CRC Report No. SM-CR-2023-01

CARBON SOURCES FOR E-FUELS

Final Report

December 2025

COORDINATING RESEARCH COUNCIL, INC.
1 CONCOURSE PARKWAY • SUITE 800 • ATLANTA, GA 30328

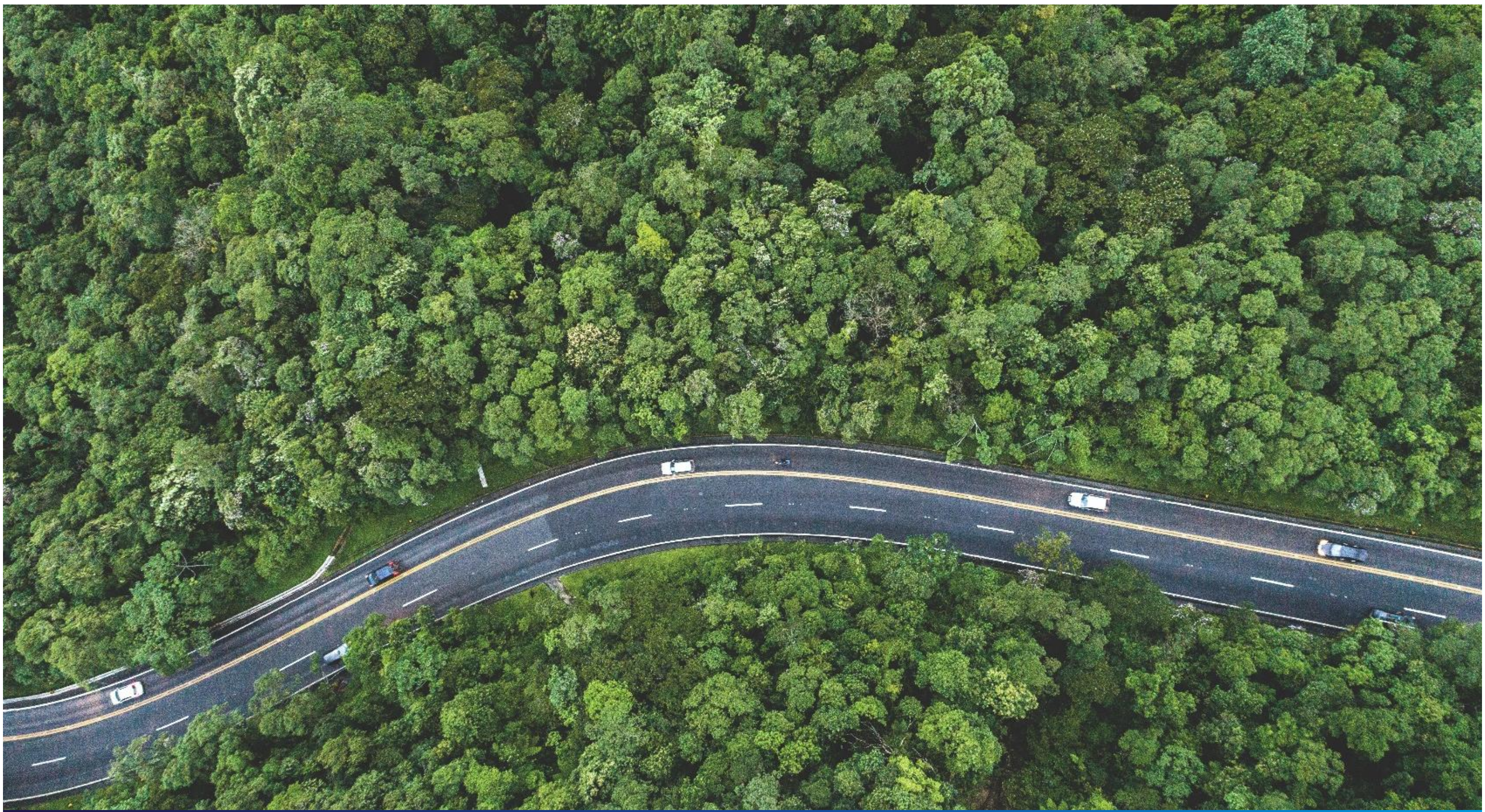
The Coordinating Research Council, Inc. (CRC) is a non-profit corporation supported by the petroleum and automotive equipment industries with participation from other industries, companies, and governmental bodies on research programs of mutual interest. CRC operates through the committees made up of technical experts from industry and government who voluntarily participate. The five main areas of research within CRC are: air pollution (atmospheric and engineering studies); aviation fuels, lubricants, and equipment performance; heavy-duty vehicle fuels, lubricants, and equipment performance (e.g., diesel trucks); light-duty vehicle fuels, lubricants, and equipment performance (e.g., passenger cars); and sustainable mobility (e.g., decarbonization). CRC's function is to provide the mechanism for joint research conducted by industries that will help in determining the optimum combination of products. CRC's work is limited to research that is mutually beneficial to the industries involved. The final results of the research conducted by, or under the auspices of, CRC are available to the public.

The Oil and Gas Climate Initiative has tried to make the information in this publication as accurate as possible. However, it does not guarantee that the information in this publication is totally reliable, accurate or complete. Therefore, the information in this publication should not be relied upon when making an investment or commercial decisions, it is intended to provide general guidance only.

All figures included in the report are stated on an estimated basis unless referenced. This report is not designed to provide legal or other advice, nor should it be relied upon as a substitute for appropriate technical expertise or professional advice. The responsibility for the interpretation and use of this publication lies with the user and in no event will OGCI or any of its members past, present or future, regardless of their negligence, assume liability for any foreseeable or unforeseeable use made thereof, which liability is hereby excluded. Consequently, such use is at the recipient's own risk on the basis that any use by the recipient constitutes agreement to the terms of this disclaimer. This disclaimer should be construed in accordance with English law.

All discussions and work within OGCI are conducted in accordance with anti-trust competition law principles. OGCI has implemented measures to ensure that all activities are compliant with competition laws, and all involved are trained and vigilant at all times to ensure such compliance.

OIL AND GAS CLIMATE INITIATIVE



CARBON SOURCES FOR E-FUELS

Final Report

Report for: OGCI & CRC

Ref. C01170

Ricardo ref. ED20103 Issue: 3 16 May 2025

Customer:
OGCI & CRC

Customer reference:
C01170

Ricardo reference:
ED20103

Contact:
Harsh Pershad
Ricardo-AEA, Gemini Building, Fermi Avenue, Harwell, Didcot, OX11 0QR, UK

T: +44 (0) 7707 175666
E: Harsh.Pershad@ricardo.com

Authors:
Amber Jenevizian, Sophia Zenon, Eleni Liakakou, Tarania Amirthalingham, Conall Martin, Grace Parker, Sofia Condes, Mohamed Ahmad, Omar Aqel

Approved by:
Dr. Harsh Pershad, Head of Industrial Decarbonisation and CCUS, Ricardo

Signed

:

Date

16 May 2025

Ricardo is certified to ISO9001, ISO14001, ISO27001 and ISO45001.

EXECUTIVE SUMMARY

Challenging global climate stabilisation targets can only be met through step changes in carbon management. The rate of growth of CO_2 levels in the atmosphere, today mainly from combustion of fossil fuels, can potentially be limited by using alternative carbon sources. This report synthesises a high-level research and analytical study into carbon sources for e-fuel production. The research illustrates the diversity in feasibility, opportunity, and economics, by comparing different technical approaches, geographies, and sensitivity analysis around costs. Recent policies and regulations in place until the end of 2024 were reviewed, recognising that support levels for specific approaches and projects can change rapidly as policies and markets change.

E-fuels are defined for this project as drop-in replacements for hydrocarbon fuels (gasoline, kerosene and diesel), produced by combining *electrolytic* hydrogen (H_2) with carbon dioxide (CO_2).[1] There are more than one billion vehicles or vessels in operation and mature supply chains to support them. Heavy Goods Vehicles (HGVs), marine vessels and aircraft are viewed as particularly hard to abate quickly because of the challenges in developing new technologies and infrastructure at the pace required to meet climate targets, E-fuels are regarded as important in enabling rapid decarbonisation for those sectors that cannot be easily electrified and by reducing the need for end-users to change established ways of working.

The Oil and Gas Climate Initiative and Coordinating Research Council have created a unique partnership bringing together fuel producers and users to build a shared understanding of e-fuels. In the summer of 2024, following competitive tender, OGCI and CRC commissioned Ricardo, an engineering and environmental consultancy, to produce this overview of e-fuels. This overview considers CO_2 sources, production pathways, techno-economics, life-cycle assessment, regulatory and policy landscape in different regions, and potential hubs for e-fuel production. This report represents the final major deliverable from the project.

Figure E-1. Overall process diagram for e-fuel production

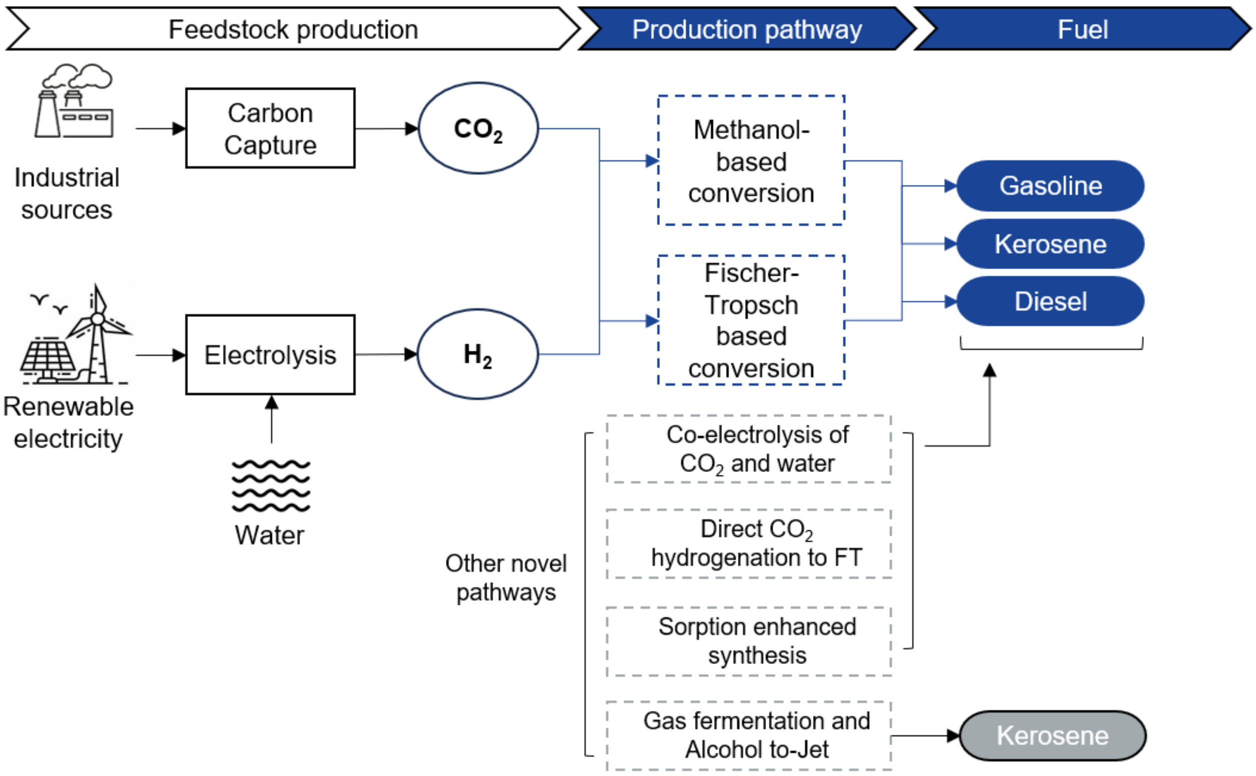


Figure E-1 highlights the main processes for developing e-gasoline, e-kerosene and e-diesel, the fuels that are the focus of this study. Processes involving a reverse Water Gas Shift and Fischer-Tropsch reaction or via e-methanol are currently the most mature, and these are therefore used to estimate costs and CO_2 savings, recognising that innovation could result in improvements to these estimates.

[1] Other sources of hydrogen and carbon, or other produced fuels, are out of scope for this project.

E-fuel production processes require industrial-scale and relatively pure hydrogen and CO_2 as important inputs to achieve e-fuel production scale in line with the scale of refineries (millions of tonnes of CO_2 per year, millions of barrels of oil equivalent per day).

CO_2 streams are a common by-product of many industrial processes (including heat and power generation), and in some cases CO_2 separation is integral offering access to relatively pure CO_2 at low cost (examples are biomethane upgrading and natural gas sweetening), though investment in CO_2 capture would likely be required in most cases. Hydrogen would need investment in electrolysers – and these would need to be run from low carbon electricity to maximise carbon savings. The feasibility, scale and costs of captured CO_2 and electrolytic hydrogen are highly site dependent, even within countries, depending on specific site characteristics (e.g. purity of CO_2, renewable electricity costs).

E-fuel hubs where CO_2 and hydrogen can be produced in sufficient quantities in very close proximity as inputs will be substantially faster, easier, cheaper, and less risky to develop than configurations where either hydrogen or CO_2 needs to be moved long distances (unless developers can take advantage of pre-existing infrastructure).

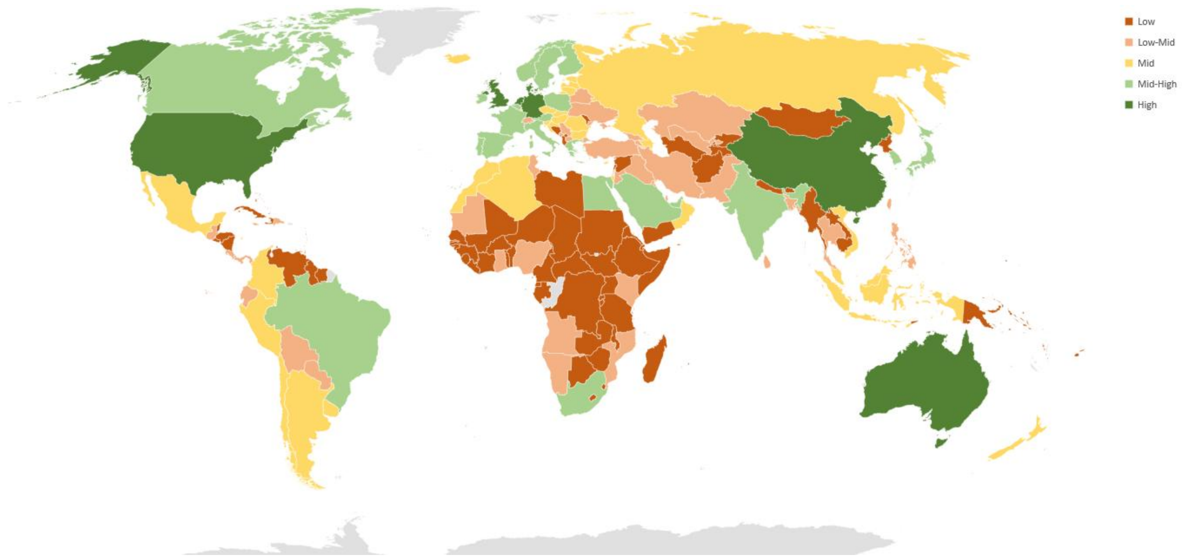
Industrial sources that have both scale and CO_2 purity to enable CO_2 capture include ethylene oxide, ammonia, bio-ethanol production, as well as the CO_2 separation from oil and gas production. Small sources of CO_2 are globally well distributed. China, India, the United States and Russia are home to large industrial sources of CO_2 that would enable production at the scale of today's oil refineries. Nearly all the largest sources currently are fossil derived, though in the future some may switch to biomass.

The report identifies political, economic, social, technological, legal and environmental barriers to both CO_2 and hydrogen supply. Policy support for carbon capture, hydrogen and e-fuel production around the world is mixed. The techno-economics shows that hydrogen costs dominate e-fuel production costs, followed by captured CO_2 costs. Hydrogen costs are driven by renewable power costs, implying that e-fuel developers need to focus on regions with very large amounts of low cost, low carbon electricity. In nearly all locations, the latter will require substantial new renewable generation investment, as well as aligned supporting electricity grid and hydrogen infrastructure to ensure that production processes operate continuously. Transport costs for hydrogen or CO_2 further depend on distance mode (e.g. pipeline vs. ship), terrain, capacity and integration within a wider transport network. As an example of an environmental challenge, water availability may further restrict the number of locations able to support e-fuel production.

Today oil refineries rely on economies of scale and fuel production is typically focussed at hubs that process many millions of barrels of oil each year, often from nearby oil and gas fields. Whilst these are likely to remain important for other reasons, future e-fuel production hubs may instead be driven as much by availability of electrolytic hydrogen and captured CO_2, which could be independent of the locations of oil and gas reserves.

This report considers the factors above to provide a high-level global assessment of relative ease of e-fuel production as shown below.

Figure E-2. High level assessment of ease of e-fuel production in countries



Country-level analysis is a reasonable starting point but limited by the heterogeneity within countries. Future work could explore specific locations in more detail, considering costs and competition for resources (such as renewable electricity or water), and understand individual CO_2 sources (timing, capture feasibility and costs, fossil/ biogenic CO_2 supply). Together with plausible scenarios for infrastructure and production configurations, this could be used to quantify the technical potential (i.e. amounts) for supply of e-fuels from locations with sufficient local resources to support production.

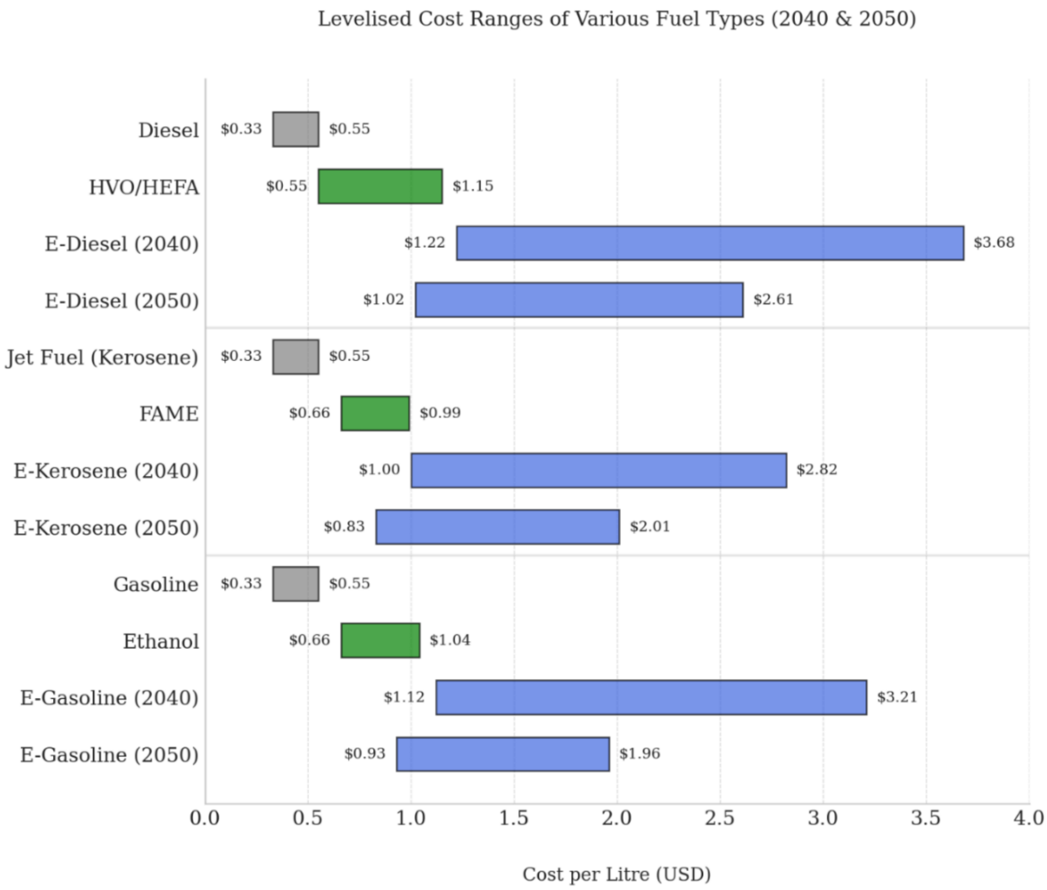
Direct air capture is currently a very early-stage technology being piloted. A theoretical advantage is geographical flexibility, not tied to an existing industrial source. Considerable technology development would be required to scale up to meet the scales associated with e-fuel production. Equally challenging is that most concepts for localised direct air capture are energy intensive, compounding the challenge of needing additional renewable generation beyond the already steep requirements for energy needed to produce hydrogen. Direct air capture of CO_2 through mineralisation does not generate a concentrated CO_2 source that can be combined with hydrogen at a particular location.

Moving beyond the high level global analysis, analysis of a few exemplar countries helps to highlight the interplay of these factors. In agreement with OGCI and CRC, the report examines current drivers and barriers to e-fuel production, techno-economics and CO_2 savings in three different countries, the US, China, and Germany, in more depth.

Costs

The techno-economic analysis in this report confirms previous studies showing that e-fuels are expected to be two to seven times more costly per litre than conventional petroleum-based fuels. In limited cases, some e-fuel production strategies can be cost competitive with some biofuels. The range of e-fuel prices shown in Figure E-3 includes possible production costs across different countries and CO_2 sources. The lower bound corresponding to the lowest cost scenarios, namely lowest hydrogen cost in China coupled with high concentration CO_2 sources. The upper bound corresponding to the highest hydrogen cost in Germany coupled with the highest estimate of captured CO_2 (from Direct Air Capture, (DAC). The underlying data can be found in Section 9.5. As recommended by OGCI and CRC, fossil fuel and biofuel costs are based on a recent OGCI report on energy demand dynamics across the Transportation Sector dated November 2024.

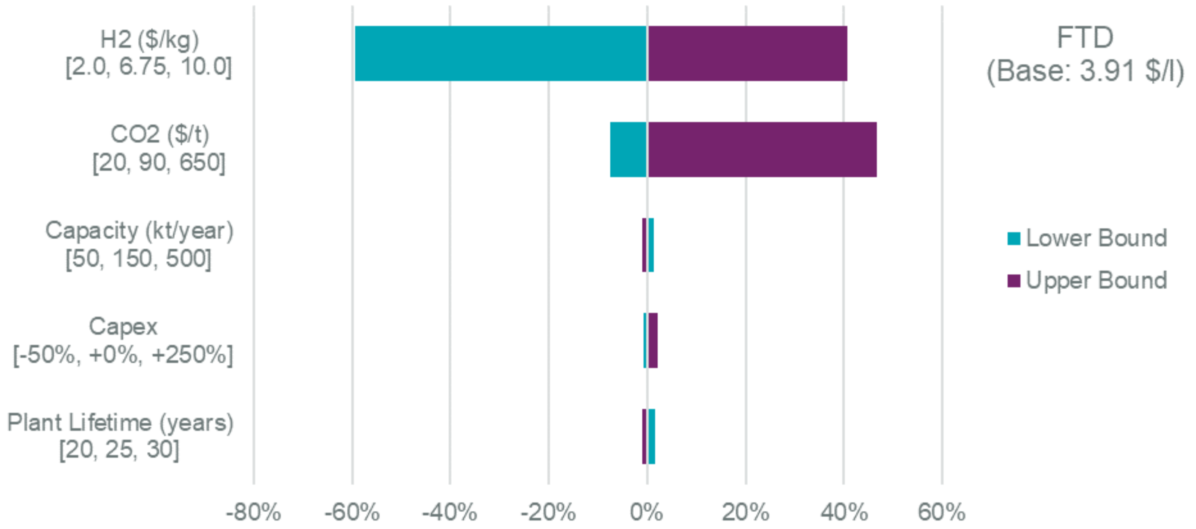
Figure E-3. Comparison of e-fuel production costs with fuel fossil- and bio-based fuels.



There are considerable uncertainties on costs and future availability of fossil fuels and sustainable biofuels today and in the future. Changes in feedstock supply, government policies,, and market dynamics might influence conventional and biofuel production costs and selling price. For example, if SAF were available at $2.80/litre (as per one ICCT report[2]), the ratio of e-fuel / biofuel cost would be close to 1.

A sensitivity analysis shows that hydrogen costs dominate the cost of e-fuel production, followed by CO_2 input cost. E-fuel production process CapEx, though important for reaching investment decisions has less influence on levelized e-fuel production cost.

Figure E-4. Sensitivity analysis for FTD (Diesel via Fischer-Tropsch)



Carbon impacts

A high-level literature review of lifecycle analysis considerations reveals that key considerations for carbon impacts associated with e-fuel production are:

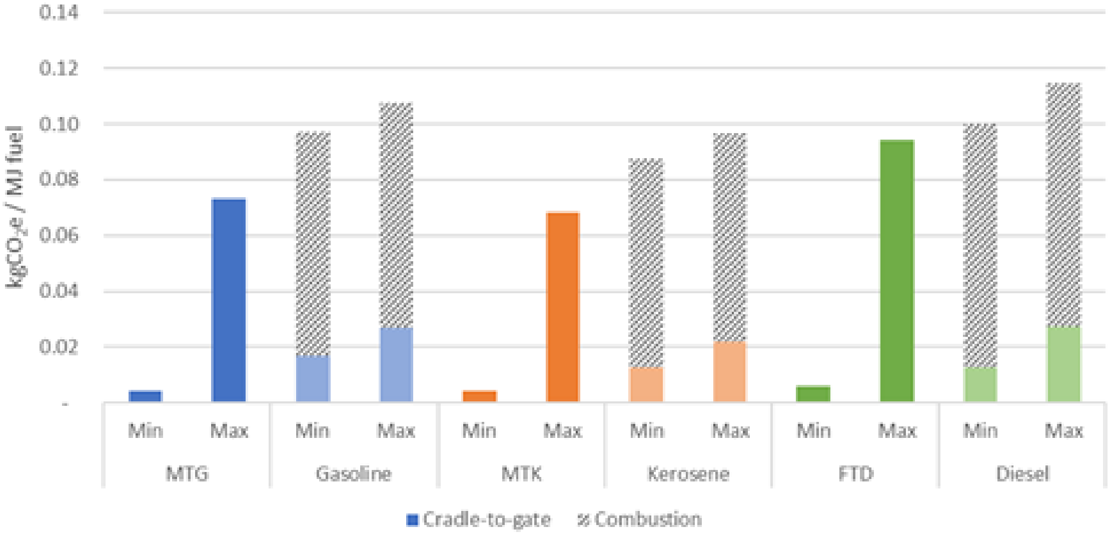
- Low carbon electricity used to produce hydrogen
- Use of high purity and biogenic CO_2 sources where available
- Heat optimisation between hydrogen, CO_2 capture and e-fuel production processes
- Legislation that may restrict the use of fossil sources of CO_2
- Proximity of CO_2 capture, hydrogen supply and e-fuel production.

Compared to fossil fuels, the e-fuel production pathways have a wider range of carbon impacts. They can result in lower cradle-to-gate emissions than conventional fossil fuels under optimum conditions. However, in the worst case, cradle to gate emissions of e-fuels can exceed those of fossil fuels.

When considering the impact of the tailpipe emissions associated with combustion, the impact associated with the carbon released by the fossil fuels in use dwarfs the cradle-to-gate impact. These results are shown below. This is because the CO_2 which is released on combustion for the fossil fuels needs to be accounted for in calculation of the total cradle-to-grave impact, whereas for e-fuels, the CO_2 released on combustion is not included in the GWP. For the e-fuels, the CO_2 emitted at combustion is considered to be the re-release of the carbon captured (in the case of DAC and biogenic CO_2) or avoided (in the case of fossil CO_2) for the production of the e-fuel and is therefore considered to have a net zero impact.

[2] Nikita Pavlenko, Stephanie Searle, and Adam Christensen, *The Cost of Supporting Alternative Jet Fuels in the European Union* (Washington, DC: International Council on Clean Transportation, 2019), https://theicct.org/wp-content/uploads/2021/06/Alternative_jet_fuels_cost_EU_2020_06_v3.pdf

Figure E-5. Comparison of ranges of GWP impact of e-fuel production (renewable electricity consumption only) against fossil fuel equivalent, using system expansion approach



Note that a full review of wider environmental and sustainability challenges associated with fossil fuels, biofuels and e-fuels are out of scope of this project but would benefit decision makers beyond lifecycle carbon impacts.

Carbon Abatement Cost Effectiveness

The carbon abatement cost can be estimated by combining US$/energy and CO_2 emissions data from the techno-economic analysis with the CO_2/energy data from the lifecycle analysis.

The US$/t$CO_2$ saved varies across a wide range, depending on the CO_2 source, the e-fuel synthesis pathway employed, and the country under consideration.

Across the three countries analysed (China, the United States, and Germany), Germany has the highest e-fuel production costs, mainly due to higher hydrogen price (mainly due to higher energy prices).

Three distinct CO_2 sources are considered: DAC, biogenic CO_2 (from biomethane upgrading), and industrial CCU. Biogenic CO_2 from biomethane upgrading appears more cost effective than industrial CCU or DAC and could be considered a best case. CO_2 feedstocks vary significantly in amounts, concentration (and nature of impurities), which in turn affects the cost of capture. While some biogenic sources, such as biomethane upgrading, provide relatively pure CO_2 streams, others may be more dilute and costly to upgrade. Certain fossil-based sources such as natural gas processing or glycol plants can also offer high-concentration CO_2 streams requiring minimal clean-up.

Figure E-6. Cost per GWP saved based upon region, pathway and CO_2 source for 2050

The primary motivation for considering replacing fossil hydrocarbon fuels with e-fuels is the lower life cycle carbon impact of e-fuels. However, for e-fuels to be an economically viable carbon abatement strategy, their costs must be competitive with other carbon reduction measures. Careful focus on e-fuels production strategy is important to minimise carbon abatement costs. E-fuels with the lowest carbon abatement cost (<US$200/t$CO_2$) can only be produced in the future from production sites in locations with access to large amounts of very low cost and low carbon electrolytic hydrogen (<$1.5/kg), and captured CO_2 that are co-located with e-fuel production to minimise hydrogen and CO_2 transportation costs.

Future work could develop supply marginal cost curves (unit cost vs. cumulative quantity) for e-fuel production quantifying location- specific amounts and costs across a wide range of locations, reflecting plausible infrastructure development at different times, to quantify the economic potential for e-fuels. This could also be overlaid with marginal cost curves for sustainable biofuels (and other alternative fuels). Excessively high e-fuel carbon abatement costs (around or above US$1,000/t$CO_2$) risk limiting the ultimate market for e-fuels: If e-fuel carbon abatement costs are too high, industry may instead focus on alternative decarbonisation strategies, including greater use of alternative low carbon fuels, or even combinations of fossil fuel combustion with direct air CO_2 capture and storage (DACCS) elsewhere, if DACCS technologies mature.

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

GLOSSARY

Abbreviation	Definition
ACCA21	Administrative Centre for China's Agenda 21 (China)
ACCU	Australian Carbon Credit Unit
ATJ	Alcohol-to-Jet
bbl/day	Barrels per day
BECCS	Bioenergy, Carbon Capture and Storage
BIL	Bipartisan Infrastructure Law
CAAC	Civil Aviation Administration of China
CapEx	Capital expenditure
CCER	China Certified Emission Reduction
CCfD	Carbon Contracts for Difference
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Utilisation and Storage
CERF	Carbon Emission Reduction Facility
CF	Capacity factor
CfD	Contracts for Difference
CIF	Climate Investment Fund
CNPC	China National Petroleum Corporation
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COD	Conversion of Olefins to Distillate
CRC	Coordinating Research Council
CRI	Carbon Recycling International
CtG	Cradle to grave
DAC	Direct Air Capture
DME	Dimethyl ether
DoE	Department of Energy
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
EEA	European Economic Area
EEG	Renewable Energy Sources Act
EIA	Energy Information Administration
EIM	European Interconnection Mechanism
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ETD	Energy Tax Directive
ETS	Emissions Trading Scheme
EU	European Union
EV	Electric Vehicle
FAME	Fatty acid methyl ester
FCV	Fuel Cell Vehicle
FID	Final Investment Decision
FT	Fischer Tropsch
FTD	Fischer-Tropsch Diesel

Abbreviation	Definition
GCOM	Gas Crediting and Offsetting Mechanism
GDP	Gross Domestic Product
GHCS	Green Hydrogen Commercialisation Strategy
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
Gt	Gigatonnes
GWP	Global warming potential
H_2	Hydrogen
HAR	Hydrogen Allocation Round
HDV	Heavy-Duty Vehicle
HEFA	Hydroprocessed Esters and Fatty Acids
HVO	Hydrotreated vegetable oil
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicles
IDHRS	Industrial Decarbonisation and Hydrogen Revenue Support
IEA	International Energy Agency
IIJA	Infrastructure Investment and Jobs Act
IMO	International Maritime Organisation
IPCEI	Important Projects of Common European Interest
IRA	Inflation Reduction Act
IRP	Integration Resource Plan
ITC	Investment Tax Credits
JCM	Joint Crediting Mechanism
KSpG	Carbon Dioxide Storage Act
LCA	Life cycle assessment
LCER	Low-Carbon Energy Research Funding Initiative
LCFS	Low Carbon Fuels Standard
LCHA	Low Carbon Hydrogen Agreement
LCOE	Levelised Cost of Electricity
LCOF	Levelised cost of fuel
L-DAC	Liquid solvent Direct Air Capture
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHCs	Liquid Organic Hydrogen Carriers
LPG	Liquefied Petroleum Gas
Mbl	Million barrels
MFS	Mobility and Fuels Strategy
MOGD	Mobil Olefins to Gasoline and Distillate
MOST	Ministry of Science and Technology (China)
MoU	Memorandum of Understanding
$MtCO_2$/year	Million tonnes of CO_2 per year
MTD	Methanol-to-Diesel
MTG	Methanol-to-Gasoline
MTGD	Methanol to Middle Distillates
MTJ	Methanol-to-Jet
MTK	Methanol-to-Kerosene
MTO	Methanol-to-Olefins

Abbreviation	Definition
Mtpa	Mega tonnes per annum
NCP	National Climate Plan
NDC	Nationally Determined Contribution
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NECP	National Energy and Climate Plan
NZE	Net Zero Emissions
OGCI	Oil and Gas Climate Initiative
OGE	Open Grid Europe
PBOC	People's Bank of China
PCI	Projects of Common Interest
PEM	Proton exchange membrane
PESTLE	Political, Economic, Social, Technological, Legal and Environmental
PSA	Pressure swing absorption
PtX	Power to X
PV	Photovoltaic
R&D	Research and Development
RED	Renewable Energy Directive
RED III	Renewable Energy Directive III
RFNBO	Renewable Fuels of Non-Biological Origin
RNG	Renewable Natural Gas
RWGS	Reverse Water Gas Shift
SAF	Sustainable Aviation Fuels
S-DAC	Solid sorbent Direct Air Capture
SDG	Sustainable Development Goals
SMR	Steam methane reforming
SOE	State-Owned Enterprise
SOEC	Solid Oxide Electrolysis Cells
TIER	Technology Innovation and Emissions Reduction Implementation
TIGAS	Topsøe integrated gasoline synthesis
TOU	Time-of-Use
TRL	Technology Readiness Level
TtW	Tank-to-wake
UHV	Ultra-High Voltage
US	United States
VRE	Variable renewable energy
WtT	Well-to-tank
WtW	Well-to-wake

1. INTRODUCTION

1.1 MOTIVATION FOR THIS STUDY

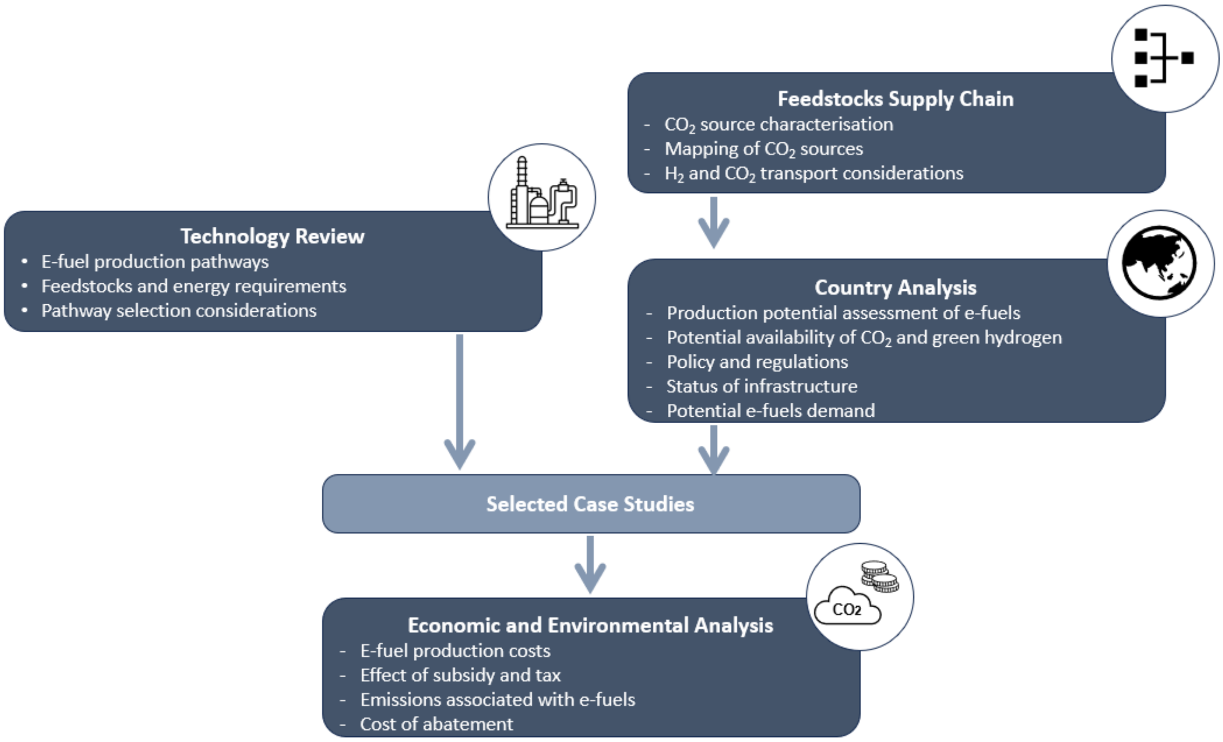
The Oil and Gas Climate Initiative (OGCI) and the Coordinating Research Council (CRC) have partnered to commission this study, focusing on the potential of carbon sources for e-fuel production. The primary objective of this project is to evaluate the opportunities and challenges of developing e-fuels by identifying CO_2 sources, estimating the associated costs and emissions reduction potential.

To achieve this, the study undertook the following key activities:

- A review and assessment of e-fuel production pathways based on key selection criteria
- An assessment of the e-fuels supply chain, focusing on feedstocks (carbon dioxide and hydrogen)
- Review of policy, regulations, and infrastructure readiness in selected exemplar countries
- A high-level techno-economic and lifecycle assessment of e-fuel production in the selected locations

The approach followed in this study is illustrated in Figure 1-1.

Figure 1-1. Study approach



1.2 STRUCTURE OF THIS REPORT

This report is organised as follows:

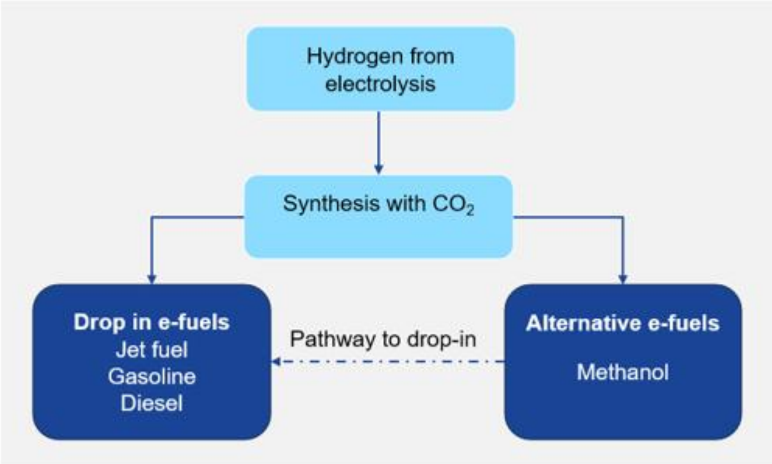
- **Section 2** provides an overview of e-fuel production pathways, including key process parameters. Based on key selection criteria, such as process efficiency, TRL and feedstock requirements, three production pathways are selected for the case studies that will be considered for the techno-economic and lifecycle assessment.
- **Section 3** provides an overview of the global supply chain for e-fuels production. This includes a review of supply considerations for CO_2 and H_2 feedstocks, as well as an analysis of CO_2 sources.
- **Section 4:** Covers global multi-criteria screening. It discusses priority CCU-enabled e-fuel production process pathways, identifies potential global locations for CCU-enabled e-fuel hubs, and provides an in-depth exploration of hub locations, incorporating policy reviews and potential e-fuels demand.
- **Section 5:** Focuses on exemplar analysis, including techno-economic assessments, and lifecycle analysis.
- **Section 6:** Brings together the conclusions from the four sections covered above.
- **Technical Annex** provides more details on the methodology, assumptions and results of each section of the main report.

1.3 DEFINITION OF E-FUELS IN THIS STUDY

E-fuels represent a promising approach to limiting net CO_2 emissions associated with fuel combustion. E-fuels are not well-established, and today's e-fuel production is relatively limited. E-fuels - also referred to as electro-fuels, power-to-fuels or power-to-liquids - are synthetic fuels typically produced from hydrogen (H_2), carbon dioxide (CO_2) and electricity derived from renewable energy sources. Hydrogen, called "green hydrogen", is produced from renewable electricity via electrolysis of water. CO_2 is captured either from a concentrated source (e.g. flue gases from an industrial site) or from the air via direct air capture (DAC). A number of different e-fuels can be produced by this route and can also be further classified by their ease of use. The chemical composition and properties of e-fuels are such that they can be used as drop-in fuels as a replacement of fossil-derived fuels or blended with conventional fuels.

E-fuels can take various forms, with main examples including e-gasoline, e-kerosene, e-diesel, e-methane, e-methanol and e-ammonia. This study is focused on drop-in liquid fuel alternatives for the on-road and aviation sectors, namely gasoline, diesel and kerosene/jet fuel, which are the most common transport fuels. E-fuel production involves three main steps: feedstock production, fuel production and product upgrade. The feedstock for carbon-based e-fuels typically consists of hydrogen and carbon dioxide. An overview of the various e-fuels that can be produced that are in scope of this study are outlined in Figure 1-2[3] below.

Figure 1-2. E-fuels and production routes in scope of this study



[3] Adapted from IEA report: The role of e-fuels in decarbonising transport, IEA, 2023, Accessed at: https://iea.blob.core.windows.net/assets/a24ed363-523f-421b-b34f-0df6a58b2e12/TheRoleofE-fuelsinDecarbonisingTransport.pdf

2. E-FUEL PRODUCTION PATHWAYS

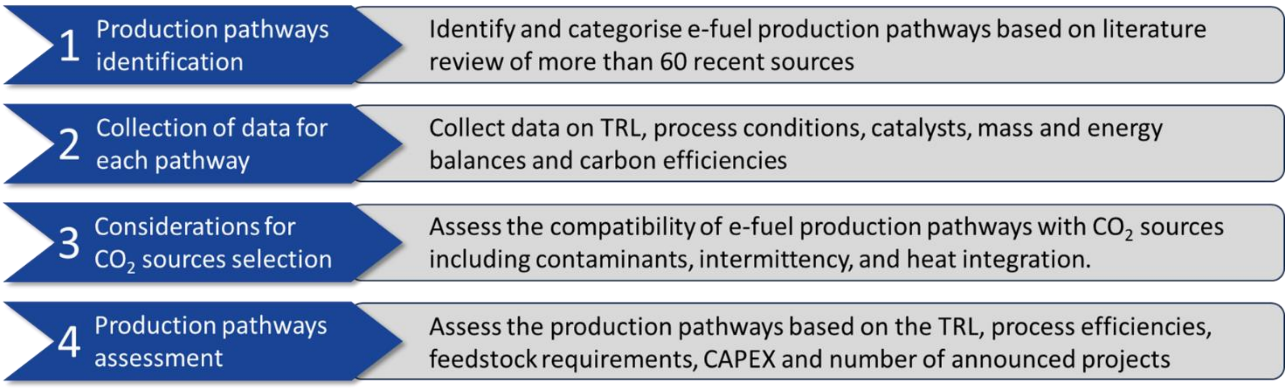
This section provides an overview of the possible e-fuel production technologies starting from H_2 and CO_2 streams as feedstocks, and the state of their development. It also outlines some key considerations for production pathway compatibility with CO_2 sources.

2.1 OVERVIEW OF THE APPROACH

In the initial phase of this study, the different technologies and production pathways to produce e-fuels were identified and categorised based on a literature review. Based on the collected data for each production technology, an assessment of the pathways was performed in order to select the three priority pathways to design the case studies to evaluate the feasibility of e-fuel production.

The approach to select the priority pathways was based on the four steps illustrated in Figure 2-1 and described below.

Figure 2-1. Overview of the approach used to select the priority e-fuel production pathways



Note: TRL is Technology Readiness Level (more information on this is provided in the technical annex).

In the initial phase of our approach, we reviewed publicly available literature on e-fuel production to identify potential production methods. Key factors such as the Technology Readiness Level (TRL), process conditions, catalyst requirements, and, most importantly, the mass and energy balance were examined for each production pathway.

From this review, three production pathways were selected for further techno-economic and life cycle assessments. The selection criteria were multifaceted. First, the combined pathways needed to produce drop-in fuels—e-diesel, e-kerosene, and e-gasoline. Additionally, each pathway had to have achieved at least a TRL of 6. Other considerations included feedstock requirements, capital investment needs, and commercial interest, as indicated by the number of announced and existing projects. Due to the emerging nature of e-fuel production and the limited publicly available data on costs and performance, only pathways with sufficient data were chosen for further assessment.

2.2 RESULTS

The main results and key takeaways of the e-fuel production pathways review are presented below.

