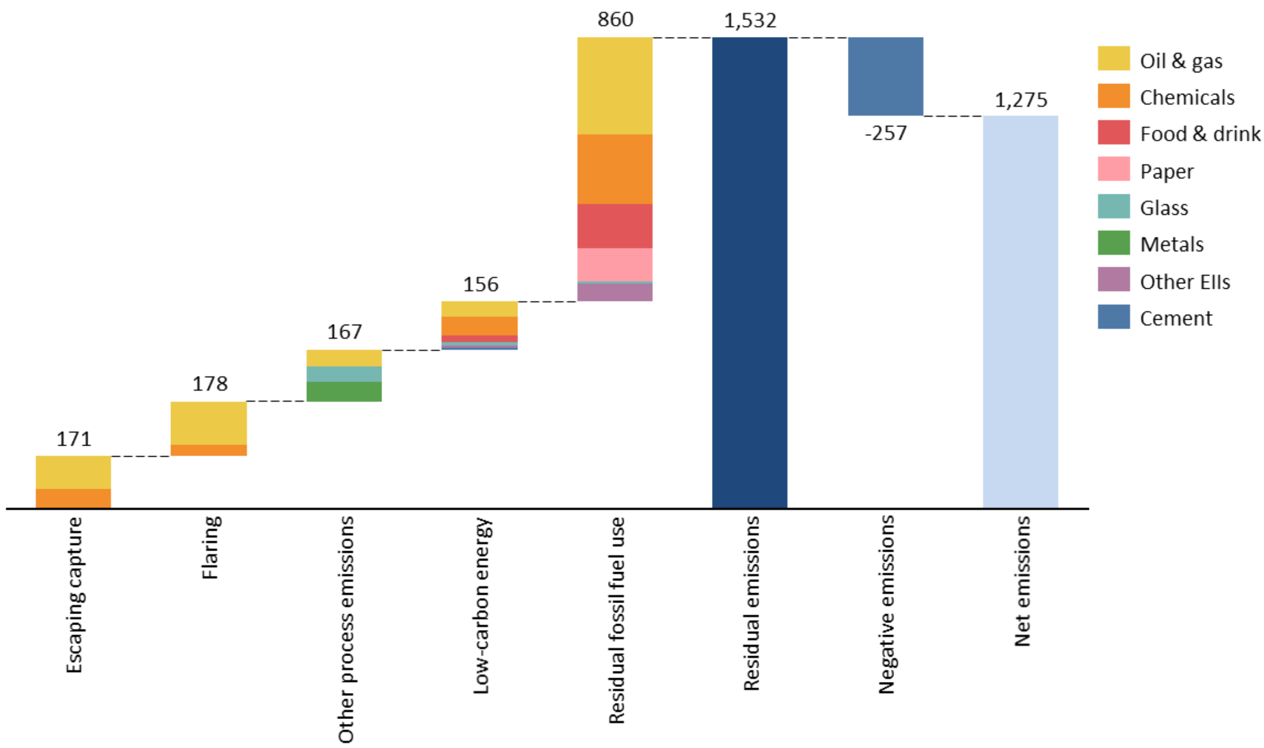


Figure 21 – Breakdown of residual emissions (Hydrogen)

8.9 Capital expenditure: annualised and financing cost

The capital expenditure, CAPEX, is annualised using MS Excel's PMT function:

Annualised CAPEX: -PMT(WACC, [Equipment lifetime], [Equipment CAPEX])

Where WACC is the Weighted Average Cost of Capital, assumed equal to 10% (representative of that for the private sector).

The annualised CAPEX is further split into two components:

Repayment of the principal loan: -PMT(0, [Equipment lifetime], [Equipment CAPEX])

Interest payments: Annualised CAPEX - Principal loan repayment

Avoided carbon costs (through a carbon price) are not included.

The overall (i.e. not levelised) cost of abatement can be calculated using the formula above but setting R = 1 (effectively no discounting).

8.10 Levelised cost of abatement methodology

The levelised cost of abatement (LCOA) represents the carbon price that would be needed to make a given carbon abatement measure economically viable – i.e. achieve a zero net-present value (NPV). The way the LCOA is calculated is similar to that used to calculate the levelised cost of energy,[190] i.e.:

$$\textit{LCOA}\ (\pounds/tCO_2) = \frac{\textit{net present cost of measure}}{\textit{total discounted lifetime abatement}} = \frac{\Sigma\left[\left(\textit{CAPEX} + \textit{OPEX} + \textit{fuel cost difference}^{191}\right)_n / (1+R)^n\right]}{\Sigma\left[(\textit{abated emissions})_n / (1+R)^n\right]}$$

Where R is the discount rate of 3.5%, *n* is the period (e.g. *n* = 1 is 2018 and *n* = 28 is 2045), and the sums are over all periods from *n* = 1 to *n* = 53 (corresponding to 2070).[192] In the calculation for the levelised cost of energy the denominator would be replaced by the discounted sum of the electrical energy produced in period *n*.

190 See e.g. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf.

191 I.e. the difference in total fuel cost comparing after and before the measure is implemented. This also factors in differences in energy prices.

192 Costs and abatement were calculated up to and including 2070 to ensure the analysis would capture the entire lifetime of all equipment deployed in 2045.

This publication is available at **www.gov.scot**

Any enquiries regarding this publication should be sent to us at

The Scottish Government
St Andrew's House
Edinburgh
EH1 3DG

ISBN: 978-1-80004-411-1 (web only)

Published by The Scottish Government, December 2020

Produced for The Scottish Government by APS Group Scotland, 21 Tennant Street, Edinburgh EH6 5NA
PPDAS794946 (12/20)