2.2.1 Summary of production pathways

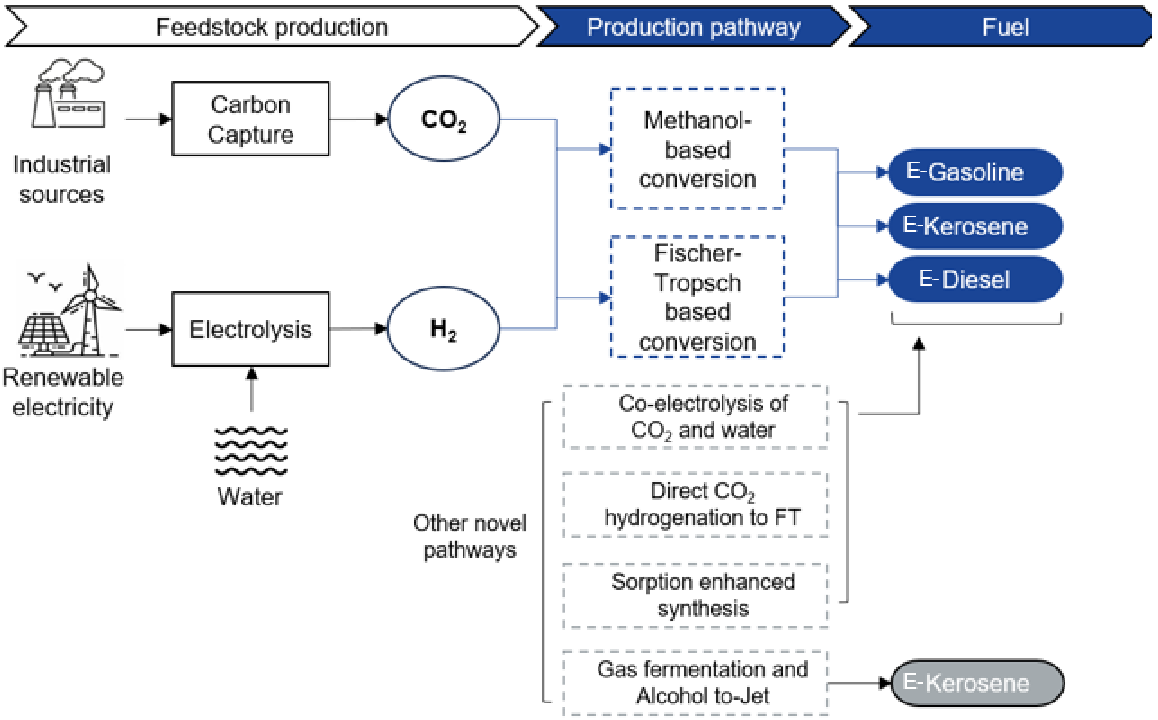
Carbon-based e-fuels can be produced from carbon dioxide and hydrogen feedstocks. The two more mature pathways to convert the feedstocks to e-fuels are:

- via **methanol-based conversion**, or
- via **Fischer-Tropsch (FT) based conversion**.

Both processes have been commercially deployed for decades, albeit using mostly synthesis gas from fossil based feedstocks. Most of the individual steps in the processes required to produce e-fuels are commercially available at large scale. However, integration of these unit processes into a fully operational e-fuel plant is currently at low TRL, with the largest plants represented by large prototypes (TRL 6)[4].

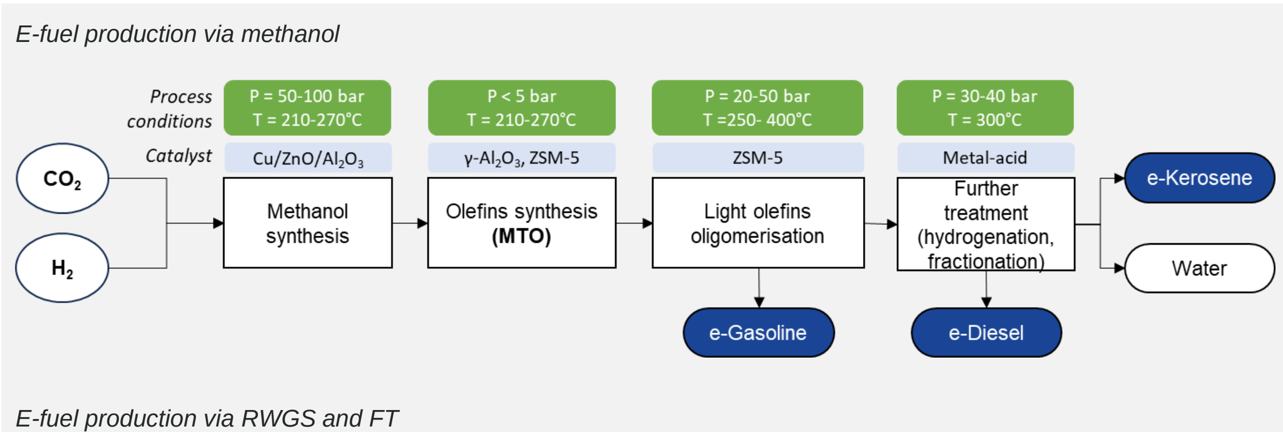
Other more novel pathways are considered for e-fuel production, aiming to increase efficiency and reduce production costs. Examples include co-electrolysis, direct CO_2 hydrogenation to FT, sorption enhanced synthesis, gas fermentation and alcohol-to-jet. However, these are not yet mature and are at lower TRL. A summary of the e-fuel production pathways is depicted in Figure 2-2 below.

Figure 2-2. Overall process diagram for e-fuel production

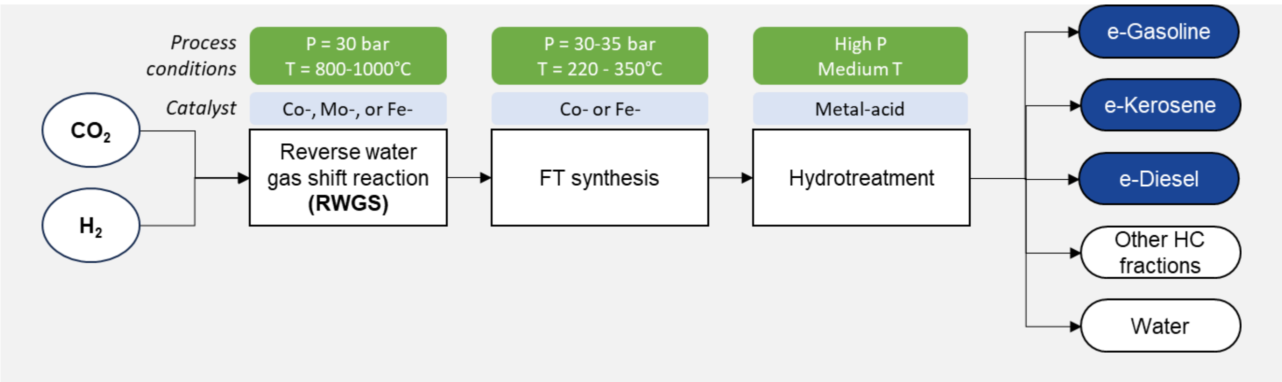


The simplified process flow diagrams of the two main production pathways for e-fuels considered in this study are presented in Figure 2-3, including the process conditions and catalysts required in the individual process steps. Details on the individual process steps, including process flow diagrams, mass and energy balances are presented in detail in the Technical Annex.

Figure 2-3. Simplified block flow diagrams of the main e-fuel production pathways



[4] The Role of E-fuels in Decarbonising Transport, 2023, *IEA*, Accessed at: https://iea.blob.core.windows.net/assets/9e0c82d4-06d2-496b-9542-f184ba803645/TheRoleofE-fuelsinDecarbonisingTransport.pdf



E-fuel production via methanol

The methanol-based conversion pathway towards drop-in liquid e-fuels can be divided into (1) the methanol synthesis and (2) the subsequent conversion of methanol into a hydrocarbon fuel mixture. E-Methanol can be produced via direct hydrogenation of CO_2 with H_2 over a heterogeneous catalyst. This process route is already demonstrated at TRL 8 to 9, with several leading companies holding licenses for direct CO_2 hydrogenation, including Johnson Matthey, Topsoe and Air Liquide.

Depending on the process conditions, e-methanol can be converted to different hydrocarbon products, such as paraffinic or aromatic compounds within the gasoline range. This can be achieved via the Methanol-to-Gasoline (MTG) or Methanol-to-Kerosene (MTK) pathways. Diesel is also produced via methanol in a similar pathway to MTK. However, in most cases in available literature, production is not optimized and it is mainly reported as a by-product of the MTK/MTG pathways. Other by-products of the methanol-based pathways include naphta/LPG. The MTG process is commercially available by several companies, such as Topsøe and ExxonMobil and is already deployed in various plants worldwide. The MTK process is currently under ASTM approval and is offered by many companies, such as Topsoe, ExxonMobil and Honeywell UOP.

E-fuel production via Reversed Water Gas Shift and Fischer-Tropsch

This pathway can be divided into (1) the reduction of CO_2 to CO and (2) with subsequent conversion of the synthesis gas (CO and H_2) to hydrocarbons via FT synthesis.

Converting H_2 and CO into hydrocarbon chains within the FT synthesis yields synthetic crude oil (syncrude), ranging from light gases (e.g. methane) to long-chain hydrocarbons (e.g. waxes). FT fuels, such as synthetic diesel, gasoline or kerosene from fossil-derived syngas (mainly coal) are proven technologies at commercial scale (TRL 9) for decades. Examples of commercial applications include Sasol's Coal-to-Liquid facility in South Africa and Shell's Pearl Gas-to-Liquid plant in Qatar. The FT process is also used in South Africa by The Petroleum Oil and Gas Corporation of South Africa (PetroSA). The plant produces gasoline and diesel fuels via a conversion of olefins to distillate (COD) process by converting light FT olefins to higher olefins[5].

As the FT reaction requires a mix of synthesis gas (H_2 and CO), this means that the captured CO_2 feedstock must be reduced to CO prior to the reaction. This is achieved through an equilibrium reaction called Reverse Water Gas Shift (RWGS), whereby CO_2 is reformed with H_2 to produce CO and water. High temperatures and pressures are required to favour the equilibrium to CO, alongside electricity to run the plant.

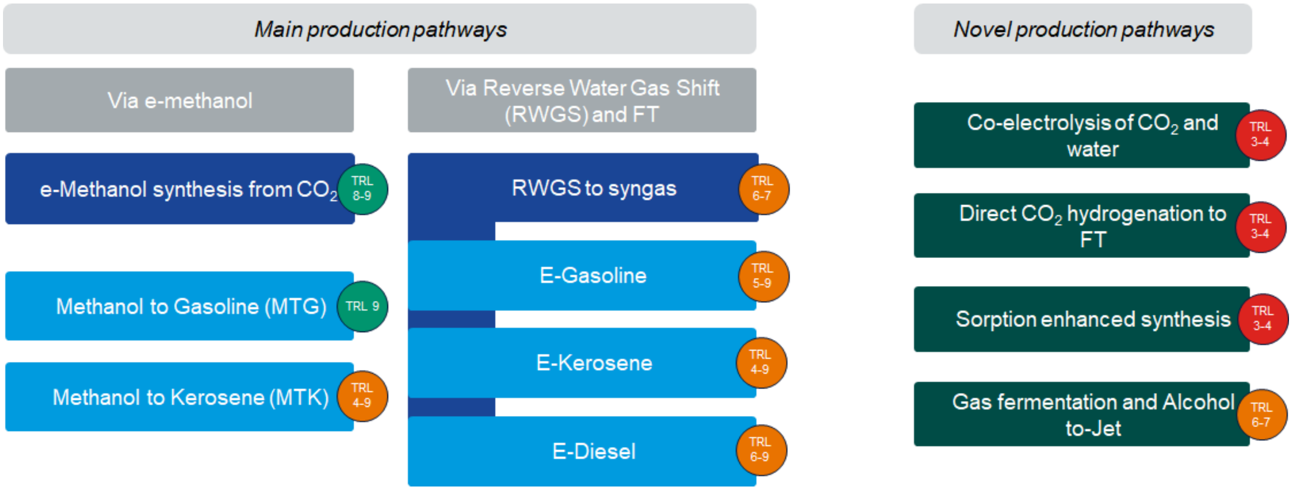
While FT technology has been commercially established for decades, with major vendors offering industrial solutions, there are fewer companies that specialize in offering RWGS systems for commercial-scale operations. Typically, custom-designed systems are required, leading to longer lead times and higher capital costs. Therefore, integrated projects using CO_2 and H_2 to produce e-fuels via FT synthesis, are still at low TRL, with low production capacities[6].

The TRL of the pathways are summarised in Figure 2-4 below.

[5] Modelling and Cost Estimation for Conversion of Green Methanol to Renewable Liquid Transport Fuels via Olefin Oligomerisation, 2021, *Processes*, Ruokonen et. al, Accessed at: https://www.mdpi.com/2227-9717/9/6/1046

[6] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

Figure 2-4. Technology readiness levels of e-fuel production pathways



2.2.2 Considerations for CO_2 sources selection

Several factors might influence the choice of a CO_2 source for e-fuels production. Below are some takeaways from the analysis in this study. Further details about these considerations can be found in Section 9.1.3 of the technical annex.

- **Flue gas cleaning is essential for both RWGS+FT and methanol to e-fuel production.** Impurities that may be present in the flue gases pose a risk to the integrity of reactor catalysts in case they end up in the CO_2 stream. Even at very low concentrations, contaminants containing sulphur, NOx, or metal carbonyls can poison and deactivate catalysts.
- **A continuous supply of CO_2 is essential for the efficient operation of reactors.** Therefore, CO_2 sources of high reliability and continuous supply should be prioritised over intermittent storage to reduce excessive feedstock buffering and storage, which can add significant costs, risks, and/or siting challenges.
- **Current fossil-based source of CO_2** are expected to reduce in global Net Zero scenarios in the future and become **less predictable** as industries decarbonize**.** Biomass-based CO_2 sources, such as from bioenergy with carbon capture and storage (BECCS), can be more sustainable but are subject to fluctuations due to agricultural trends, land-use changes, and policy shifts, which could impact their long-term stability. Direct air capture (DAC) offers a stable and independent CO_2 supply but is energy-intensive and costly, posing challenges for widespread adoption.
- **Co-location of e-fuel plants with CO_2 capture improves process** efficiency and may reduce the emissions associated with e-fuel production as transporting CO_2 over long distances increases costs and reduces overall system efficiency.
- **Effective heat integration** between e-fuel production and CO_2 capture can improve power-to-liquid efficiency by repurposing excess heat from exothermic processes to drive solvent regeneration in thermal swing absorption. The RWGS+FT pathway has greater heat integration potential than the methanol-to-e-fuels pathway due to its higher syngas production temperatures, while the specific e-fuel produced also influences the extent of efficiency gains.

2.2.3 Production pathways assessment

The pathways were qualitatively rated based on the specific indicators listed below:

- Technology readiness level (TRL)
- Process efficiency
- Feedstock (H_2 and CO_2) requirements
- High level capital expenditure (CapEx)
- Number of deployed or announced e-fuel projects

More details can be found in Section 9.1.3 of the Technical Annex. These were chosen as they represent key influencers in the techno-economics of e-fuel production.

The environmental impact of the pathways was not considered as a key indicator, because it is largely determined by process efficiency, H_2, and CO_2 requirements, thus is indirectly covered by these indicators. The use of multipliers to amplify indicators over others was avoided at this stage to avoid implying precarious precision which may be inaccurate given the uncertainty associated with the information provided in the literature. Additionally, the relative importance of each of the indicators depends on several factors and may change depending on the location, the nature of upstream processes, or the timeframe i.e. deployment in 2030 or 2050. The differentiating indicators are translated into RAG rating according to Table 2-1.

Table 2-1. Weightings of criteria used for RAG rating of pathway indicators[7]

	TRL	Process energy efficiency [%]	H_2 requirements [kg/kg of fuel]	CO_2 requirements [kg/kg of fuel]	CapEx [US$/kW]	No of projects
Red	1-4	<50	>0.5	>4	>1600	< 3
Amber	5-7	50 – 75	0.4 – 0.5	3 – 4	1000 – 1600	3 – 8
Green	8-9	>75	<0.4	< 3	<1000	>8

Novel pathways are not considered in the comparison because of their low TRL but have been included in Table 2-2 nonetheless. Although at a higher TRL than other novel pathways, gas fermentation to ethanol and ATJ was not included in the comparison because it has only been demonstrated at small scale and there is a lack of public information to merit a comparison.

[7] Emission is excluded because it would be largely determined by process efficiency, H_2, and CO_2 requirements, thus is indirectly covered.

Table 2-2. RAG rating of the e-fuel production pathways indicators. Values are assumed as for the target fuel(i.e. gasoline, kerosene or diesel).

Production Pathway	TRL[8]	Process energy Efficiency[9] [%]	Hydrogen requirements [kg / kg fuel]	CO_2 requirements [kg / kg fuel]	CapEx [US$/kW][10]	No of projects
Methanol to Gasoline (MTG)	9	66-85	0.49	3.5	1,500	6
Methanol to Kerosene (MTK)	4-9	71-81	0.46	3.2	1,500	0
RWGS with FT derived Gasoline	5-9	54-66	0.60	4.3	1,400	6
RWGS with FT derived Kerosene	4-9	59-79	0.48	3.5	1,400	9
RWGS with FT derived Diesel	6-9	55-63	0.39	3.1	1,400	6
Co-electrolysis (1-step electrolysis + RWGS)	3 – 4					
Direct CO_2 hydrogenation to FT	3 – 4					
Sorption enhanced FT or methanol synthesis	3 – 4					
Gas fermentation to ethanol and ATJ	6 – 7					

With few real world examples at meaningful scale, there is considerable uncertainty around CapEx estimates. Previous techno-economic assessments have identified **feedstock quantity requirements,** specifically hydrogen, as the main obstacle for e-fuel cost reduction. A similar conclusion was reached in the techno-economic assessment section of this report as well (see Section 5). Therefore, production pathways with higher process efficiencies and lower feedstock requirements provide cheaper e-fuels. On the other hand, both in Section 5.2.1 of this study and in previous work by others, the **capital costs** of the synthesis plant were found to be of minor importance relative to feedstock costs over the life of a synthesis plant. Technical and commercial maturity are indicated by the **TRL and the number of existing projects**, however, feedstock requirements take precedence. More details about the number of projects, including their stage of development, can be found in Figure 9-8 of the technical annex.

Based on the above analysis and with **steer from OGCI and CRC members**, the following pathways were considered :

- **Methanol to Gasoline:** This pathway promises good efficiency, has been established at a high-TRL commercial scale, and has lower feedstock requirements than the RWGS+FT pathway. Moreover, MTG may be adjusted to produce kerosene, once MTK pathway becomes ASTM certified.
- **Methanol to Kerosene:** This pathway has lower feedstock requirements than the RWGS+FT pathway, hence presents an opportunity to reduce the final cost of the e-fuel and its associated emissions, and builds on an established industry.

[8] Some of the processes have a wide TRL range because various sources evaluate the TRL differently. The lower end of the range corresponds to the TRL of the integrated system, whereas the higher end of the TRL range corresponds to the subcomponents with the highest TRL.

[9] Process efficiency is defined as the ratio between the useful energy output compared to the total energy input.

[10] See Table 9-14. Capital cost estimates for e-fuel synthesis based on literature This high-level CapEx estimation was based on the basic conversion pathway (methanol vs FT) and did not differentiate between the different products. Presented to two significant figures.

- **RWGS+FT derived Diesel:** Having excluded MTD from the study due to its low diesel yield and the lack of data on process parameters, RWGS+FT remains the only pathway to diesel production.

2.2.4 Main barriers to e-fuels deployment

Some general barriers for the deployment and scale up of e-fuels are summarised below:

- **Technological Barriers:** Large-scale e-fuel production is limited by the maturity of renewable energy, green hydrogen production, and carbon capture technologies. Some production pathways rely on lower TRL - commercially unproven technologies, such as RWGS, and face challenges in integrating all process steps.
- **Economic Barriers:** The production costs of e-fuels are significantly higher than those of fossil fuels, driven mainly by the costs of green hydrogen and CO_2 capture. This makes e-fuels less competitive in the market.
- **Regulatory Barriers:** Uncertainty in future green premiums and lack of standard global definitions for e-fuels create revenue risks and financing challenges for producers.
- **Environmental Risks:** While e-fuels offer lower carbon emissions, they may still produce other pollutants like NOx. Additionally, water requirements for green hydrogen production can be a concern in water-scarce regions.

More specifically, the **barriers** for the two main conversion pathways are discussed:

- **Methanol-based conversion pathway:** The methanol synthesis step is relatively mature, but the conversion of methanol into specific fuels (e.g., MTG for gasoline) requires additional steps, increasing complexity.

- **RWGS and FT-based conversion pathway:** The RWGS step is still commercially unproven, adding complexity and risk. Integrating all process steps into a single facility is challenging. Furthermore, high capital and operational costs are required due to the need for capital-intensive equipment and energy requirements. The energy requirements for the RWGS are high, resulting in high energy costs, though this may decrease as renewable energy costs decrease.

2.3 KEY TAKEAWAYS

- The two more mature pathways to produce e-fuels from hydrogen and carbon dioxide are: via **methanol-based** conversion, via reverse water gas shift (RWGS) and **Fischer-Tropsch (FT) based** conversion.

- Other novel pathways are considered for e-fuel production, aiming to increase efficiency and reduce production costs. Examples include co-electrolysis, direct CO_2 hydrogenation to FT, sorption enhanced synthesis, gas fermentation and alcohol-to-jet. However, these are not yet mature and at lower TRL.

- For e-gasoline production, the Methanol-to-Gasoline (MTG) pathway is generally preferred, as it is a well-established and mature process.

- For e-diesel production, the RWGS and FT synthesis is preferred, as the FT syncrude mainly consists of linear saturated hydrocarbons, so drop-in diesel can be easily obtained via condensation or distillation of the FT syncrude.

- For e-kerosene production, both Methanol-to-Kerosene (MTJ) and the RWGS and FT synthesis pathways are equally developed and viable pathways. The MTJ offers higher kerosene selectivity, while the RWGS and FT pathway demonstrates high total product efficiency and is currently ASTM approved. Nonetheless, MTK offers potential for decentralized e-methanol production sites.

- A review of literature suggests that methanol pathways have a higher CapEx than RWGS+FT. The estimation was based on the basic conversion pathway (methanol vs FT) and did not differentiate between the different products.

- Considerations for the selection of CO_2 sources for e-fuel production include contaminant content, supply intermittency and reliability. Also, co-locating e-fuel production with CO_2 capture reduces transportation costs and may improve process efficiency by heat integration of the two plants.

- The three main pathways that will be considered in this analysis have been decided based on the above considerations after consultation with **OGCI and CRC** and are listed below:
- **Methanol to Gasoline:** This pathway promises good efficiency, has been established at a high-TRL commercial scale, and lower feedstock requirements than the RWGS+FT pathway. Moreover, MTG may be adjusted to produce kerosene, once MTK pathway becomes ASTM certified.
- **Methanol to Kerosene:** This pathway has lower feedstock requirements than the RWGS+FT pathway, hence presents an opportunity to reduce the final cost of the e-fuel and its associated emissions, and builds on an established industry.
- **RWGS+FT derived Diesel:** Having excluded MTD from the study due to its low diesel yield and the lack of public data on process parameters, RWGS+FT remains the only pathway to diesel production.

3. FEEDSTOCKS SUPPLY CHAIN ASSESSMENT

This section provides an overview of the enablers and barriers of CO_2 and H_2 feedstocks for e-fuels, as well as a global review of CO_2 sources for e-fuels. The specific approach to each is outlined in the subsequent sections.

The locations in which e-fuel facilities are most likely to be developed will require a robust supply of the key process inputs alongside the ability to distribute the produced fuels to areas of demand. The purpose of this chapter is to review the drivers behind the availability and transport of hydrogen and carbon dioxide, alongside the relative economics, to determine the influence these may have on e-fuel hub locations. In addition, a review of e-fuel transport options from the production facility to the distribution centre has also been conducted as a comparator.

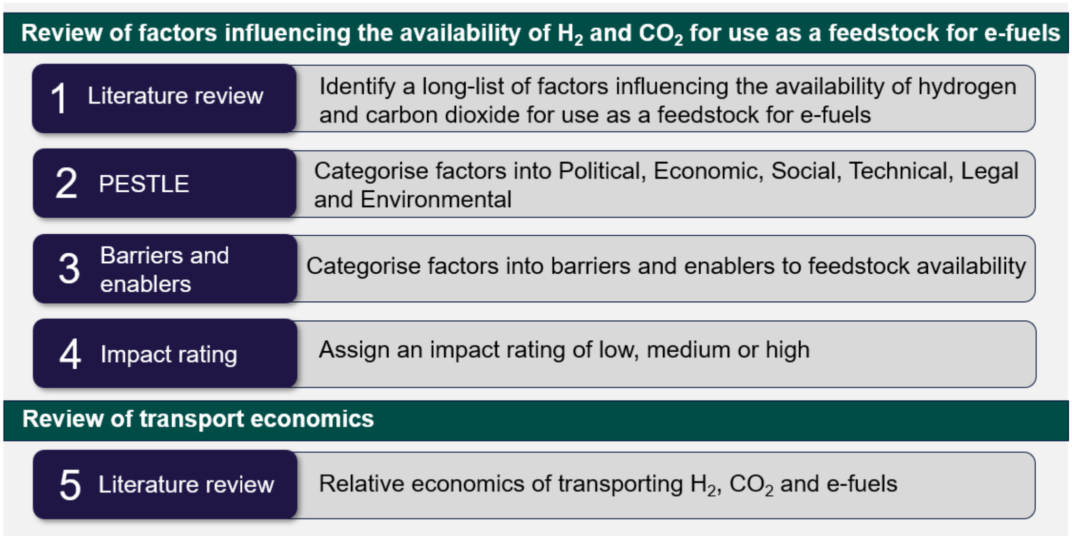
This supports the assessment of whether e-fuel facilities are best-placed close to areas of high demand, or alternatively closed to areas with good hydrogen and/or carbon dioxide availability. A global survey of CO_2 sources for e-fuels was then undertaken, aiming to identify potential point sources of CO_2 that could be utilised for the purpose of e-fuels production.

3.1 DRIVERS OF FEEDSTOCK SUPPLY

3.1.1 Overview of the approach

The overall approach to identifying barriers and enablers to feedstock supply for e-fuels is outlined Figure 3-1.

Figure 3-1. Approach to identifying enablers and barriers to feedstock supply for e-fuels



A literature review was conducted, with the aim of identifying a long-list of factors which could influence the availability of hydrogen and carbon dioxide for use as a feedstock for e-fuels. The review followed a PESTLE format, covering Political, Economic, Social, Technological, Legal and Environmental considerations. These factors were then characterised as a barrier or enabler to feedstock availability and given an impact rating of high, medium, or low based on the descriptors in Table 9-16. From the PESTLE analysis, factors identified as having a high importance rating form the key enablers and barriers to feedstock availability. These have been reviewed and discussed in further detail, providing examples of these factors in action where available and key recommendations.

Further to this, a review of the relative economics of transporting carbon dioxide, hydrogen, and e-fuels was undertaken. The purpose of this was to explore the methods of transportation available, the quantity and distances typically associated with each and the relative costs. The outcome of this review supported the identification of e-fuel hub locations in relation to the CO_2 hotspots identified, the potential for hydrogen availability, and access to existing hydrocarbon transport routes. Case studies of three developing CO_2 transport networks across the United States, Europe and Asia have also been prepared, to provide further insight as to how these networks are forming and the challenges they are facing. These can be found in Section 9.2.1.3 in the technical annex.

3.1.2 Results and key takeaways

3.1.2.1 PESTLE

An overview of the key findings from the CO_2 and H_2 supply PESTLE analysis are represented in the figures below. Full details of the analysis can be found in Section 9.2.1.2 in the technical annex.

Figure 3-2. CO_2 supply PESTLE analysis

HIGH	MEDIUM	LOW	CO_2 SUPPLY IMPACT	LOW	MEDIUM	HIGH
• Policy support prioritises storage		• Planning and permitting	P POLITICAL		• Limited availability of sustainable biofuels	• Policy support for e-fuels
• High CAPEX costs • Proximity to storage	• Competing utilisation pathways • Aligning transport network stakeholders		E ECONOMIC		• Carbon Price • Opportunity for revenue generation from CO_2 • Benefits of multi-user networks	
• Public apathy or scepticism	• Safety – handling, transport and adverse events • Skills gap		S SOCIAL			• Public support
• Ease of transport	• Changes to emissions over time - fewer CO_2 sources • Ability to retro-fit or integrate carbon capture • Variability of CO_2 composition	• Intermittent CO_2 sources	T TECHNOLOGICAL		• Advancing Technology • Changes to emissions over time - new CO_2 sources emerging • Re-use of existing transport infrastructure	
	• Eligibility of CO_2 sources • Cross-border CO_2 transport		L LEGAL		• Development of global CO_2 standards	
		• GHG impact of CO_2 transport • Potential for adverse CO_2 release events	E ENVIRONMENTAL			• Reduction of GHG emissions

Key enablers and barriers: CO_2 supply

Transport conditions: As CO_2 is gaseous at room temperature and often available for capture at ambient pressure, compression and/or liquefaction, both of which are energy intensive, are often required to improve transport economics. Additionally, any impurities present in CO_2 streams (such as N_2, O_2, SO_2 and H2S), as well as the presence of water, can add additional complexities when transporting CO_2. Transport systems need to strike a balance of setting a CO_2 specification that ensures safe and economic passage of CO_2 through the system, without requiring excessive purification steps to be performed as part of the capture process, resulting in increased cost of capture.

High CapEx costs: Carbon capture and transport projects are capital intensive, meaning that financing is a key factor. For e-fuels, ensuring strong links between CO_2 suppliers and the offtake facility and being able to demonstrate a robust supply would support development of these projects. For e-fuel facilities developed with a single source CO_2 supply, consideration should be made as to the impact if that source becomes unavailable and whether there are alternatives in reasonable proximity. Where possible, converting CO_2 to e-fuels close to the source would significantly reduce transport costs. This will need to be balanced with availability and costs to supply hydrogen and the ability to economically transport the produced e-fuels to areas of demand.

Proximity of CO_2 sources to storage: In areas identified as CO_2 hotspots, where storage is under development in proximity, then e-fuels production could end up competing against storage facilities to source CO_2. In countries where carbon capture is in development, legal and regulatory frameworks for CO_2 storage are at a higher level of maturity than those for utilisation and access to incentives or subsidies can also be reliant on permanent storage of the captured CO_2. As such, when assessing the CO_2 hotspots, understanding accessibility to and maturity of local CO_2 storage resources will ensure CO_2 sources are chosen which have the highest potential to supply a utilisation use-case.

Public acceptance, apathy or scepticism of CCU: Public support for CO_2 capture and transport projects, meaning less opposition during the planning and permitting phase is key to enabling delivery of projects at pace and scale, particularly in areas with high population density. Unfortunately, negative public sentiment has been observed for CO_2 pipeline projects, examples include Navigator's Heartland Greenway[11] pipeline in the U.S or more recently ExxonMobil's Solent pipeline[12] in the UK. Effective communication with the general public and key stakeholder groups on the environmental, economic and social benefits of carbon capture, transport and e-fuel production projects is crucial to enable deployment.

Policy support for CO_2 utilisation, particularly within e-fuels: Policy support and implementation of regulations for CO_2 utilisation and more specifically for e-fuels is gaining traction, with national targets being established across several regions. These initial targets will help provide e-fuel project developers with confidence that there is to be a growing market for e-fuels in the coming years and assess the scale of demand. When considering how e-fuel hubs may form, consideration of the policy environment across carbon capture, utilisation and production of e-fuels will support locations and regions which are likely to be leaders in deployment of this technology.

The need to reduce GHG emissions: The driving force behind the development of sustainable fuel alternatives is the need to reduce CO_2 emissions to prevent further damage to the environment as a result of climate change. In some cases, carbon emissions from the production of e-fuels is lower in comparison to fossil-based counterparts[13] although this is heavily reliant on the carbon intensity of electricity used and the CO_2 feedstock. Establishing the lifecycle benefits of e-fuels and how this may compare with other low-carbon fuels will be key to understanding the potential role of e-fuels in the future energy mix.

---

[11] Cancellation of Heartland Greenway CO2 pipeline underlines US regulatory bottlenecks | S&P Global (spglobal.com)

[12] Fawley: Concerns raised over planned carbon dioxide pipe - BBC News

[13] E-fuels: A Challenging Journey to a Low-Carbon Future, S&P Global, 2024. Accessed at: E-fuels: A Challenging Journey To A Low-Carbon Future (spglobal.com)

Figure 3-3. Hydrogen supply PESTLE analysis

−			H_2 SUPPLY IMPACT			+
HIGH	**MEDIUM**	**LOW**		**LOW**	**MEDIUM**	**HIGH**
• Future demand uncertainty	• Lack of support for the scale-up of manufacturing capacity • Political shift from support for hydrogen		P POLITICAL		• Direct financial support	
• High CAPEX costs • High OPEX costs			E ECONOMIC	• Opportunity for countries to play role in future fuels		• National Strategies
• Public awareness and acceptance	• Safety - existing infrastructure and population density	• Opposition to the use of renewable electricity to produce green hydrogen	S SOCIAL			
• Ease and costs of hydrogen transportation • Availability of renewable electricity			T TECHNOLOGICAL		• Favourable geological formations for longer term storage • Advancement in electrolyser technology	
• Lack of hydrogen standards	• Lack of consistency in electrolyser standards by region • Infrastructure and materials safety standards		L LEGAL		• Targets for E-fuels in sustainable fuel mandates	
• Water requirements		• Land requirements • Conversion to green Ammonia	E ENVIRONMENTAL		• Lower environmental risk	

Key enablers and barriers: Hydrogen supply

Future demand uncertainty: Lack of certainty regarding future demand of hydrogen creates a major hurdle to scaling up the production of green hydrogen. Hydrogen demand overall remains concentrated in traditional applications. Novel applications for low carbon hydrogen as an energy carrier, including its use heavy industry and long-distance transport, currently make up under 0.1% of demand. The uncertainty surrounding future demand is closely linked to high costs, and the lack of clarity about certification and regulation, and the lack of infrastructure available to deliver hydrogen to end users reliably and affordably.

High CapEx and OpEx costs: Green hydrogen projects are capital intensive, which makes financing a key factor. The production cost of green hydrogen depends on the cost of electricity, costs for electrolysers, and their capacity factor. Green hydrogen can achieve cost parity with fossil-based hydrogen, however optimal conditions including low-cost renewable electricity and carbon pricing would be required. There is an expectation that cost reductions in large plants may be achieved, in stacks and across the balance of plant. However currently, the cost of producing green hydrogen is approximately four times more expensive than grey hydrogen. In some countries, green hydrogen expected to be more expensive than other forms of low carbon hydrogen[14].

Public awareness and acceptance: Public awareness and acceptance are crucial for the successful rollout of hydrogen technologies and can be a critical determinant. Public concerns often revolve around safety, given hydrogen's flammability, and scepticism about its environmental benefits. For instance, the proposed hydrogen heating trial in Redcar, UK, was cancelled in 2023 due to strong public opposition. Residents expressed concerns about safety, potential disruptions, and the overall effectiveness of hydrogen, leading to the project's termination[15].

Ease and cost of hydrogen transportation: A key barrier regarding transportation of hydrogen is its low volumetric energy density, which results in higher costs of transportation for a given amount of energy when compared with carbon fuels. Each mode of hydrogen production, treatment, transport, and storage has the potential to introduce inefficiencies into the end-to-end process. An option to mitigate this is by conversion to hydrogen-based fuels and derivatives, however many of the technology pathways to achieve this are not implemented at scale.

Availability of renewable electricity: Sustainably produced green hydrogen is produced using additional renewable electricity, either from dedicated renewable supply or sometimes otherwise curtailed power. i.e. electricity capacity that would not otherwise have been commissioned and electricity that would not have been otherwise consumed. Wind and solar renewable electricity are variable, which sharply reduces electrolyser utilisation, in turn driving costs up. A potential solution to this is to connect to the local grid during renewables downtime, however this increases the carbon intensity of the hydrogen produced.

Lack of hydrogen standards: Green hydrogen relates to hydrogen produced using renewable electricity and electrolysers, however it is not linked to an agreed definition of embedded emissions. As such, generally governments talk about low carbon hydrogen which can include steam methane reforming (SMR) with CCUS (blue hydrogen). The lack of international standards and regulation is a major obstacle affecting the development of the global green (or low carbon) hydrogen market[16]. There are still no international standards addressing hydrogen production and use, with countries establishing their own standards and regulations.

Water requirements: Water requirements for hydrogen production vary significantly by technology pathway.[17] Water is required as an input for production and as cooling medium for production of all types of hydrogen. Green hydrogen relies on a relatively high share of water withdrawal for cooling at 56%, however this is lower than blue hydrogen requirements (92%). Current freshwater withdrawals for hydrogen production could increase six-fold by 2050, and currently more than 35% of global green and blue hydrogen production capacity

[14] Green Hydrogen Market: Potentials and Challenges, 100re, 2023, Accessed at: https://100re-map.net/green-hydrogen-market-potentials-and-challenges/

[15] Hydrogen may never heat British homes after Redcar trial cancelled, Sky News, 2023, Accessed at: https://uk.news.yahoo.com/hydrogen-may-never-heat-british-132500958.html

[16] Green Hydrogen Market: Potentials and Challenges, 100re, 2023, Accessed at: https://100re-map.net/green-hydrogen-market-potentials-and-challenges/

[17] Water demand for Hydrogen Production, Ricardo et al. (2024) for UK Government available at https://assets.publishing.service.gov.uk/media/680b9752b0d43971b07f5ba7/water-demand-for-hydrogen-production.pdf

is located in water-stressed regions[18]. This has significant environmental impact. Larger plants may have such significant water requirements that they may have to rely on desalination plants, thus further increasing costs.

National strategies: Clear policy direction is a crucial enabler of hydrogen production, and a growing number of countries are releasing national hydrogen strategies. Outlining targets and providing support for scale up and efficiency of factories could help attract private sector investment in green hydrogen. In countries with existing hydrogen development strategies, however, policies to support the construction and growth of hydrogen markets have not yet been put into action. Many nations continue to focus more on blue hydrogen in their development plans rather than other types of hydrogen. In addition, while there is an increasing number of national strategies globally, the pathway towards achieving certain targets and ambitions remains unclear.

3.1.2.2 *Transport economics*

Hydrocarbons, CO_2 and hydrogen can be challenging and expensive to transport, as they require specific infrastructure which can take time and money to develop, and project development and operation needs to overcome multiple risks. There are a range of options available for gathering both hydrogen and CO_2 at an e-fuels production facility to provide the necessary inputs to produce e-fuels.

The main modes for transport are road, rail, ship or pipelines, and combinations of these. Systems for storage, or for maintaining appropriate temperature and pressure during transport and storage are also often needed. There are substantive design choices within each mode related to capacity, temperature, pressure, materials, flexibility, purity, and use of backup systems that impact capital and operating costs, timings, and risks.

The transport economics and risks for hydrogen and CO_2 play an important role in determining transport strategy. The lowest cost and lowest risk scenario may well be choosing locations for e-fuel hubs close to CO_2 sources, hydrogen generation and e-fuels demand to minimise transport distances of all three. However, this may not always be the most feasible option, and the risk and economics for transport of pre-cursors for CO_2 or hydrogen, such as electricity, water, or industrial production may also need to be considered.

Key options to consider therefore include transporting CO_2 away from sources, transporting hydrogen away from generation, or transporting e-fuels production towards demand and away from production. There is also the potential to transport the electricity required for hydrogen generation away from the source, rather than transporting the hydrogen once it has been produced. To minimise some of the costs and safety issues for moving hydrogen directly, a lot of interest is building into the use of potential "carriers" of hydrogen, including ammonia. An overview of the main methods of transport for H_2, CO_2 and hydrocarbons are outlined below.

CO_2 transport

Methods of CO_2 transportation include road, rail, ship or pipeline transfer. In some cases, combinations of these may be required. The required conditions of the CO_2 during transport vary depending on the transportation method, where CO_2 can be transported as a gas, liquid, dense phase or in a supercritical state. The purity of the CO_2 to be transported is an additional important consideration as impurities impact the phase, flow behaviour and material compatibility of the CO_2. As an example, small amounts of water content can accelerate corrosion of carbon steel or result in blockages from hydrate.

There are therefore a range of different factors which must be considered when determining the most appropriate and economic solution for transportation of CO_2. The cost of transport is also dependent on the mode, pressure, capacity requirements, asset lifetime, terrain, and total transportation distance. Therefore, more precise estimates of the cost of transport can only be calculated once the locations of the source and sinks are determined. A summary of the key modes of CO_2 transport are outlined in Table 3-1 below, with further details on key operating parameters, considerations and a possible range of costs, including CapEx and OpEx, for each method of transport outlined in Section 9.2.1.4 in the technical annex.

[18] Water for hydrogen production, IRENA, 2023, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2023/Dec/IRENA_Bluerisk_Water_for_hydrogen_production_2023.pdf?rev=4b4a35632b6d48899eb02bc54fd1117f

Table 3-1. Methods of CO_2 transport

Transport	Benefits	Drawbacks
Road	• Suitable for small quantities and shorter distances • Quick deployment • Allows for CO_2 transport for isolated emitters	• Technical and economic limitations for large-scale transport • Exponential increase in costs over certain distances
Rail	• Potential cost advantages over medium distances • Flexibility in accessing various locations	• Loading/unloading and temporary storage infrastructure required • Dependent on existing railway infrastructure
Ship	• Relatively low capital cost • Flexibility in accessing sites • Enhanced source sink matching	• High operating costs • Limited experience in large-scale transport • Specialised vessels required
Pipeline	• Relatively low operating cost • High maturity • Efficient for larger distances • Can handle varying conditions	• Higher capital cost • Complexity in managing varying CO2 streams

Hydrogen transport

Due to its low volumetric energy density, hydrogen requires conversion into a compressed gas or to another hydrogen 'form' for cost-effective transportation. The methods of transporting hydrogen, depends on its 'form', scale, and distance. The four mature technologies for hydrogen transport considered in this section are road, rail, pipeline, and shipping. Road and pipeline are the preferred modes for domestic hydrogen transport, while shipping provides a more flexible method for large-scale international import and export. As the hydrogen market develops, so will innovative methods of transportation. Table 9-20 in the technical annex provides a theoretical overview of different hydrogen 'forms' by cost, mature transport methods and use cases. Further details on methods of transport can be found in Section 9.2.1.4 in the technical annex.

Transport of hydrogen versus transport of electrons

In addition to transporting hydrogen after it is produced from electricity via electrolysis, there is also the possibility of transporting green electricity in the form of electrons, through high voltage direct current lines (HDVC). The hydrogen would then be produced closer to demand. A summary of the benefits and drawbacks of each method are outlined in Table 3-2 below.[19]

Table 3-2. Benefits and drawbacks of transporting hydrogen and electrons (electricity)

Transport	Benefits	Drawbacks
Hydrogen	Hydrogen pipelines have the capability of transporting larger energy volumes	Challenges in siting and financing novel infrastructure Repurposing natural gas pipeline infrastructure is not universally feasible
Electrons	There is a large amount of existing HDVC line infrastructure	HDVC lines are not universally suitable for long-distance transport at a large-scale

[19] Hydrogen pipeline vs HDVC lines: Should we transfer green molecules or electrons?, The Oxford Institute for Energy Studies, 2023, Accessed at: ET27-Hydrogen-pipelines-vs.-HVDC-lines.pdf (oxfordenergy.org)

Transport of e-fuels

Supply chain costs can significantly impact the overall cost of supplied hydrocarbons, constituting a few percentage points to several tens of percent of the cost, depending on the supply chain structure.[20] This demonstrates the substantial influence that the choice of transportation mode has. Hydrocarbons are typically transported through four primary modes: pipeline, maritime shipping, road, and rail. Each method offers distinct advantages and is selected based on factors such as distance, volume, and the specific fuel being transported.

Drop-in e-fuels, such as e-kerosene, e-diesel, and e-gasoline, possess identical chemical and physical properties to traditional fuels, and as such, are compatible with existing refuelling infrastructure.[21] This presents the potential for direct substitution, thereby relying on existing infrastructure and legacy equipment for the distribution and supply of e-fuels. This contrasts with CO_2 and H_2, which requires significant pipeline infrastructure upgrades or new pipelines, as transporting H_2 or CO_2 through existing natural gas pipelines, either pure or as a blend with natural gas, risks compromising pipeline integrity, capacity, flow, pressure, or stability.[22,23]

It should be noted however, that whilst some e-fuels with drop-in characteristics can be blended at any ratio up to 100%, others are limited to lower concentrations, depending on specific standards and fuel specifications. Certain e-fuels require blending at the final stages of the value chain, necessitating parallel infrastructure despite their drop-in classification. Retrofitting existing infrastructure or constructing parallel networks presents complex logistical and economic challenges.

Unlike CO_2 and H_2**,** e-fuels are liquids at ambient conditions, like petrol and diesel, ultimately eliminating the need for liquefaction or pressurisation during transportation. This results in lower additional energy requirements and costs, as existing hydrocarbon transportation infrastructure and distribution networks, including tank farms, pipelines, and vehicle fleets can be leveraged without significant, if any, additional modifications and hence investment.[24]

Pipelines are considered the most economical and efficient method for transporting large volumes of liquid hydrocarbons over long distances without interruption.[25] Pipeline transport can be cheap e.g. up to 4 US$ per barrel.[26] For this reason, they are the primary method for transporting most hydrocarbon fuels. The transportation of hydrocarbon fuels in liquid state is typically easier to manage than gaseous states because of the lower pressure and challenges in detecting or managing leaks of liquids.

The maritime transport of hydrocarbons plays a pivotal role in the world's energy supply, accounting for approximately 30% of global seaborne trade. Ships are capable of transporting substantial quantities of hydrocarbons, making them highly efficient for large-scale, long-distance transportation, particularly across international borders.[27,28] Whilst distance is a major factor in maritime transportation costs, it is often more economical than rail but less so than pipeline.[26] Due to the low energy density of gaseous hydrocarbons, long-distance transport in this state is inefficient; as a result, hydrocarbon fuels are often liquefied for transportation. For instance, natural gas must be transformed into liquefied natural gas (LNG) for maritime shipment. In LNG transportation, 30 – 45% of the capital cost is spent on liquefaction.[26] As e-fuels are liquid at ambient conditions, there are no additional energy requirements or liquefaction costs associated with transportation.

---

[20] Costs relations in the hydrocarbons supply chain project, Klepikov et al., 2024, Accessed at: https://www.sciencedirect.com/science/article/pii/S2352484724004372

[21] The Role of E-fuels in Decarbonising Transport, International Energy Agency, 2024, Accessed at: https://iea.blob.core.windows.net/assets/a24ed363-523f-421b-b34f-0df6a58b2e12/TheRoleofE-fuelsinDecarbonisingTransport.pdf

[22] Blending hydrogen in existing natural gas pipelines: Integrity consequences from a fitness for service perspective, Mariano A. Kappes and Teresa E. Perez, 2023, Accessed at: https://www.sciencedirect.com/science/article/pii/S2667143323000331#:~:text=Blending%20hydrogen%20in%20existing%20natural%20gas%20pipelines%20compromises%20steel%20integrity,cracking%20and%20decreases%20fracture%20toughness.

[23] Repurposing Natural Gas Lines: The CO2 Opportunity, ADL Ventures, Caroline Kenton and Ben Silton, 2024, Accessed at: https://www.adlventures.com/blogs/repurposing-natural-gas-lines-the-co2-opportunity

[24] Are e-fuels the answer to future fuel requirements?, Diersch & Schröder, 2024, Accessed at: https://www.ds-bremen.com/en/better-together/e-fuels-the-fuels-of-the-future

[25] Oil and Gas Industry: A Research Guide, Library of Congress, 2024, Accessed at: https://guides.loc.gov/oil-and-gas-industry/midstream/modes

[26] Transporting Oil: Why Pipelines Still Rule, Forbes, 2016, Accessed at: https://www.forbes.com/sites/tortoiseinvest/2016/05/13/transporting-oil-why-pipelines-still-rule/

[27] How Fuel is Transferred via Ocean Freight, Clipper Oil Marine Fuels, 2017, Accessed at: https://www.clipperoil.com/fuel-transferred-via-ocean-freight/

[28] A review of cleaner alternative fuels for maritime transportation, Al-Enazi et al., 2021, Accessed at: https://www.sciencedirect.com/science/article/pii/S2352484721002067#:~:text=The%20shipping%20of%20hydrocarbons%20constitutes,global%20gas%20mix%20by%202022.

Although rail transportation accounts for a comparatively minor portion of hydrocarbon export volumes, it offers a more flexible range of destinations and faster delivery times compared to pipelines.[29] Similar to maritime transport, transporting hydrocarbons in liquid form by rail offers greater efficiency and economic benefits. However, rail transport incurs significantly higher costs than pipeline per barrel-mile shipped, typically costing 2-5 times that of pipeline transport, with reported costs ranging from 10 – 15 US$ per barrel.[26]

Road transportation of hydrocarbons is primarily utilised in emerging basins and over shorter distances, as in these instances the costs are not prohibitive.[26] Like maritime and rail transportation, it is most efficient to transport hydrocarbons in a liquid state by road. Of all the transport modes, road transportation is the most expensive and least commonly deployed.

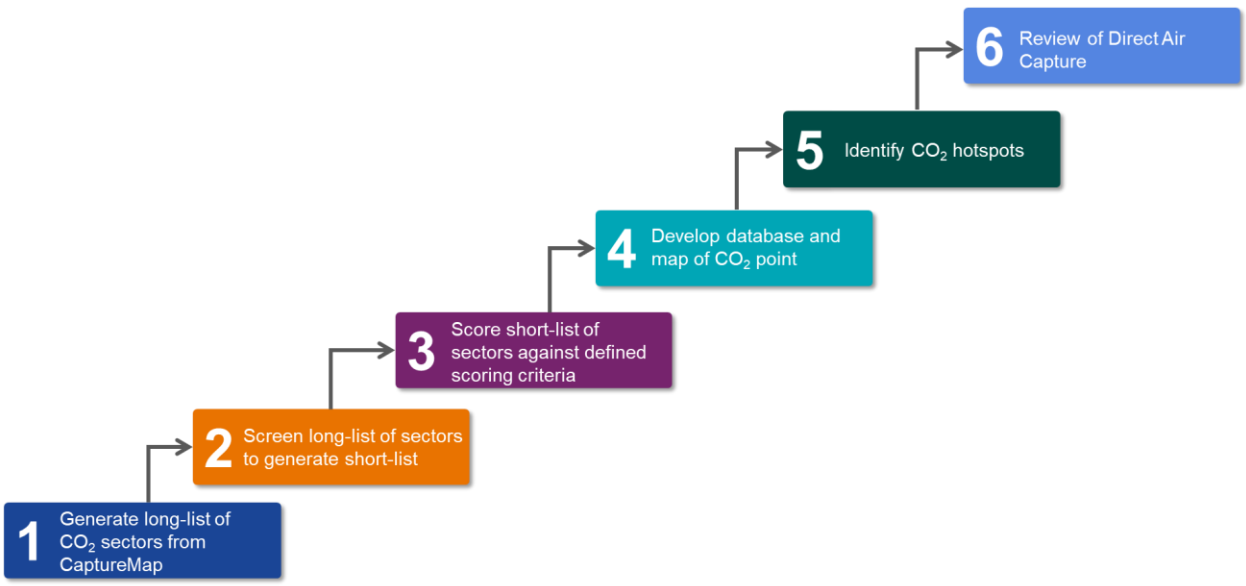
3.2 GLOBAL SURVEY OF CO_2 SOURCES

A review of CO_2 sources was undertaken, subsequently identifying and developing a database of CO_2 point sources with higher potential to be utilised as a feedstock for e-fuel production. This was followed by a review of the CO_2 sources and locations to identify CO_2 hotspots, and hence identify potential e-fuels hub locations on a map.

3.2.1 Overview of the approach

An overview of the full approach and methodology, consisting of six stages, is outlined in Figure 3-4 below.

Figure 3-4. Staged approach to identifying CO_2 hotspots



1. Long-list of sub-sectors

The full list of sub-sectors for initial consideration covers all classes, sectors and sub-sectors within CaptureMap. This covers 65 sub-sectors, within energy, industrial and waste and wastewater classes, as shown in Table 9-21. CO_2 point source data in each of the 65 sub-sectors was extracted, resulting in a database of 23,113 sites, with a combined total of 20.9 Gt CO_2 emissions per year. Further detail on the distribution of CO_2 emissions and facilities in the long-list database can be seen in Figure 9-17.

2. Screening of sub-sector long-list

To determine which sub-sectors within the complete list to exclude from further review, and hence which sources to exclude from further review, the following criteria were devised.

[29] the external costs of transporting petroleum products by pipelines and rail: evidence from shipments of crude oil from north Dakota, Clay et al., 2017, Accessed at: https://www.nber.org/system/files/working_papers/w23852/w23852.pdf

Table 3-3. Criteria for CO_2 sub-sector short-listing

Criterion	Description	Rationale
Step 1.	Exclude sub-sectors with average facility CO_2 emissions of <0.1 million tonnes of CO_2/year ($MtCO_2$/year)	CO_2 capture becomes less economic at lower volumes. Quantity and quality of underlying data are patchier for smaller sites.
Step 2.	Exclude "undefined" sub-sectors in CaptureMap	There is insufficient information on the facilities within these sub-sectors for analysis
Step 3.	Review of status of CO_2 capture in remaining sub-sectors. Exclude any with no announced interest in CO_2 capture	Sub-sectors with no announced interest in CO_2 capture will have less prospects for effective CO_2 capture

Full detail on screening of the long list can be found in Section 9.2.2.1 in the technical annex. The final sub-sector short list consists of 22 sub-sectors, is outlined in Table 3-4 below.

Table 3-4. Sub-sector short-list

Class	Sector	Shortlisted sub-sectors
Energy	Power and heat	Coal and lignite Natural gas and other gases Biomass and bioenergy
	Oil and gas extraction and processing	Upstream oil and gas CO_2 removal Midstream oil and gas
Waste and wastewater	Waste management	Energy from waste Hazardous waste incineration
Industry	Chemicals	Ethylene oxide Ammonia and other nitrogen fertilisers Methanol Hydrogen and other gases Ethanol
	Iron and steel	Basic iron and steel
	Non-ferrous metals	Aluminium
	Food	Alcohol Sugar
	Oil and gas, downstream	Refinery
	Pulp and paper	Pulp Paper and board
	Non-metallic minerals	Cement Lime and plaster

3. Scoring of sub-sector short-list

The short-list of 22 sub-sectors consists of the sub-sectors which are likely to have higher prospects for CO_2 capture when compared to those excluded from the long list. Shortlisting provides a more pragmatic opportunity for further interrogation of the CaptureMap database. To further assess the relevance of different sub-sectors, a simplified system was developed to score the 22 sub-sectors against the prospects for CO_2 capture for the purpose of e-fuels production.

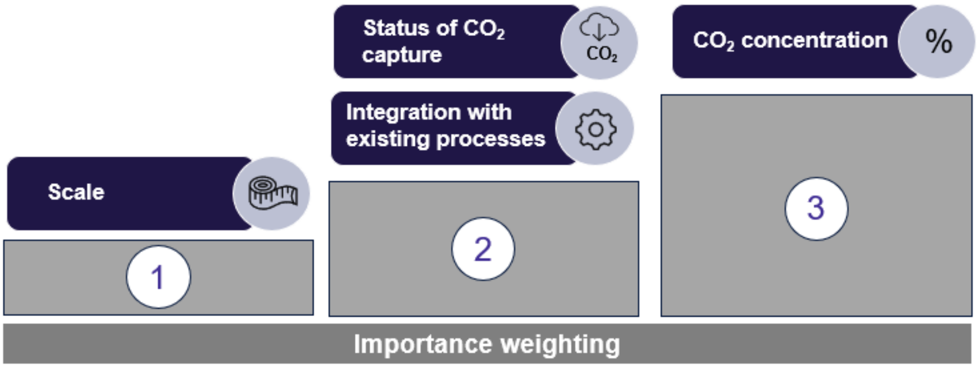
This simplified scoring system considers some of the factors that might differentiate the opportunity for CO_2 capture between sources in the CaptureMap database[30]. However, other factors, for example site-specific factors, may be greater drivers than sectoral factors. Sub-sector average estimates may hide opportunities, creating both false positive and false negatives, and the coverage and accuracy of the underlying database for screening sectors may be limited.

[30] We recognise that there are many other factors that are required (some of these are reviewed later in this report and project), but the presence and scale of these drivers or barriers are not available in the existing database.

Criteria influencing ease of capture

Four criteria were utilised to score each of the sub-sectors in the short-list. Each sub-sector was assigned a score from 1 to 3 against each of the criterion, based on specified thresholds. A weighted score was then calculated for each sub-sector, based on the sum of the assigned scores for each criterion, multiplied by an "importance" weighting. The four criterion and the associated importance weighting for each criterion is outlined in Figure 3-5 below.

Figure 3-5. Ease of capture criterion and weightings



A sensitivity analysis on the assigned thresholds and weightings was also undertaken, recognising the scoring system, though efficient, deals bluntly rather than finely with differences in categories, and is potentially subjective.

Minimum CO_2 volume threshold

A minimum volume threshold was applied to the facilities within the sub-sectors in the short-list, based on the CO_2 concentration in the stream to be captured, as shown in Table 9-24 in the technical annex. Any facilities below the minimum threshold in each sub-sector were excluded from the CO_2 point source short-list.

The unit cost of capturing CO_2 is inversely proportional to the concentration of CO_2 in the stream to be captured. The higher the CO_2 concentration, the lower the operational cost of CO_2 capture, as this will result in a lower amount of energy required per tonne of CO_2 captured. Additionally, the higher the CO_2 concentration, the smaller the required equipment plant size, and hence lower capital costs. For these reasons, the higher the CO_2 concentration, the lower the minimum threshold that has been applied. In the case of the lowest CO_2 concentrations (<20%) a minimum threshold of 1 $MtCO_2$/year has been applied, as capturing small volumes of CO_2 from low concentration sources will result in extremely high costs per tonne of CO_2 captured. However, as the volume of CO_2 captured increases, economies of scale can be realised.

4. Develop database and map of CO_2 point sources

A supporting excel database was developed, detailing all of the shortlisted CO_2 point sources, covering the facility name, company name, country name, total CO_2 emissions (and associated year), biogenic portion of CO_2 emissions (where available), data quality, original data source, facility address, latitude, longitude, and source sector.

5. Identify CO_2 hotspots

Experience of CCUS project development has shown that the availability of individual sources for CO_2 capture is extremely uncertain:

- With increasing competition in some locations from lower carbon power sources such as solar PV and wind, some fossil power sources may operate at lower load factors than in the past.
- The future levels and locations for industrial CO_2 output are also uncertain, and some sites may change output (or even close) before a Carbon Capture and Utilisation (CCU) project could be developed.
- Even if the CO_2 source is expected to persist for decades, CCU is a major undertaking and various factors may stop or delay CCU implementation, such as technical feasibility, economics, commercial, regulatory or financing model, or simply lack of support.

Therefore, it may be unwise for e-fuel developers to rely too heavily on a single CO_2 source for e-fuel production, even when this has a promising CO_2 stream at an attractive scale. Instead, developing an e-fuels production plant in a geographic area with multiple CO_2 point sources in close proximity might de-risk CO_2 supply that would otherwise be linked to an individual source. This can also provide an opportunity to leverage shared infrastructure, enabling scale up. Areas with multiple relevant CO_2 sources might be expected to be lower risk for e-fuel production than those areas with only few sources. To understand where the locations are, where e-fuel producers are less likely to have concerns on amount of CO_2 supply, we introduce the exploration of CO_2 hotspots.

'CO_2 hotspots' have been defined as areas with a density of emitted CO_2 with the potential for CO_2 to be captured for the purpose of production of e-fuels. Three scenarios of CO_2 hotspots have been defined with a specified CO_2 quantity, based on the associated production capacity of an e-fuels production facility. A radius has also been defined for each of the scenarios, where each scenario is represented in Table 9-25 in the technical annex. A sensitivity analysis was also conducted for the medium and large-scale e-fuels production scenarios, considering how the specified distance influences the presence of CO_2 hotspots.

In some cases, shared infrastructure can also reduce CO_2 capture and transport costs, times, resources needs, or risks, relative to locations where solutions are developed independently for each source. Designs for multi-user CO_2 transport networks leveraging shared CO_2 transport infrastructure are emerging, particularly for CCUS clusters, where this model is gaining popularity for reducing transport costs - this model also has the potential to reduce CO_2 transport costs for e-fuels hubs. Whilst these benefits are expected, to date, few if any integrated CO_2 networks involving multiple sources have passed final investment decisions.

6. Review of Direct Air Capture

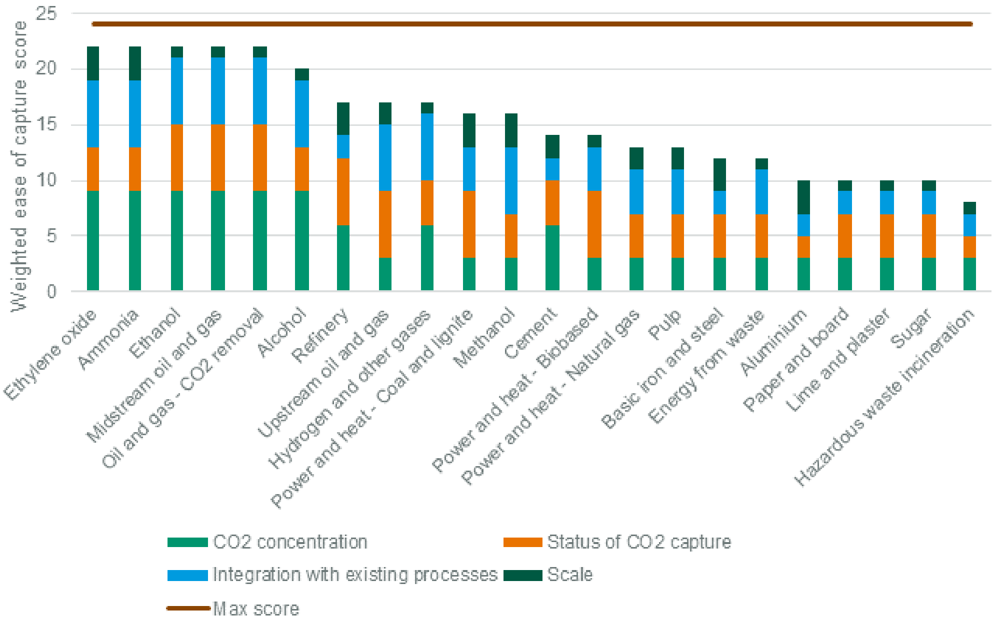
An additional potential opportunity to obtain CO_2 is from Direct Air Capture (DAC). To mitigate the global warming effects outlined in the Paris Agreement, Direct Air Capture has emerged as a promising strategy for CO_2 removal and reduction on a global scale. DAC technologies remove CO_2 directly from the atmosphere, which is a dilute CO_2 source, for permanent storage or utilisation in a variety of processes. The global landscape for DAC was therefore reviewed as a potential CO_2 source for e-fuels.

3.2.2 Results and key takeaways

3.2.2.1 *CO_2 sub-sector source scores*

The overall results per sub-sector can be found in Figure 3-6 below. From this figure, it can be seen that the sectors that scored the highest include ethylene oxide, ammonia, ethanol, midstream oil and gas, oil and gas CO_2 removal and alcohol. This is largely due to the high CO_2 concentration in the stream where CO_2 is to be captured, resulting in simpler capture processes with lower overall capture costs.

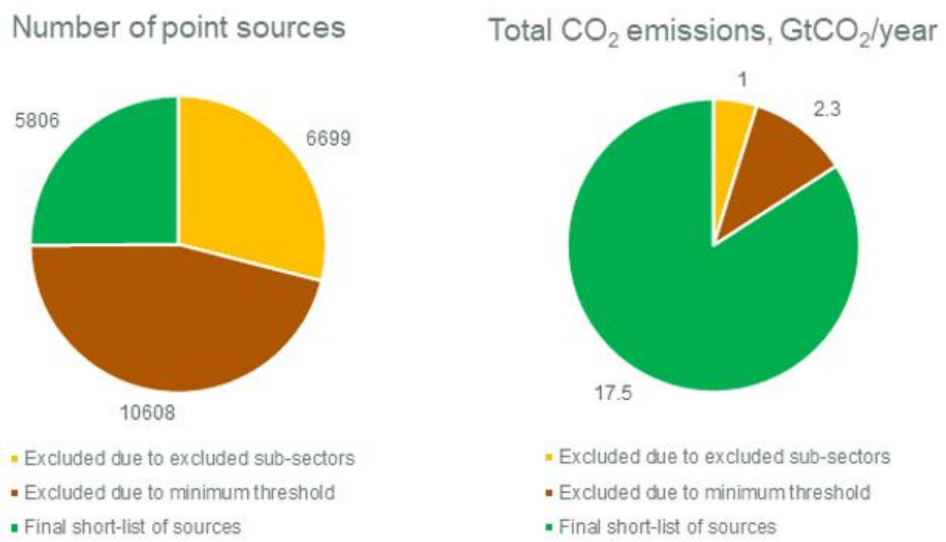
Figure 3-6. Weighted ease of capture score per sub-sector



3.2.2.2 *Availability of CO_2 sources*

The final short-list of CO_2 point sources consists of 5,806 sources within the 22 short-listed sub-sectors, emitting a combined total of 17.5 $GtCO_2$/year. Figure 3-7 below shows the total number of point sources and CO_2 emissions within the long list of point sources, and the number of sources and quantity of emissions excluded at each step towards the short-list. From this figure, it can be seen that although almost 75% of the facilities have been excluded, this only equates to approximately 16% of the total volume of CO_2 emitted annually.

Figure 3-7. Number of point sources and total CO_2 emissions in final short-list database versus long-list database

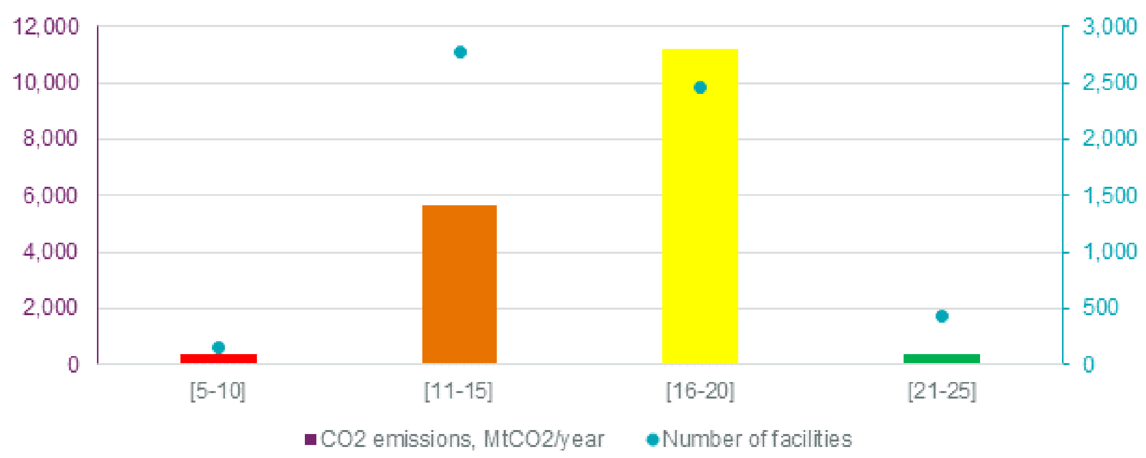


Availability of CO_2 point sources will determine the potential for CO_2 use as a feedstock for e-fuels production. This report examines the global availability of CO_2 point sources, considering the region, country, sector, sub-sector, size of emissions, number of sources, type of CO_2 (fossil or biogenic) and overall capture score.

CO_2 availability by CO_2 capture score

The histogram in Figure 3-8 below depicts the quantity of CO_2 emissions and number of facilities between specified ranges of the calculated ease of CO_2 capture score, where the maximum possible score is 24. From this figure, the largest quantity of CO_2 with the potential to be captured and utilised in the production of e-fuels is available from facilities in sub-sectors with an ease of capture score between 15 – 20, followed by 10-15, with the smallest amount available from facilities in sub-sectors with a score from 5-10 and 20-25. This provides potential opportunity to capture large volumes of CO_2 from medium-score CO_2 sources, in addition to lower volumes of CO_2 from high-score CO_2 sources.

Figure 3-8. CO_2 emissions and number of facilities by CO_2 capture score (incremental range)

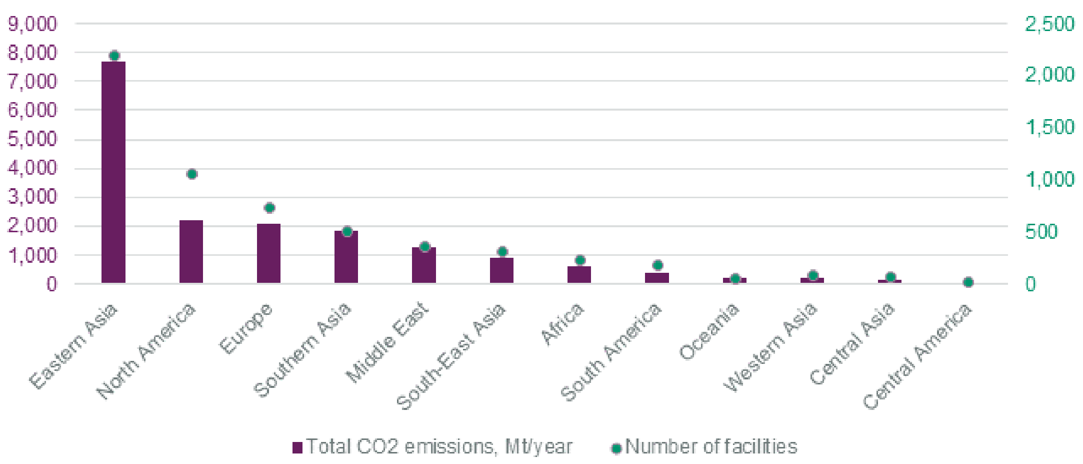


Regional CO_2 availability

Availability of CO_2 was also reviewed by region, in order to better understand the spread of CO_2 availability by ease of CO_2 capture score across each region and country. An overview of the countries included within each region for this part of the analysis can be found in Table 9-26 in the technical annex.

When reviewing global CO_2 availability by region, as shown in Figure 3-9 below, it is evident that Eastern Asia accounts for the largest share of global CO_2 availability. The largest share of emissions from Eastern Asia arises from China, accounting for 38% of total global CO_2 availability. After Eastern Asia, North America, Europe and Southern Asia account for the largest availability of CO_2.

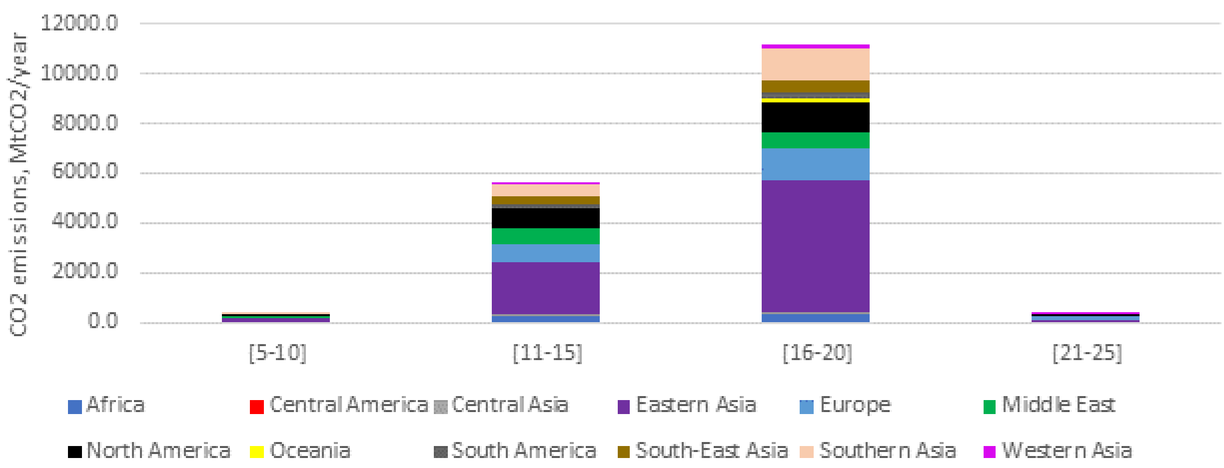
Figure 3-9. Total annual CO_2 emissions and number of CO_2 point sources by region



The available CO_2 by region is further broken down by CO_2 capture score, in Figure 3-10 below. The following can therefore be deduced:

- CO_2 with the highest ease of capture scores, between 21-25, is only available in 8 out of the 12 regions, including Africa, Eastern Asia, North America, South America, South-East Asia, Southern Asia and Western Asia. However, the majority of this CO_2 is within Eastern Asia, Europe, North America and Southern Asia, accounting for 95% of all available CO_2 from facilities within sectors with a score between 21-25.
- The countries with the highest availability of CO_2 with a score between 21-25 include China, United States and Russia, accounting for 33%, 19% and 14% of total available CO_2 within this range, respectively.

Figure 3-10. CO_2 emissions by region and CO_2 capture score (range)



Availability of biogenic CO_2

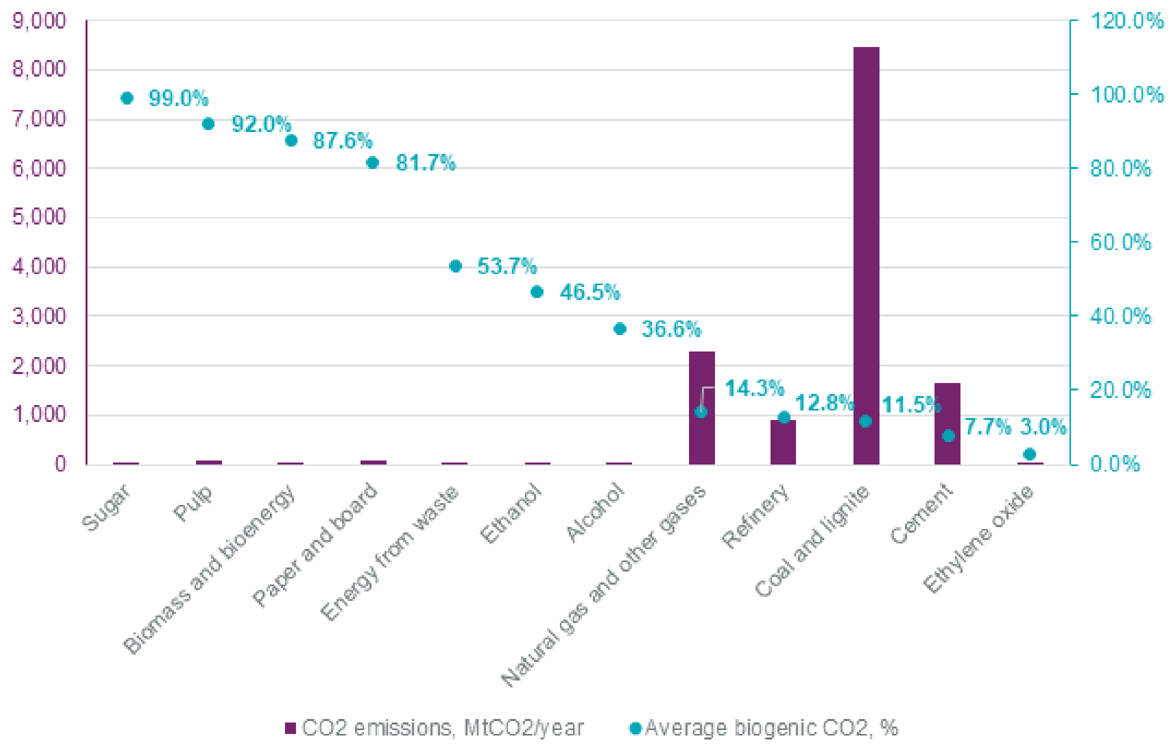
Currently, the Renewable Energy Directive (RED)II/III regulations in Europe will exclude fossil CO_2 to be considered as avoided emissions for Renewable Fuels of Non-Biological Origin (RFNBO) after 2041. For this reason, global availability of biogenic CO_2 is important to the production of e-fuels. At the current time, there are no existing regulations occurring in other countries or regions around the world. The choice to utilise fossil CO_2 to produce e-fuels will depend on several factors, including location of production and sales. This aspect will be explored further later in this study.

There is limited data available on the biogenic portion of CO_2 emissions in most regions, with data predominantly available in Europe and North America. Data from CO_2 emissions from biogenic sources are sometimes missing in datasets due to fewer reporting requirements. In light of this, the subsequent findings are based on the available data on biogenic CO_2 emissions within Europe and North America.

There are 234 facilities with reported biogenic CO_2. The biogenic portion of CO_2 reported in each facility was utilised to determine the average biogenic CO_2 per sector as shown in Figure 3-11 below. Based on this figure, there are 12 sub-sectors with reported biogenic CO_2 content.

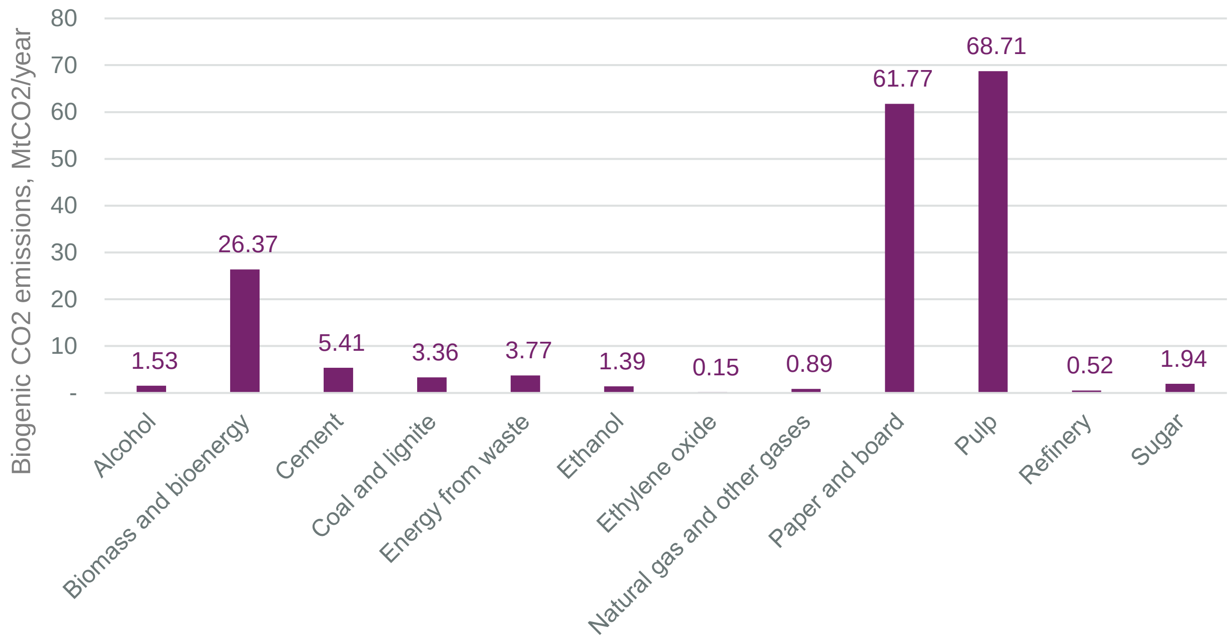
Sugar, pulp, biomass and bioenergy power generation and Energy from Waste are the sub-sectors with the highest biogenic portion of CO_2, all with biogenic CO_2 content above 80%.

Figure 3-11. Average biogenic CO_2 % per sub-sector and availability of CO_2



An overview of the annual biogenic CO_2 emissions available from these sectors in Europe and North America is depicted in the figure below. From this figure, it can be seen that in Europe and North America, the sectors that provide the largest quantities of biogenic CO_2 emissions include pulp, paper and board and biomass and bioenergy.

Figure 3-12. Annual biogenic CO_2 emissions in Europe and North America, by sector



Note: This figure is indicative only, as data on biogenic CO_2 emissions is limited

3.2.2.3 CO_2 hotspots

The results of the CO_2 hotspot identification can be found in Table 3-5 below and the corresponding figures in Section 9.2.2.2 in the technical annex.

Table 3-5. CO_2 hotspot scenario results

Scenario	Number of single sources	Number of hotspots
1 – Small scale e-fuels production	2543	N/A
2 – Medium scale e-fuels production	50	111
3 – Large scale e-fuels production	2	21

It is evident that there is large potential for small, medium and large-scale e-fuels production facilities and hubs, when considering the global availability of CO_2.

- For small scale, the largest number of point sources originate in Eastern Asia, North America and Southern Asia, with additional potential sources in Europe and South America.
- For medium-scale e-fuels production, there are the largest number of potential CO_2 hotspots in China and India, followed by the United States and Russia.
- There are a much smaller number of potential CO_2 hotspots at large scale e-fuels production, predominantly in China and India.
- At large scale e-fuels production, there are two single point sources above 100$MtCO_2$/year that could potentially result in an e-fuels production rate of 500k bbl/day.
- Some offshore CO_2 sources can be seen within the maps. Utilising CO_2 from offshore sources may result in additional complexity. This will be considered further in later tasks when narrowing down CO_2 sources for further review.

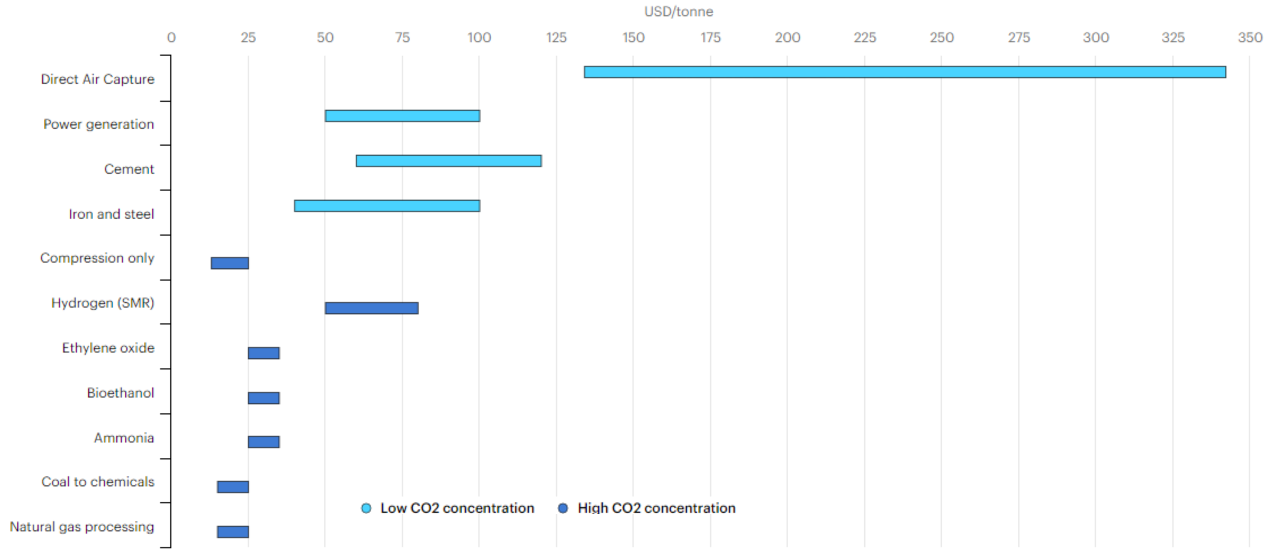
3.2.2.4 Direct Air Capture

The two most well-developed capture technologies currently in use are liquid solvent (L-DAC) and solid sorbent (S-DAC), Emerging technologies offer variations to these two fundamental processes such as using catalysts, membranes, or electrochemical processes, among others.

Fundamentally, the function of the sorbents in both L-DAC and S-DAC are the same; to capture CO_2 from the gas stream, a process known as sorption, followed by release.[31] After each sorption step, the sorbent releases the trapped CO_2 as a concentrated stream for further use or storage; this process regenerates the sorbent and enables it to undergo subsequent rounds of capture. Whilst both technologies are principally the same, there are differences in their operating conditions.

A factor that notably affects the ease of capture, and hence energy requirements and operating costs is the concentration of CO_2 in the capture stream. The concentration of CO_2 in ambient air is relatively low, approximately 0.04%, therefore large volumes of air need to be processed by the DAC system to obtain a concentrated stream of CO_2.[31] For this reason, the costs of DAC is significantly higher compared to carbon capture plants that process flue gases where the CO_2 concentrations are more than two orders of magnitude greater, as seen in Figure 3-13.[32]

Figure 3-13. Levelised cost of CO_2 capture by sector and CO_2 concentration, 2019



Although conventional carbon capture technologies often have lower energy demands, DAC potentially offers advantages: Unlike other carbon capture technologies, DAC plants are not constrained by the locations of point source emitters. Therefore, it is possible to locate these plants close to the storage or utilisation site, thus reducing capital investment. Location flexibility also means that DAC plants can be located wherever there is low-cost, low carbon energy, thus reducing both operating costs and carbon emissions. Additionally, S-DAC plants can be constructed in modular, self-contained units, enabling automated manufacturing at high volumes, thus indicating good scale-up potential. Further details on DAC can be found in Section 9.2.2.2 in the technical annex.

[31] Understandings on design and application for direct air capture: From advanced sorbents to thermal cycles, 2023, Carbon Capture Science and Technology Journal, W.K.Shi et al, Accessed at: [Understandings on design and application for direct air capture: From advanced sorbents to thermal cycles - ScienceDirect]

[32] Levelised cost of CO2 capture by sector and initial CO2 concentration, IEA, 2019, Accessed at: https://www.iea.org/data-and-statistics/charts/levelised-cost-of-co2-capture-by-sector-and-initial-co2-concentration-2019

3.3 KEY TAKEAWAYS

- Both hydrogen and CO_2 infrastructure are potentially costly, challenging and risky to develop.
- A number of key challenges exist as potential barriers to ensuring adequate hydrogen and CO_2 supply for e-fuels, including high costs, uncertainty in future supply and demand, safety, standards, skills, complexity, lead times, competition for resources, asset specificity and challenging critical paths.
- Site specific issues are also likely, such as for hydrogen, where abundant and reliable low-cost green electricity, and water availability are crucial to the successful supply of hydrogen.
- However, there are a number of enablers that may provide support to overcome barriers, including national strategies, clear policy direction and aligned stakeholder decision making.
- Transport of CO_2 and hydrogen as feedstocks for e-fuels is also an important consideration when considering development of an e-fuels production facility, as there are many different modes of transport, each with their own benefits and drawbacks.
- Attention must be given to the form of the transport material, including phase of CO_2 or use of carrier molecules such as ammonia for hydrogen.
- Pipelines and ships are the most relevant options for supplying larger volumes of hydrogen and CO_2 cost effectively over long distances and shorter timescales.
- There are also a number of different factors to consider when determining a source of CO_2 for e-fuels. The sectors with the greatest potential to supply CO_2 for e-fuels at lower costs include ethylene oxide, ammonia, ethanol, midstream oil and gas and alcohols. This is due to the higher CO_2 concentration in the stream to be captured, hence reducing costs. However, there is much less availability of CO_2 from these sources compared to others (such as power generation), potentially resulting in increased complexity in transport logistics when needing to gather CO_2 from multiple different sources. There is the potential to reduce costs due to economies of scale when capturing CO_2 from larger sources, hence there is a balance that must be made when determining the sources of CO_2 for e-fuels.
- In terms of availability of CO_2 across the globe, Eastern Asia accounts for the largest share of global CO_2 availability, predominantly in China.
- The availability of biogenic CO_2 is also an important factor to consider, as the REDII/III regulations will exclude fossil CO_2 to be considered as avoided emissions for Renewable Fuels of Non-Biological Origin (RFNBO) after 2041. However, data on biogenic CO_2 is much more limited when compared to data availability for fossil sources of CO_2.
- Sugar, pulp, biomass and bioenergy power generation and Energy from Waste are the sub-sectors with the highest biogenic portion of CO_2.
- DAC also provides opportunities for a potential source of CO_2; particularly as industrial decarbonisation progresses and the availability of fossil-derived CO_2 decreases. Moreover, DAC offers the flexibility in terms of plant location and scale, however, has much higher capture costs.
- When considering potential CO_2 hotspots, the results demonstrate that there are a significant number of single point sources available to provide CO_2 as a feedstock for a small-scale e-fuel production facility. At large scale, there are two single CO_2 point sources greater than 100 $MtCO_2$/year that may be capable of producing approximately 500k bbl/day of e-fuels. For medium and large-scale e-fuel production, the largest number of potential e-fuel hub locations are located in China and India, with the United States and Russia also providing significant potential for medium-scale e-fuel production.

4. PROSPECTS FOR E-FUELS PRODUCTION

A number of challenges currently exist for scaling deployment of e-fuels. Green hydrogen production and CO_2 capture costs are high, resulting in high costs for production of e-fuels and hence limiting overall commercial viability. The subsequent conversion process of hydrogen and CO_2 to e-fuels also has high costs, as it is both energy and capital intensive[33]. Policy and financial support must therefore be considered to enable growth in both e-fuels supply and demand.

Key success criteria are heavily correlated to the location of e-fuels production facilities, pairing access to low-carbon electricity generation for hydrogen production and access to the most promising CO_2 sources. An additional challenge is therefore discovering these optimum locations. The main aim was to select three exemplar countries as case studies to deep-dive into the factors influencing the prospects for e-fuels production.

A high-level global review was first undertaken, analysing each country against key criteria relevant to the production of e-fuels, and aiming to determine which regions and countries may possess some of the promising opportunities for e-fuels deployment. The methodology utilised offers a comprehensive understanding of e-fuel prospects worldwide, covering all countries and focusing on key factors essential for e-fuel deployment. However, it should be noted that in some cases, full data sources are not available to fully assess the criteria, and the scope of the analysis does not cover all criteria relevant to conducting business operations for e-fuels production. It is therefore expected that there may be some gaps in the results. The approach simply provides a justified basis for determining which regions and countries to focus on in more detail.

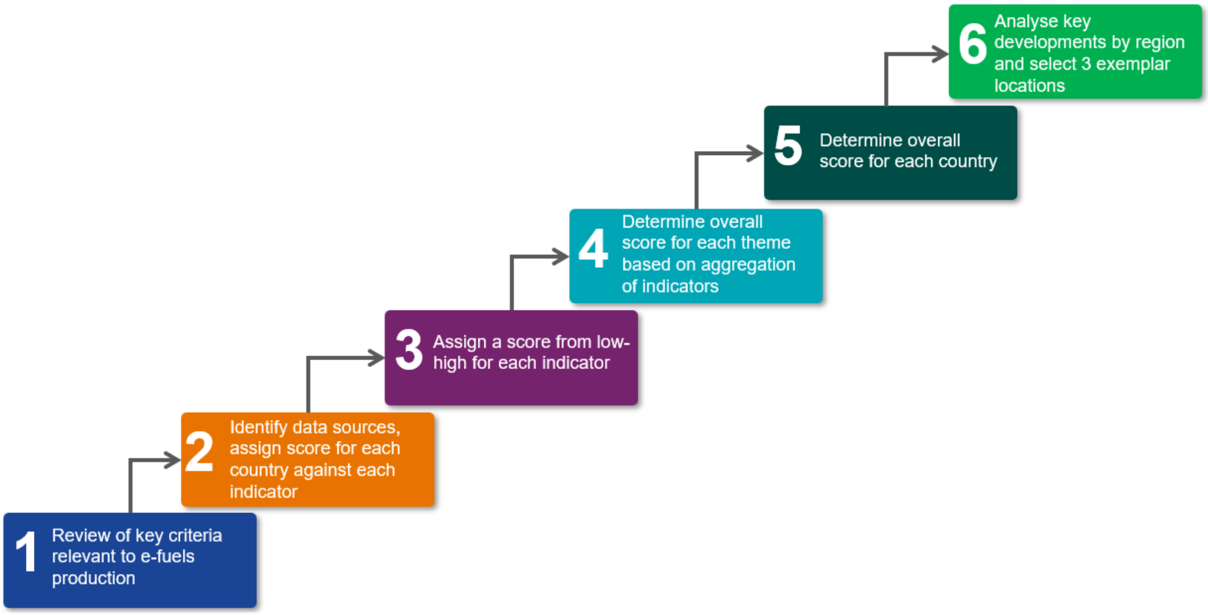
A selection of key examples in countries with promising developments relevant to e-fuels production and the associated inputs to e-fuels production (CO_2 and green hydrogen) are therefore also outlined in this section in order to provide further insight into the country rankings determined through the methodology. Finally, three exemplar locations were selected for further analysis.

4.1 HIGH-LEVEL GLOBAL REVIEW

4.1.1 Overview of the approach

The overall approach to selecting three countries to conduct a review of the prospects for e-fuels production is outlined in Figure 4-1 below.

Figure 4-1. Staged approach to selecting three countries to review the prospects for e-fuels production



[33] Adding fire to e-fuels: Are synthetic fuels the key to unlocking growth in hydrogen? Wood Mackenzie, 2024

Step 1. Review of key criteria relevant to e-fuels production

Factors influencing the ability of a country to produce and export e-fuels were reviewed, building on the review of drivers for supply of CO_2 and hydrogen in this report. Firstly, the key overarching themes were determined, namely policy and regulation, financial incentives, feedstocks for e-fuels production (CO_2 sources and hydrogen supply), as well as business and innovation prospects. Secondly, the individual indicators within the overarching themes were determined. An overview of the key themes, and the indicators within the themes are outlined in Table 4-1 below.

Table 4-1. Theme and indicator criteria for the prospects for e-fuels production

Theme	Indicator
Policy and regulation	CCS policy
	CCS legal and regulatory
	National hydrogen strategy
Financial incentives	CCUS financial incentives
	Hydrogen financial incentives
CO_2	Number and volume of biogenic sources - all sources, above 2 $MtCO_2$/year
	Number and volume of sources in top 50% scoring sub-sectors (output of scoring in section 3.2)
	Number and volume of sources within 3 scenarios identified in WP1
	CO_2 transport projects
	CO_2 capture projects
	CCU projects
	DAC projects
Hydrogen	Levelised cost of hydrogen
	Capacity of hydrogen production projects (electrolysis)
Business and innovation prospects	Global innovation index
	Ease of doing business
	Digital readiness score

Locations with good prospects for e-fuels production are likely to be correlated to the availability of CO_2 sources and supply of green hydrogen, as these are key inputs into the production of e-fuels. A selection of indicators related to CO_2 sources were utilised, covering availability of CO_2 within the hotspot scenarios identified, availability of biogenic CO_2, and the availability of CO_2 from sectors with lower costs of capture.

The prospects for CO_2 supply, as well as hydrogen supply, are also influenced by the availability of infrastructure. Indicators were therefore selected to represent CCU and hydrogen infrastructure, namely existing and planned CO_2 capture, utilisation, and transport projects, as well as existing or planned green hydrogen production projects. The cost of hydrogen supply is also an important factor when considering hydrogen production, and hence a 'levelised cost of hydrogen' indicator was selected to represent this factor, which also incorporates the associated cost and opportunities of renewable electricity to produce this hydrogen.

As a number of challenges currently exist for the production of e-fuels, policy and regulation and financial incentives are seen as important mechanisms to promote the deployment of e-fuels. A selection of indicators within these themes were therefore selected, representing the landscape for feedstocks for e-fuels, namely CO_2 capture and green hydrogen production.

Finally, the business landscape within a country also provides an indication of the opportunities for conducting business. Three indicators were selected to represent this theme, namely the ‘Global Innovation Index’, ‘Ease of Doing Business’ and ‘Digital Readiness Score’. The Global Innovation index captures the innovation ecosystem performance of economies and tracks the most recent global innovation trends; since e-fuels are a nascent technology, a country with good innovation prospects can support in providing the enabling environment to promote and develop e-fuels. The Digital Readiness Score indicator is determined by examining seven components which are standardised and summed to obtain an overall digital readiness score: basic needs, business and government investment, ease of doing business, human capital, start-up environment, technology infrastructure and technology adoption. This indicator provides a well-rounded representation of the business operations landscape within a country.

Limitations to the approach (step 1)

While the themes and indicators provide an indication of the relevant factors related to e-fuels production, it must be noted that the list is not exhaustive. The analysis is intended to provide high-level insight into the prospects for e-fuels by country. Additional factors that could also be considered include:

- Labour costs
- Energy prices
- Social and political factors

Other criteria were identified but subsequently excluded due to lack of readily available, public, and comprehensive data sources covering all, or at least the majority of,countries. These include:

- E-fuels specific policies, regulations, and financial incentives. Where applicable, detail on this has been covered within the ‘Regional Insights’ section.
- Existing infrastructure for transport of e-fuels. This will be very location specific and will be covered further in Task 8 within the three exemplar locations.
- Demand for e-fuels. This will be covered further in Task 8 within the three exemplar locations.

A follow up study could be undertaken to consider additional criteria and obtain a more comprehensive result.

Step 2. Identifying data sources

A literature review was undertaken to identify data sources, covering data for each of the indicators across all countries in the world. An overview of the data sources utilised for each indicator can be found in Table 9-28 in the technical annex.

Each of the countries was then assigned a score against each of the individual indicators, where the initial score assigned is dependent on the scoring approach of the underlying data. Table 9-28 in the technical annex, therefore, also outlines the original scoring style associated with each of the data sources.

Limitations to the approach (step 2)

- Some of the data sources have gaps and hence do not provide data for all countries. In these cases, we have assumed that the gap is due to less developments in the country, and hence assigned a low score. This may result in some key insights missed.
- In some countries, there will be variation in the landscape across different parts of the country, due to different distribution of resources, or bespoke policy and financing that is not applicable to the whole country. This is not reflected in this analysis, as scores and data are provided at a country level. Some regions will also have overarching policies that may influence multiple countries.
- Countries in close proximity or with good political and trading relationships and infrastructure can potentially overcome barriers each country may have individually, which may positively influence the potential opportunities in these countries.
- The future landscape and opportunity for e-fuels production is expected to rapidly evolve, and hence data sets can quickly become out of date.
- The overall quality of the data is variable.

- Some underlying data for CCUS policy, regulatory and financial indicators does not distinguish between CO_2 utilisation or CO_2 storage.
- The benefits of availability of CO_2 and hydrogen transport infrastructure is location specific.

Step 3. Assign score from low-high for each indicator

As the underlying data scored countries in different manners (e.g. some qualitative, some quantitative), the underlying data was turned into a score from low-high for each country for each indicator, and a subsequent rating from 0 – 2. Table 9-29 in the technical annex outlines the criteria that were utilised per indicator to determine what ranges of scores resulted in a score of low, low-mid, mid, mid-high, or high.

Step 4. Determine overall score for each theme

An overall score from low – high was then calculated for each theme, based on the sum of indicator scores within a theme. The scoring range for each theme is outlined in Table 9-30 in the technical annex.

Step 5. Determine overall score for each country

Finally, an overall score from low – high for the prospects for e-fuels was determined for each country, based on the sum of scores across each theme. The scoring range for the overall score is outlined in Table 9-31 in the technical annex.

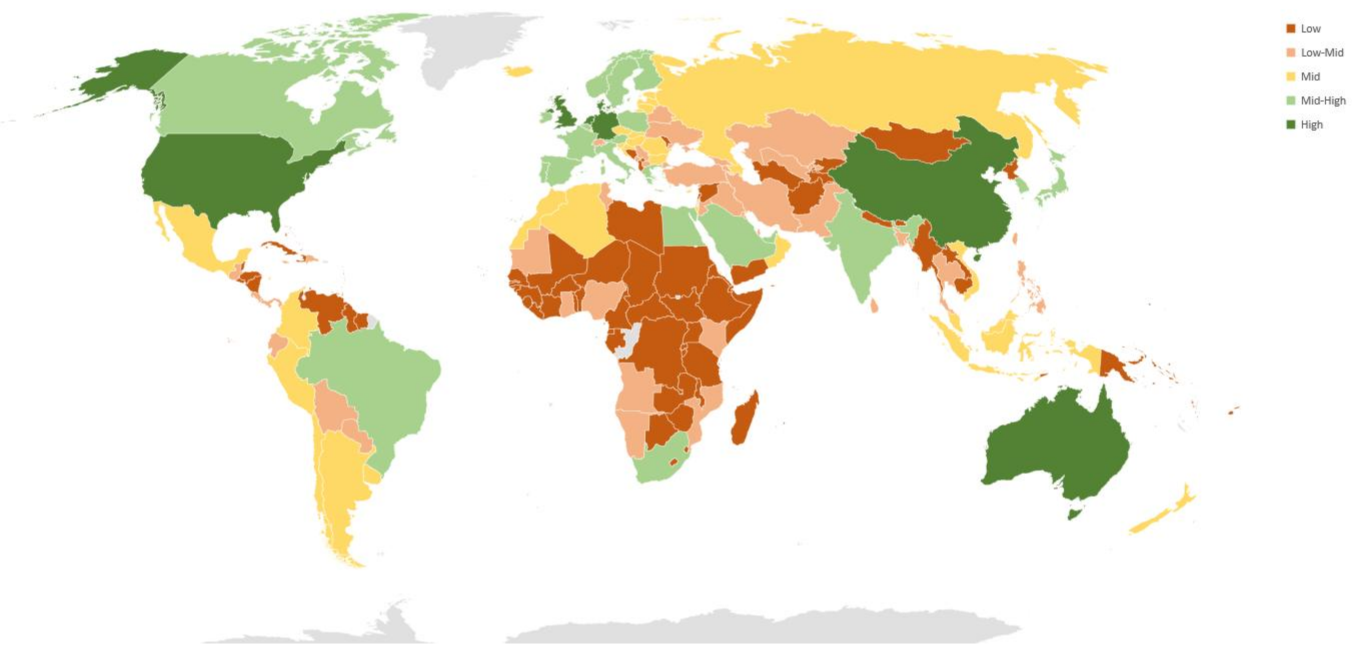
Limitations to the approach (steps 3 – 5)

- Classifying the data into ranges may limit the potential to compare certain countries that fall into the same category rank.
- The approach to define the ranges for each indicator, theme, and overall score, aimed to support rapid and convenient differentiation and screening, particularly identify the top scoring regions per indicator, theme, and overall score within mid-high and high category ranks.
- Certain criteria may be more influential over the prospects for e-fuels than others. This is not considered in this analysis, as a weighting was not applied to the criteria or themes.

4.1.2 Results and key takeaways

Once aggregating the scores of the individual themes, the overall results from low-high by country for the prospects for e-fuels production are represented in Figure 4-2 below. The results for the individual themes can be found in Section 9.3.1.2 in the technical annex.

Figure 4-2. Overall prospects for e-fuels production: results



Key takeaways

Europe is the region with the most advanced policy and funding landscape for CCUS and hydrogen production:

- 23 countries scored high in the policy and regulation theme, of which almost 80% are in Europe. North America and Asia each make up 9% of the high scoring countries, with the final 2% in Oceania.
- When considering the individual indicators within the policy and regulation theme, countries in Europe make up the largest portion of countries scoring high in all three indicators, namely CCS policy, CCS legal and regulatory, and the status of the national hydrogen strategy.
- Europe contains 24 countries which have implemented a national hydrogen strategy, and 8 countries that are in the process of developing a national hydrogen strategy.
- 30 countries scored high in the financial incentives theme, of which 87% are in Europe. The remaining are in North America and Asia.
- Norway is the country with the greatest level of CCUS financing.

South America has more advanced hydrogen policies than CCUS policies:

- 7 countries in South America have developed a national hydrogen strategy, with 2 countries currently developing a national hydrogen strategy.
- No countries in South America scored higher than low, or low-mid for the CCUS policy indicator.
- Brazil is the only country in the region that scored above low, or low-mid in the CCUS legal and regulatory indicator.

Asia is the region with the greatest prospects for e-fuels production in terms of CO_2, followed by North America.

- 5 countries scored high in the CO_2 theme, 3 of which were in Asia (China, India, Japan), and two in North America (United States, Canada).
- China has a significantly larger availability of CO_2 sources than any other country, followed by India.
- Although the United States has a lower availability of CO_2 sources than China, the overall availability is still high, and the United States has many more CCUS project developments than China.

Europe has leading CCUS projects, however has lower availability of CO_2 sources when compared to Asia and North America.

Countries with good prospects for hydrogen production are evenly distributed across all regions.

- 6 countries scored high, with one in all regions apart from Europe.
- 16 countries scored mid-high, of which almost 45% are in Europe.
- South America benefits from low forecast costs for levelised cost of hydrogen.

There are a number of countries with good prospects for e-fuels production.

- 7 countries received an overall score of ‘high’, namely, Australia, China, Denmark, Germany, Netherlands, the United Kingdom, and the United States.
- 21 countries received an overall score of ‘mid-high’, located in North America, South America, Europe, Asia, Africa and in the Middle East.

4.1.2.1 Regional insights

This section highlights a selection of key developments occurring in countries across the themes. The themes are colour coded to represent the prospects for e-fuels, where red is weak, yellow is medium and green is strong.

Figure 4-3. Regional insights from Africa, Middle East, Asia, and Europe

Africa (excluding Middle East)

Financial Incentives
- South Africa has a carbon tax.
- No specific financial incentives for CCUS outside of South Africa.
- Funding for hydrogen projects from European partners in South Africa, Namibia and Morocco.

Hydrogen Development
- Several countries have National Hydrogen Strategies or Roadmaps, focusing on infrastructure, expertise, and investment.
- Well-positioned for production and export, but less mature than other regions.
- South Africa has the only operational green hydrogen facility.

E-fuels Potential
- Limited, except for South Africa.
- Lack of policies, regulations, and financial incentives.

CO_2 Source
- Morocco and South Africa have the most sources, with South Africa having medium and large-scale potential.

CCUS Development
- Limited deployment, with a South African pilot project.
- DAC being explored in Kenya
- South Africa is the leader but focuses on storage rather than utilisation.
- Few other African countries have specific policies, although Morocco and Algeria show interest.

Middle East

Financial Incentives
- Insufficient CCUS incentives.
- Saudi Arabia developing a carbon trading mechanism.
- Substantial investment in hydrogen by governments

Hydrogen Development
- Countries are seeking to diversify revenue streams.
- Several countries have announced hydrogen strategies.
- UAE aims for 25% of global market share in low-carbon hydrogen.
- Saudi Arabia has a goal to be a world leader in clean hydrogen.
- Limited number of operational green hydrogen projects, but several are planned.
- The world's largest green hydrogen plant is under development in Saudi Arabia.

E-fuels Potential
- Potential due to established carbon capture, abundant resources, and net-zero ambitions, but lacks sufficient policy and preference for CO_2 storage.

CO_2 Source
- High number of CO_2 sources available, particularly in Saudi Arabia.
- Sources are in power and heat, oil and gas, and cement.

CCUS Development
- Lacks policy frameworks and incentives.
- Focus on EOR and CO_2 storage.
- CCS has a significant presence but lacks firm policy frameworks and support compared to Europe and the US.
- The UAE and Saudi Arabia have net-zero targets.
- Projects in Qatar, Saudi Arabia, the UAE and Oman.
- Saudi Arabia is developing the first CCUS hub.

Asia

Financial Incentives
- Funding for CCUS in some countries, like Singapore, and Japan.
- CCUS funding prioritises EOR or storage.
- Carbon pricing systems are increasing but low.
- Significant investment in the hydrogen economy

Hydrogen Development
- National Hydrogen Strategies in eight economies, with ten more in development.
- Strong national hydrogen strategies in many countries.
- South Korea, Japan and Singapore view hydrogen as key to decarbonisation.

E-fuels Potential
- Lower opportunities due to CCUS policies focusing on storage.
- Strong hydrogen strategies suggest future potential.

CO_2 Source
- Significant number of sources, with China having the most.

CCUS Development
- CCUS policies are in their early stages and mainly focus on EOR or permanent storage.
- China, Japan, and South Korea have the most comprehensive regulations.
- Over 50 projects in development, construction, or operation China has the most operational CCUS projects.

Europe

Financial Incentives
- Financial backing for CCUS from the EU.
- Market-based subsidy pool for CO_2 in Denmark.
- Germany has funding for decarbonising industry.
- UK offers financial support to CCUS clusters.
- Significant investment in hydrogen in Germany, Denmark and the UK.

Hydrogen Development
- 25 countries have National Hydrogen Strategies or Roadmaps.
- Germany has the largest hydrogen funding and a 10GW production target.
- Largest volume of announced green hydrogen supply.
- Germany has the largest share of operational projects.

E-fuels Potential
- Potential due to the European Commission's Industrial Carbon Management Strategy .
- Mandates for e-fuel adoption through the Renewable Energy Directive (RED).

CO_2 Source
- Mainly suitable for small-scale production, with a medium-scale hotspot in Germany.

CCUS Development
- Several countries have CCUS strategies and roadmaps, supported by incentives.
- Germany's stance has shifted to recognise CCUS as essential.
- Significant deployment in the UK, Norway, Denmark and the Netherlands.
- Germany is focusing on CO_2 capture and transport.

Figure 4-4. Regional insights from North and South America and Oceania.

North America

Financial Incentives
- USA relies on subsidies such as the Inflation Reduction Act.
- Canada has various regulatory and investment measures.
- US has funding for hydrogen projects and tax incentives.
- Canada has investment tax credits for hydrogen.

E-fuels Potential
- Promising potential with US and Canada as potential leaders in hydrogen and e-fuel markets.
- Both countries have net-zero targets.

CO_2 Source
- Significant availability of CO_2 in the US, with some potential in Canada.
- Limited biogenic sources for large-scale production.

Hydrogen Development
- Both the US and Canada have national hydrogen strategies. The strategies mention the potential of liquid synthetic fuels.
- Hydrogen is seen as pivotal for net-zero.
- US is a global leader in deployment. Canada has several commercial-scale projects.

CCUS Development
- Both the US and Canada have committed to net-zero by 2050 and acknowledge the importance of CCUS.
- US has a goal for CO_2 removal.
- Canada released a Carbon Capture Industrial Strategy.
- Significant prospects for CCUS due to available financing.
- The US is the global leader in CCUS deployment.

Oceania

Financial Incentives
- Grants to support CCUS development.
- Government investment in hydrogen. Financial support for large-scale renewable hydrogen projects

E-fuels Potential
- Significant potential, especially in Australia, with established CCUS policies and hydrogen developments.

CO_2 Source
- CO_2 sources are mainly suitable for small-scale e-fuel production.

Hydrogen Development
- Australia is a pioneer in hydrogen. National Hydrogen Strategy aims for commercially viable renewable hydrogen exports by 2030.
- Green hydrogen production in Australia could reach 6 Mtpa by 2030.
- Most projects are in early stages.

CCUS Development
- Australia has a National CCUS Technology Emissions Abatement Strategy.
- Carbon credits available for CO_2 storage.
- Focus on CO_2 storage with frameworks in place.

South America

Financial Incentives
- No robust national financing initiatives for CCUS.
- Significant investment in hydrogen production.
- Funding schemes in Uruguay, Chile and Brazil.

E-fuels Potential
- Well-positioned for e-fuels in the medium to long term.
- Multiple countries are exploring hydrogen.

CO_2 Source
- Greatest potential for CO_2 sources at small scale, with Brazil having a medium-scale hotspot.
- Potential to capture from oil and gas, energy generation, and biogenic sources.

Hydrogen Development
- Multiple countries are developing hydrogen policies and strategies.
- Chile has the largest share of announced green hydrogen projects, followed by Brazil and Colombia.
- Chile and Argentina aim to export hydrogen and derived products.

CCUS Development
- CCUS evolving, particularly in Brazil, Chile, Argentina, and Colombia.
- Brazil has a bill to establish a CCUS framework.

4.1.2.2 Selection of exemplar locations

Following on from the global analysis and identification of key regional and country insights relevant to the production of e-fuels, the final aim of this task was to shortlist three exemplar locations for further analysis. **The selected exemplars chosen were the United States, China and Germany.**

The following approach was utilised to determine which three exemplar locations to take forward:

- **Selecting locations from three different regions**: This will enable the greatest insights to be realised, by conducting a deep dive in different locations and subsequently gaining a deeper understanding into the prospects for e-fuels considering regional variations, such as in resource and infrastructure availability.
- **Selecting locations with the highest scoring for overall prospects for e-fuels production:** Where there is more potential and more developments occurring, greater insight can be developed by considering how the landscape for e-fuels is evolving, and better understanding enablers and barriers to upscaling e-fuels.

Further details on the selection approach can be found in the technical annex (section 9.3.2).

4.2 E-FUEL PRODUCTION POTENTIAL IN USA, CHINA, AND GERMANY

The regulatory and policy landscape, as explained in this section, influences the deployment prospects of e-fuels. This chapter provides detail on the three exemplar countries selected for further analysis, namely the United States (US), Germany and China. A literature review was undertaken in each country to better understand the prospects for e-fuels production.

It is important to note that since the date of this analysis (November 2024), there have been changes in government in the US and Germany. In the US there is a notable and accelerating transition of policies away from those developed under the Biden administration policies. These changes and their impacts are out of scope for this project..

4.2.1 Approach

An overview of the key review parameters is outlined in Figure 4-5 below.

Figure 4-5. Themes identified for reviewing prospects for e-fuels in exemplar locations

Current energy landscape	Energy sources, share of renewables, electricity prices, policy priorities
Resource availability	Solar and wind potential, water availability
CO_2 sources	Availability and distribution of CO_2 sources
Carbon capture	Carbon capture activity, CO_2 transport infrastructure, market drivers and barriers: policy and regulation and financial
Hydrogen	H_2 activity, H_2 transport infrastructure, market drivers and barriers: policy and regulation and financial
E-fuels	Market for e-fuels, e-fuels activity, market drivers and barriers: policy and regulation and financial

4.2.2 Results

Using the six themes outlined in Figure 4-5, this section examines the availability of key feedstocks - renewable electricity, green hydrogen, and captured CO_2 - alongside relevant policies and financial incentives. It also explores the existing and planned e-fuel projects and the market drivers and barriers specific to each country. The findings are based on readily available English-language sources, acknowledging potential biases. A summary of the findings on the themes are summarised in Table 4-2 and the main policies that are relevant to e-fuels have been summarised in Table 4-3. The basis of the summary and more details on each country can be found in Section 9.4 of the technical annex.

4.2.2.1 Prospects

Table 4-2. Summary of key findings under each theme for the USA, China, and Germany.

Theme	United States	China	Germany
Current energy landscape	• Major global economic power, significant energy producer and consumer. • Second largest energy producer and consumer. • Aims for net-zero GHG emissions by 2050. • Varying industrial electricity costs. • **Gulf Coast region** is a substantial industrial presence and large GHG emitter.	• World's second-largest economy, major energy consumer and producer. • Coal is a dominant fuel source. • Rapid growth in renewable energy. • Regional disparities in electricity costs. • Policy priorities: carbon neutrality by 2060, increased non-fossil energy consumption. • **Leads in global renewables deployment**.	• Largest energy consumer in Europe, third-largest economy globally. • Net energy importer. • Energy mix includes oil, natural gas, coal, and renewables. • Renewable energy is the fastest-growing power source. • Regional differences in renewable energy production and electricity costs. • Aims for GHG neutrality by 2045.
Resource availability	• Vast renewable energy resources from wind and solar. • E-fuel facilities proposed in regions with low-cost renewable electricity. • Some regions experience water stress.	• World's largest installed capacity of solar and wind power. • Competition for renewable electricity across sectors. • Water scarcity is a challenge in some regions. **Inner Mongolia, Qinghai, and Xinjiang** are well-positioned due to abundant renewable resources.	• Leader in wind and solar PV deployment. • Significant renewable energy resource potential. • **Unprecedented expansion rates required to achieve national targets for wind and solar power by 2030**. • Water is needed for hydrogen production, carbon capture processes and some e-fuel production.
CO_2 Sources	• One of the largest CO_2 emitters. • CO_2 emissions concentrated in specific regions. • **Gulf Coast region** accounts for a quarter of the US's energy-related GHG emissions. • Priority sectors for CO_2 capture: ammonia, ethanol, oil and gas, alcohol, and refineries.	• World's largest CO_2 emitter. • Majority of emissions from energy-related activities. • Power sector is the largest source of CO_2 emissions, followed by industry and transport. • Key CO_2 sources: cement, steel and iron, coal-to-chemicals, ammonia and ethanol, and coal-fired power plants. • Regional variations in emissions, with eastern China being a major contributor.	• Largest CO_2 emitter in the EU. • Energy industry is the largest source of CO_2 emissions, followed by heavy industry and transportation. • Some industrial subsectors are more suited to carbon capture than others. • Clusters of industrial facilities can facilitate CCUS hub development.

Theme	United States	China	Germany
Carbon Capture	• CCUS hub development occurring, with projects concentrated in Texas and Louisiana. • Financial incentives such as federal and state grants and tax incentives in place to support CCUS deployment.	• Numerous CCUS demonstration projects initiated. • Focus on establishing regional hubs with shared pipelines and transport systems. • Limited large-scale CO_2 transport infrastructure currently in place.	• Limited experience in deploying CCUS technologies, with no operational CCUS projects currently. • Several CCUS projects proposed in the country, some with planned operational dates by 2030. • CO_2 storage sites are not permitted, so CCUS projects focus on capture with long-distance transport. • Financial support mechanisms include the EU Innovation Fund and Horizon Europe.
Hydrogen production	• Evolving hydrogen production landscape with investments from the DOE's Hydrogen Hub initiative and the Inflation Reduction Act (IRA). • Hydrogen production projects are concentrated in the Gulf Coast and California, but are proposed throughout the country.	• Most hydrogen production from carbon-intensive sources. • Hydrogen Energy Development Plan (2021-2035) aims to increase green hydrogen's share to 10% by 2030 and 15% by 2035. • Green hydrogen projects being developed in various regions. • Exploring hydrogen for transportation. • Development of a long-distance hydrogen pipeline network in progress.	• Leader in hydrogen production and water electrolysis capacity in Europe. • Majority of hydrogen production currently from fossil fuel reforming processes. • Developing green hydrogen facilities using water electrolysis, with many more projects planned. • Existing hydrogen pipeline infrastructure in some areas.
E-fuels	• E-fuel market expected to reach a value of US$ 31 billion by 2032. • Aviation sector expected to be a dominant consumer of e-fuels. • Multiple e-fuel production projects in various stages of development across the country. • **Gulf Coast region** has growing opportunities and markets for e-fuels.	• Efforts to decarbonise are expected to increase demand for e-fuels. • Aviation sector and heavy-duty vehicles are key areas for e-fuel adoption. • More than 20 e-fuel projects underway. • E-fuel hubs emerging in regions like Guangdong and Jiangsu. • Investments in sustainable aviation fuel (SAF) production. Policies in place to support e-fuel production.	• Hydrogen and synthetic energy carriers might constitute approximately 24% of Germany's final energy demand by 2050. • E-fuel production already underway. • Multiple pilot facilities operational and various projects in different stages of development. • E-fuel projects are dispersed across the country with a higher concentration in the northwest and eastern regions.

4.2.2.2 Policy and regulations

The development and deployment of e-fuels are significantly influenced by governmental policies and regulations, which vary considerably between countries. These policies provide the necessary frameworks, incentives, and targets to drive the e-fuels market. The following table summarises some of the key policies and regulations that are relevant to e-fuels in the United States, China and Germany.

Table 4-3. Summary of key policies and regulations relevant to e-fuel development in the USA, China, and Germany

Policy/Regulation	United States	China	Germany
Overarching climate goals	• **Net-zero greenhouse gas emissions by 2050**.	• **Carbon neutrality by 2060**; "1+N" policy framework focuses on reducing emissions across ten critical sectors.	• **Greenhouse gas (GHG) neutrality by 2045**, with interim targets of reducing emissions by 65% by 2030 and 88% by 2040 compared to 1990 levels.
Renewable energy targets	• Prioritises clean fuels like carbon-free hydrogen and sustainable biofuels, especially in sectors hard to electrify. • However, there is **little national policy consensus**.	• Focus on expanding renewable energy capacity, with strong government policies, subsidies, and feed-in tariffs. • The 14th Five-Year Plan includes ambitious targets.	• **Renewable energy to account for at least 80% of electricity consumption by 2030**, supported by specific expansion goals of 115 GW of wind power and 215 GW of solar capacity. • "Easter Package" outlines a roadmap to achieve 100% renewable electricity by 2035.
E-fuels specific policies	• No medium-term SAF or e-fuels blending mandate to boost demand. • The growth of the e-fuels market relies primarily on policy incentives, such as the **Inflation Reduction Act (IRA)**. **Sustainable Aviation Fuel (SAF) Grand Challenge** aims for 3 billion gallons/year of domestic SAF production by 2030.	• **Proposed SAF blending mandate**: 2% by 2025, increasing to 15% by 2030 (subject to policy refinement). • **Guidance on Methanol Vehicle Application** supports the development of methanol as a fuel and associated infrastructure.	• **Renewable Energy Directive (RED) III** promotes the adoption of renewable energy. Includes specific targets for renewable energy in the transport sector and for RFNBOs. • **Mobility and Fuels Strategy (MFS)** aims to increase the share of renewable energy (fuels) to 18% by 2030 and 60% by 2045. • **RefuelEU Aviation** sets a target for SAF use of 2% by 2025 and 6% by 2030, increasing to 63% by 2050, and establishes a minimum share of 1.2% e-fuels in aviation by 2030.
Carbon Capture and Utilisation Support	• **45Q tax credit** provides a greater financial incentive for permanent storage of CO_2 (US$85/t$CO_2$)	• CCUS is a critical tool for mitigating industrial emissions. **National Key R&D Program for CCUS** directs funding towards research.	• **Carbon Management Strategy (draft)** aims to establish a robust foundation for the use of carbon capture technologies.

Policy/Regulation	United States	China	Germany
	compared to CO_2 utilisation (US$60/t$CO_2$). • The **Infrastructure Investment and Jobs Act** includes provisions for CCUS infrastructure.	• The **14th Five-Year Plan** focuses on CCUS deployment in industrial clusters. • The **National Emissions Trading System (ETS)** covers 2,000 facilities accounting for 40% of emissions.	• The **EU Industrial Carbon Management Strategy** fosters an enabling environment for carbon management technologies. • EU's **Net Zero Industry Act** introduces an injection capacity target of 50 Mtpa of CO_2 by 2030.
Hydrogen production	• **DoE's Hydrogen Hub initiative** and the provisions of the **IRA** are driving investments. • The **Infrastructure Investment and Jobs Act** includes hydrogen-specific provisions. • The **45V tax credit** provides incentives for clean hydrogen production.	• **14th Five-Year Plan** focuses on hydrogen energy development. • **Hydrogen Pipeline Network Initiative** plans a 6,000-km pipeline network by 2050. • **Guidelines for Establishing the Standards System on Hydrogen Energy Industry (2023)** regulates hydrogen production, storage, transport and usage.	• **EU Hydrogen Strategy** proposes a strategic roadmap for hydrogen uptake. • **National Hydrogen Strategy** sets out plans for launching the hydrogen market. • The **Net Zero Industry Act** includes hydrogen provisions, identifying electrolysers and fuel cells as net-zero technologies.
Financial incentives	• Federal and State grants, tax incentives, and business models support CCUS deployment. • The **45Q tax credit** is a key financial incentive.	• **China Clean Development Mechanism Fund** provides support for CCUS projects. • The **China Certified Emission Reduction (CCER)** allows ETS participants to offset emissions. **Direct operational investment** by State-Owned Enterprises (SOEs).	• **Carbon Contract for Difference (CCfD)** scheme compensates companies for the additional costs of reducing CO_2 emissions. • The **EU Innovation Fund** provides financial support for innovative low-carbon technologies. Multiple funding incentives for CCUS projects are available, including the **EU ETS tax credits**.

4.3 KEY TAKEAWAYS

Regional insights:

- **Africa**: South Africa has potential CO_2 hotspots, mainly from coal fired power plants.
- **Asia**: China and India have the largest availability of CO_2 sources. China has a greater number of CCUS projects under development than India.
- **Europe**: Europe leads in CCUS and hydrogen funding, with Norway having the greatest level of CCUS financing. Europe is also a leader in deployment of CCUS and CO_2 transport projects.
- **Middle East**: Saudi Arabia has significant potential for e-fuels production due to many reasons, including but not limited to its existing carbon capture industry and oil and gas infrastructure, its target to be Net-Zero by 2060, abundance of renewable electricity, and its investment in hydrogen production.
- **North America**: The US and Canada are key players, with a large number of CO_2 point sources.
- **Oceania**: Australia has potential for small and medium scale e-fuel production.
- **South America:** Brazil has opportunities for biogenic CO_2 capture and hydrogen production.

The analysis led to the selection of the **United States, China, and Germany** as exemplar locations for further analysis. These countries were chosen due to their high overall scores for e-fuels production potential, as well as to cover a wide range of regions globally in this study.

- **Strategic importance of e-fuels:** All three countries (US, China, Germany) view e-fuels as important for decarbonising their economies, particularly in sectors like aviation and heavy transport, where electrification is challenging.
- **Policy-driven markets:** The development of e-fuels in these countries is strongly influenced by government policies, such as the Inflation Reduction Act in the US, China's 14th Five-Year Plan, and Germany's Federal Climate Protection Act. These policies are driving investment, target-setting and infrastructure development.
- **Regional variations:** There are significant regional differences within each country in terms of renewable energy availability, industrial infrastructure, and CO_2 emissions. For instance:
    - In the **US**, the Gulf Coast is emerging as a key region for both CO_2 capture and hydrogen production, presenting strong potential for e-fuel hubs. Texas leads in renewable electricity generation in the Gulf Coast.
    - In **China**, western regions like Xinjiang and Qinghai are attractive for green hydrogen production due to lower electricity costs, with industrial clusters on the east coast and south coast providing potential for e-fuel hubs.
    - In **Germany**, the Ruhr area is a significant CO_2 emitter and is a potential location for e-fuel production. Germany also has a developed hydrogen infrastructure in its northern regions.
- **Carbon Capture challenges & opportunities:**
    - **US:** The US has existing CCUS experience, particularly in the Gulf Coast, and is focusing more on CO_2 storage than utilisation. The 45Q tax credit favours CO_2 storage over utilisation.
    - **China**: China is rapidly developing its CCUS capacity, with many demonstration projects underway, although it does not have much geological storage capacity.
    - **Germany:** Germany has limited CCUS experience and faces restrictions on underground storage. The German government is drafting a Carbon Management Strategy to promote the use of carbon capture technologies, including transport and storage of CO_2.
- **Hydrogen production strategies:** All three countries are investing in hydrogen production, but with different approaches. The US is focusing on regional hubs, China on large-scale projects, and Germany on electrolysis capacity.

5. TECHNO-ECONOMIC ASSESSMENT

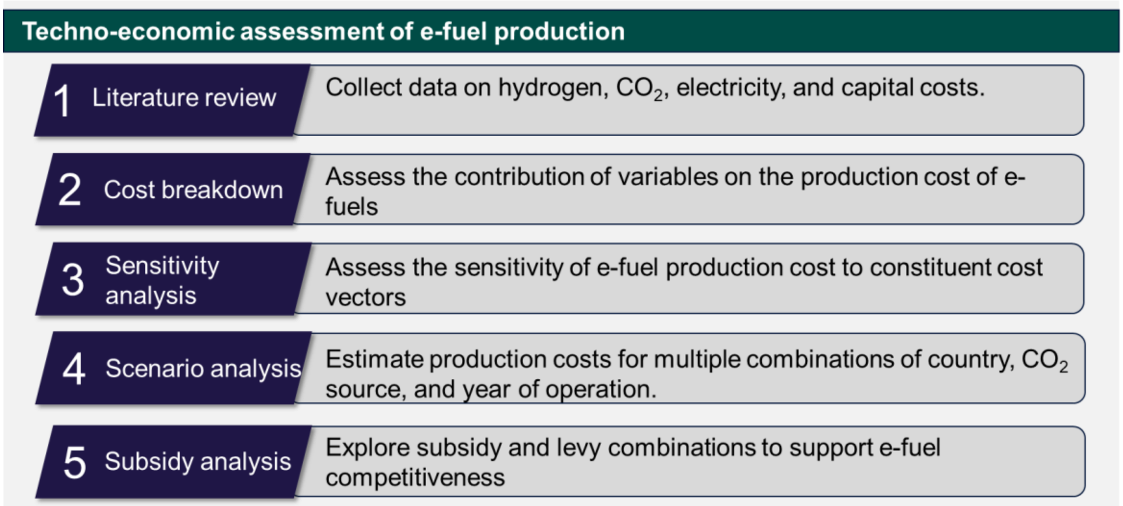
The primary objective of this chapter is to illustrate and compare, in a transparent manner, the range of costs of e-fuel production under different conditions. This is important as there are a range of costs for e-fuels in the literature, however it is not always clear how to compare these.

The three e-fuels examined are e-gasoline (petrol), e-diesel, and e-kerosene, and the analysis focusses on three pathways: Reverse Water Gas Shift (RWGS) and Fischer Tropsch (FT) route to e-diesel (FTD), methanol route to e-kerosene (MTK), and methanol route to e-gasoline (MTG). Both MTK and MTG include methanol production.

5.1 OVERVIEW OF THE APPROACH

The approach to explore the range of costs of e-fuel production pathways was based on the five steps illustrated in Figure 5-1 and described below.

Figure 5-1. Approach to techno-economic assessment of e-fuel production.



The Levelised Cost of Fuel (LCOF) is employed as a key metric for evaluating the economic viability of e-fuel production. It captures the lifetime costs, including capital investment, operational expenditure, feedstock, and energy inputs, apportioned across production output to ensure consistency over time. By anchoring this approach in a cost-based framework, LCOF facilitates standardised comparisons across production pathways, regions, and alternative fuels. This metric is well-suited for assessing emerging technologies such as e-fuels, offering a basis for evaluating cost-effectiveness. The formula below focuses on the production of the main selected fuel, for example kerosene in an MTK process or Diesel in an RWGS+FT-Diesel process. Potential revenues from by-products are out of the scope of the present study.

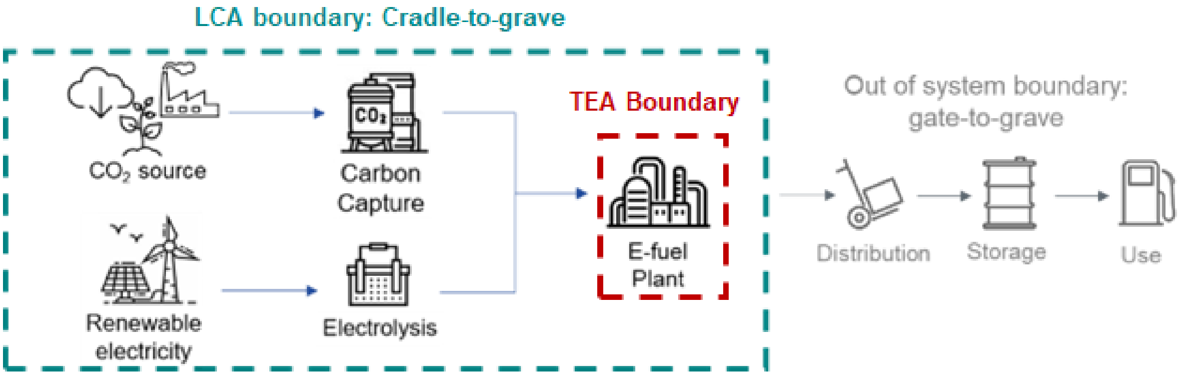
$$LCOF = \frac{Discounted\ total\ capital\ costs + Total\ lifetime\ variable\ operating\ costs + Total\ lifetime\ fixed\ operating\ costs}{Total\ lifetime\ of\ selected\ fuel\ production}$$

E-fuel production involves multiple steps that may be separated both geographically and temporally. A schematic representation of the e-fuels value chain is provided in Figure 5-2. The definition of system boundaries is critical in techno-economic assessments (TEAs) of e-fuel production, as these boundaries determine the inclusion or exclusion of specific process steps. A review of the literature of TEA of e-fuels highlights variation in system boundary conditions.

This chapter adopts system boundaries that exclude feedstock production processes, such as CO_2 capture and hydrogen generation via electrolysis powered by renewable electricity. The adopted boundaries, illustrated in Figure 5-2, align with the production pathways described in Section 2 of this study. Illustrative scenarios are developed to evaluate the economic feasibility of e-fuels and are intended to illustrate diverse combinations of hydrogen and CO_2 supply prices across geographic locations, temporal contexts, and carbon sources.

The techno-economic assessment of e-fuel production requires a set of economic assumptions pertaining to key input variables and operational parameters that influence the levelized cost of fuel.

Figure 5-2. Illustration of techno economic assessment (TEA) boundary (in red) considered in this study



This analysis examines economic factors influencing e-fuel production across three national contexts - **the United States**, **China**, and **Germany** - projected for **2030**, **2040**, and **2050**. By focusing exclusively on levelised cost of fuel, this chapter aims to:

- Estimate the cost of production of e-gasoline, e-kerosene and e-diesel
- Assess the competitiveness of e-fuels relative to alternative fuels
- Identify key cost drivers and opportunities for cost-reduction in e-fuel production.
- Provide stakeholders with insights on ways to support future e-fuel development.

5.2 RESULTS

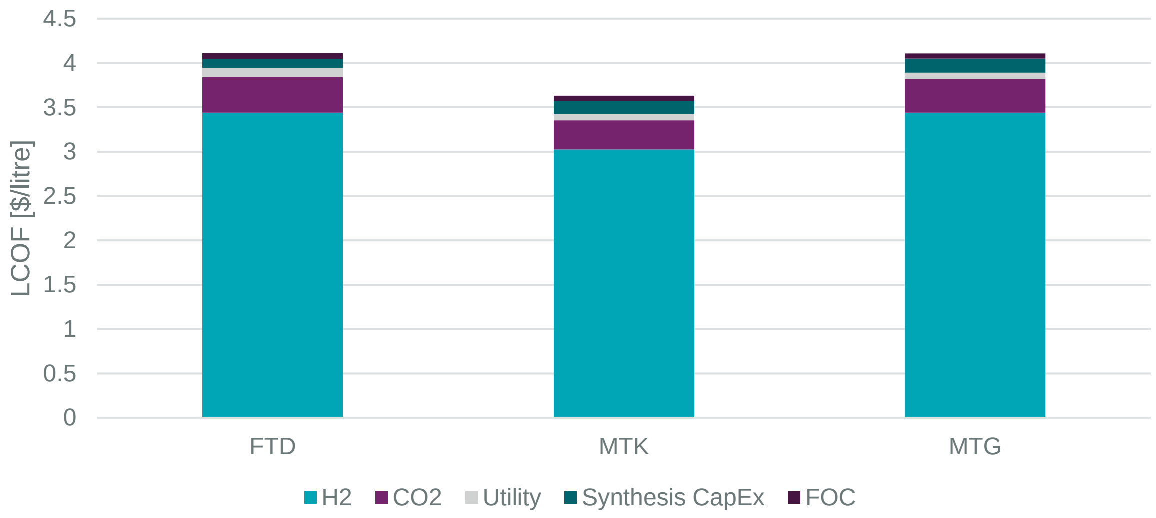
5.2.1 Cost breakdown

A baseline scenario, as described in Table 5-1, has been modelled to investigate the contribution of main cost components to e-fuel production cost. This example is meant to be illustrative of a 'realistic' case with a medium sized e-fuel plant, reasonable hydrogen prices (based on expert input), and CO_2 price corresponding to capture from an industrial source such as cement plant or a steel mill. The proportional contribution of the components will differ depending on multiple conditions, including but not limited to the size of the plant with CapEx contributing a larger proportion of the cost in smaller plants, the geographic location, feedstock costs, and year of production. The baseline scenario excludes any assumptions on subsidies.

Table 5-1. Baseline value for a FTD synthesis plant used to study the effect of subsidies in Figure 5-9

H_2 price [US$/kg]	CO_2 price [US$/t]	Production capacity [kt/year]	Plant lifetime [years]
6.75	90	150	25

Figure 5-3. Cost breakdown for production pathways based on the baseline scenario



The cost breakdown shown in Figure 5-3 indicates that e-kerosene would have the lowest cost of production through MTK route, compared to e-gasoline through MTG route and e-diesel through RWGS-FTD which have similar costs.

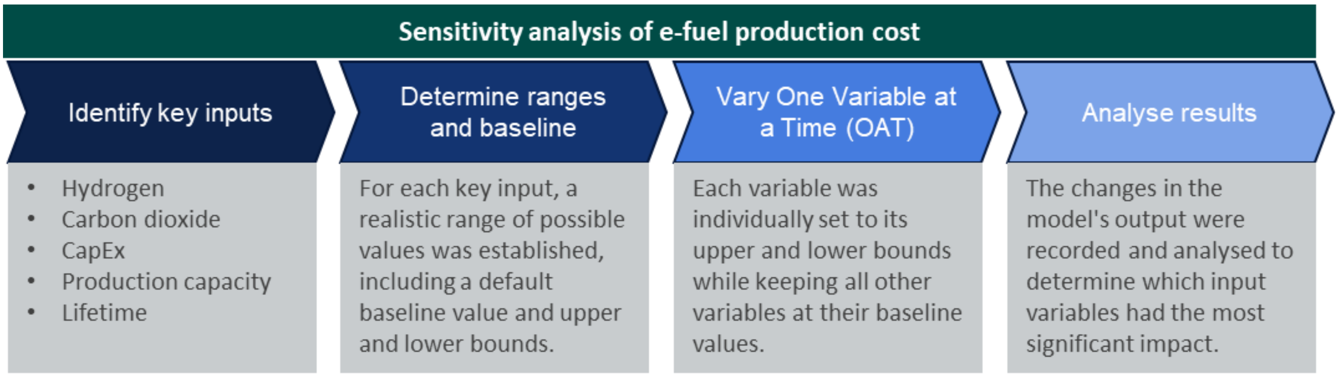
- **Hydrogen** costs dominate the cost of e-fuel production, accounting for **83.5-85.2%** of total production costs across all pathways.
- **CO_2** feedstock represents the second most significant cost component, contributing **7.7-8.5%** of total costs across the pathways.
- **Capital expenditure** shows some variation across technologies. The relatively modest contribution of capital costs **(2.5-5%)** indicates that policy support mechanisms might be more effectively directed towards operational expenditure rather, specifically towards the reduction of hydrogen costs, than capital grants for e-fuel synthesis plants, particularly in early market development phases.

These findings establish a crucial foundation for sensitivity analyses and optimisation strategies in e-fuel production. The dominant role of hydrogen costs suggests that improvements in hydrogen production efficiency and reductions in renewable electricity costs will have the most significant impact on overall economic viability. Meanwhile, the relatively modest contributions of capital and operating costs indicate that process intensification efforts may best focus on reducing hydrogen consumption rather than capital optimisation.

5.2.2 Sensitivity analysis

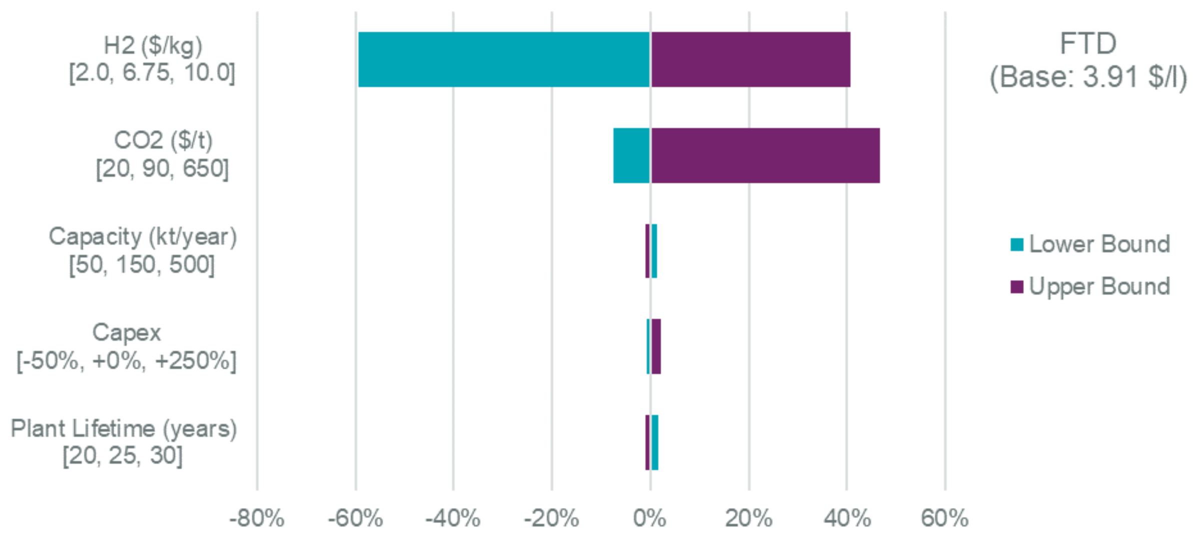
Understanding the sensitivity of output costs to inputs helps to prioritise opportunities to optimize the processes, mitigate risks, and enhance the competitiveness of e-fuels compared to conventional fossil fuels and other low-carbon alternatives. The approach to the sensitivity analysis is described in Figure 5-4.

Figure 5-4. Approach to e-fuel production cost sensitivity analysis



This analysis considers sensitivity to the costs of hydrogen and CO_2, and parameters related to plant design and operation, including production capacity, capital cost, and plant lifetime. The range of values chosen for the current sensitivity analysis was informed by current and expected changes in the parameters studied and are shown in Figure 5-5.

Figure 5-5. Sensitivity analysis for FTD (Diesel via Fischer-Tropsch)



Note: [Low, Base, High], e.g. H2 ($/kg) [Low:2.0, Base: 6.75, High:10.0].

Overall, the three pathways have similar sensitivities to the studied parameters. Several conclusions can be deduced from these results:

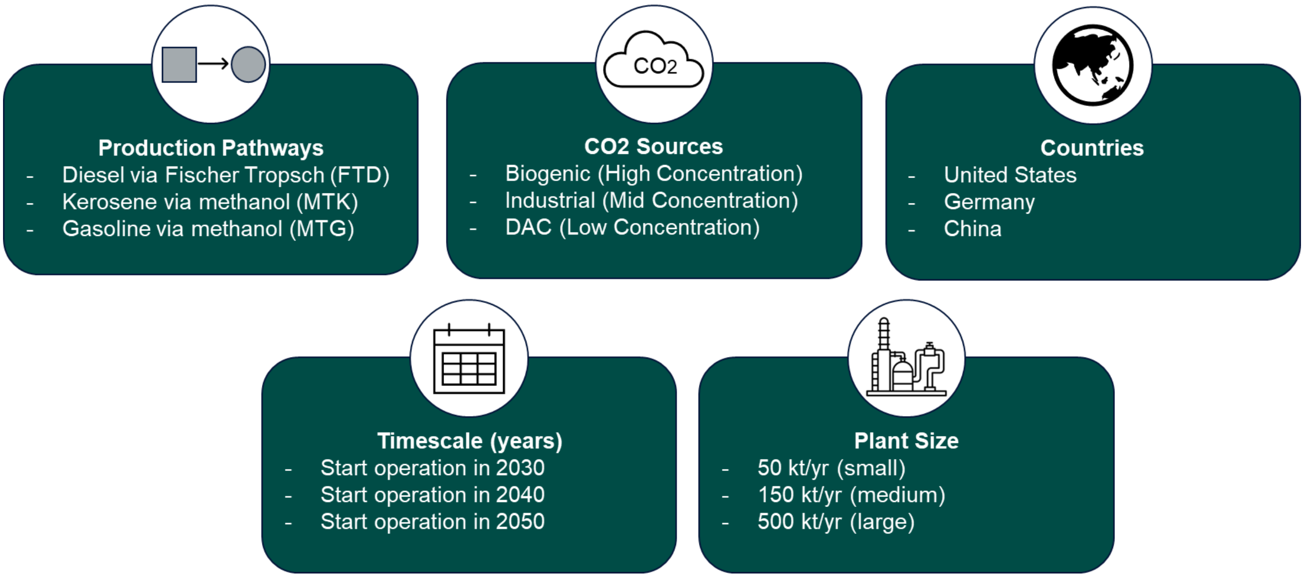
- **Importance of feedstock**, specifically H_2, indicates that e-fuels are best located in areas with cheap electricity. The availability of cheap renewables in the future may play a role in reducing e-fuel cost considerably, especially if e-fuel plants are built for flexible operations to take advantage of cheap, or even possibly zero cost, electricity prices during periods of abundant renewable electricity generation. The importance of hydrogen price also suggests that the marginal benefit of investment in electrolyser cost reduction may be as important, if not more important, than the investment in the reduction on capital cost of synthesis.
- **The cost of CO_2 is also important, albeit less important than the cost of H_2**. The upper bound of the CO_2 price corresponds to a DAC source. The analysis indicates that very low hydrogen (US$2/kg) prices would be required to counteract the likely high CO_2 price associated with DAC (US$650/t$CO_2$). Therefore, **investment in DAC to reduce its costs and energy requirements could reduce the cost of associated e-fuels.** As DAC becomes cheaper in the future, the importance of hydrogen costs, and of electricity as a prerequisite, grows as a decisive factor in determining e-fuel plant location, especially because cheaper electricity would also reduce CO2 capture cost through DAC.
- The greater influence of hydrogen cost compared to CO_2 cost suggests that it would be cheaper to **produce e-fuels in a location with cheap hydrogen (US$2/kg) and expensive CO_2 (US$650/t) than in a location with expensive hydrogen (US$7/kg) and cheap CO_2 (US$20/t), all other factors being equal.** This is a fundamental understanding that should inform e-fuel plant locations.
- The low importance of the synthesis plant CapEx indicates investment in e-fuel synthesis technology capital cost reduction may not be a priority. Instead**, investments into e-fuel synthesis should focus on increasing its efficiency to reduce feedstock consumption**. The reduction of both hydrogen and CO_2 feedstock requirements would influence the cost of e-fuel like the effect of the reduction in feedstock costs. However, CapEx will still have a significant impact on investment decision making. Large-scale plants comparable in size to oil refineries may cost several billions of dollars, and financing costs for first-of-a-kind projects are likely to be substantial. Moreover, while this sensitivity analysis focuses on the synthesis plant itself, the capital costs of associated infrastructure—such as hydrogen production, CO_2 capture, and renewable electricity generation—are excluded but will represent a considerable share of total system investment and must be carefully considered when evaluating the overall economics of e-fuel production should these facilities fall within the scope of the project.

5.2.3 Scenario analysis

This analysis explores the implications of e-fuel plant location and CO_2 source on production costs over the coming decades. Multiple scenarios were modelled considering different combinations of production pathway, CO_2 source, location of the plant (country), year of operation, and plant size. These considerations are summarised in Figure 5-6.

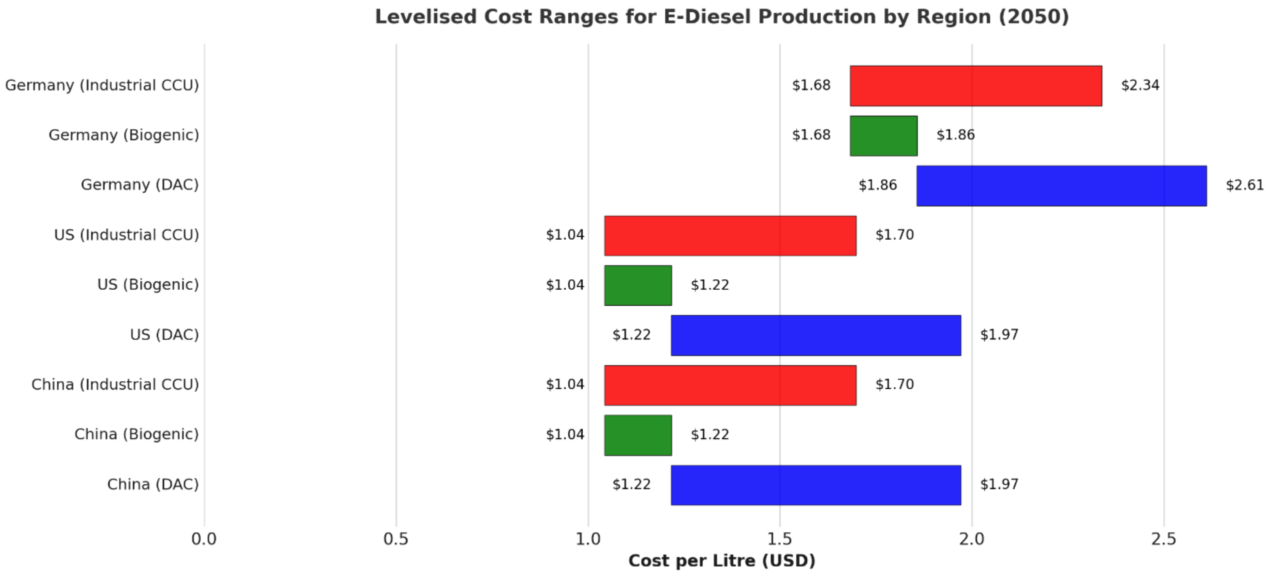
For this analysis, it is assumed that e-fuel plant capacities will evolve over time from small-scale plants (50 kt/year) in the near term (2030), medium-scale plants in the medium term (2040), and large-scale plants in the long term (2050). CO_2 costs are presumed to depend on the source of CO_2, while hydrogen costs are influenced by the country of production and the year in question. Details on the costs assumed for electricity, hydrogen, CO_2, and plant CapEx are available in the technical annex.

Figure 5-6. Variables considered for the scenarios considered in the techno-economic assessment.



The analysis for all production pathways reveals notable regional variations in e-fuel production costs, with China showing a cost advantage, the USA occupying a middle ground, and Germany facing higher production costs. These differences primarily stem from variations in hydrogen production costs, which are directly influenced by regional electricity prices. Lower renewable electricity prices in China reduce electrolysis operating costs, offering a comparative advantage. The USA's moderate electricity prices position it between China and Germany, while Germany's higher electricity costs result in the highest projected production costs. The Chinese context therefore presents a more favourable environment for early adoption and scaling of e-fuel technologies, while Germany's higher electricity prices create a more challenging pathway to commercialisation.

Figure 5-7. Comparison of the production cost for e-diesel by region and CO_2 source (2050).



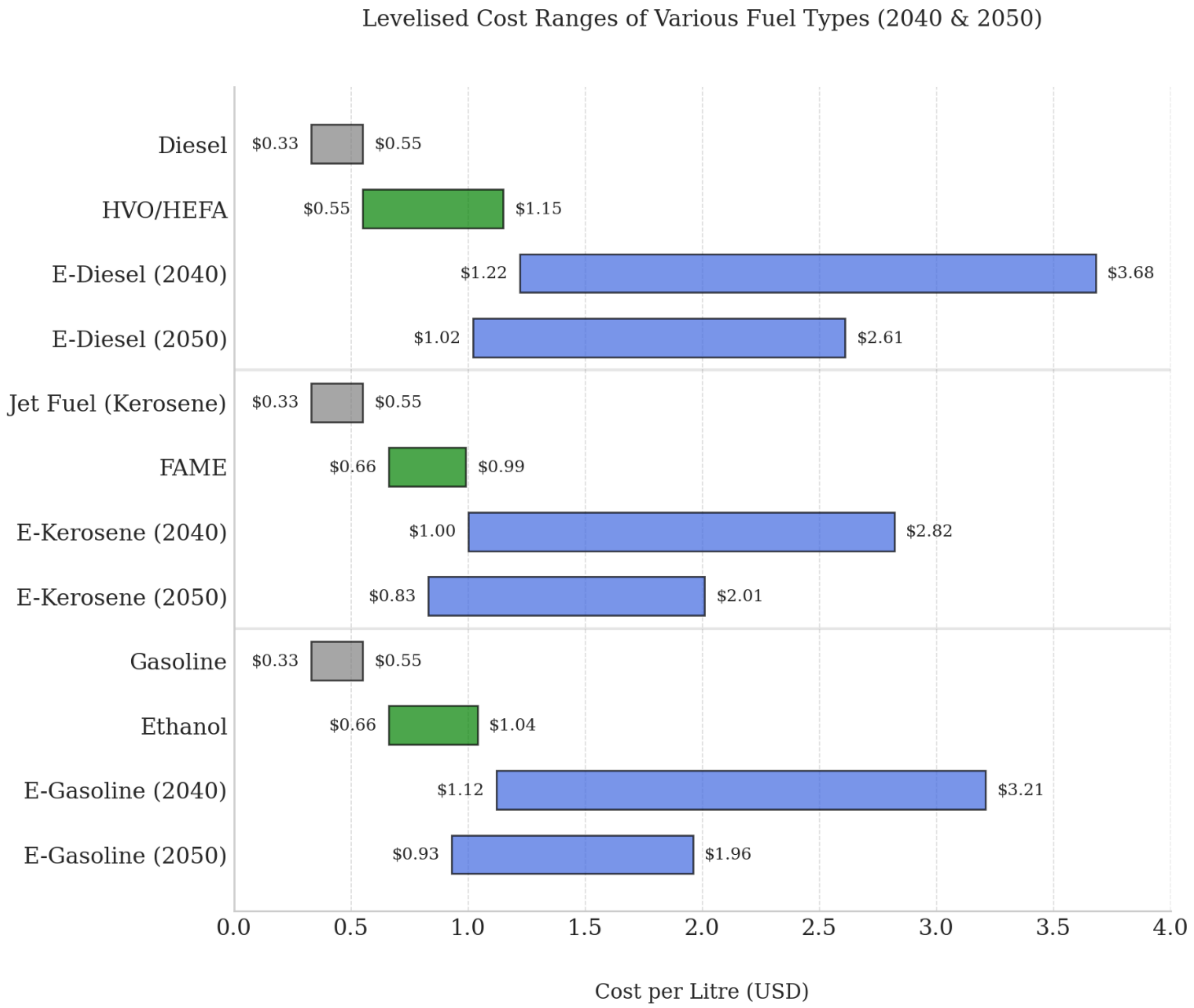
High-concentration CO_2 sources present lower cost uncertainties, making them a more predictable option for early e-fuel development. A critical factor in e-fuel economics emerges from the concentration of CO_2 sources utilised. High-concentration sources, such as those from bioethanol production and industrial processes, exhibit markedly lower uncertainty in cost projections. This reduced uncertainty reflects the mature nature of capture technologies for concentrated streams, well-established process economics, and extensive operational experience. The relative simplicity of capturing CO_2 from concentrated sources translates to more predictable operating costs and lower energy requirements, making these sources particularly attractive for early project development. For example, based on our analysis, in China in 2030, the cost of producing e-fuel using CO_2 from bioethanol has a narrower uncertainty range of US$ 1.5 to 1.8 / litre, compared to the wider range of US$2.3 to 3.5 / litre for direct air capture (DAC).

Reaching cost parity with conventional fuels by 2050 is unlikely without substantial advancements in technology or supportive policy measures. The analysis shows that even under optimistic cost reductions for hydrogen and CO_2 capture, e-fuels face significant challenges to become economically competitive. While lower hydrogen costs in China may accelerate progress in that region, the USA and Germany are likely to require additional interventions or a different approach. These findings suggest that the economic viability of e-fuels will evolve unevenly across regions, heavily influenced by the availability of low-cost renewable energy, infrastructure, and supportive policy frameworks.

5.2.4 Fuel cost comparison

Based on the assumptions of this study, the costs of e-fuel supply are higher than those for fossil fuels, even in 2050 considering cost reductions through technological advancements and the decrease in hydrogen and CO_2 prices. The range of e-fuel prices shown in Figure 5-8 includes possible production costs across different countries and CO_2 sources, with the lower bound corresponding to the lowest cost scenarios, namely lowest hydrogen cost in China coupled with high concentration CO_2 sources, and the upper bound corresponding to the highest hydrogen cost in Germany coupled with the highest estimate of CO_2 price from DAC. The underlying data can be found in Section 9.5. As recommended by OGCI and CRC, fossil fuel and biofuel costs are based on a recent OGCI report on energy demand dynamics across the Transportation Sector dated November 2024.

Figure 5-8. Comparison of e-fuel production costs with fossil- and bio-based fuels. Alternative fuel costs sourced from a report previously commissioned by OGCI.



In 2050 **e-fuels may be between 2 to 7 times more expensive than fossil fuels**, the cost difference is smaller compared to biofuels. In 2050, the production costs of biofuels are expected to range between US$0.55 – 1.15 / litre of diesel equivalent. **So, e-fuels may reach price parity with biofuels at best or be four times as expensive**.

There are considerable uncertainties on costs and future availability of fossil fuels and sustainable biofuels. Changes in feedstock supply, government policies, or other market dynamics might influence biofuel production costs and selling price substantially, and thereby the ratio of prices of biofuels:e-fuels. For example, if SAF were available at $2.80/litre (as per one ICCT report[34]), the ratio of e-fuel / biofuel cost would be close to 1.

It should be noted that the e-fuel costs are production costs and do not include logistics costs associated with storing and transporting the e-fuel to its destination, whereas the estimates for fossil and biofuels are landed costs that include delivery to destination.

5.2.5 Use of subsidies and levies to support e-fuel demand

The competitiveness of e-fuels against fossil fuel alternatives is heavily influenced by the relative costs of key inputs, such as hydrogen and CO_2, as well as the price of conventional fuels. Given that e-fuels will remain

[34] Nikita Pavlenko, Stephanie Searle, and Adam Christensen, *The Cost of Supporting Alternative Jet Fuels in the European Union* (Washington, DC: International Council on Clean Transportation, 2019), https://theicct.org/wp-content/uploads/2021/06/Alternative_jet_fuels_cost_EU_2020_06_v3.pdf

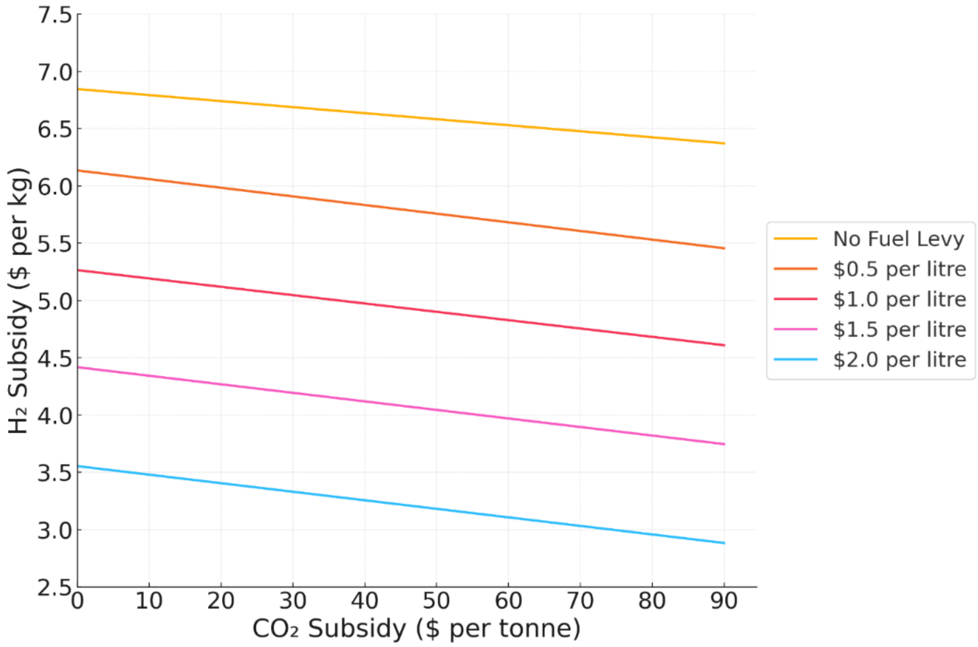
more expensive to produce than fossil fuels, policy mechanisms such as subsidies for hydrogen and CO_2 feedstocks, combined with levies on fossil fuels, could help bridge the cost gap and create a more level playing field. By reducing input costs and increasing the economic burden of fossil fuel consumption, these measures can accelerate the adoption of e-fuels in sectors where direct electrification is not feasible. This section explores how a targeted combination of subsidies and levies could enhance the market viability of e-fuels and drive their integration into existing fuel markets by taking a RWGS+FT plant producing e-diesel (FTD as an example), the details of which are shown Table 5-2.

Table 5-2. Baseline value for a FTD synthesis plant used to study the effect of subsidies in Figure 5-9

Pathway	H_2 price [US$/kg]	CO_2 price [US$/t]	Production capacity [kt/year]	Plant lifetime [years]
FTD	6.75	90	150	25

Based on the baseline case above, the results presented in Figure 5-9 demonstrate the relationship between **CO_2 subsidies** and **H_2 subsidies** required for e-diesel to achieve cost parity with fossil fuel diesel subject to a range of levies. Five scenarios were examined: a baseline with no fuel levy and incremental fuel levies of US$0.5, US$1.0, US$1.5, and US$2.0 per litre. To put these levies into context, they would be equivalent to paying US$200, US$400, US$600, and US$800, respectively, per ton of CO_2 emitted from diesel combustion.

Figure 5-9. Combination of Hydrogen and CO_2 subsidies required to reach price parity with fossil diesel



In the absence of a fuel levy, the required H_2 subsidy remains substantial. At **US$0 CO_2 subsidy per tonne**, the H_2 subsidy required to achieve cost parity is **US$6.75 per kg**. Even with a CO_2 subsidy of US$90 per tonne ($CO_2$ at zero cost), this figure only decreases slightly to **US$6.3 per kg**, highlighting the **limited efficacy of CO_2 pricing in addressing the high production costs of e-diesel**. Some of the datapoints in Figure 5-9 have been tabulated in Table 5-3.

Table 5-3. Hydrogen subsidy required for price parity with fossil diesel.

Fuel levy $/litre	0	0.5	1.0	1.5	2.0
H_2 subsidy $/kg (with US$0 CO_2 subsidy)	6.75	6.1	5.3	4.4	3.5
H_2 subsidy $/kg (with US$90 CO_2 subsidy)	6.4	5.5	4.6	3.8	2.9

Some of the key takeaways from the analysis include:

- CO_2 pricing alone struggles to displace fossil diesel due to high H_2 production costs.
- Fuel levies help narrow the cost gap by making fossil diesel more expensive, indirectly supporting e-fuel production.
- Unlike direct subsidies, fuel levies internalize environmental costs and create market-driven incentives but may also benefit other alternatives like biofuels.
- Cost parity for e-diesel depends on a balance of H_2 subsidies and fuel levies; a US$2.0 fuel levy can significantly reduce required H_2 subsidies to US$3.5/kg, making e-diesel more viable.

5.3 KEY TAKEAWAYS

- **E-fuels remain significantly more expensive than fossil fuels** across all examined scenarios. Even under optimistic projections for cost reductions, e-fuels are expected to be **two to seven times** more costly than conventional petroleum-based fuels by 2050.
- **Hydrogen cost is the primary determinant of e-fuel production economics**, contributing approximately **80% or more** to total production costs. The availability of low-cost, renewable hydrogen is therefore **critical for improving cost-competitiveness**.
- **CapEx of e-fuel synthesis plants, excluding the CapEx associated with feedstocks production, plays a comparatively minor role in overall cost structure**. While economies of scale provide some cost benefits, **reducing hydrogen costs and improving conversion efficiencies** will have a far greater impact on economic viability than reducing the capital cost of synthesis facilities.
- **CO_2 feedstock costs are a secondary but significant factor** in determining e-fuel production costs. While **high-concentration industrial CO_2 sources** can offer cost advantages, reliance on **Direct Air Capture (DAC) remains economically challenging** due to its **higher cost and energy requirements**. Other low-cost, high concentration sources, such as biogenic sources, should be considered to improve the economics of e-fuel production.
- **Scaling up e-fuel production capacity has only a limited impact on cost reduction**. Unlike conventional petroleum refineries, where economies of scale drive cost efficiencies, e-fuel production remains constrained by **feedstock costs (particularly hydrogen and CO_2) rather than capital investment**.
- **E-kerosene exhibits the lowest production costs among the three assessed e-fuels (e-diesel, e-kerosene, and e-gasoline)**. This is primarily due to the **lower energy intensity and conversion efficiency advantages** of the methanol-to-kerosene (MTK) production pathway.
- **Comparisons with biofuels indicate that e-fuels may achieve cost parity with certain biofuels (e.g., Hydroprocessed Esters and Fatty Acids - HEFA)** under **best-case scenarios**. However, in most cases, **e-fuels remain two to four times more expensive than biofuels**. E-fuels could be more competitive with biofuels in the future if sustainable biofuel supply becomes costlier or limited in scale.
- **Market competitiveness of e-fuels is dependent on policy interventions**, through **carbon pricing mechanisms, fossil fuel levies, and subsidies** for hydrogen production and CO_2 capture, as well as demand drivers such as obligations. Levies on conventional fossil fuel hydrocarbons to raise their relative price would **reduce amount of direct subsidies** required for e-fuel producers, though this could have wider effects.
- **Large-scale e-fuel plants equivalent in size to modern oil refineries (e.g., 500,000 barrels per day) are unlikely in the near term**. The primary limiting factor is the **high electricity demand required for green hydrogen production**, which would necessitate substantial expansions in low carbon electricityy supply (both renewable power generation capacity and supporting grid infrastructure).
- **Achieving widespread adoption of e-fuels will require transformative reductions in hydrogen costs.**

6. LIFE-CYCLE ASSESSMENT

This section provides an overview of the potential range in global warming potential (GWP) associated with three e-fuel production pathways from cradle-to-gate (including production and sourcing of feedstock, pre-processes, such as methanol synthesis and syngas production, and the subsequent upgrade to the final fuel). The three e-fuels examined are e-methanol to Gasoline (MTG), e-methanol to Kerosene (MTK), and Reverse Water-Gas-Shift (RWGS) and Fischer-Tropsch derived e-Diesel (FTD).

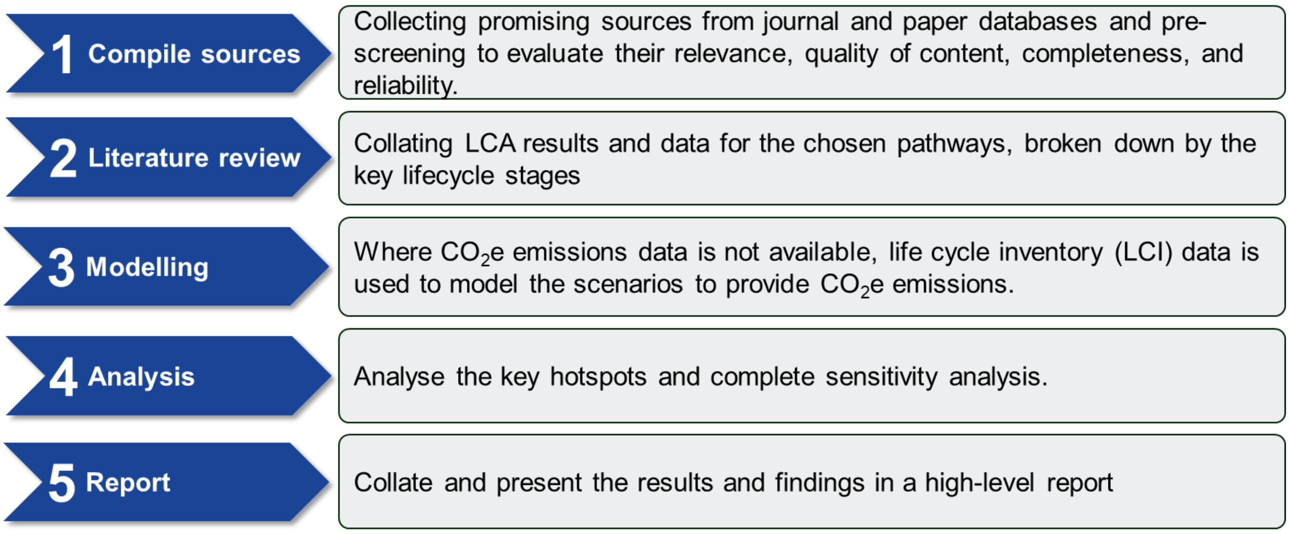
The pathways were reviewed assuming that that the e-fuels are produced from captured carbon dioxide (CO_2) sources (direct air capture (DAC), fossil and biogenic) and green hydrogen[35] from electrolysis. The following scenarios were considered;

- CO_2 source: Biogenic, DAC, and Industrial Carbon Capture and Utilisation (CCU);
- Geographical scenarios: US, China and Germany;
- Temporal scenarios: Current, 2030 and 2050.

6.1 OVERVIEW OF THE APPROACH

To conduct the study, a literature review of published LCAs was undertaken to obtain high level insights into the life cycle CO_2e emissions for each stage within the e-fuels' production pathway. This data was adapted to better reflect the scenarios under study. The focus of the study is the relative impact of the three e-fuel pathways under the different scenarios, however the results are also benchmarked against conventional fossil fuel-based gasoline, kerosene and diesel. The approach to explore the potential life cycle carbon impacts for three e-fuel production pathways was based on the five steps illustrated in Figure 6-1.

Figure 6-1. Overview of the approach used to understand the potential range in GWP for e-fuel production



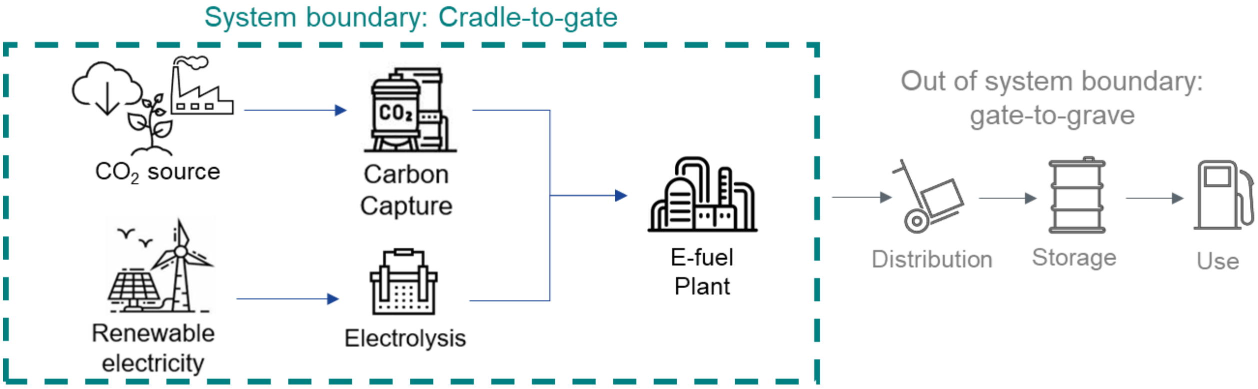
Full details of the approach, scope, functional unit, and allocation procedures are available in Section 9.7 of the technical annex.

This system boundary can be described as a cradle-to-gate system boundary and is illustrated in Figure 6-2 below. For the hydrogen step, only green hydrogen, produced through electrolysis using renewable electricity, has been covered. For the fuel processing, this includes all pre-processes (such as methanol synthesis, syngas production) and the subsequent upgrade to the final fuel (e-gasoline, e-kerosene and e-diesel). Distribution, storage and use of the e-fuels after production, and any additives required to make the fuels 'drop-in ready', are considered out of scope and have not been included in the analysis. Burdens associated with infrastructure, such as the infrastructure impacts associated with the production facilities, have been included.

[35] Note that nuclear is excluded from the European definition of green hydrogen and as such the term green hydrogen refers to renewable hydrogen produced by renewable electricity via electrolysis (Erbach, 2023).

This approach differs to the scope recommended in the Renewable Energy Directive (RED) but has been adopted in this study so as to ensure that the impact of all relevant flows are considered.

Figure 6-2. LCA system boundary considered for this study



6.1.1 Literature review

Data collection first involved a process mapping to identify the steps associated with each of the e-fuel pathways. These were systematically mapped to enable a thorough understanding of e-fuel production for the three e-fuels included in the study. The output of the process mapping is shown in Section 9.7.3.2 in the technical annex. These were built largely on the block flow diagrams included in Section 2.

Following this initial mapping, a list of promising literature sources were collated and pre-screened to evaluate their relevance, quality of content, completeness, and reliability. The sources deemed most suitable to the project scope were then taken forward for a more thorough review. They were deemed suitable if they contained relevant life cycle inventory (LCI) data applicable to the chosen pathways under consideration and if they reflected any of the given temporal or geographical scenarios also being considered. The majority of sources were collated from journal and paper databases (e.g. Science Direct) and LCA specific Emission Factor (EF) databases such as ecoinvent. Sources were not carried forward if they were not aligned to the technologies included within the three e-fuel pathways or if they were based on data beyond a 10-year cut-off from the current temporal scenario being considered.

6.1.2 Modelling

On completion of the desktop-based literature review, the findings were analysed to provide a likely range of life cycle CO_2e emissions for each of the fuels. However, comprehensive values were not available for all the scenarios and lifecycle stages, that could be used to fairly compare the e-fuel scenarios. Therefore, LCI data was collected from the sources and independently modelled to calculate the scenario ranges under study.

As stated, a number of different scenarios have been considered covering three geographical scenarios (US, Germany and China) and three temporal scenarios (Current, 2030 and 2050). For each mix of geographical region and timescale, a minimum and maximum range has been considered. Table 6-1 lists the scenarios that have been modelled as part of this assessment.

Table 6-1. Summary of the geographical and temporal scenarios being considered within the assessment

Temporal Scenario	Geographical Scenario		
	US	Germany	China
Current	Min.	Min.	Min.
	Max.	Max.	Max.
2030	Min.	Min.	Min.
	Max.	Max.	Max.
2050	Min.	Min.	Min.
	Max.	Max.	Max.

6.1.3 Life cycle inventory

The life cycle inventory (LCI) data collated for each of the temporal and geographic scenarios required data for each of the key flows within the cradle-to-gate system boundary. This includes:

1. the inputs of green hydrogen production,
2. the inputs associated with the carbon capture, purification and transport (for the three considered sources: DAC, biogenic and industrial CCU),
3. the inputs associated with the fuel production, including the electricity grid mixes.

As with any LCA study, a number of assumptions have been made. The LCI data and assumptions utilised in this study are described in Section 9.7.4 in the Technical Annex.

6.2 RESULTS

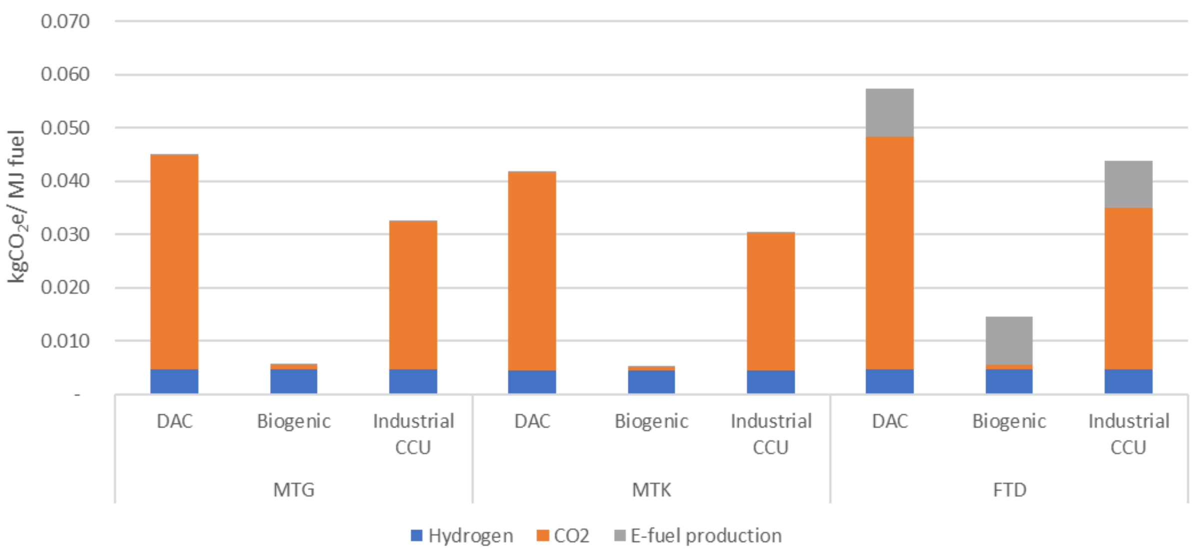
This section provides an overview of the key results of literature review and modelling and analyses key components of the life cycle. The full results are available in Section 9.7.5 of the Technical Annex.

As noted earlier, the study is based on publicly available data. Therefore, the results should be interpreted as indicative ranges as they are dependent on the availability and quality of literature data and the respective assumptions. These results are not intended to be utilised as singular results for set scenarios but rather to facilitate high-level comparisons and analysis regarding likely hotspots and variables within the cradle-to-gate impact associated with the three e-fuel production pathways studied. It is also important to note that these results are not intended for external comparison.

6.2.1 Life cycle stages

When exploring the impact across the cradle-to-gate impact of e-fuel production, it is important to explore the breakdown of each life cycle stage. The following figure displays the cumulative GWP for each life cycle stage, by CO_2 source, for each e-fuel, using the average China renewable electricity scenario only.

Figure 6-3. **Average scenario**: Cradle-to-gate GWP impact for e-fuel production broken down by lifecycle stage, for each CO_2 source, assuming China renewable electricity only



For each fuel and across the minimum, average and maximum scenarios, the biogenic scenario is lower than the industrial CCU and DAC carbon sources. This is because it is assumed that capturing CO_2 from a biogenic source requires less electricity than in the case of industrial CCU and DAC and has no heat requirement.

DAC has the highest footprint under the average and maximum scenarios as it has the highest heat requirement. However, under the minimum scenarios, heat requirements for both industrial CCU and DAC are assumed to be sourced from waste heat, and therefore industrial CCU is higher due to the higher heat requirements of monoethanolamide required to capture CO_2 for industrial CCU.

The relative contribution of the life cycle stages remains fairly steady within each fuel. The production of the feedstocks (the hydrogen and CO_2), account for the majority of the impact in nearly all scenarios, at >97% of the GWP for the MTG and the MTK. Within this, for the DAC and industrial CCU scenarios, the CO_2 sourcing is by far the most significant. However, for the FTD, the fuel production process accounts for a much more significant proportion of the total cradle-to-gate footprint (average of 21%). This is due to the RWGS and FT processing requiring higher utility input than the MTG and MTK fuel production processes.

The impact of hydrogen sourcing is very similar across each scenario as only green hydrogen is considered and the graph only shows the results as per the China renewable electricity scenario.

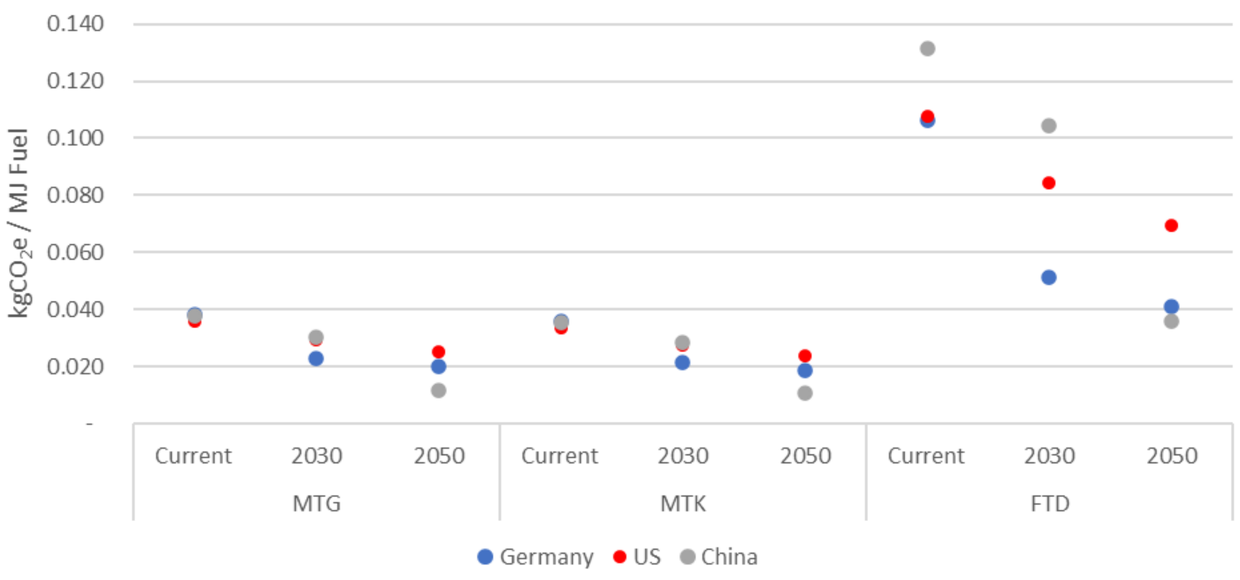
Within the minimum scenario assuming China renewable electricity only, electricity consumption and infrastructure burdens account for a significant proportion of the total cradle-to-gate footprint for each e-fuel. The GWP associated with electricity consumption accounts for between 23% to 91% of the total footprint depending on the fuel type and CO_2 source, whilst the infrastructure burden ranges from 7% to 63%. Heat accounts for 0% of the total cradle-to-gate footprint for each e-fuel under all minimum scenarios as utilisation of waste heat is assumed for the CO_2 and H_2 sourcing and FTD fuel production is assumed to be electricity only.

However, when considering the maximum scenario assuming China renewable electricity only, the contribution of heat significantly increases up to a top range of 81% under the DAC scenario, whilst the proportion associated with infrastructure burdens decreases to between 3% and 15%. The impact associated with electricity decreases substantially for DAC and industrial CCU scenarios to 8% to 48% as the heat usage dominates, however no heat is assumed within the biogenic CO_2 capture, and therefore electricity still accounts for the greatest proportion of the footprint (70-96%).

6.2.2 Geographic and temporal scenarios

As noted previously, three geographic and temporal scenarios have been considered: China, US and Germany for the geographic scenarios and current, 2030 and 2050 for the temporal. To understand the relative impact of these scenario choices, a sensitivity analysis was undertaken, considering the average inventories under a biogenic carbon source scenario for each geography and time scenario. The results are provided in Figure 6-4 below.

Figure 6-4. Sensitivity on GWP based on country grid mix variation across the geographic and temporal scenarios (average scenario used assuming biogenic sourced carbon)



The results show that based on the current grid mix data (2024), the difference between the three countries is much smaller than in 2030 and 2050. This is in part due to the difference in the carbon intensities modelled for the grid mix (used for the CO_2 and fuel production) and renewable electricity scenarios (used for the H_2).

Within the current grid mix data, China has the highest carbon intensity, but its renewable scenario (used for H_2) is the lowest. Therefore, since H_2 accounts for a significant proportion of the cradle-to-gate impact, the increase caused by using China's grid mix is mitigated by the use of the lower GWP renewable electricity within the MTG and MTK scenarios. For the FTD, the impact of greater electricity consumption associated with the FTD fuel production process highlights the high carbon intensity of China's current grid mix.

By 2030, Germany shows the greatest reduction in carbon intensity, however, by 2050, the lowest carbon intensities for fuels are achieved in China. Therefore, in 2050, under the average biogenic carbon source scenario, it is projected that e-fuel production in Germany and China will have GWP impacts of around half that of e-fuel production in the US. Therefore, Germany is likely to be the region that will have the lowest GWP associated with e-fuel production if production utilises grid electricity. Use of renewable electricity in the H_2 supply suggests that China will remain a competitor, particularly in 2050, assuming that hydro power can be used. It should be noted that the variation in GWP is more pronounced for the FTD than MTG and MTK, due to the additional electricity used for the production stage. Additionally, this variation will be intensified under the industrial CCU and DAC scenarios due to the greater use of electricity in these processes.

6.2.2.1 *Renewable only sensitivity*

This section explores how low the e-fuels' GWP could be if renewable energy is utilised for the entire production pathway, not just hydrogen. This sensitivity found that when using renewable electricity only, China has the lowest impact across all scenarios, since hydropower has a lower GWP than that of wind power modelled for US and Germany. Under this scenario, DAC scenarios are seen to be the highest, due to having the highest modelled heat requirement. Additionally, the DAC FTD pathway is seen to have the highest GWP, due to requiring the greatest quantity of CO_2 per kg of fuel, and due to having the highest modelled heat requirement within the fuel production process.

6.2.2.2 *Hydrogen hotspot*

There is a lack of standardisation in the definition of green hydrogen. The EU has set a definition of green/renewable hydrogen that requires the hydrogen to be produced within a carbon intensity threshold of 3.4 kg of CO_2e per kg of H_2 [36,37]. Within the US, green hydrogen must have GHG emissions no greater than 4 kg of CO_2e per kg of H_2. The China Hydrogen Alliance defines green hydrogen with a threshold of 4.9 kg of CO_2e per kg of H_2 [38,39]. This has been ambiguously addressed in official governmental documents but is used as the threshold for China within this study. It is unlikely that these thresholds will be altered in the foreseeable future unless a global standard is defined.

Table 6-2 below presents the regional limits alongside the modelled GWP ranges for H_2 under the renewable energy scenarios. These ranges were modelled based on the geographic scenarios assuming renewable production only, with the maximum value provided as the upper bound for the GWP impact per kg of green hydrogen set by each region. The ranges presented in the table below fall within the ranges found within the literature review, which was seen to be between 0.003 – 0.05 kgCO_2e / MJ[40,41,42,43,44].

---

[36] Williams, J., 2023, GH2 statement on new EU rules defining green hydrogen, retrieved from: https://gh2.org/article/gh2-statement-new-eu-rules-defining-green-hydrogen

[37] CertifHy, 2021, What is CertifHy, retrieved from: https://www.certifhy.eu/wp-content/uploads/2021/10/CertifHy_folder__leaflets.pdf

[38] Lou, Y., and Corbeau, A., 2023, China's Hydrogen Strategy: National vs Regional Plans, retrieved from: https://www.energypolicy.columbia.edu/publications/chinas-hydrogen-strategy-national-vs-regional-plans/#:~:text=However%2C%20this%20framework%20establishes%20a,2e%2FkgH2%20for

[39] Liu, W., et al., 2021, Green Hydrogen Standard in China: Standard and Evaluation of Low-Carbon Hydrogen, Clean Hydrogen, and Renewable Hydrogen, retrieved from: https://www.eria.org/uploads/media/Research-Project-Report/RPR-2021-19/15_Chapter-9-Green-Hydrogen-Standard-in-China_Standard-and-Evaluation-of-Low-Carbon-Hydrogen%2C-Clean-Hydrogen%2C-and-Renewable-Hydrogen.pdf

[40] Element Energy, 2021, Low Carbon Hydrogen Well-to-Tank Pathways Study, retrieved from: https://www.zemo.org.uk/assets/reports/Zemo%20Low%20Carbon%20Hydrogen%20WTT%20Pathways%20-%20full%20report.pdf

[41] Vilbergsson, K., et al., 2023, Can remote green hydrogen production play a key role in decarbonizing Europe in the future? A cradle-to-gate LCA of hydrogen production in Austria, Belgium, and Iceland, retrieved from: https://www.sciencedirect.com/science/article/pii/S0360319923000824

[42] Weidner, T., Tulus, V., and Guillen-Gosalbez, 2023, Environmental sustainability assessment of large-scale hydrogen production using prospective life cycle analysis, retrieved from: Environmental sustainability assessment of large-scale hydrogen production using prospective life cycle analysis - ScienceDirect

[43] Iyer, R., et al., 2024, Life-cycle analysis of hydrogen production from water electrolysers, retrieved from: https://www.sciencedirect.com/science/article/pii/S0360319924025953?ref=pdf_download&fr=RR-2&rr=9047b4fbbf977330

[44] Buffi, M., Prussi, M. and Scarlat, N., 2022, Energy and environmental assessment of hydrogen from biomass sources: Challenges and perspectives, retrieved from: https://www.sciencedirect.com/science/article/pii/S0961953422002185

Table 6-2. Green hydrogen impacts ($kgCO_2e$ / kg of hydrogen) as defined as limits in national standards or modelled in this study

Country / region	Limit in standard $kgCO_2e$ / kg of hydrogen	Modelled impact $kgCO_2e$ / kg of hydrogen		
		Min	Average	Max
EU	3.4	1.1	1.3	1.5
China	4.9	0.4	0.4	0.5
USA	4	0.8	1.0	1.1

These results show the impact that the country specific limitations have on the extent of the potential range of GWP for green hydrogen. While the LCI inventory data used to model the most prevalent renewable in each country suggest that green hydrogen from China would have the lowest GWP, in practice it is possible that other renewables could be used. However, these would still have to meet the threshold set in each country. If this was the case, then this would be lowest for Germany as it is within the EU not China which has a more stringent threshold.

6.2.3 Heat source

In addition to the renewable electricity considerations discussed above, heat consumption within the CO_2 sourcing stage represents another important hotspot. Therefore, another sensitivity was completed on the potential impact of sourcing waste heat on the total cradle-to-gate GWP. The sensitivity compared the results under the China renewable electricity scenario only. Within this, the GWP associated with the supply of waste heat for the CO_2 sourcing and FTD fuel production are assumed to be negligible and so are modelled as zero GWP. This is in line with the modelling of waste heat in ecoinvent.

The results indicate that sourcing waste heat can substantially reduce the impact on DAC and industrial CCU. However, it has a much smaller impact on biogenic CO_2 outcomes because heat is not modelled as a factor in the biogenic CO_2 process. Consequently, there is no observed change in the biogenic CO_2 MTG and MTK pathways, as their production processes do not require heat. Under the FTD pathway, a reduction of up to a 71% of the total cradle-to-gate GWP impact is seen if waste heat is used. Within the DAC sourced carbon scenarios, utilising waste heat is shown to potentially reduce the total cradle-to-gate GWP impact by 64-85% under the China renewable electricity scenario, and 46-72% within the industrial CCU scenarios. However, even when utilising waste heat, the DAC and industrial CCU systems return a GWP impact higher than the biogenic systems due to their higher electricity requirements.

6.2.4 Transportation

Within this study, it has been assumed that the hydrogen production is co-located at the e-fuel production plant. Additionally, it has been assumed that the carbon dioxide is transported from the source to the plant by pipeline. To assess the potential impact of transportation, a sensitivity has been conducted on the impact of using truck transport instead of pipeline for the CO_2 and on the impact of including transportation of the H_2.

Pipeline transportation has been assumed for the default scenario for carbon dioxide transportation since it is typically the most common method of transportation due to scalability, efficiency and cost efficiency. However, when initially setting up fuel production, and additionally when sourcing biogenic carbon from smaller anaerobic digestion plant, then transport by truck and trailer can be more common as CO_2 pipeline infrastructure may not be available for these smaller more distributed sources.

When compared to the results from the renewable electricity scenarios only, for the carbon sourcing, the assumed pipeline transport accounts from between 0.1% of the total cradle-to-gate footprint to an average of 6% for transport over 100km. If this is switched to truck transport, this increases to an average of 3.4% of the total cradle-to-gate footprint for 20km up to an average of 16% for 100km.

Similarly for the hydrogen, if transport were included, pipeline transport would account for an average increase of 1% of the total cradle-to-gate footprint even for 100km, whilst the potential impact of truck transport could result in an average increase of 2% for 100km. This highlights that though transport by pipeline can be negligible, transportation over greater distances and by truck can have a significant impact, in particular regarding CO_2 transport, since a greater quantity is required.

6.2.5 Electrolyser efficiency

This study has assumed an efficiency of 70% for the alkaline electrolysis used for the green hydrogen. Alkaline electrolysis is typically within a range of 60-80% efficiency[45]. In order to assess the impact of this range, and the impact of the potential for improved efficiency over time, a sensitivity was completed altering the efficiency. The results of altering the electrolyser efficiency between 60% and 80%, under the China renewable electricity scenario, are shown in the technical annex (Electrolyser Efficiency).

The results show that reducing the electrolyser efficiency to 60% increases the total cradle-to-gate GWP footprint by up to 15%, whilst increasing the electrolyser efficiency to 80% decreases the total cradle-to-gate GWP footprint by up to 11%. This is a result of a 17% increase in H_2's GWP under the 60% electrolyser efficiency scenario and a 13% decrease in the H_2 GWP under the 80% electrolyser efficiency scenario. This highlights the potential impact on the range in GWP associated with assumptions used, whilst also indicating the potential reductions in the GWP that are possible if electrolyser efficiency is improved in future.

6.2.6 Benchmarking against fossil equivalent

When evaluating and comparing the life cycle carbon impacts of fuels, it is important to account for the carbon modelling approach used to represent prevented CO_2 emissions. Within this study, we have selected a focus on the cradle-to-gate impact of e-fuel production without including the gate-to-grave impacts (associated with distribution, storage and use), as, excluding carbon allocation, the GWP impact of gate-to-grave impacts will be identical at a net level. Therefore, the cradle-to-gate system boundary of this study allows for greater focus on the key differences.

Under the system expansion approach used in this study for fossil fuels, the CO_2 which is released on combustion needs to be accounted for in calculation of the total cradle-to-grave impact, whereas for e-fuels, the CO_2 released on combustion does not need to be included in the GWP since the additional consideration of the carbon captured (in the case of DAC and biogenic CO_2) or avoided (in the case of fossil CO_2) will be re-released on combustion of the fuel (see Figure 9-93: Carbon allocation modelling).

Therefore, to contextualise the results and enable a more holistic comparison of GWP impacts of e-fuels with counterfactuals, we have included results that also include the gate-to-grave impact associated with the combustion of the fuels.

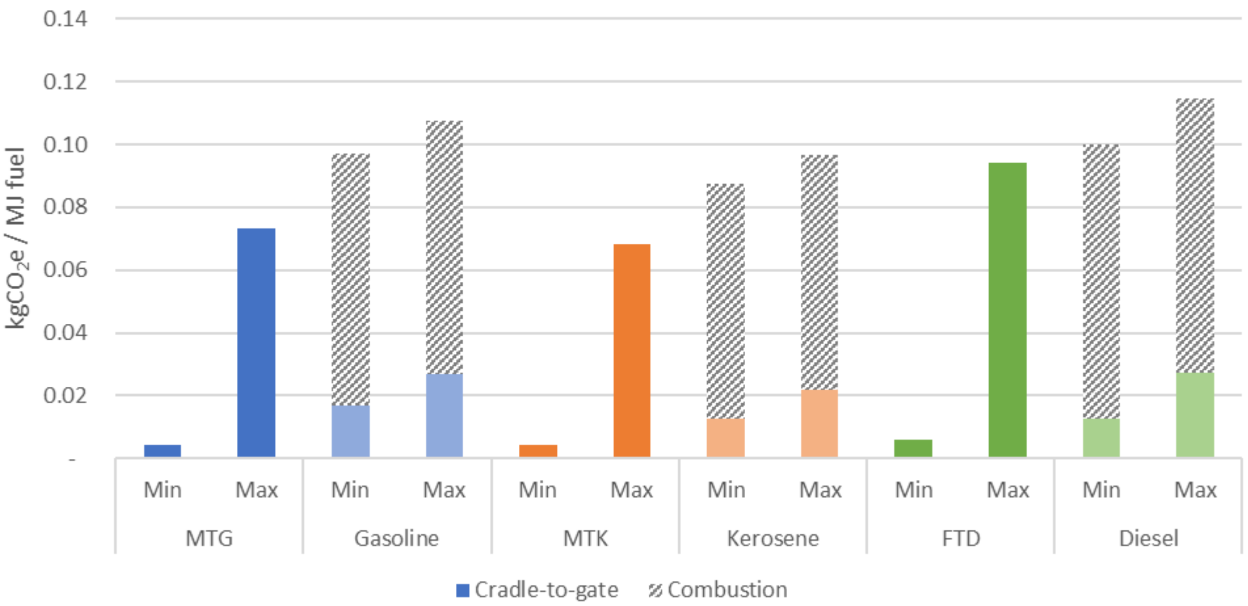
Figure 6-5 compares the GWP ranges for the cradle-to-gate impact of e-fuel production, for MTG, MTK and FTD, and against that of fossil fuel equivalents (gasoline, kerosene and diesel), including the impact associated with combustion. The graph shows that though there is significant cross over between the GWP ranges for each e-fuel and its respective fossil fuel, the impact of the combustion for each fossil fuel is greater than the highest potential GWP range for each of the e-fuels assessed. This highlights the benefit of e-fuels vs fossil-based fuels.

However, the results also show that when looking at cradle-to-gate (i.e. production) footprints only, there is potential for the e-fuel to have substantially higher GWP impact than the production impact of counterfactuals. This is largely associated with the heat requirements under the maximum scenarios for the DAC and industrial CCU sourced CO_2 scenarios which account for up to two thirds of the total cradle-to-gate impact.

It should be noted that this comparison is assuming that the combustion of the counterfactual is not utilising carbon capture and storage (CCS) to prevent the release of the carbon emissions and storing it to prevent it entering the atmosphere long term. This would reduce the advantage of the e-fuels in comparison to fossil-based fuels. However, CCS, as with the carbon capture and utilisation (CCU) used to produce e-fuels, is currently only utilised on industrial installations, with limited pilot scale deployment in mobile combustion (e.g. vehicles). Moreover, it is not economically viable on a small scale.

[45] El-Shafie, M. (2023). Hydrogen Production by water electrolysis technologies: A review. Results in Engineering, 101426. doi:10.1016/j.rineng.2023.101426

Figure 6-5. Comparison of ranges of GWP impact of e-fuel production (renewable electricity consumption only) against fossil fuel equivalent, using system expansion approach



6.3 KEY TAKEAWAYS

H_2 source

- This study assumes that green hydrogen is sourced in the production of e-fuels but has taken the decision to include the impacts associated with infrastructure, both for the electrolyser and the renewable electricity. This results in hydrogen representing an important hotspot, even though it is sourced via 100% renewable electricity.
- China may present the best decarbonisation opportunity due to hydro-power electricity availability.
- The green hydrogen standard in Europe (and therefore Germany) is more stringent than China, so more generally, Europe may provide more certainty around the sourcing of hydrogen with a lower GWP.
- Therefore, the key recommendation is to take care understanding the likely source of renewable electricity and ensure that supply by this source can be well evidenced, such as through guarantees of origin, power purchase agreements or, better yet, direct wire arrangements.

CO_2 feedstocks

- Biogenic CO_2 in particular is a term that covers a wide range of options. This study has only explored biogas purification and consequently its conclusions are limited to this technology.
- It is found that biogenic CO_2 presents the greatest opportunity to reduce the e-fuels' carbon footprint.
- Sensitivity analysis indicates that this is principally linked to assumptions regarding the source of heat within the DAC and industrial CCU options that are not applicable to the bio pathway and that each of the sources are far more comparable if waste heat can be utilised.
- Therefore, the key recommendation is that care is given to heat sources for CO_2 capture. With regards to industrial CCU, this study assumes that industrial CCU prevents CO_2 from industry reaching atmosphere. However, this assumption is unlikely to be the case as the economy decarbonises. This point is reflected in European legislation around e-fuels - the European Commission has stated that "the continued use of transport fuels of non-biological origin and recycled carbon fuels that contain carbon from non-sustainable fuel is not compatible with a trajectory towards climate neutrality by 2050"[46]. It is therefore not recommended that industrial CCU is prioritised given the parity of results under a waste heat scenario.

[46] European Commission, 2023, Commission delegated regulation (EU) 2023/1185, retrieved from: https://cdn.prod.website-files.com/643691764f0ee331841022ac/64a7f7c181f284e775833e7d_CELEX_32023R1185_EN_TXT.pdf

Fuel processing and transportation

- The recommendations regarding electricity and heat are also applicable for the fuel processing steps. Utilising 100% renewable electricity and sources of waste heat can offer significant reductions in the carbon footprint of these stages.
- Consideration should be given to the location of fuel processing plants. This study assumes relatively short distances between the CO_2 source and the fuel processing plants, with hydrogen electrolysers being co-located. Sensitivity analysis suggests that if these distances are increased and transport mode is shifted from pipeline to truck movements, the GWP of the e-fuel can increase by as much as 16%.
- Co-locating and minimising transport movements is key. Given the previous recommendations, it is suggested to first identify good renewable energy and waste heat sources and then locate fuel plants as closely as possible to minimise impacts.

Comparison to fossil fuels

- Compared to fossil fuel equivalents, the pathways considered in this assessment can result in lower emissions when under optimum conditions. However, under adverse conditions, they can have much higher cradle-to-gate impacts, which in some worst-case scenarios can exceed the cradle to grave impacts.
- When considering the impact of the tailpipe emissions associated with combustion, the impact associated with the carbon released by the fossil fuels in use dwarfs the cradle-to-gate impact.

7. CARBON ABATEMENT COSTS

The primary objective for the use of e-fuels is to decarbonise energy systems and decrease the reliance on fossil fuels. Therefore, the cost of CO_2 abatement compared to fossil fuels is a key indicator of e-fuels attractiveness. This section examines the economic viability of reducing greenhouse gas emissions through the production and use of synthetic fuels. The following analysis examines the value for money from a CO_2 saving perspective for different e-fuel production pathways. This analysis is based on the outputs from the techno-economic and life cycle assessments, Sections 5 and 6, respectively.

Figure 7-1. Cost per GWP saved based upon region, pathway and CO_2 source for 2050.

The data indicate that the US$/$tCO_2$ saved varies across a wide range, depending on the CO_2 source and the e-fuel synthesis pathway employed.

High energy costs in Germany make e-fuels the least cost competitive across the three countries analysed (China, the United States, and Germany).

- Three distinct CO_2 sources are considered:

1. DAC
2. biogenic CO_2 from biomethane upgrading
3. industrial CCU

Biogenic CO_2 consistently appears more cost effective than industrial CCU or DAC.

- The consistently lower costs associated with biogenic CO_2 pathways suggest these may offer the most economically viable route (relative to environmental benefits) to e-fuel production, particularly in regions with abundant biomass resources.
- In the worst-case scenarios, where the carbon abatement costs for e-fuel exceed US$1,000/$tCO_2$, it is important to question whether e-fuels are indeed the most appropriate decarbonisation strategy. There may be alternative approaches, potentially including combinations of conventional fossil fuel use and matched negative emissions plants.

8. CONCLUSIONS AND RECOMMENDATIONS

The aim of this report is to evaluate carbon dioxide sources for e-fuel production. The work involved a global analysis of potential e-fuels hubs, focusing on transport sectors (aviation, heavy-duty and light-duty on-road).

The study assessed several e-fuel production pathways. The two more mature pathways to produce e-fuels from hydrogen and carbon dioxide were found to be via methanol-based conversion, and via reverse water gas shift (RWGS) and Fischer-Tropsch (FT) based conversion. Based on several criteria, mainly feedstock quantity requirements and TRL, only three pathways were chosen for further assessment: e-kerosene via methanol (MTK), e-diesel via Fischer-Tropsch (FTD), and e-gasoline via methanol (MTK).

A review of the supply chain associated with e-fuel production indicated that developing hydrogen and CO_2 infrastructure for e-fuels is both costly and complex, with challenges including high capital costs, uncertain supply and demand, safety and standards concerns, and competition for resources. Site-specific issues, such as the need for abundant, low-cost green electricity and water for hydrogen production, further complicate these efforts. Nevertheless, enablers including robust national strategies, clear policy directions, and coordinated stakeholder decision-making can help mitigate these barriers. Transport logistics also play a critical role, as the choice of mode (e.g., pipelines or ships) and the physical form of the material (such as CO_2 phases or hydrogen carrier molecules) directly affect cost and efficiency. In sourcing CO_2, sectors such as ethylene oxide, ammonia, ethanol, midstream oil and gas, and alcohols are attractive due to higher CO_2 concentrations, though their limited availability may complicate logistics. However, some regulations may influence the choice of CO_2 source for e-fuels, such as the REDIII in the EU. REDIII allows the use of CO_2 from Direct Air Capture, and Biogenic CO_2 to be considered as avoided emissions, whilst industrial point sources are only considered to be avoided until 2041.

A global assessment of e-fuel production was conducted to find locations with high potential for e-fuel production. The analysis identified the United States, China, and Germany as complementary locations for further study, due to their high potential and regional diversity. All three nations see sustainable fuels as key to decarbonising sectors such as aviation and heavy transport, where electrification is challenging, and their markets have been strongly influenced by supportive government policies—the Inflation Reduction Act in the US, China's 14th Five-Year Plan, and Germany's Federal Climate Protection Act. Regional differences are notable: the US Gulf Coast, particularly Texas, is emerging as a hub for CO_2 capture and hydrogen production; in China, cost-effective green hydrogen is promising in western regions like Xinjiang and Qinghai, while the east and south host significant industrial clusters; and in Germany, the Ruhr area stands out due to high CO_2 emissions, complemented by a robust hydrogen infrastructure in the north. Each country also presents different carbon capture and storage challenges and opportunities, with the US leveraging its CCUS experience and storage incentives, including the 45Q tax credit, China rapidly developing CCUS capacity despite limited geological storage, and Germany navigating its constrained CCUS landscape through emerging strategies.

A techno-economic assessment was conducted to estimate and compare the range of costs of e-fuel production under different conditions, including country of production (USA, China, and Germany) and source of CO_2 (biogenic, industrial CCU, and DAC). The analysis shows that e-fuels remain significantly more expensive than fossil fuels—expected to cost two to seven times more by 2050 even with optimistic cost reductions. The levelized costs of e-fuels are found to be generally two to four times more expensive than biofuels under most scenarios, making their market competitiveness highly dependent on supportive policy measures such as carbon pricing, fossil fuel levies, and subsidies. Further work is required to compare the wider sustainability impacts for e-fuels against biofuels, and how this might change in the future.

Further resolution on cost sensitivity could potentially be provided by further analysis including associated with upstream contributors to hydrogen or CO_2 prices such as infrastructure. Monte Carlo simulation can be a helpful tool to explore the response to variations in multiple parameters, though requires correlation functions between inputs (or inputs are known to be independent of each other).

The primary cost driver is hydrogen, which accounts for the better half of total production expenses, underscoring the critical need for low-cost, renewable hydrogen. The cost of CO_2 is also important, albeit not as important as hydrogen in most cases. However, in cases where hydrogen costs are relatively low and DAC is used as a source of CO_2, the price of CO_2 will increase in importance. While capital expenditures and scaling effects of the e-fuel synthesis plant play a relatively minor role, improvements in conversion efficiency and feedstock management are more important. Furthermore, the prospect of large-scale e-fuel plants is limited by the enormous electricity demand for green hydrogen production, indicating that transformative reductions in hydrogen costs and requirements would be necessary if e-fuel production needs to step up to meet current levels of hydrocarbon use in fuels. Considering the Germany, China, and US exemplars, e-fuels produced in Germany are likely to be more expensive in the near future due to high energy costs. Additionally, Germany's reliance on imported energy means it is unlikely to have cheap hydrogen. The use of a biogenic source with a high concentration of CO_2 results in cheaper production costs compared to industrial point sources of medium CO_2 concentration or diluted sources such as direct air capture.

A lifecycle assessment was conducted for the same exemplar locations and sources of CO_2 to estimate the emissions reduction potential of e-fuel under different production scenarios compared to fossil fuels. Biogenic CO_2 offers the lowest global warming potential (GWP) compared to other sources, while DAC and industrial CCU become more comparable when waste heat is used. However, prioritizing industrial CCU is not advised since its assumed CO_2 mitigation benefits may diminish as the economy decarbonises. Additionally, varying regional standards for what qualifies as “green hydrogen” necessitate a detailed understanding of hydrogen production methods and renewable electricity sources. More crucial than location is the design of e-fuel production facilities; employing waste heat and ensuring renewable electricity across the supply chain are essential to minimise GWP. Finally, even at their combustion peak, e-fuels emit less than the lowest emissions levels of fossil fuels.

The primary objective for the use of e-fuels is to decarbonise energy systems and decrease the reliance on fossil fuels. Therefore, the cost of CO_2 abatement compared to fossil fuels is a key indicator of e-fuels attractiveness. Based on the scenarios modelled in the techno-economic and in the life cycle assessments, the CO_2 abatement cost in 2050 could range from US\$180/tCO_{2eq} at its lowest in China using biogenic sources with high CO_2 concentrations to well above US\$2,000/tCO_{2eq} in Germany using DAC. Whilst the uncertainties are very large, clearly careful focus on e-fuels production strategy is important to avoid excessive carbon abatement costs (> US\$1,000/tCO_2), where more competitive alternatives may be available. High e-fuel carbon abatement costs risk limiting the ultimate market for e-fuels.

Since understanding the long-term economic potential is important for understanding the value of early industry investments and public policy support, we recommend further quantitative assessment of the technical, economic and commercial potential for e-fuels including more detailed analysis for specific locations and sustainability and competitiveness vs. alternative approaches. By understanding local barriers to growth (e.g. water), upper bounds for production could be estimated. This work would quantify the amounts of e-fuel that could be produced sustainably in particular locations, i.e. without disrupting resources needed for others (e.g. water, renewable electricity), consider individual sources in more detail (recognising timings, feasibility and costs of capture and transport, and future ratio of biogenic:fossil emissions).

Future work could also consider how these impact the competition between hydrocarbons, biofuels, e-fuels, and alternatives to drop-in replacement hydrocarbons that might be considered include electrification, hydrogen, methanol, ethanol, ammonia, recognising that associated power conversion, infrastructure , and wider sustainability challenges, would need to be considered in these cases to get the full picture.

Based on this study's analysis, e-fuel abatement costs below \$200/tCO_2 occur only under the most favourable supply chain conditions, namely, hydrogen costs below \$1.5/kg (which, as discussed in Section 9.6.6 of the annex, is highly improbable), low-cost CO_2 capture from high-concentration industrial or biogenic sources, and minimal feedstock transportation costs. This could potentially be limiting to a few locations in countries where very large amounts of low carbon electricity and water are readily available for electrolytic hydrogen production and co-located with biogenic CO_2 sources with high concentrations of CO_2. E-fuel production using DAC as a carbon source is unlikely to compete with the abatement of fossil fuel emissions through DAC with geological CO_2 sequestration.

9. TECHNICAL ANNEX

9.1 E-FUEL PRODUCTION PATHWAYS

9.1.1 General approach

The overall approach to assess the e-fuel production pathways is summarised in Figure 2-1 and analysed below.

In order to assess the current landscape of e-fuel production pathways, our approach involved an in-depth literature review. The primary objective was to identify and categorise both established and emerging pathways for the production of the e-fuels in scope. This involved scanning more than 60 sources, including peer-reviewed journal articles, reviews, technoeconomic studies and industry reports, to ensure comprehensive and up-to-date insights of the industry.

For each production pathway, we examined some process conditions (such as temperature and pressure), catalysts used, and the technology readiness level (TRL) of the overall process and each process step, by analysing the most frequent cited and recent sources. Additionally, we evaluated the mass balances, the carbon efficiencies[47] and energy efficiencies[48], where available, based on data provided in peer-reviewed papers and industry reports.

It is important to note that our analysis includes only high-level process efficiencies either reported or calculated based on the data provided across various literature sources. These efficiencies are only indicative and not directly comparable due to the different boundary conditions assumed in each study, including variations in recycling and recovery streams, heat integration scenarios, technologies and process conditions used. For instance, the thermal energy required by the process can be provided in the form of renewable electricity or by combusting natural gas or light ends produced by the process, or by recovering part of the low temperature heat produced in different steps of the process.

The key criteria for the assessment of the e-fuel production pathways included TRL, process efficiency, quantity of feedstocks (H_2 and CO) required, capital expenditure and number of deployed or announced projects.

Following the initial analysis of the different production pathways, the compatibility of each pathway with CO_2 sources was explored. This analysis was focused on the established pathways due to the lack of sufficient data for the emerging pathways. The aim was to identify the most promising options for efficient and scalable e-fuel production. **The boundaries of this study were limited to the e-fuel production process and did not account for how hydrogen, CO_2, or energy are supplied to the e-fuel production facility**. However, occasional references to these factors were made where necessary.

[47] Carbon efficiency is a ratio between the amount of carbon in the products compared to that in the reactants.
[48] Energy efficiency is the ratio between the useful energy output compared to the total energy input.

9.1.2 Summary of the e-fuel production pathways

Table 9-1 summarises the main production pathways for e-fuels considered in this study, including their technology readiness levels (TRL) and process efficiencies. The mass and energy balances of the production routes are listed in the relevant paragraphs below. The main unit processes, apart from the syngas production, required to produce e-fuels are all commercially available at large scale. However, integration of these unit processes into a fully operational e-fuel plant currently has a low technology readiness level, with the largest plants represented by large prototypes (TRL 6)[49]. Table 9-1 summarises the novel production pathways for e-fuels considered in this study and described below.

Table 9-1. Long list of production pathways for e-fuels, alongside their TRLs, and process requirements

e-Fuel	Process conditions	Catalyst	Process efficiency	TRL
e-fuel production pathways via methanol				
Methanol synthesis from CO_2 and H_2				
Methanol (intermediate)	210 – 270°C, 50 – 100 bar	$Cu/ZnO/Al_2O_3$	80-90%	8 – 9
Methanol to Gasoline (MTG)			82-94%	9
Gasoline	**Methanol to Olefins (MTO):** 400°C, <5 bar	γ-Al_2O_3 and Zeolite ZSM-5		
	Oligomerisation: 400°C, 20 bar	Zeolite ZSM-5		
Methanol to Kerosene (MTK)			89-90%	4 – 9
Kerosene	**Methanol to Olefins (MTO):** 400°C, <5 bar	γ-Al_2O_3 and Zeolite ZSM-5		
	Oligomerisation: 250°C, 40-50 bar	Zeolite ZSM-5		
e-fuel production pathways via RWGS and FT				
Reverse Water Gas Shift (RWGS) to syngas				
Syngas (intermediate)	800 – 1000°C, up to 30 bar	Co-, Mo-, or Fe-based		6-7
e-fuel production from CO_2 and H_2 via RWGS and FT				
Gasoline	325 – 350°C, 30 bar	Fe-based	54-66%	5-9
Kerosene	240°C, 35 bar	Fe-based	59-79%	4-9
Diesel	220 – 270°C, 30 bar	Co-based	55-63%	6-9

Grey shading = Not mentioned in study.

[49] The Role of E-fuels in Decarbonising Transport, 2023, *IEA*, Accessed at: https://iea.blob.core.windows.net/assets/9e0c82d4-06d2-496b-9542-f184ba803645/TheRoleofE-fuelsinDecarbonisingTransport.pdf

Table 9-2. Novel production pathways for e-fuels, alongside their TRLs, and catalyst requirements

Process	e-Fuel	Catalyst	TRL
Co-electrolysis (electrolysis + RWGS in one step)	Syngas (intermediate) for all fuels		3 – 4
Direct CO_2 hydrogenation to Fischer-Tropsch	All fuels	Multifunctional catalyst	3 – 4
Sorption enhanced FT and methanol synthesis	All fuels	Water sorbent and conventional catalyst	3 – 4
Gas fermentation to ethanol and ATJ	Kerosene	Biocatalyst (microorganisms)	6 – 7

Grey shading = Not mentioned in study.

The table below details the descriptions of the technology readiness levels.

Table 9-3. Technology Readiness Level descriptions.[50]

Maturity	Rating	Description of readiness level
Basic research	**TRL 1**	Basic principles of scientific research observed and reported
	TRL 2	Invention and research of practical application
	TRL 3	Proof of concept with analytical and experimental studies to validate the critical principles of individual elements of the technology
Development	**TRL 4**	Development and validation of component in a laboratory
	TRL 5	Pilot scale testing of components in a simulated environment to demonstrate specific aspects of the design
	TRL 6	Prototype system built and tested in a simulated environment
Demonstration	**TRL 7**	Prototype system built and validated in a marine operational environment (including small-scale/auxiliary use/demonstration deployments)
	TRL 8	Active commissioning where the actual system is proven to work in its final form under expected marine operating conditions (pilot/trial deployments)
Deployment: early adoption	**TRL/CRL 9**	Operational application of system on a commercial basis – technically ready but a limited number of vessels/first-of-a-kind facilities
	CRL 10	Integration needed at scale: solution available commercially but needs further integration efforts to achieve full potential – may be 10's or small number of at-scale facilities, small share of market
Mature	**CRL 11**	Proof of stability reached, with predictable growth

9.1.2.1 *E*-fuel production via methanol

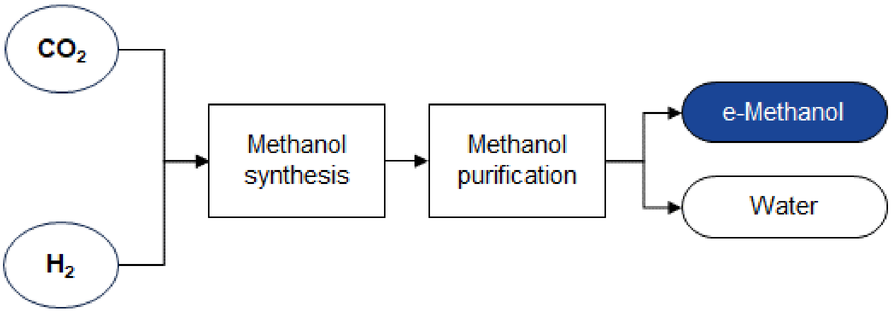
The methanol-based conversion pathway towards drop-in liquid e-fuels, can be divided into the (1) methanol synthesis, and the (2) subsequent conversion of methanol into a hydrocarbon fuel mixture. Depending on the process conditions used, e-methanol can be converted to different hydrocarbon products, towards paraffinic and aromatic compounds within the gasoline range, via the Methanol-to-Gasoline (MTG), or and the Methanol-to-Kerosene (MTK) pathways. Diesel is also produced via methanol in a similar pathway to MTK. However, in most cases in available literature, production is not optimized and it is mainly reported as a by-product of the MTK/MTG pathways.

E-methanol can be produced either via (1) synthesis gas (two-step route), or via (2) a process that uses CO_2 directly as a feedstock (direct route). The first route involves the reduction of CO_2 to carbon monoxide (CO), followed by conversion of CO and hydrogen to methanol. The second route involves the direct hydrogenation of CO_2 with H_2 over a heterogeneous catalyst. The direct route is already demonstrated and commercially viable at TRL 8 to 9, with several leading companies holding licenses for direct CO_2 hydrogenation.

[50] https://www.iea.org/reports/innovation-gaps

The choice of catalyst is key in ensuring a high selectivity of methanol, and low formation of water as the main by-product. The most popular catalyst for industry is $Cu/ZnO/Al_2O_3$[51]. However, recent studies have shown that the addition of a catalyst support (like ZrO_2 or silica[52]) can improve conversion and selectivity of the CO_2 conversion reaction. This reaction requires high pressures of 50 – 100 bar, alongside temperatures of 210 - 270°C[53]. The flow diagram for the process is highlighted in Figure 9-1. In addition to the feedstocks and catalyst, water is also required for use as heat exchanger fluid.

Figure 9-1. Simplified block flow diagram for e-methanol production



The main chemical reactions for the direct route are shown below[54], with high selectivity for methanol as a product.

$$CO_2 + 3H_2 \leftrightarrow CH_3OH + H_2O$$

$$CO_2 + 3H_2 \leftrightarrow CO + H_2O$$

$$CO + 2H_2 \leftrightarrow CH_3OH$$

The mass and energy balances of methanol synthesis from CO_2 are displayed in Table 9-4. Data has been collected across various sources, on requirements for feedstock, utilities, power and heat where provided, as well as outputs produced. The calculated energy efficiencies of methanol production are also provided, range between ~80 to 90% depending on the process conditions and reported data on heat and power consumption and/or production. Typical methanol carbon conversion efficiencies from CO_2 range between 90 and 99%[55,56].

[51] Methanol from CO2: a technology and outlook overview, 2023, Narayanan, P., Accessed at: https://www.digitalrefining.com/article/1002891/methanol-from-co2-a-technology-and-outlook-overview#:~:text=In%20the%20presence%20of%20catalysts,gases%20and%20purified%20through%20distillation

[52] Progress in Commercialization of Biojet /Sustainable Aviation Fuels (SAF): Technologies and policies , 2024, *IEA*, Accessed at: https://task39.ieabioenergy.com/wp-content/uploads/sites/37/2024/05/IEA-Bioenergy-Task-39-SAF-report.pdf

[53] An Overview of Promising Alternative Fuels for Road, Rail, Air, and Inland Waterway Transport in Germany, 2022, *Energies*, Breuer et. al, Accessed at: https://juser.fz-juelich.de/record/906321/files/energies-15-01443.pdf

[54] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[55] Technology factsheet – Methanol production from CO2, 2019, *Remko Detz*, Accessed at: https://energy.nl/wp-content/uploads/technology-factsheet-methanol-from-co2-7.pdf

[56] Techno-Economic Modelling of Carbon Dioxide Utilisation Pathways at Refineries for the Production of Methanol, 2022, *AIDIC*, d'Amore et. al, Accessed at: https://re.public.polimi.it/retrieve/102e86c0-fe75-443f-bb42-78af3e0d4b33/2022_AIDIC_dAmore-etal_016.pdf

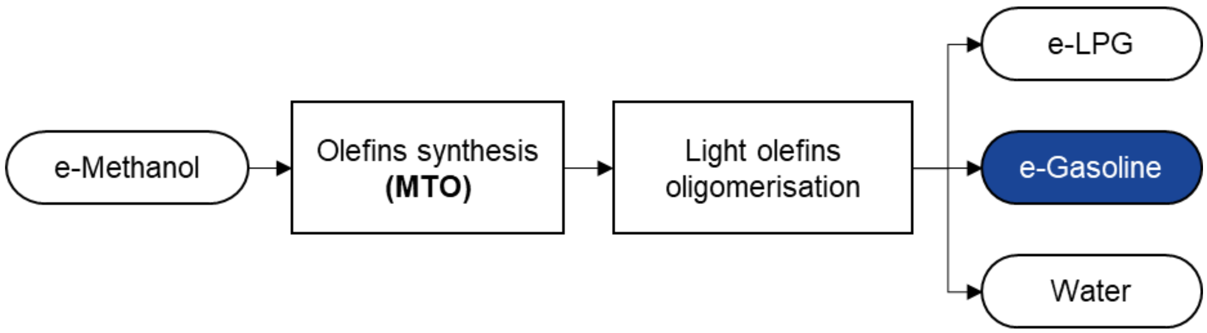
Table 9-4. Mass and energy balances of methanol synthesis (from CO_2 and H_2)

Component	Mass/energy balances				Units
	[57]	[58]	[59]	[60]	
Inputs:					
H_2 use	0.193	0.189	0.208	0.188	kg / kg fuel
CO_2 use	1.400	1.370	1.450	1.380	kg / kg fuel
Catalyst			0.58		kg / kg fuel
Electrical energy	1.07	1.03	0.74		MJ / kg fuel
Outputs:					
Methanol	1.00	1.00	1.00	1.00	kg
Water	0.59	0.56		0.56	kg / kg fuel
Energy Efficiency[a]	81.7	83.6	77.0	88.0	%

Grey shading = Not mentioned in study.
[a] Energy efficiencies calculated based on lower heating values (LHV).

The **Methanol to Gasoline (MTG) process** has been extensively developed by ExxonMobil since the 70's, using ZSM-5 zeolite catalysts. Haldor Topsøe developed this process further and integrated methanol and gasoline production in a one-step process called Topsøe integrated gasoline synthesis (TIGAS). The MTG process is commercially available from fossil methanol at TRL 9[61,62]. In the case of e-fuel synthesis, following the production of e-methanol, this can be converted to hydrocarbons over zeolite catalysts via the following steps: (1) methanol to olefins (MTO), and (2) light olefin oligomerization[54]. The flow diagram for the process is shown in Figure 9-2.

Figure 9-2. Simplified block flow diagram for the methanol-to-gasoline process



[57] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[58] What is the energy balance of electrofuels produced through power-to-fuel integration with biogas facilities?, 2022, Gray et. al, Renewable and Sustainable Energy Reviews, Accessed at: https://www.sciencedirect.com/science/article/pii/S1364032121011539

[59] Renewable methanol production from green hydrogen and captured CO2: A techno-economic assessment, 2023, *Journal of CO2 Utilisation*, Sollai et. al, Accessed at: https://www.sciencedirect.com/science/article/pii/S2212982022004644

[60] Quantitative Design of a New e-Methanol Production Process, 2022, *Energies*, Rufer, A., Accessed at 29-07-24: https://www.mdpi.com/1996-1073/15/24/9309

[61] An Overview of Promising Alternative Fuels for Road, Rail, Air, and Inland Waterway Transport in Germany, 2022, *Energies*, Breuer et. al, Accessed at: https://juser.fz-juelich.de/record/906321/files/energies-15-01443.pdf

[62] Modelling and Cost Estimation for Conversion of Green Methanol to Renewable Liquid Transport Fuels via Olefin Oligomerisation, 2021, *Processes*, Ruokonen et. al, Accessed at: https://www.mdpi.com/2227-9717/9/6/1046

Initially, methanol is converted into dimethyl ether (DME) and water, under γ-Al_2O_3 catalyst[63], via a dehydration reaction at 300°C and 27 bar[64]. DME is converted to light olefins via the MTO process, at around 400°C and below 5 bar[65]. These olefins are then oligomerized to produce higher olefins in the C_5-C_{20} range, under acidic catalysts (typically zeolites), at around 250°C and 40-50 bar, under zeolite catalyst, typically ZSM-5[54]. The overall MTG process usually contains multiple gasoline conversion reactors in parallel because the zeolites have to be regenerated frequently to burn off the coke formed during the reaction. The raw gasoline contains some heavy fractions that require further upgrading (hydrotreatment). The chemical equations for the overall process are shown as follows[66,67]:

$$2CH_3OH \quad \rightleftharpoons \quad CH_3OCH_3 + H_2O \quad \rightarrow \quad C_2{-}C_5\ olefins + H_2O \quad \rightarrow \quad \begin{matrix} C_{5+} \\ Olefins \\ Paraffins \\ Aromatics \\ Cycloparaffins \end{matrix}$$

Table 9-5 shows the mass and energy balances of the methanol to gasoline process and the calculated process efficiencies. Data has been collected across various sources, on requirements for feedstock, utilities, power and heat, as well as outputs produced.

Exxonmobil has recently licensed the fluid bed MTG process, which demonstrates overall advantages in CAPEX, OPEX and operational reliability, over the fixed bed MTG process.[68] In this design, methanol is fed into a single fluid bed reactor for conversion into hydrocarbons and water. At the MTG reactor conditions, light olefins oligomerize into higher olefins, which combine through various reaction paths into paraffins, naphthenes, and methylated aromatics. It should be noted that limited information is available on the catalyst, reaction conditions and product yields, by Exxonmobil.

The MTG process demonstrates a highly favorable energy balance, retaining up to 95% of the thermal energy from the methanol feedstock in the resulting hydrocarbon products. The gasoline yield constitutes approximately 85-90% of the hydrocarbons produced, the rest being liquefied petroleum gas (LPG). Since both the methanol-to-dimethyl-ether and dimethyl-ether-to-hydrocarbon reactions generate excess heat, most auxiliary systems in the subsequent gasoline refining stage are self-sustained. Consequently, even when accounting for energy consumption by the auxiliary systems, the overall energetic efficiency remains between 90% and 93% (including both gasoline and LPG)[69]. The calculated MTG process efficiencies (conversion of methanol and hydrogen to gasoline, LHV based) based on the reported literature data ranges between 82% (when other hydrocarbon products (i.e. LPG) are not considered for the efficiency calculation) to 94% (including LPG). The exact process efficiency can vary depending on the specific process configuration, reactor technology, catalysts and operating conditions used.

The energy efficiency of the overall MTG process from H_2 and CO feedstocks until the final e-gasoline product is estimated 66-85% (the upper range includes by-products, such as LPG).

The MTG process presents several advantages compared to the FT gasoline production. Notably, CO_2 can be directly utilised in methanol synthesis, eliminating the need for an initial conversion to monoxide in an additional reverse water gas shift reactor (RWGS). Furthermore, the MTG process yields a narrower product distribution

---

[63] Kinetic Modeling and Techno-Economic Analysis of a Methanol-to-Gasoline Production Repurposed Refinery Equipment, 2024, Clean Combustion Research Center, Gallego et. al, Accessed at: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC11137730/

[64] Progress in biofuel production from gasification, 2017, Progress in Energy and Combustion Science Journal, Singh et. al, Accessed at: https://www.sciencedirect.com/science/article/pii/S036012851630106X

[65] Fischer-Tropsch & Methanol-based Kerosene, 2024, Bube et. al, Accessed at: https://aireg.de/wp-content/uploads/2024/07/airegWebinar_FT_and_MeOH-based_Kerosene_TUHH.pdf

[66] Methanol to Gasoline Process, n.d., Joseph, S., Accessed at: https://www.fischer-tropsch.org/DOE/DOE_reports/60054/doe_pc_60054-t9/doe_pc_60054-t9-A.pdf

[67] Methanol conversion to gasoline technology, n.d., Exxonmobil, Accessed at: https://www.exxonmobilchemical.com/-/media/project/wep/exxonmobil-chemicals/chemicals/products/technology-licensing-and-services/methanol-to-gasoline-synthesis/mtg_factsheet_enpdf.pdf

[68] Methanol to gasoline (MTG) technology process, n.d., Exxonmobil, Accessed at: https://www.exxonmobilchemical.com/en/catalysts-and-technology-licensing/methanol-to-gasoline-technology

[69] EASE, Power to Methanol/Power to Gasoline, Accessed at: https://ease-storage.eu/wp-content/uploads/2021/03/2018.08_TVAC_WG1_TD-Power-to-Methanol-Gasoline-b.pdf

in gasoline and LPG range, whereas FT products consist of gases, liquids and waxes that necessitate further processing.

Table 9-5. Mass and energy balances of gasoline production from e-methanol

Component	Mass/energy balances		Units
	[70]	[71]	
Inputs:			
Methanol	2.28	2.67	kg / kg fuel
H_2 use	0.001		kg / kg fuel
Cooling water			kg / kg fuel
Electrical energy	0.71		MJ / kg fuel
Outputs:			
Gasoline	1.00	1.00	kg
Water	1.28	1.50	kg / kg fuel
Heat	1.29		MJ / kg fuel
Energy efficiency[a]	93.9	81.8[b]	%

Grey shading = Not mentioned in study.
[a] Energy efficiencies calculated based on lower heating values (LHV).
[b] Energy efficiency calculated on basis of gasoline only (i.e. excludes LPG fractions).

Following the production of e-methanol, this can be converted to kerosene via the **Methanol to Kerosene (MTK)**, can be also found as **Methanol to Jet (MTJ)**, similar to the MTG route described above. While the MTG process focuses on gasoline as the main hydrocarbon product, MTK includes the MTO process coupled to Methanol to Middle Distillates (MTGD) process, and can convert methanol into gasoline, kerosene, and diesel. The integrated MTGD process is not commercially proven, although licenses are offered for the Mobil olefins to gasoline and distillate (MOGD) from Exxonmobil and the MtSynfuel process from Lurgi (today AirLiquide). However, none of these processes is currently optimized for kerosene production[72]. The MOGD process was only developed to the pre-commercial stage in the 1990s and the TRL of MTO-MOGD can be estimated to be 8[73]. The route consists of dehydration, oligomerisation, hydrogenation and fractionation; with the former two influencing the product formation. Main by-products of the MTK process include naphtha and diesel.

The methanol route offers advantages over other processes for developing e-kerosene, as sustainable aviation fuels (SAF), however this SAF-certified pathway production process is currently under evaluation by ASTM and has not been approved yet as by ASTM. Depending on progress of certification and development, this is expected to be commercialized around 2026[74]. Various sources evaluate the TRL of the MTK process as 7-8[72], however, other sources report a TRL of 4, since only single sections have been tested on a demonstration level instead of the entire process. As such, given the different technologies developed for this route, a wide range of TRL, from 4 to 9 has been reported in the literature[75]. Figure 9-3 shows a block flow diagram of the overall process.

[70] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, p. 176, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[71] Methanol-to-Gasoline Process, 2023, Knop, V., *AWOE*, Accessed at: https://www.awoe.net/Synthetic-Gasoline-MTG-Process.html

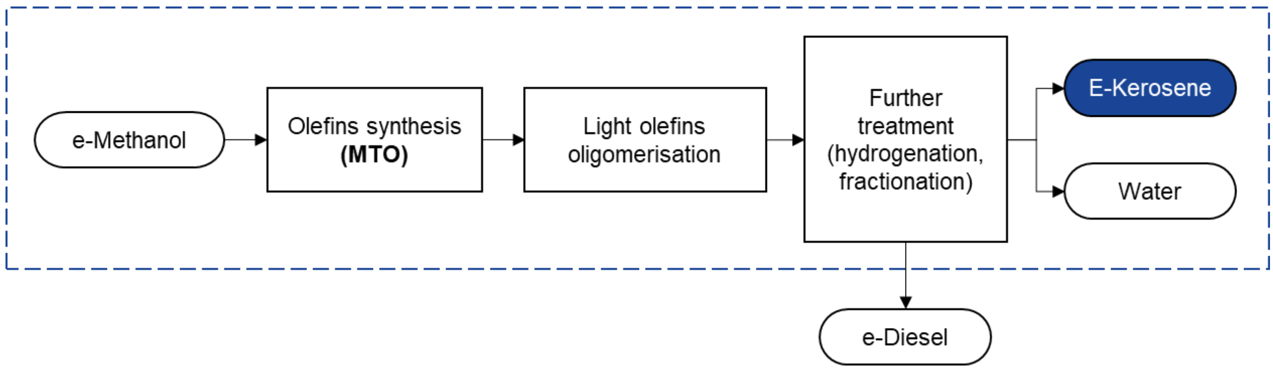
[72] Fischer-Tropsch & Methanol-based Kerosene, 2024, Bube et. al, Accessed at: https://aireg.de/wp-content/uploads/2024/07/airegWebinar_FT_and_MeOH-based_Kerosene_TUHH.pdf

[73] Modelling and Cost Estimation for Conversion of Green Methanol to Renewable Liquid Transport Fuels via Olefin Oligomerisation, 2021, *Processes*, Ruokonen et. al, Accessed at: https://www.mdpi.com/2227-9717/9/6/1046

[74] https://www.thyssenkrupp.com/en/stories/sustainability-and-climate-protection/green-methanol-a-raw-material-for-sustainable-aviation-fuels

[75] An Overview of Promising Alternative Fuels for Road, Rail, Air, and Inland Waterway Transport in Germany, 2022, *Energies*, Breuer et. al, Accessed at: https://juser.fz-juelich.de/record/906321/files/energies-15-01443.pdf

Figure 9-3. Simplified block flow diagram of the methanol-to-kerosene process



Methanol is initially dehydrated to dimethyl ether (DME), following which the DME is converted to light olefins, C_2-C_6, via the MTO process, at around 400°C and below 5 bar[72, 76]. These olefins are then oligomerized to produce higher olefins in the C_5-C_{20} range, under acidic catalysts (typically zeolites), at around 250°C and 40-50 bar. Further hydrotreatment is performed to refine the hydrocarbons, under 300°C and around 30-40 bar. The main chemical reactions[76] for the e-kerosene production are as follows[73]:

$$2n\, CH_3OH \leftrightarrow n\, CH_3OCH_3 + n\, H_2O$$

$$n\, CH_3OCH_3 \rightarrow 2(CH_2)_n + n\, H_2O$$

$$2(CH_2)_n \rightarrow C_{2n}H_{4n}$$

As with the MTG process, majority of research studies use zeolite ZSM-5 as a catalyst[77]. The mass and energy balances for the process are shown in Table 9-6 alongside the calculated process efficiencies. The overall MTK process efficiency is calculated at ~90%. based on literature data

A parametric study reported carbon efficiencies of the overall CO_2 hydrogenation to Kerosene pathway (via methanol) between 60 and 90%; however, the total product carbon efficiency (including by products, naphtha and diesel) is reported between 74 to 92%[78]. The same study, reported energy efficiencies of the overall process from H_2 and CO_2 until e-kerosene synthesis, based on LHV, of 60% only to kerosene and up to 67%, including by products - excluding heat integration with the capture facility.

The energy efficiency, based on LHV, of the overall MTK process from H_2 and CO feedstocks until the final e-kerosene product is calculated 70-80%, although some studies report efficiencies as low as 60%, based on different assumptions and boundary conditions.

Compared to the FT pathway, the methanol pathway to kerosene was found to be more efficient due to the thermodynamic advantage of the methanol pathway which doesn't require additional energy for the RWGS reaction.

[76] Fischer-Tropsch & Methanol-based Kerosene, 2024, Bube et. al, Accessed at: https://aireg.de/wp-content/uploads/2024/07/airegWebinar_FT_and_MeOH-based_Kerosene_TUHH.pdf

[77] https://www.ri.se/en/what-we-do/projects/methanol-to-jet#:~:text=The%20zeolite%20ZSM%2D5%20is,catalyst%20has%20also%20been%20demonstrated.

[78] Kerosene production from power-based syngas -A technical comparison of the Fischer-Tropsch and methanol pathway, 2024, Fuel Journal, Bube et. al, Accessed at: https://www.researchgate.net/publication/379543754_Kerosene_production_from_power-based_syngas_-A_technical_comparison_of_the_Fischer-Tropsch_and_methanol_pathway

Table 9-6. Mass and energy balances for the methanol to kerosene process

Component	Mass/energy balances		Units
	[79]a	[80]	
Inputs:			
Methanol	2.32	2.4	kg / kg fuel
H_2 use	0.01	0.01	kg / kg fuel
Cooling water			kg / kg fuel
Electrical energy	0.72		MJ / kg fuel
Thermal energy			MJ / kg fuel
Outputs:			
Kerosene	1.00	1.00	kg
Water	1.30		kg / kg fuel
Energy efficiency[a, b]	90.4	88.7	%

Grey shading = Not mentioned in study.
[a] Allocated balance, corresponding to the part of feedstock and energy associated to the kerosene only (excluding co-products).
[b] Energy efficiencies calculated based on lower heating values (LHV).

The optimal route for diesel production is from CO_2 and H_2 is via FT synthesis, described in the next section. Diesel is also produced from methanol in a similar pathway to MTK, however as resulted from our desk research, **Methanol-to-Diesel (MTD)** production is not optimized and it is mainly reported as a by-product of the MTK pathway. The methanol to diesel carbon efficiency during the MTK process is reported around 5.4%[81]. Due to the limited information on the mass and energy balance or process efficiency of MTD route this is not included in one of the core e-fuel production pathways.

9.1.2.2 E-fuel production via Reverse Water Gas Shift and Fischer-Tropsch

Another possible route for producing e-fuels is via Fischer-Tropsch (FT) synthesis. This pathway involves the reduction of CO_2 to CO, with subsequent conversion of the synthesis gas (CO and H_2) to hydrocarbons via FT synthesis.

Converting H_2 and CO into hydrocarbon chains within the FT synthesis yields synthetic crude oil (syncrude), ranging from light gases (e.g. methane) to long-chain hydrocarbons (e.g. waxes). FT fuels, such as synthetic diesel, gasoline or kerosene from fossil-derived syngas (mainly coal) are proven technologies at commercial scale (TRL 9) for decades. Examples of commercial applications include Sasol's Coal-to-Liquid facility in South Africa and Shell's Pearl Gas-to-Liquid plant in Qatar. The FT process is also used in South Africa by The Petroleum Oil and Gas Corporation of South Africa (PetroSA). The plant produces gasoline and diesel fuels via a conversion of olefins to distillate (COD) process by converting light FT olefins to higher olefins[82]. However, PtX projects using CO_2 and water to produce hydrocarbons via FT synthesis, are still at research stages, with low production capacities[83].

As the FT reaction requires a mix of synthesis gas (H_2 and CO), this means that the captured CO_2 feedstock must be reduced to CO prior to the reaction. This is achieved through an equilibrium reaction called Reverse Water Gas Shift (RWGS), whereby CO_2 is reformed with H_2 to produce CO and water. High temperatures (800

[79] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, p. 177, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[80] Life Cycle Assessment of synthetic hydrocarbons for use as jet fuel: "Power-to-Liquid" and "Sun-to-Liquid" processes, Treyer Karin, Sacchi Romain, Bauer Christian, February 2022

[81] Kerosene production from power-based syngas -A technical comparison of the Fischer-Tropsch and methanol pathway, 2024, Fuel Journal, Bube et. al, Accessed at: https://www.researchgate.net/publication/379543754_Kerosene_production_from_power-based_syngas_-A_technical_comparison_of_the_Fischer-Tropsch_and_methanol_pathway

[82] Modelling and Cost Estimation for Conversion of Green Methanol to Renewable Liquid Transport Fuels via Olefin Oligomerisation, 2021, *Processes*, Ruokonen et. al, Accessed at: https://www.mdpi.com/2227-9717/9/6/1046

[83] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

- 1,000°C) and pressures (up to 30bar) are required to favour the equilibrium to CO, alongside electricity to run the plant.

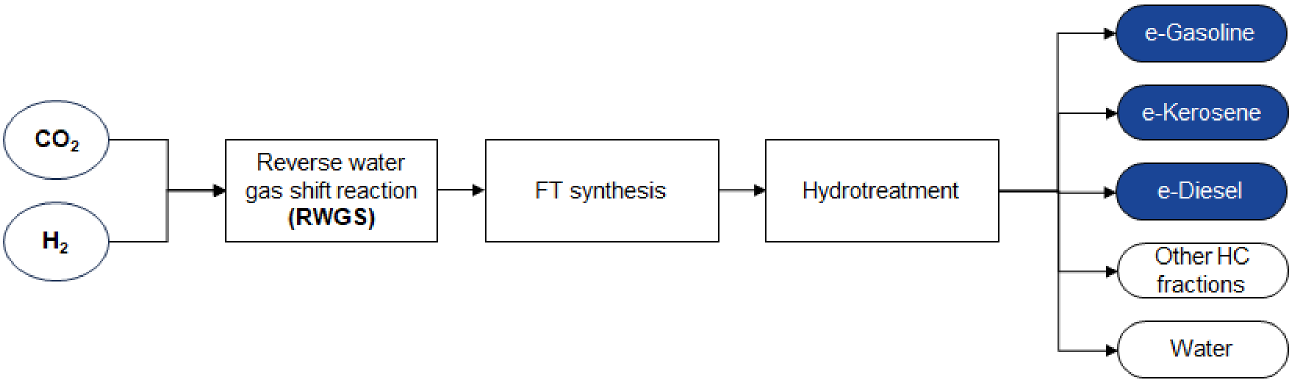
Various catalysts can be used for the RWGS reaction, including noble metals (Pt, Pd, Rh, Ru, Au), as well as Fe, Mo, Co, Cu, and Ni-based catalysts, supported on metal oxides. Noble metal catalysts have a very high hydrogenation activity, however their industrial application is hindered by high cost. Although Cu- and Ni-oxides have high activity and selectivity and a lower price, they tend to become deactivated in RWGS. Consequently, ongoing research and development are focused on overcoming problems with these catalysts and the development of alternative catalysts based on Mo, Co, and Fe[84].

Although the RWGS technology is not yet commercial, there are several companies involved in the advancement of that technology (e.g. IFPEN/Axens, the-company, Topsoe, Shell). The TRL of the RWGS is currently 6-7[85], being lower than FT synthesis, which has a TRL of 9[86]. The TRL for the overall integrated process is at the Reverse Water Gas Shift Reaction (RWGS) level, which is at about TRL 6-7[84,87].

Following the RWGS reaction and FT synthesis processes, a syncrude is produced, which requires further refining by hydrotreatment and fractionation to produce fuels (e-gasoline, e-kerosene, e-diesel) with appropriate specifications[88]. The overall process is shown in the flow diagram below, see Figure 9-4.

The distribution of products is dependent on the process conditions, choice of catalyst and downstream refining processes; hence, the selectivity of certain fuels can be optimised via modification of these conditions.

Figure 9-4. Simplified block flow diagram of the RWGS and FT process



The chemical reactions for the overall process are shown as follows[89], via the RWGS reaction and subsequent FT synthesis:

$$CO_2 + H_2 \leftrightharpoons CO + H_2O$$

$$nCO + (2n+1)H_2 \longrightarrow C_nH_{2n+2} + nH_2O$$

An efficient catalyst should be used for both RWGS and FT processes, under the same conditions. The distribution of products is determined by the structure and composition of the catalysts. Iron, cobalt and ruthenium based supported catalysts are predominantly used for such reactions, with the former two being used in commercial-scale FT processes, and the latter not yet used in practice[90]. There are no commercially

[84] Kerosene production from power-based syngas -A technical comparison of the Fischer-Tropsch and methanol pathway, 2024, Fuel Journal, Bube et. al, Accessed at: https://www.researchgate.net/publication/379543754_Kerosene_production_from_power-based_syngas_-A_technical_comparison_of_the_Fischer-Tropsch_and_methanol_pathway

[85] Progress in Commercialization of Biojet /Sustainable Aviation Fuels (SAF): Technologies and policies , 2024, *IEA*, Accessed at: https://task39.ieabioenergy.com/wp-content/uploads/sites/37/2024/05/IEA-Bioenergy-Task-39-SAF-report.pdf

[86] https://www.sciencedirect.com/science/article/pii/S2212982023000604

[87] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[88] Kerosene production from power-based syngas -A technical comparison of the Fischer-Tropsch and methanol pathway, 2024, Fuel Journal, Bube et. al, Accessed at: https://www.researchgate.net/publication/379543754_Kerosene_production_from_power-based_syngas_-A_technical_comparison_of_the_Fischer-Tropsch_and_methanol_pathway

[89] Modified fischer-tropsch synthesis: A review of highly selective catalysts for yielding olefins and higher hydrocarbons, 2022, *Front. Nanotechnol.*, Tavares et. al, Accessed at: https://www.frontiersin.org/journals/nanotechnology/articles/10.3389/fnano.2022.978358/full

[90] A critical review of technologies, costs, and projects for production of carbon-neutral liquid e-fuels from hydrogen and captured CO2, 2022, *Energy Adv.*, Singh et. al, Accessed at: https://pubs.rsc.org/en/content/articlehtml/2022/ya/d2ya00173j

viable catalysts for the RWGS reaction, however the same catalyst as for FT synthesis can theoretically be used[91].

The selectivity of **FT gasoline** can be optimised by using higher temperatures (325-350°C), pressures of 30bar and passing over an iron catalyst, as this shifts the selectivity towards lower carbon number products[92]. The RWGS reaction is also optimised at higher temperatures, due to being an endothermic reaction. The TRL of gasoline production via the RWGS and FT synthesis processes is 5 – 9[93].

The mass and energy balances for the process, and the calculated energy efficiencies are shown in Table 9-7. Regarding the carbon efficiencies, reported values range from 52% to 77%[94].

The overall process efficiency for FT gasoline production, calculated based on literature data reported in Table 9-7 **ranges from 54% to 66%.**

Table 9-7. Mass and energy balances for the RWGS and FT route to gasoline

Component	**Mass/energy balances**		**Units**
	[95]	[96]	
Inputs:			
CO_2 use	4.65	3.91	kg / kg fuel
H_2 use	0.64	0.55	kg / kg fuel
Cooling water			kg / kg fuel
Electrical energy	1.54		MJ / kg fuel
Thermal energy	23.73		MJ / kg fuel
Outputs:			
Gasoline	1.00	1.00[b]	kg
Water	3.68	2.94	kg / kg fuel
Energy efficiency[a]	54.4[c]	66.0	%

Grey shading = Not mentioned in study.
[a] Energy efficiencies calculated based on lower heating values (LHV)
[b] Fuel type not specified, assumed to be gasoline
[c] Thermal energy streams not taken into account for the energy efficiency calculation, due to their use in heat integration systems.

The production of **FT kerosene** from CO_2 via RWGS and FT processes can be prioritized through extensive hydrotreatment, however it is almost impossible to produce kerosene alone, no matter how the process is adjusted[97]. Following the FT synthesis to form the syncrude intermediate, this requires further processing to yield kerosene, via hydrocracking, hydro-isomerisation, hydrogenation and fractionation. Hydrogenation can saturate unsaturated hydrocarbons, with hydrocracking converting waxes into fuel components.

[91] Large scale bio electro jet fuel production integration at CHP-plant in Östersund, Sweden, 2021, *Swedish Environmental Research Institute*, Accessed at: https://www.diva-portal.org/smash/get/diva2:1552218/FULLTEXT01.pdf

[92] What is the energy balance of electrofuels produced through powerto-fuel integration with biogas facilities?, 2022, *Renewable and Sustainable Energy Reviews,* Gray et. al, Accessed at: https://www.netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/ftsynthesis

[93] CO2 conversion & utilization pathways: Techno-economic insights, 2022, Nishikawa, E., Accessed at: https://www.prescouter.com/2022/04/co2-conversion-utilization-pathways/

[94] Modelling and Cost Estimation for Conversion of Green Methanol to Renewable Liquid Transport Fuels via Olefin Oligomerisation, 2021, *Processes*, Ruokonen et. al, Accessed at: https://www.mdpi.com/2227-9717/9/6/1046

[95] Economic and environmental assessment of directly converting CO2 into a gasoline fuel, 2022, *Energy Conversion and Management*, Fernandez-Torres et. al. Accessed at: https://www.sciencedirect.com/science/article/pii/S0196890421012917

[96] A look into the role of e-fuels in the transport system in Europe (2030–2050) (literature review) , 2019, *Concawe*, Yugo et. al, Accessed at: https://www.concawe.eu/wp-content/uploads/E-fuels-article.pdf

[97] Large scale bio electro jet fuel production integration at CHP-plant in Östersund, Sweden, 2021, *Swedish Environmental Research Institute*, Accessed at: https://www.diva-portal.org/smash/get/diva2:1552218/FULLTEXT01.pdf

Additional hydro-isomerisation can be applied if the cold flow properties required by ASTM standards are not achieved. The overall process has a TRL of 6[98].

It is reported that low-temperature FT synthesis can optimise the yield of kerosene fractions, compared to high-temperature FT synthesis and other pathways[99], with optimal process conditions of 240°C and 35 bar. For the RWGS reaction, however, this is optimised with higher temperatures, and hence conditions of 900°C and 5 bar are required. An iron-based catalyst has been reportedly used for this process[99].

The mass and energy balances for the process are shown in Table 9-8.

The overall process efficiency for FT kerosene production calculated based on literature data ranges from 59% to ~79%.

A parametric study reported carbon efficiencies of the overall FT to Kerosene pathway between 61 and 77%; however, the total product carbon efficiency (including by products, naphtha and diesel) is reported up to 99%[100]. The same study, reported energy efficiencies of the overall process, based on LHV, of 53% only to kerosene and up to 72%, including by products - excluding heat integration with the capture facility.

Table 9-8. Mass and energy balances for the RWGS and FT route to kerosene

Component	Mass/energy balances			Units
	[101]	[102,99]	[103]	
Inputs:				
CO_2 use	3.23	3.42	3.79	kg / kg fuel
H_2 use	0.43	0.52	0.50	kg / kg fuel
Oxygen[a]		0.29		
Electrical energy	3.10	4.86	1.90	MJ / kg fuel
Outputs:				
Kerosene	1.00	1.00	1.00	kg
Water		3.21	3.03	kg / kg fuel
Energy efficiency [b]	78.8	58.8	63.9[c]	%

Grey shading = Not mentioned in study.
[a] Oxygen required here for autothermal reactor, where light olefins are reformed.
[b] Energy efficiencies to kerosene calculated based on lower heating values (LHV). Thermal energy streams not taken into account, due to their use in heat integration system.
[c] Energy efficiency calculated on basis of kerosene only. Increases to 84.3% when including lighter hydrocarbons fractions.

[98] An Overview of Promising Alternative Fuels for Road, Rail, Air, and Inland Waterway Transport in Germany, 2022, *Energies*, Breuer et. al, Accessed at: https://juser.fz-juelich.de/record/906321/files/energies-15-01443.pdf

[99] Process analysis and comparative assessment of advanced thermochemical pathways for e-kerosene production, 2023, *Energy*, Atsonios et. al, Accessed at: https://pure.strath.ac.uk/ws/portalfiles/portal/164159101/Atsonios_etal_Energy_2023_Process_analysis_and_comparative_assessment_of_advanced_thermochemical_pathways_for_e_kerosene.pdf

[100] Kerosene production from power-based syngas -A technical comparison of the Fischer-Tropsch and methanol pathway, 2024, Fuel Journal, Bube et. al, Accessed at: https://www.researchgate.net/publication/379543754_Kerosene_production_from_power-based_syngas_-A_technical_comparison_of_the_Fischer-Tropsch_and_methanol_pathway

[101] Life Cycle Assessment of synthetic hydrocarbons for use as jet fuel: "Power-to-Liquid" and "Sun-to-Liquid" processes, Treyer Karin, Sacchi Romain, Bauer Christian, February 2022

[102] Process analysis and comparative assessment of advanced thermochemical pathways for e-kerosene production, 2023, *Energy*, Atsonios et. al, Accessed at: https://pure.strath.ac.uk/ws/portalfiles/portal/164159101/Atsonios_etal_Energy_2023_Process_analysis_and_comparative_assessment_of_advanced_thermochemical_pathways_for_e_kerosene.pdf

[103] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, p. 170, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

The selectivity of **FT diesel** can be optimised by using lower temperatures (220-270°C), with pressures of 30 bar, over a cobalt catalyst, as this shifts the selectivity towards higher carbon number products[104]. The overall process has a TRL of 6[105].

The mass and energy balances for the process are shown in Table 9-9.

The overall process efficiency for FT diesel production as calculated by literature data ranges from 55% to 63%.

The lower efficiencies are due to the production of diesel not being optimised, such that other hydrocarbon fractions are also produced (kerosene, naphtha); upon factoring the energy content of all hydrocarbon fractions, the efficiency is calculated to be ~84% (from 55%). Based on the technologies used and the heat integration, efficiencies up to 71% have been reported in literature[106].

The carbon efficiency of the FT diesel production process ranges between 50% and 89%, depending on the process configuration[107]. It should be noted that higher efficiencies are typically reported where recycle streams are integrated in the process.

Table 9-9. Mass and energy balances for the RWGS and FT route to diesel

Component	Mass/energy balances			Units
	[108]	[109]	[110]	
Inputs:				
CO_2 use	3.72	1.54	4.61	kg / kg fuel
H_2 use	0.49	0.14	0.63	kg / kg fuel
Cooling water		0.62		kg / kg fuel
Electrical energy	1.90	42.62	2.24	MJ / kg fuel
Thermal energy[a]	9.95			MJ / kg fuel
Outputs:				
Diesel	1.00	1.00	1.00	kg
Water	2.97		3.78	kg / kg fuel
Energy efficiency[b]	60.0	63.4	55.3[c]	%

Grey shading = Not mentioned in study.
[a] Supplied via natural gas.
[b] Energy efficiencies calculated based on lower heating values (LHV)
[c] Energy efficiency calculated on basis of diesel only. Efficiency is 83.7% including light fractions and wax products.

[104] Fischer-Tropsch Synthesis, n.d., National Energy Technology Laboratory, Accessed at: https://www.netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/ftsynthesis

[105] An Overview of Promising Alternative Fuels for Road, Rail, Air, and Inland Waterway Transport in Germany, 2022, *Energies*, Breuer et. al, Accessed at: https://juser.fz-juelich.de/record/906321/files/energies-15-01443.pdf

[106] https://publications.tno.nl/publication/34639115/MybRuD/TNO-2021-R12731.pdf

[107] Preparation of Synthesis Gas from CO2 for Fischer–Tropsch Synthesis—Comparison of Alternative Process Configurations, 2020, Hannula et. al, Accessed at: https://www.mdpi.com/2311-5629/6/3/55

[108] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, p. 12, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[109] Life Cycle Assessment of synthetic hydrocarbons for use as jet fuel: "Power-to-Liquid" and "Sun-to-Liquid" processes, Treyer Karin, Sacchi Romain, Bauer Christian, February 2022

[110] What is the energy balance of electrofuels produced through power-to-fuel integration with biogas facilities?, 2022, *Renewable and Sustainable Energy Reviews*, Gray et. al, Accessed at: https://www.netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/ftsynthesis

9.1.2.3 Novel e-fuel production pathways

As the demand for sustainable energy solutions increases, several emerging technologies are being developed to improve the efficiency and economics of e-fuel production. These novel pathways aim to overcome the limitations of traditional methods by introducing innovations in process efficiency and carbon utilization, and thus improve the cost-effectiveness. However, these technologies are not as well developed and thus, detailed information on mass and energy balances, utilities, and process efficiencies is still limited. In this section, we focus on the most frequently cited technologies in recent literature.

The **co-electrolysis of CO_2 and water** technology, proposed by Sunfire for the FT pathways, combines high temperature electrolysis (Solid Oxide Electrolysis Cells, also known as SOEC) with RWGS, producing syngas directly in one single step from water and CO_2, evolving from a 3- to a 2-stage process. High temperature electrolysis, operating between 700-1000°C, can lower the electricity consumption as the energy needs can be covered partially by heat input. The integration of waste heat from the FT-process reduces electricity demand. High-temperature electrolysis (SOEC – ion conducting solid oxide electrolysis) are already offered by companies such as Sunfire who offer modular designs, such as the Sunfire-Synlink SOEC technology[111]. Sunfire claims higher energy efficiency for this configuration, increasing by 15% points in the Fischer-Tropsch pathway and by 10% points in the methanol pathway[112]. However, this process is still at low TRL (3-4) and the technology developer estimation on efficiency gains are still to be verified when the first e-fuel production plant will be in operation.

High-temperature **direct CO_2 hydrogenation to FT** synthesis without separate reverse water-gas shift (RWGS) reactor is one way to improve the efficiency and the economics of the FT process from CO_2. However, studies about this process are rare and are limited to laboratory experimental research. This process is called non-methanol mediated CO_2 hydrogenation and combines FT and RWGS reactions in a single reactor by use of Fe catalysts[113]. More recent studies involve the use of multifunctional catalysts that lead to improved efficiency[114]. Compared to conventional FT synthesis from synthesis gas (a mixture of CO and H_2), CO_2 hydrogenation involves three moles of hydrogen per mole of CO_2 and produces plenty of by-product water, which is a deactivation agent for Fe-based FT catalysts. Hence, CO_2 hydrogenation is much slower than CO hydrogenation reaction under the same conditions. The hydrocarbon products include light hydrocarbons (C1-C4 paraffins and olefins), and heavier hydrocarbons (C5+), and oxygenates. Because CO is the chain growing agent in FT reaction, CO_2 hydrogenation produces mainly low molecular weight hydrocarbons instead of C5+ products that are more valuable as liquid transportation fuels.

Future plants are expected to be more efficient, driven by the development of improved methods such as **sorption enhanced H_2O removal, during methanol or FT synthesis** (currently at TRL 3[115]). This process uses a solid sorbent to remove water during FT synthesis, in order to increase e-fuel production rates and decrease catalyst deactivation. Gavrilović et.al (2024)[116] showcase the use of commercial water sorbents (Zeolites type 13X and 4A), enabling for a 10% higher CO conversion compared to FT synthesis without any sorbents. Bayat et. al (2013)[117] showcases the use of Zeolite 4A, with the composition of $Na_{12}(Si_{12}Al_{12}O_{48})\cdot 27H_2O$, alongside a gas-flowing solids fixed bed reactor; this allows for a 45% and 57% enhancement in gasoline and hydrogen yields and 84% reduction in CO_2 production, compared to conventional FT synthesis. Similar to the sorption enhanced FT synthesis, water sorbents are used to improve the e-methanol production rates. The sorption-enhanced methanol synthesis increases methanol yield by up to

---

111 Syngas – The Renewable Feed Gas, 2023, *Sunfire*, Accessed at: https://www.sunfire.de/en/syngas

112 E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050 – Update, 2024, *Concawe*, Accessed at: https://www.efuel-alliance.eu/fileadmin/Downloads/Rpt_24-4-1.pdf

113 Process analysis and comparative assessment of advanced thermochemical pathways for e-kerosene production, 2023, *Energy*, Atsonios et. al, Accessed at: https://pure.strath.ac.uk/ws/portalfiles/portal/164159101/Atsonios_etal_Energy_2023_Process_analysis_and_comparative_assessment_of_advanced_thermochemical_pathways_for_e_kerosene.pdf

114 A review of the recent progress on direct heterogeneous catalytic CO2 hydrogenation to gasoline-range hydrocarbons, 2023, *EES Catalysis.* Accessed at: https://pubs.rsc.org/en/content/articlelanding/2023/ey/d3ey00026e

115 E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

116 Sorption-enhanced Fischer-Tropsch synthesis – Effect of water removal, 2024, Gavrilovic et. al, *Catalysis Today,* Accessed at: https://www.sciencedirect.com/science/article/pii/S0920586124001081

117 Sorption-enhanced reaction process in Fischer–Tropsch synthesis for production of gasoline and hydrogen: Mathematical modelling, 2013, Bayat et. al, *Journal of Natural Gas Science and Engineering*, Accessed at https://www.sciencedirect.com/science/article/abs/pii/S1875510013000553

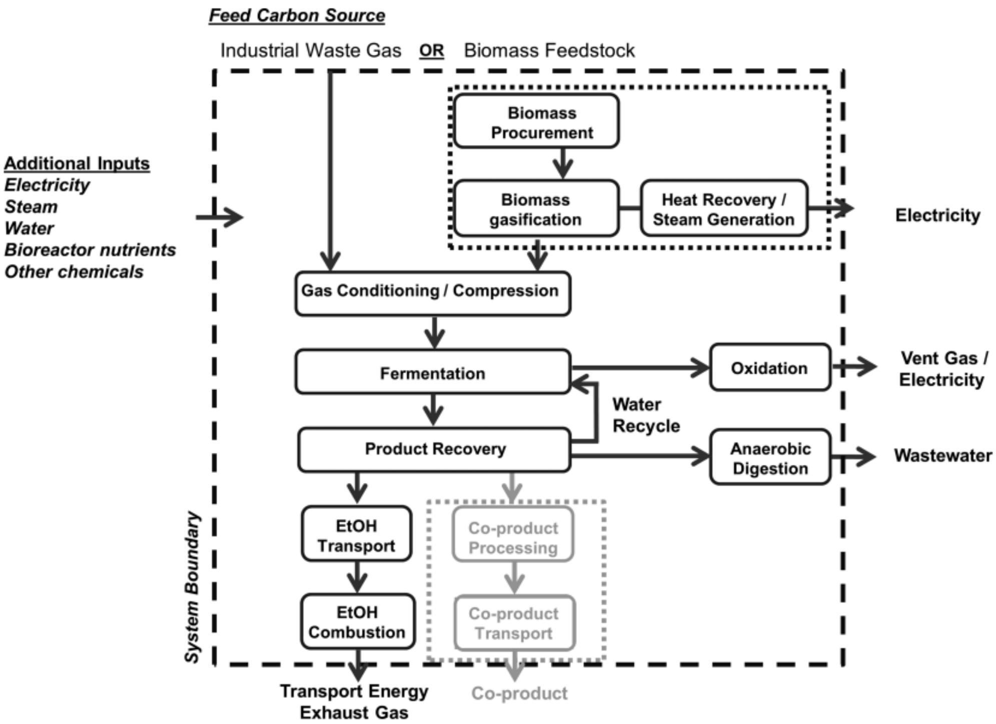
130% compared to direct CO_2 hydrogenation[118]. However, this method does result in a reduced selectivity for CH_3OH, with an increased production of CO. Despite this drawback, the advantages of water sorption clearly outweigh the minor decline in selectivity.

Another novel technology for e-kerosene production is the combination of **gas fermentation to ethanol and the alcohol-to-jet**. Gas fermentation to ethanol has been commercialised by LanzaTech. This technology has been industrially demonstrated, with or without supplementary electrolytic hydrogen, from steel mill waste gases that contain significant amount of CO (typically consisted of 50-60% CO, 10-20% CO_2 and 20-30% N_2) and syngas from industrial MSW gasification to produce ethanol, with the use of specialised biocatalysts[119]. Therefore, the TRL can be estimated to be 8-9. Despite the relatively high TRL this process has only been demonstrated at quite small scale and will need to prove its ability to scale up.

LanzaTech process can convert carbon monoxide and hydrogen-containing gases into ethanol, and other products, such as 2,3-butanediol, acetic acid, isopropanol, acetone, butanol, succinic acid, and isoprene. In the absence of CO, excess H_2 can be used to fix the carbon in CO_2. However, this process still needs to be proven under pure high CO_2 concentration feedstock at large scale.

The LanzaTech process from industrial waste gases involves three key steps: a) the gas handling step, where carbon monoxide containing gases are deoxygenated and compressed, b) the gas fermentation step, where the treated gas is fed to the biological reactor where proprietary microorganisms suspended in a liquid solution utilize CO as carbon and energy source. In case H_2 is present in the process, it can be also utilized by the microorganisms as energy source. The final step is c) the product and coproduct recovery, where the fermentation broth, containing ethanol, 2-3 butanediol and acetic acid, is continuously withdrawn from the bioreactor and sent for distillation[120].

Figure 9-5. LanzaTech gas fermentation process, adopted from literature[121][120]



[118] Overcoming the equilibrium barriers of CO2 hydrogenation to methanol via water sorption: A thermodynamic analysis, 2017, Zachopoulos et. al, *Journal of CO2 Utilisation*, Accessed at: https://www.sciencedirect.com/science/article/pii/S2212982017301531

[119] Success Stories of Advanced Biofuels for Transport, 2020, *IEA Bioenergy*, Accessed at: https://www.ieabioenergy.com/wp-content/uploads/2020/11/8-AFF_IEABio_SuccessStories_LanzaTech-Shougang_GasFermentation.pdf

[120] Life Cycle Assessments of LanzaTech Ethanol Production: Anticipated Greenhouse Gas Emissions for Cellulosic and Waste Gas Feedstocks, 2015, Handler, R., *Industrial & Engineering Chemistry Research*, Accessed at: https://www.researchgate.net/publication/286234884_Life_Cycle_Assessments_of_LanzaTech_Ethanol_Production_Anticipated_Greenhouse_Gas_Emissions_for_Cellulosic_and_Waste_Gas_Feedstocks

[121] The Alcohol-to-Jet Conversion Pathway for Drop-In Biofuels: Techno-Economic Evaluation, 2018, Geleynse et. al, Accessed at: https://chemistry-europe.onlinelibrary.wiley.com/doi/am-pdf/10.1002/cssc.201801690

The Alcohol-to-Jet (ATJ) process is used to produce hydrocarbon fuels suitable for jet engines, from alcohols (C_2-C_5) which are derived from renewable resources. The process involves three key catalytic reactions: alcohols dehydration to olefins, olefins oligomerization to higher olefins, and hydrogenation, in order to produce a mixture of synthetic paraffins in the kerosene ranges. The resulting fuel mixture is then fractionated to produce a jet fuel as well as by-products that are further refined into gasoline and diesel fuels[121]. This process is estimated to be at TRL 7-8. The overall process of gas fermentation to ethanol, followed by immediate conversion of ethanol to jet fuel is estimated to be at TRL 6-7[122].

Another way to improve the e-fuel production efficiency is by **improving the system integration**. This can be achieved by better heat integration between e-fuel synthesis and the CO_2 capture islands or including additional renewable heat sources like solar-thermal plants, by using buffer storage to avoid intermittency of renewable electricity or by process integration combining novel technologies that minimise the process steps.

9.1.3 Assessment of the e-fuel production pathways

Several factors influence the relevance, technical feasibility, economics, and scalability of pathways to make e-fuels from diverse carbon sources. In this section, e-fuel production pathways are assessed based on a combination of differentiating and non-differentiating criteria. The evaluation considers several non-differentiating indicators that are common among the pathways, including compatibility with CO_2 feedstock purity and intermittency, efficiency benefits from heat integration with carbon capture. Additionally, differentiating criteria are also considering, including CO_2 and hydrogen requirements, capital expenditure, and the overall maturity of the technology. For the purposes of this analysis, it is assumed that the operating costs (OpEx) across all pathways are comparable and will not be a basis for comparison.

Additionally, a sample survey of existing drop-in e-fuel production projects is presented, highlighting trends in the choice of production pathway, CO_2 sources, and hydrogen sources. Building upon the findings of the first interim report, considerations for the suitability of CO_2 sources for e-fuel production are elaborated on, highlighting the advantage of steady and reliable sources.

Novel pathways are excluded from the analysis due to the lack of sufficient data and detailed information necessary for accurate comparison. Therefore, the following analysis will focus on Reverse Water Gas Shift + Fischer-Tropsch and Methanol to e-fuel production pathways. Table 9-10 below presents the criteria used to assess the e-fuel production pathways.

Table 9-10. Criteria used to assess e-fuel production pathways

Type	Indicator
Non-differentiating	Purity of CO_2 supply
	Intermittency of CO_2 supply
	Heat integration with CO_2 capture
	Compatibility with CO_2 sources
Differentiating	Technology and supply chain readiness levels
	Process efficiency
	Hydrogen feedstock requirements
	CO_2 feedstock requirements
	Capital cost
	Emissions
	Commercial interest

[122] Low Carbon Hydrocarbon Fuels From Industrial Off Gas, 2023, Harmon et. al, *LanzaTech*, Accessed at: https://www.energy.gov/sites/default/files/2023-05/beto-10-project-peer-review-sdi-sup-apr-2023-harmon.pdf

9.1.4 Non-differentiating criteria

9.1.4.1 Purity of CO_2 supply

When carbon capture is employed to supply CO_2 for e-fuel production, the flue gases from industrial processes often contains contaminants. These impurities must be removed before the CO_2 is introduced into the reactors, as they can lead to inefficiencies, catalyst poisoning, and reactor degradation. The type and concentration of these contaminants depend on the source of the CO_2, and they pose different risks to the e-fuel production pathways.

RWGS+FT: The RWGS reaction and subsequent FT synthesis require clean CO_2 and hydrogen streams to avoid catalyst poisoning. RWGS involves high temperatures, which can exacerbate corrosion and degradation if contaminants like NOx or sulphur compounds are present. The FT process, which converts syngas into hydrocarbons, is highly sensitive to catalyst poisoning by sulphur, NOx, and particulates. Any contamination could reduce the selectivity and yield of the FT reaction, necessitating frequent regeneration or replacement of the catalysts. This leads to increased downtime and operational costs.

Methanol to e-fuel: The methanol synthesis process is also highly sensitive to catalyst poisoning, particularly from sulphur. The copper-based catalysts used in methanol synthesis are easily deactivated by even trace amounts of sulphur. Additionally, contaminants like NOx, H_2S, and water vapor can affect the yield and selectivity of methanol production, leading to inefficiencies in the downstream methanol-to-e-fuel conversion process. However, this pathway operates at lower temperatures compared to RWGS, making it somewhat less susceptible to thermal degradation and corrosion from acidic contaminants.

Table 9-11. Sensitivity to contaminants

Contaminant	RWGS + FT	Methanol to e-fuel
Sulphur compounds	High (FT catalysts deactivated)	Very High (methanol catalyst poisoned)
Nitrogen oxides	High (catalyst degradation)	Moderate to High (catalyst poisoning)
Particulate matter	Moderate (fouling)	Moderate (fouling)
Carbon monoxide	Moderate (affects stoichiometry)	Moderate (affects reaction balance)
Ammonia	Moderate (salt deposits)	Moderate (salt deposits)
Hydrogen sulphide	Very High (catalyst poisoning)	Very High (catalyst poisoning)

In a previous study on liquid biofuels, it was found that the acceptable concentration of impurities in syngas depends on the type of catalytic material used[123]. The impurity limits mentioned in the table below are general values found in the literature for methanol and FT synthesis.

For H_2S, the allowed concentration varies depending on the catalyst: for methanol it should be kept below 50 ppb (and preferably below 100 ppb), while for FT synthesis the reported tolerance varies between 60 ppb and 1000 ppb (without specifying the selected catalyst). Halogen species pose a stricter limitation than H_2S, with methanol catalysts requiring levels below 1 ppb and FT catalysts requiring less than 10 ppb. In terms of nitrogen species, NH_3 must be limited to 10000 ppb, NOx to 100 ppb, and HCN to 10 ppb to avoid catalyst damage. Heavy metals such as arsenic (As), selenium (Se), and mercury (Hg) should be reduced to parts-per-billion (ppb) concentrations to prevent poisoning of the catalysts.

Another category of impurities to control are metal carbonyls, particularly nickel (Ni) and iron (Fe), which can alter catalyst selectivity; their levels should be kept below 5 ppb. Finally, other harmful poisons like arsenic (As) and phosphorus (P) must also be avoided to maintain catalyst integrity. Moreover, irreversible deactivation was observed when Cu/ZnO was operated in CO/H_2 gases without CO_2 or H_2O.

[123] Boymans, E.H. and Liakakou, E.T., 2018. *Advanced Liquid Biofuels Synthesis*. ECN-E--17-057. [pdf] Available at: https://publications.tno.nl/publication/34629460/dQ3r61/e17057.pdf

Table 9-12. Syngas impurities tolerance for the Fischer-Tropsch and methanol catalysts [124]

Impurity	Methanol catalyst tolerance	Fischer-Tropsch catalyst tolerance
Sulphur	50 – 100 ppb	60 ppb – 1000 ppb
Halogen species (Cl, Br, F)	1 ppb	10 ppb
HCN	10 ppb	10 ppb
NH_3	10000 ppb	10000 ppb
As, Se, Hg	ppb levels	ppb levels

9.1.4.2 Intermittency of CO_2 supply

The intermittency of CO_2 sources influences the efficiency and operational flexibility of e-fuel production pathways. Fluctuations in plant duty has a cost impact and the cycling of materials, especially at different temperatures, can cause degradation or poor product control for RWGS+FT and methanol pathways.

Production intermittency may be reduced by relying on continuous hydrogen and CO_2 sources. However, in the future, e-fuel production might depend more on hydrogen and CO_2 produced through electrolysers and DAC plants powered by intermittent renewables, respectively. Therefore, production pathways that can operate flexibly in response to feedstock availability may be advantageous, but this is likely to be at an added cost.

FT synthesis requires a stable and consistent supply of syngas to maintain optimal reactor conditions. Therefore, FT reactors are designed for continuous operation, and fluctuations in CO_2 supply can disrupt syngas production, leading to inefficiencies and increased wear on catalysts due to frequent start-ups and shutdowns[125].

Maintaining process temperatures and pressures for FT synthesis is energy-intensive, and any interruptions can significantly reduce heat integration efficiency resulting in higher energy consumption and costs. The sensitivity of the RWGS step to hydrogen availability compounds this issue, as CO_2 fluctuations directly impact hydrogen utilization, reducing overall process efficiency.

Therefore, the RWGS + FT pathway requires more stable input conditions to operate effectively. For example, large-scale FT synthesis plants, such as those operated by Sasol, rely on a continuous and reliable supply of syngas from fossil fuels, indicating the pathway's inherent need for stability[126].

9.1.4.3 Heat integration with CO_2 capture

Both RWGS + FT and methanol to e-fuel pathways involve exothermic processes that produce heat which may be recovered and reused. One way to make this excess heat useful is by integrating the e-fuel plant with the CO_2 source, wherein the heat is used to drive solvent regeneration in thermal swing absorption CO_2 capture, a common capture technology used for large scale plants. This approach benefits from an increase in the power to liquid efficiency of the e-fuel production process and highlights the benefit of co-locating e-fuel production and CO_2 capture. Lack of heat integration implies that additional energy may be needed to supplement the energy required for CO_2 capture, which has cost and carbon footprint implications.

The extent of heat integration depends on the temperature of the synthesis process and the amount of heat produced. RWGS+FT has an advantage in that regard because of the high temperatures required in syngas production, hence has a higher potential for heat integration with CO_2 capture than the methanol to e-fuels pathway. Moreover, heat integration potential may also depend on the e-fuel produced. Gasoline production shows slightly lower energy efficiency gains compared to Kerosene since the shorter hydrocarbon chains release less heat. Diesel production offers the least efficiency gain due to its higher energy demand[127].

---

[124] P.L. Spath and D.C. Dayton, Preliminary Screening —Technical and Economic Assessment of Synthesis Gas to Fuels and Chemicals with Emphasis on the Potential for Biomass-Derived Syngas, NREL Report, NREL/TP-510-34929, December 2003

[125] Pratschner, S., Hammerschmid, M., Müller, S. et al. (2023). Evaluation of CO_2 sources for Power-to-Liquid plants producing Fischer-Tropsch products. Journal of CO_2 Utilization. Available at: https://www.sciencedirect.com/science/article/pii/S2212982023001191

[126] Sasol (2018). Sasol Technology: Fischer-Tropsch Process and Synthetic Fuel Production. Available at: https://www.sasol.com

[127] Pratschner, S., Hammerschmid, M., Müller, S. et al. (2023). Evaluation of CO_2 sources for Power-to-Liquid plants producing Fischer-Tropsch products. Journal of CO_2 Utilization. Available at: https://www.sciencedirect.com/science/article/pii/S2212982023001191

9.1.4.4 Compatibility with CO_2 sources

When assessing the suitability of CO_2 sources for e-fuel production, several factors must be considered to determine their viability, efficiency, and environmental impact. One critical factor is the concentration and purity of the CO_2 source. Higher concentrations of CO_2 reduce the energy required for capture, making industrial sources like cement production or ammonia plants more suitable than air capture, where CO_2 is more dilute [128,129].

Another important aspect is permanence, which in this context refers to the longevity and stability of the CO_2 source. Many point sources, such as industrial facilities, may diminish in the future as decarbonization efforts progress, making them less reliable over time. For instance, CO_2 emissions from fossil fuel-based industries might decline as these industries transition to lower-carbon technologies. Biomass-based CO_2 sources, such as from bioenergy with carbon capture and storage (BECCS), can be more sustainable but are subject to fluctuations due to agricultural trends, land-use changes, and policy shifts, which could impact their long-term stability[130]. On the other hand, direct air capture is potentially a highly stable and reliable source of CO_2 because it is not tied to industrial processes and can operate regardless of industrial shifts. However, DAC is more energy-intensive and costly compared to other sources, which poses a significant challenge to its widespread adoption[131].

Intermittency and temporal matching also play a critical role in determining the suitability of CO_2 sources. Some sources, such as biogas plants or peaking power plants, may have intermittent CO_2 output, which could hinder continuous e-fuel production. Temporal matching between CO_2 availability and renewable energy supply for production processes is essential to avoid using non-renewable energy during times of low renewable generation[132]. Buffer CO_2 storage systems may be used to temporarily store surplus CO_2 during periods of high availability, ensuring continuous e-fuels production even when CO_2 supplies fluctuate. However, while CO_2 storage can act as a buffer to balance intermittent supply for continuous e-fuel production, it introduces additional costs for the construction and maintenance of large CO_2 storage systems (e.g., pressurised tanks or underground storage), including the energy cost of compression and liquification, as well as potential CO_2 losses through leakage.

The geographical location of CO_2 sources also influences their suitability. Proximity to e-fuel production facilities reduces transportation costs and enhances overall system efficiency, making local, stable CO_2 sources more favourable. Finally, geopolitical and policy stability can influence the future availability of CO_2 sources. Industrial processes may change or relocate due to regulatory or economic shifts, which may reduce the availability of certain CO_2 sources for e-fuel production.

9.1.5 Differentiating criteria

9.1.5.1 Technology and supply chain readiness levels

While FT technology has been commercially established for decades, with major vendors such as Sasol, Shell, and Velocys offering industrial solutions, there are fewer companies that specialize in offering RWGS systems for commercial-scale operations. Typically, custom-designed systems are required, leading to longer lead times and higher capital costs. In contrast, the methanol-to-e-fuel pathway enjoys a broader base of technology vendors and a more mature supply chain. The MTG process is widely available from vendors like Haldor Topsoe and ExxonMobil, which have developed commercial technologies that are already deployed in various plants worldwide. The methanol production process itself is well-established and benefits from many suppliers. Methanol synthesis technology has been used for decades and is offered by numerous vendors, including Johnson Matthey and Air Liquide. The methanol-to-e-fuel pathway has more commercial-ready options and requires fewer bespoke or pilot-scale technologies than RWGS + FT, resulting in a more accessible supply chain.

---

[128] Linjala, O., & Kajolinna, T. (2023). Industrial CO2 supply pathways for CCU-based electrofuel production in Finland. VTT. Available at: [https://cris.vtt.fi/files/98747849/E-Fuel_T2.1_Industrial_CO2_supply_pathways_for_CCU-based_electrofuel_production_in_Finland.pdf]
[129] Dell'Aversano, S., Villante, C., Gallucci, K., & Vanga, G. (2024). E-Fuels: A Comprehensive Review of the Most Promising Technological Alternatives. Energies. Available at: [https://www.mdpi.com/1996-1073/17/16/3995]
[130] Dell'Aversano, S., Villante, C., Gallucci, K., & Vanga, G. (2024). E-Fuels: A Comprehensive Review of the Most Promising Technological Alternatives. Energies. Available at: [https://www.mdpi.com/1996-1073/17/16/3995]
[131] Cames, M., Chaudry, S., & Göckeler, K. (2021). E-fuels versus DACCS. Transport & Environment. Available at: [https://www.transportenvironment.org/assets/files/2021_08_TE_study_efuels_DACCS.pdf]
[132] Langenmayr, U. & Ruppert, M. (2023). Renewable origin, additionality, temporal and geographical correlation: eFuels production in Germany under the RED II regime. Energy Policy. Available at: https://www.sciencedirect.com/science/article/pii/S0301421523004159

9.1.5.2 Hydrogen and Carbon dioxide feedstock requirements

The feasibility of an e-fuel plant is highly dependent on the availability, sourcing, and infrastructure required to secure the feedstocks (H_2 and CO_2). These two feedstocks are critical for synthetic fuel production, and any limitations or intermittencies in their supply can impose significant challenges. To address such limitations, the plant may require extensive infrastructure investments, such as new pipelines for feedstock delivery, storage facilities for H_2 and CO_2, and transport systems. These additional capital and operational costs can significantly impact the economic viability of the plant. As a result, minimising feedstock requirements - by maximising feedstock efficiency - becomes a critical factor when evaluating different production pathways. Estimates of feedstock requirements for each of the processes are shown in Table 9-13.

Table 9-13. Estimates of feedstock requirements for e-fuel production. Based on the averages from Table 9-4 to Table 9-9

Production pathway	Hydrogen [kg / kg fuel]	Carbon dioxide [kg / kg fuel]
Methanol to Gasoline (MTG)	0.49	3.49
Methanol to Kerosene (MTK)	0.46	3.21
RWGS + FT Gasoline	0.60	4.28
RWGS + FT Kerosene	0.48	3.51
RWGS + FT Diesel	0.49	3.72

The RWGS + FT pathway demands large quantities of hydrogen, both in the RWGS reaction and FT synthesis, alongside substantial CO_2 inputs due to conversion inefficiencies. In comparison, the methanol-based pathways have lower hydrogen and CO_2 demand. The first stage - methanol synthesis - directly converts CO_2 and hydrogen into methanol, avoiding the syngas production step required in RWGS + FT. Once methanol is synthesised, its conversion to gasoline or kerosene requires some additional hydrogen for the upgrading process, though less than the RWGS + FT pathway, due to the simpler and more selective methanol-to-fuel conversion process.

9.1.5.3 Capital cost

The capital cost of e-fuel plants can be estimated using public data of existing projects. However, because e-fuel plants are nascent, capital cost data is scarce and is mostly confined to small scale prototypes that may not be relevant for commercial scale production. Moreover, the battery limits of existing projects are difficult to ascertain and may include the cost of the CO_2 capture equipment and water electrolysers for H_2 production. Therefore, relaying on real world cost data, which is normally a sensible approach, is in the case of e-fuel plants limited by the scale of the existing plants and their battery limits.

Alternatively, the cost of the plant may be estimated by estimating the cost of individual components (i.e. reactors, compressors, columns, coolers, heaters, etc.). Most often, cost data are not for the same sized components, hence scaling factors are used. This approach was used by Zang et al. (2021) to estimate the cost of a RWGS+FT plant for e-fuel production from CO_2 and H_2. The battery limits of the study included feedstock compression but excluded CO_2 capture and water electrolysis. Product distillation and separation was also within the system boundary limits as well as included equipment for auxiliary processes such as power generation and water treatment.

Component-specific cost prediction models may also be used to estimate the cost of the components in a plant. Schorn et al. (2021) used this approach to estimate the equipment cost of a methanol production plant. Yet another option would be to use chemical process simulators, such as Aspen Plus, to estimate costs based on equipment dimensions. This approach was used by Ruokonen et al. (2021) to estimate the cost of methanol to gasoline (MTG) plant consisting of two processes: methanol to olefins (MTO), and Mobil's Olefins to Gasoline and Distillate (MOGD).

It is important to note that this study focuses on estimating the production costs of e-fuels based on data literature available. Among the surveyed literature, those with clearly defined process conditions, equipment, and costs either through Aspen Plus simulations or traceable and verifiable references, were chosen as the basis for the estimation of the e-fuel production plant capital cost, resulting in specific investment costs that are in agreement with the ranges found in the literature. Table 9-14 lists literature references that were reviewed specifically to provide e-fuel investment cost estimates.

The primary challenges stem from differences in the underlying assumptions across the reference sources. These include variations in plant battery limits, assumptions about the cost of capital, and the allocation of indirect cost contributions. Additionally, the small sample size and the dispersion of data points in the dataset further complicate the derivation of a precise cost model. Consequently, the best-fit line for the power law equation is associated with errors, reflecting the variability and uncertainty in the input data.

Table 9-14. Capital cost estimates for e-fuel synthesis based on literature

Source	**Process**	Average Capacity [MW]*	**Mean CapEx [US$/kW]****	**Year**	**Used to estimate CapEx?*****
D'Adamo et al. (2024)	FT	0.05	1,512	2024	Yes
Brynolf et al. (2018)	FT	5	2,313	2015	Yes
Schmidt (2018)	FT	28	1,007	2018	Yes
Brynolf et al. (2018)	FT	50	1,117	2015	Yes
Grahn et al. (2022)	FT	50	1,734	2019	Yes
Yugo and Soler (2019)	FT	70	1,915	2015	Yes
Zang et al. (2021)	FT	180	1,625	2021	Yes
Brynolf et al. (2018)	FT	200	798	2015	Yes
Zhou et al. (2022)	FT	200	417	2022	Yes
Concawe (2024)	FT	1500	1,188	2024	No
Brynolf et al. (2018)	MeOH + MTG/MTK	5	2,712	2015	Yes
Schmidt (2018)	MeOH + MTG/MTK	29	1,026	2018	Yes
Brynolf et al. (2018)	MeOH + MTG/MTK	50	1,356	2015	Yes
Grahn et al. (2022)	MeOH + MTG/MTK	50	1,107	2019	Yes
Yugo and Soler (2019)	MeOH + MTG/MTK	70	1,915	2015	Yes
Brynolf et al. (2018)	MeOH + MTG/MTK	200	957	2015	Yes
Project Skypower (2024)	MeOH + MTG/MTK	1000	1,944	2024	No
Concawe (2024)	MeOH + MTG/MTK	1700	1,162	2024	No
Concawe (2024)	MeOH + MTG/MTK	1700	1,162	2024	No

Source	Process	Average Capacity [MW]*	Mean CapEx [US$/kW]**	Year	Used to estimate CapEx?***
Ruokonen et al. (2021)	MTG/MTK (no MeOH)	12.7	2,591	2021	No
Grahn et al. (2022)	MTG/MTK (no MeOH)	50	664	2019	No
Ravi et al. (2023)	MTG/MTK (no MeOH)	7100	622	2023	No
Brynolf et al. (2018)	MeOH	5	1,436	2015	No
Bos et al. (2020)	MeOH	41	411	2020	No
Brynolf et al. (2018)	MeOH	50	718	2015	No
Brynolf et al. (2018)	MeOH	200	479	2015	No
Ash et al. (2020)	FT	N/A	1,076	2017	No
Agora (2018)	FT	N/A	996	2017	No
ElSayed et al. (2023)	FT	N/A	1,046	2023	No
Agora (2018)	MeOH + MTG/MTK	N/A	1,076	2017	No

** Conversion to MW assumed a lower heating value of 43 MJ/kg, 7 barrels/tonne of oil, or 8000 hours of operation per annum, as necessary.*

*** CEPCI Index used to convert prices to the base year of 2024. Currency conversion of Euro to US Dollar based on the average closing price for the year of the cited source.*

**** Only references with e-fuel production capacities within 50 – 200 MW were selected to estimate CapEx in this study.*

The capital cost of e-fuel plants can be estimated using public data of existing projects. However, because e-fuel plants are nascent, capital cost data is scarce and is mostly confined to small scale prototypes that may not be relevant for commercial scale production. Moreover, the battery limits of existing projects are difficult to ascertain and may include the cost of the CO_2 capture equipment and water electrolysers for H2 production. Therefore, relaying on real world cost data, which is normally a sensible approach, is in the case of e-fuel plants limited by the scale of the existing plants and their battery limits.

Alternatively, the cost of the plant may be estimated by estimating the cost of individual components (i.e. reactors, compressors, columns, coolers, heaters, etc.). Most often, cost data are not for the same sized components, hence scaling factors are used. This approach was used by Zang et al. (2021) to estimate the cost of a RWGS+FT plant for e-fuel production from CO_2 and H_2. The battery limits of the study included feedstock compression but excluded CO_2 capture and water electrolysis. Product distillation and separation was also within the system boundary limits as well as included equipment for auxiliary processes such as power generation and water treatment.

Component-specific cost prediction models may also be used to estimate the cost of the components in a plant. Schorn et al. (2021) used this approach to estimate the equipment cost of a methanol production plant. Yet another option would be to use chemical process simulators, such as Aspen Plus, to estimate costs based on equipment dimensions. This approach was used by Ruokonen et al. (2021) to estimate the cost of methanol to gasoline (MTG) plant consisting of two processes: methanol to olefins (MTO), and Mobil's Olefins to Gasoline and Distillate (MOGD).

It is important to note that this study focuses on estimating the production costs of e-fuels based on data literature available. Among the surveyed literature, those with clearly defined process conditions, equipment, and costs either through Aspen Plus simulations or traceable and verifiable references, were chosen as the basis for the estimation of the e-fuel production plant capital cost, resulting in specific investment costs that are in agreement with the ranges found in the literature.

Capital cost estimates for e-fuel synthesis plants were gathered from multiple sources. These estimates were utilized to develop a predictive equation for capital cost based on a power law relationship, enabling the extrapolation of costs across various plant scales that is dependent on the e-fuel production pathway. While this approach facilitates a systematic scaling analysis, it is acknowledged that there are inherent limitations to its accuracy and applicability.

The primary challenges stem from differences in the underlying assumptions across the reference sources. These include variations in plant battery limits, assumptions about the cost of capital, and the allocation of indirect cost contributions. Additionally, the small sample size and the dispersion of data points in the dataset further complicate the derivation of a precise cost model. Consequently, the best-fit line for the power law equation is associated with errors, reflecting the variability and uncertainty in the input data.

Figure 9-6. Trendline was used to estimate the CapEx [US$/kW] of the RWGS and FT pathway

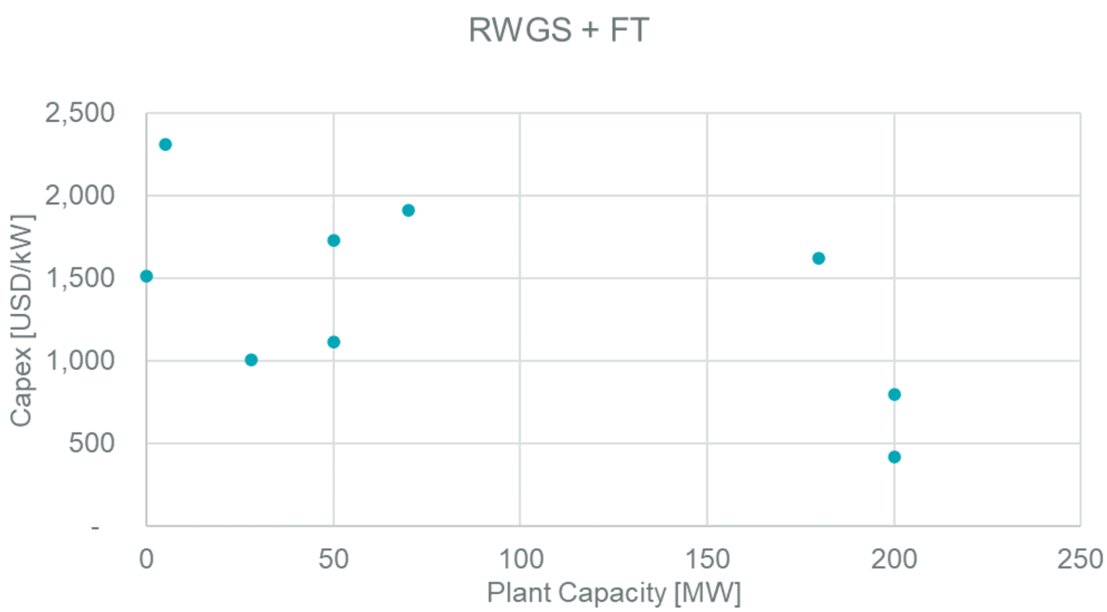
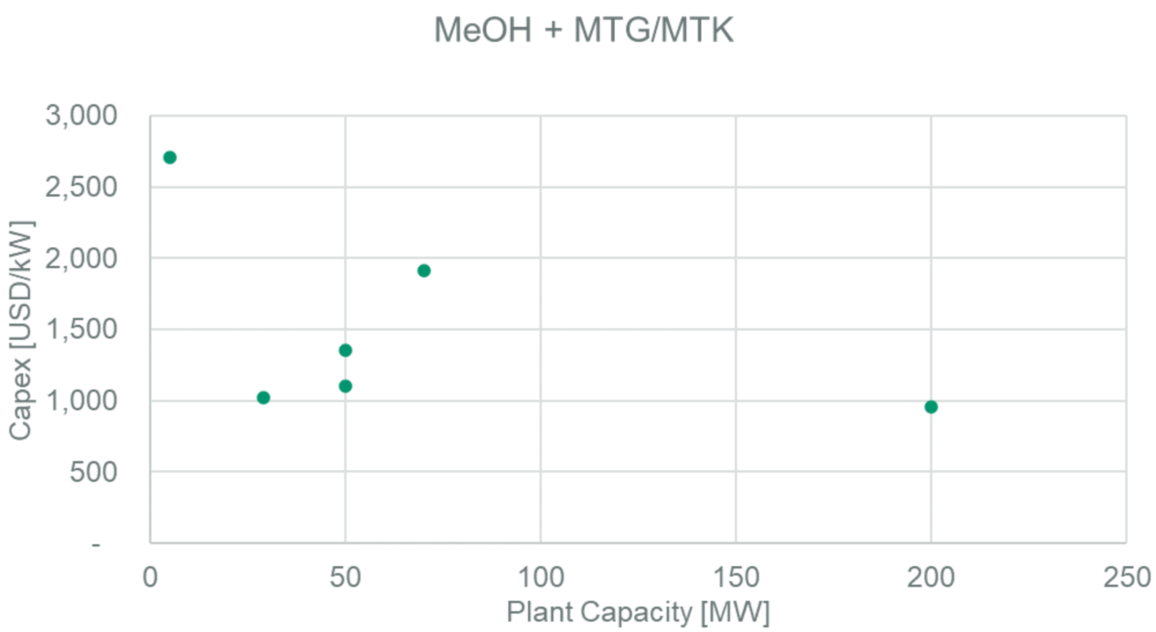


Figure 9-7. Data was used to estimate the CapEx [US$/kW] of the MeOH and MTK/MTG pathway



9.1.5.4 Emissions

A past study of the techno-economics of e-fuel production found that the majority of Cradle-to-Grave (CtG) emissions are due to the infrastructure required for hydrogen production and CO_2 capture, i.e. renewable power plants, electrolysers, and capture equipment[133]. Therefore, the emissions from the RWGS + FT and the methanol to e-fuel pathways will largely be a consequence of the emission associated with the source of hydrogen and CO_2 rather than the e-fuel production process itself. In any case, methanol pathways may have lower emissions because they are more hydrogen-efficient, consuming less hydrogen per unit of fuel, which directly reduces the energy required for electrolysis and their associated emissions. The methanol pathways' higher carbon efficiency means they require less CO_2 to produce the same amount of fuel, minimizing the carbon footprint associated with CO_2 capture and use. Additionally, the methanol pathways have higher energy efficiency and lower overall energy consumption compared to RWGS + FT.

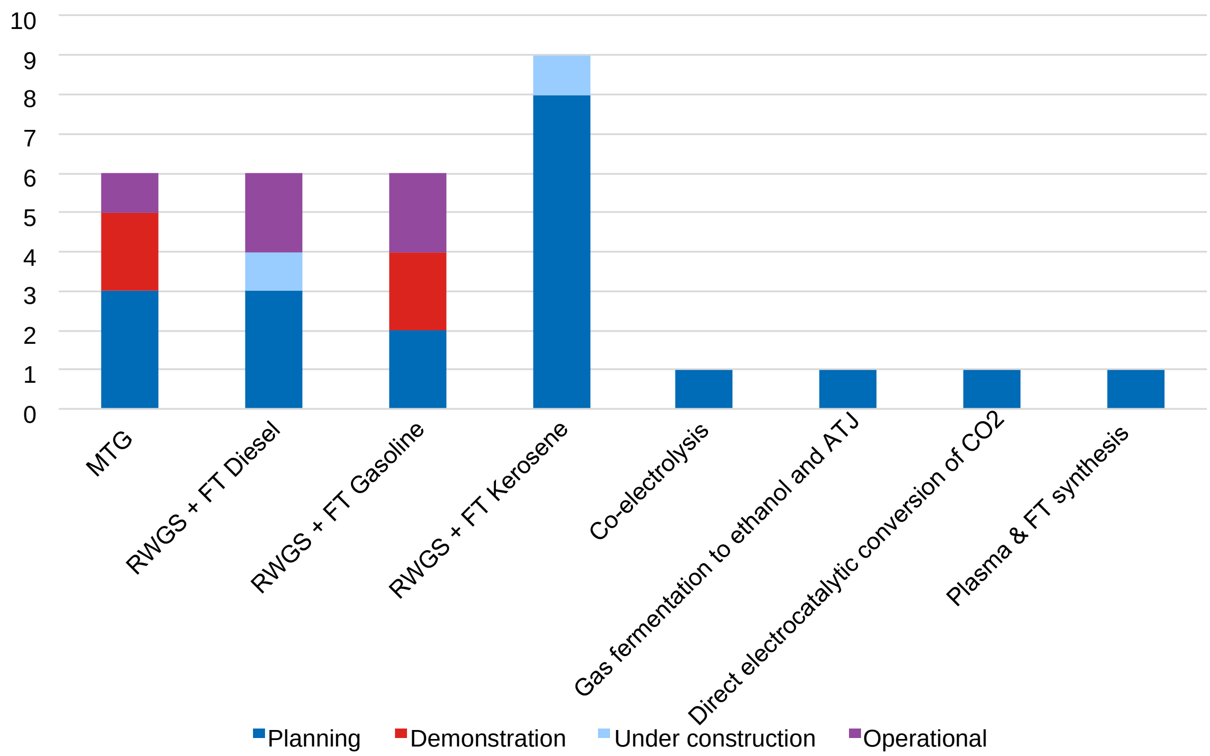
9.1.5.5 Commercial interest

A sample survey of e-fuel production facilities has been performed in order the understand the status of e-fuel production projects, and review trends in the choice of production pathway, CO_2 source, hydrogen source and system integration. The development stage of these projects ranges from early planning and feasibility studies to operational or mass-production phases. For instance, Arcadia e-Fuels and Norsk e-Fuel are in the planning stages, while Haru Oni Plant is already operational. Other projects, such as HIF Global, are currently in the demonstration phase with plans for large-scale production by 2026. Many of these projects have signed Memorandums of Understanding, indicating a commitment to future development, while some are still finalizing feasibility studies. This diversity in project maturity reflects the experimental and evolving nature of e-fuel technologies, with some initiatives close to scaling and others still proving their technological and economic viability. The full list is presented in the table at the end of this section.

The drop-in e-fuel projects employ a range of production pathways, with the most common including the MTG route, the RWGS+FT pathway for various fuels, as well as co-electrolysis, which integrates electrolysis with CO_2 reduction in one step. Some projects also explore emerging technologies like PlasmaFuel. These production methods are often designed to integrate CO_2 capture and hydrogen production processes, aiming to create synthetic fuels like gasoline, kerosene, and diesel. For example, Green Fuels for Denmark is specifically focused on gasoline production, while projects like Solar JET are targeting kerosene production for aviation.

[133] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

Figure 9-8. Number of projects identified by pathway and facility stage



Regarding the CO_2 sources used by producers, this is seen to vary across projects. Some, such as HIF Global, use DAC to capture atmospheric CO_2, while others, such as Norsk e-Fuel rely on industrial and biogenic CO_2 sources. The Solar JET project also taps into atmospheric CO_2, reflecting a trend toward utilizing carbon-neutral or carbon-negative CO_2 sources to align with sustainability goals. Several projects are designing CO_2 capture systems as part of the plant's core infrastructure, ensuring a continuous supply of CO_2 for the production process. In several cases the CO_2 is captured on site, however some projects source the CO_2 externally; for example, Norsk e-Fuel obtains recycled CO_2 from Carbon Centric and transports it to the site, to complement carbon captured via DAC.

In terms of hydrogen sources, most projects use hydrogen produced via electrolysis, typically powered by renewable energy such as offshore wind (e.g. Green Fuels for Denmark) or solar power (e.g. Solar JET). Several projects use locally produced hydrogen which is transported to site, either to complement on-site production (e.g. with Concrete chemicals) or to supply it entirely (e.g. Breogan project). The integration of renewable hydrogen sources is critical to keeping the carbon footprint of e-fuels as low as possible. Some projects, like HIF Global, integrate hydrogen production closely with CO_2 capture and fuel synthesis, optimizing the efficiency of the entire process.

The development stage of these projects ranges from early planning and feasibility studies to operational or mass-production phases. For instance, Arcadia e-Fuels and Norsk e-Fuel are in the planning stages, while Haru Oni Plant is already operational. Other projects, such as HIF Global, are currently in the demonstration phase with plans for large-scale production by 2026. Many of these projects have signed Memorandums of Understanding, indicating a commitment to future development, while some are still finalizing feasibility studies. This diversity in project maturity reflects the experimental and evolving nature of e-fuel technologies, with some initiatives close to scaling and others still proving their technological and economic viability.

Table 9-15. E-fuel projects

Project / plant	Location	Process Route	Fuel	Integration with electrolysis and CC processes	CO_2 sources	H_2 / electricity sources	Facility stage	Capacity
Green fuels for Denmark	Copenhagen, Denmark	Methanol to Gasoline (MTG)	Gasoline	Yes - plant at same location as CC	Biogenic CO_2	Electrolyser on site, powered by offshore wind from Bornholm energy island	Planning	1.3 GW
Norsk e-Fuel and Carbon Centric	Oslo, Norway	RWGS + FT derived Gasoline	Gasoline	Not fully - CO_2 liquefied and transported to plant	DAC + import	Low-temperature electrolyser for hydrogen production		50m litres / yr
Norsk e-Fuel and Carbon Centric	Oslo, Norway	Co-electrolysis (electrolysis + RWGS in one step)	Gasoline	Not fully - CO_2 liquefied and transported to plant	DAC + import	No hydrogen required for SOEC		50m litres / yr
HIF Global	Magallanes Region	Methanol to Gasoline (MTG)	Gasoline	Fully integrated	DAC, or captured from industrial / biogenic source	Wind farms - Magallanes	Demonstration - mass production due in 2026	700,000 tonnes per year
Solar JET - Bauhaud Luftfahrt	Taufkirchen, Germany	RWGS + FT derived Kerosene	Kerosene	Integrated in tests, but not at large scale yet	Atmospheric CO_2	Concentrated light as a high-temperature energy source. Thermochemical splitting of CO_2 and water	Proof of concept completed	Not mentioned
Concrete chemicals	Rüdersdorf, Germany	RWGS + FT derived Kerosene	Kerosene	Initially fully integrated with CC & green H2 production, but in second stage green hydrogen transported to the site.	Captured from cement factory. Onsite Will also use Co-SOEC electrolysis onsite.	Regional wind and solar power & co-located Sunfire electrolyser. Green H_2 initially produced on site. Aim to receive more hydrogen via pipeline from the ENERTRAG-IPCEI project.	Testing	15,000 tonne per annum

Project / plant	**Location**	**Process Route**	**Fuel**	**Integration with electrolysis and CC processes**	**CO_2 sources**	**H_2 / electricity sources**	**Facility stage**	**Capacity**
KerEAUzen	France	RWGS + FT derived Kerosene	Kerosene	Planned to be on site	Biogenic CO_2 - recycled local CO_2 from onsite & nearby industries		Feasibility study is launched	70,000 metric tons a year
EcoFuel	Austria	Other - direct electrocatalytic conversion of CO_2		Not mentioned	CO_2 capture from the air Low-temp electrocatalytic conversion to HCs	No hydrogen required.	Planning	35,000 tonnes a year
C3-Mobility	Germany	Methanol to Gasoline (MTG)	Gasoline	Not mentioned	Biomass CO_2, cement and steel production and atmospheric CO_2 - integrated on site	Renewable hydrogen - source not mentioned	Demonstration	Not mentioned
Breogan project	Galicia, Spain	RWGS + FT derived Kerosene; RWGS + FT derived Gasoline	Gasoline; Kerosene	Fully integrated	Captured biogenic CO_2 - from Greenalia's biomass plant	Green hydrogen produced in Curtis-Teixeiro.	Planning - operating due in 2027	20,000 tonnes/year of synthetic crude
PlasmaFuel	Germany	Other - plasma induced CO_2 reduction & FT synthesis	Diesel	Unknown	DAC and exhausts from the cement industry Plasma-induced reduction of CO_2 to CO, then FT synthesis	Renewable electric excess energy from wind and solar power plants		Not mentioned
Haru Oni Plant	Chile	Methanol to Gasoline (MTG)	e-Gasoline	Fully integrated	DAC	Renewable energy	Operational	25MM barrels of e-fuels per day
INERATEC and Zenith Energy Terminals e-fuel plant	Amsterdam, Netherlands	RWGS + FT derived Kerosene	Sustainable kerosene, clean diesel and CO_2-	Possible to Integrate (Green hydrogen will be locally generated and imported)	Captured from Dutch industry	Locally generated and imported green hydrogen	Memorandum of Understanding signed (Planned)	Up to 35,000 tonnes of e-fuels per year

Project / plant	Location	Process Route	Fuel	Integration with electrolysis and CC processes	CO_2 sources	H_2 / electricity sources	Facility stage	Capacity
			neutral gasoline					
P2X Kopernikus project	Germany	RWGS + FT derived Diesel	Gasoline, kerosene, and diesel	Fully integrated	Direct Air capture	Green energy by renewable energy installations	Operational and next phase is planned	10 liters per day (operational); 200 liters per day (planned); 1500-2000 liters per day (planned)
Repsol Plant	Bilbao, Spain	RWGS + FT derived Kerosene	Synthetic gasoline, diesel and kerosene	Yes	Industrial environments	Renewable electricity	Operational	8000 lt/day
SAS, Vattenfall, Shell and LanzaTech Electrofuel Production	Sweden	Gas fermentation to ethanol and ATJ	E-fuels	Yes	Waste-to-energy plant	Fossil-free electricity	Memorandum of Understanding signed (Planned)	50,000 tons per year
Sasol Secunda Synfuels plant	Secunda, South Africa	RWGS + FT derived Kerosene	Sustainable aviation fuel (SAF)	Possible to Integrate (exploring feasibility)	Biomass or other unavoidable industrial carbon dioxide sources	Green hydrogen through electrolysis using renewable energy	Feasibility study	N/A
The Navigator Company and P2X Europe Joint Venture	Portugal	Power-to-Liquid (PtL)	Carbon-neutral synthetic kerosene	Yes	Biogenic CO_2 - recycled local CO_2 from onsite & nearby industries	Green hydrogen	Memorandum of Understanding signed (Planned)	80,000 tons per year
HIF Global	Tasmania, Australia	Methanol to Gasoline (MTG)	Gasoline	Yes	Biogenic from biomass combustion	Grid renewables	Planning	80,000 tonnes per annum
Arcadia eFuels (Project Arc)	Texas, USA	RWGS + FT derived Kerosene RWGS + FT derived Diesel	Kerosene Diesel	Unknown	Unknown	Unknown	FEED	23.2 million gallons

Project / plant	Location	Process Route	Fuel	Integration with electrolysis and CC processes	CO_2 sources	H_2 / electricity sources	Facility stage	Capacity
Infinium Electrofuels Corpus Facility	Texas, USA	RWGS + FT derived Kerosene RWGS + FT derived Diesel	Kerosene Diesel	No	Industrial environments	Renewables	Operational	Unknown
HIF Global	Texas, USA	Methanol to Gasoline (MTG)	Gasoline	Yes	Industrial environments	Renewables	Planning	200 million gallons per year
Nordic Electrofuel's "Plant 1"	Norway	RWGS + FT derived Kerosene RWGS + FT derived Diesel	Kerosene Diesel	No	Furnace gas	Green hydrogen	Under construction	10 million litres per annum
Arcadia eFuels (Project Endor)	Denmark	RWGS + FT derived Kerosene RWGS + FT derived Diesel	Kerosene Diesel	Unknown	Biogenic CO_2	Green hydrogen	FEED	80,000 tonnes per annum
Arcadia eFuels (Project Naboo)	Denmark	RWGS + FT derived Kerosene RWGS + FT derived Diesel	Kerosene Diesel	Unknown	Biogenic CO_2	Green hydrogen	FEED	80,000 tonnes per annum

9.2 FEEDSTOCKS SUPPLY CHAIN ASSESSMENT

9.2.1 Drivers of feedstock supply

9.2.1.1 Approach

Table 9-16. Importance rating criteria for Hydrogen and Carbon Dioxide PESTLE analysis

Importance rating	Rationale
High	Critical to the supply of hydrogen or carbon dioxide as a feedstock for e-fuels. Unlikely that projects will be able to move forward unless this enabler is present or the barrier removed.
Medium	Likely to significantly impact the pace and/or scale of hydrogen and carbon dioxide availability as a feedstock for e-fuels.
Low	Some impact on pace and/or scale of hydrogen and carbon dioxide availability as a feedstock for e-fuels. Possibility of early indicators that the enabler will be in place, or the barrier removed.

9.2.1.2 PESTLE

Table 9-17. CO_2 supply PESTLE

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Policy	Support for CO_2 utilisation	Supportive policies and regulations for CO_2 utilisation and e-fuels are gaining ground, with national targets for sustainable fuel production present in several countries. However, some sites given subsidies for CO_2 capture or transport as part of permanent CO_2 storage projects may be restricted on their ability to provide CO_2 for applications that don't offer permanence of CO_2 storage.	Both	High	Prioritise locations that are supporting carbon capture and utilisation applications as part of their decarbonisation strategy. Prioritise hub locations with good E-fuel transport links to markets with sustainable fuel targets.
Policy	Suitability of bioenergy	Sustainability constraints may limit the availability of biofuels. Considerations such as water availability, protection of biodiversity and competing uses for land (e.g. food growth) will influence the level of biomass which can be sustainably produced.	Enabler	Medium	
Policy	Permitting and planning for CCU projects	As an emerging sector, relevant regulatory bodies are still in the process of understanding carbon capture and transport technologies meaning permitting and planning timelines can increase significantly compared to other projects.	Barrier	Low	Prioritise CO_2 hotspot locations with carbon capture and transport development experience (e.g. projects that have undergone or are undergoing relevant processes).

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Economic	High CapEx costs	Carbon capture and transport projects have high capital costs which means projects are often reliant on financing. As an emerging sector, there is perceived risk surrounding the development and delivery of carbon capture and transport at scale, which could significantly limit the ability of projects to gain access to financing. However, capture projects with strong links to an off-taker (such as an E-fuel facility) and being used to provide a product with an established market may help alleviate some of the concerns.	Barrier	High	Prioritise CO_2 hotspot locations where supporting frameworks (e.g. business models and off-taker agreements) have been developed or are under development which will help to establish risk allocation and give additional confidence to potential funders.
Economic	Rising carbon costs	For regions with a carbon price, as this increases or free allowances are removed this will incentivise carbon capture. It is important to understand how this will interface with carbon utilisation applications rather than storage.	Enabler	Medium	Prioritise locations with tariffs that incentivise carbon capture.
Economic	Opportunity for revenue generation via utilisation	Utilising CO_2 that would otherwise be emitted to atmosphere to produce E-fuels provides an opportunity for facilities to generate income from a by-product that would otherwise be seen as waste.	Enabler	Medium	Understand how the incentive for CO_2 emitters to send CO_2 for e-fuels compares to other opportunities (e.g. storage)
Economic	Competition with other forms of utilisation	If all carbon capture and utilisation options are equally incentivised, then other established and emerging applications could serve as competition for feedstock CO_2 streams. Existing applications, for example in food and drink, horticulture and urea manufacturing have an established demand. In addition, emerging techniques such as alternative fuels, building materials, e-methane or carbon black production could result in significant changes to current levels of CO_2 demand for utilisation.	Barrier	Medium	Understand value proposition for E-fuels vs. alternative uses vs. storage.

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Economic	Proximity to storage	Sources of CO_2 that are located with ready access to Onshore or Offshore geological storage, particularly in areas where CCS networks are already in development, have an increased likelihood of sending any captured CO_2 to storage.	Barrier	High	Prioritise CO_2 hotspots that don't have ready access to geological storage, or in locations where no development of geological storage is currently planned.
Economic	Shared costs/economies of scale for multi-user transport networks	There is an emerging model of multi-user CO_2 transport networks being developed compared to historical projects which focussed on a single source to sink approach. Benefits of a multi-user network approach include cost-sharing for shared infrastructure, increased scale of CO_2 available for transport and streamlining planning and permitting and the opportunity to share resources[134].	Enabler	Medium	For potential medium and large scale E-fuel production hubs, review types of CO_2 hotspots (e.g. small number of large CO_2 sources, high number of small CO_2 sources) and assess formations which enable the benefits of a multi-user model without becoming excessively complex.
Economic	Alignment of stakeholders across a transport network	Despite the benefits offered by a multi-user transport network, it can also increase the complexity of the pathway to project delivery. Alignment of the timeline for development, design, planning, permitting and Final Investment Decisions across multiple carbon capture projects with the transport network can leave projects vulnerable to cross-chain risks.	Barrier	Medium	For potential medium and large scale E-fuel production hubs, review types of CO_2 hotspots (e.g. small number of large CO_2 sources, high number of small CO_2 sources) and assess formations which enable the benefits of a multi-user model without becoming excessively complex.

[134] Status and perspectives on CCUS clusters and hubs - ScienceDirect

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Social	Public Awareness and Acceptance	Public support for CO_2 capture and transport projects, meaning less opposition during the planning and permitting phase will support delivery at scale and pace. Unfortunately, negative public sentiment and opposition has been observed for CO_2 pipeline projects, examples include Navigator's Heartland Greenway pipeline in the U.S or more recently ExxonMobil's Solent pipeline in the UK. This backlash has potential to significantly extend timescales for regulatory approval, or to even result in approval not being granted.	Both	High	Effective communication with and education of the general public on the environmental, economic and social benefits of E-fuels projects could garner support and reduce risk of local objections to new developments. Areas where there is existing industry may have more local understanding of the importance of these projects and economic benefits.
Social	Skills gap for delivery and operation of CCU projects	To facilitate the delivery of projects to support decarbonisation in-line with climate goals, a significant The IEA estimates that the clean energy transition could create 14 million new jobs, see 5 million jobs transition from fossil fuels and require additional skills and training for up to 30 million employees[135]. The delivery of significant decarbonisation projects spanning different industries and technologies between now and 2050 could see significant competition for resources which could result in delays.	Barrier	Medium	-

[135] Skills Development and Inclusivity for Clean Energy Transitions, IEA, 2022. Accessed at: Skills development and inclusivity for clean energy transitions (iea.blob.core.windows.net)

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Social	Safety – handling, transport and adverse events	Carbon dioxide has an established history of transport, storage and utilisation within industry. However, development of carbon capture and transport networks will increase the scale and types of facilities which will potentially be handling large quantities of CO_2. As an asphyxiant, careful understanding of potential release events and dispersion is key to ensuring minimal risk, particularly in regions with high population density.	Barrier	Medium	-
Technological	Ease of CO_2 transportation	CO_2 is gaseous at room temperature, and often available for capture at ambient pressure. For onwards transport, this results in the need for compression and/or liquefaction which are capital and energy intensive process steps. Additionally, whilst pipelines and road haul for CO_2 transport are well understood and established (although at a much-reduced scale compared to future requirements), CO_2 shipping and rail carriage are less mature technologies. Additionally, presence of impurities usually associated with captured CO_2 can result in significant corrosion risk across all forms of transport.	Barrier	High	Convert CO_2 close to source where possible.
Technological	Re-use of existing infrastructure	Opportunity to re-use existing pipelines to reduce transport costs of carbon dioxide, although this will limit available capacity and operating conditions dependent on the existing pipe characteristics.	Enabler	Medium	For smaller scale developments (20Mtpa and below), consider access to existing pipeline infrastructure.
Technological	Advancement in technologies	New advances in capture techniques likely to result in lower cost of capture of CO_2. As CO_2 transport networks develop and scale transport costs will also reduce.	Enabler	Medium	Prioritise countries with strong support in research and development of carbon capture and transport (e.g. grant funding).

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Technological	Variation in CO_2 composition post-capture	There is a lack of standardised CO_2 output from capture. Different capture technologies (applied to different CO_2 sources) produce different profiles and levels of impurities, at different pressures or temperatures. Typically, low purity, ambient pressure or ambient temperature CO_2 output is cheapest to produce, but this may not be compatible with subsequent transport steps or conversion to E-fuel. That may then create the need for additional conditioning steps. Differences in CO_2 specifications across CO_2 sources may prolong the engineering design phase, delay individual site permitting, and globally might reduce economies of scale.	Barrier	Medium	Reduce complexity in CO_2 value chain where possible, by prioritising CO_2 hotspots with similar or lower numbers of CO_2 point sources.
Technological	Intermittent sources - variable CO_2 output over time	With increasing renewable generation, many thermal power stations will cycle their output more often resulting in lower load factors and reduced CO_2 emissions for capture. This can increase the complexity and unit cost of CO_2 capture equipment to the point that it is less economically viable, compared to sources which have a stable output.	Barrier	Low	Prioritise CO_2 sources from facilities which operate on a continuous basis.

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Technological	Retrofit/integration of capture to existing plants	Existing sources of CO_2 are typically optimised for their current activities - there may be limited space available to add capture (or other equipment) which may limit choice of capture technology available and raise costs; there are potentially higher installation costs when working alongside live equipment and/or additional downtime to install capture or other equipment which could reduce site revenues. Additional environmental and safety requirements would likely be needed to handle CO_2- this may or may not be possible at all existing sources	Barrier	Medium	Sectors with higher levels of deployment or planned capture projects could indicate facilities are better prepared for integration with carbon capture technology – included within sector scoring.
Technological	Changes to emissions over time	Over time as more industries look to decarbonise, for example via electrification or fuel switching, the landscape of CO_2 available for capture and transport will change.	Both	Medium	**As a barrier:** prioritise CO_2 hotspots where there is a surplus of CO_2 available compared to requirements and the point sources are expected to have longevity. **As an enabler:** consider potential for new CO_2 sources to arise (e.g. DAC) close to CO_2 hotspots.
Legislative	Eligibility of carbon sources for consideration as a renewable fuel	Examples include the Renewable Energy Directive (RED) in the EU, which supports the use of Renewable Fuels from Non-Biological Origin (RFNBOs). Eligibility of CO_2 for production of fuels as defined under REDII includes the CO_2 source being covered by a carbon pricing system (e.g. EU ETS), after 2036 CO_2 generated from combustion of fossil fuels for power generation will not be eligible and after 2041 all fossil sources of CO_2 will not be eligible.	Barrier	Medium	For CO_2 hotspots located within the EU, review how the eligibility criteria would affect the CO_2 volume available.

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Legislative	Cross-border transport	Developing carbon dioxide transport networks which span across different countries may increase complexity, particularly with respect to planning, permitting and regulatory approaches for onshore developments such as pipelines. Current plans for cross-border pipeline transport networks are largely being focussed across EU member states[136], which may be due to shared legal and regulatory frameworks.	Barrier	Medium	Minimise onshore cross-border transport of CO_2 to reach E-fuel hubs.
Legislative	Development of a global CO_2 standard	Development of a global CO_2 standard for transport would reduce design complexity for transport networks and ensure that transport vessels (e.g. ships, road tankers and freight vessels) from different transport networks could be used interchangeably.	Enabler	Medium	-
Environmental	Reduction in GHG emissions	The driving force behind the development of sustainable fuel alternatives is the need to reduce CO_2 emissions in order to prevent further damage to the environment as a result of climate change. Carbon emissions from the production of E-fuels can be significantly decreased in comparison to fossil-based counterparts[137] although this is heavily reliant on the carbon intensity of electricity used and the CO_2 feedstock.	Enabler	Medium	Review results of LCA against other alternative fuels to understand positioning of E-fuels with respect to GHG emission reduction.

[136] Challenges in CO_2 Transportation: Trends and Perspectives, Rene Simonsen et al., 2023. Accessed at: https://doi.org/10.1016/j.rser.2023.114149
[137] E-fuels: A Challenging Journey to a Low-Carbon Future, S&P Global, 2024. Accessed at: E-fuels: A Challenging Journey To A Low-Carbon Future (spglobal.com)

Category	Factor	Detail	Enabler/ Barrier	Impact Rating	Recommendation
Environmental	GHG impact of transport	Each CO_2 transport method has its own associated carbon footprint, from embodied carbon within materials and fuel or energy requirements to operate. Optimising transport methods for the quantity, distance and	Barrier	Low	Where CO_2 transport is required for e-fuel production, consider how selection of transport methods will influence the overall GHG impact and reduce as far as possible.
Environmental	Potential for CO_2 release events	Capture and transport of carbon dioxide gives rise to the potential for adverse events, which could lead to CO_2 being released or vented. CO_2 is an asphyxiant and a release can pose health risks to humans and wildlife. Safe design and operation of such facilities is paramount and would reduce the risk of such events.	Barrier	Low	-

Table 9-18. Hydrogen supply PESTLE

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
Political	Direct financial support	Targets and support for scale up and efficiency of factories could help attract private sector investment in green hydrogen. However, costs remain high so financial incentives such as grants or loans would still be needed. To date, green hydrogen production has benefited from subsidies for pilot programmes and R&D funding. Since the pandemic, a number of countries have committed to green hydrogen through recovery plans[138].	Enabler	Medium	Regions with direct financial incentives may help overcome high production costs
Political	Future demand uncertainty	A major hurdle to scaling up the production of green hydrogen which has been identified is a lack of certainty surrounding future demand. Creating demand for green hydrogen will be a key instrument to stimulate investment across the low-emission hydrogen supply including via measures such as quotas, fuel standards and public procurement rules. While hydrogen demand overall has continued to grow, it remains concentrated in traditional applications with novel applications including heavy industry and long-distance transport making up under 0.1% of demand. However, by 2030 they are anticipated to account for one third of global hydrogen demand according to the IEA's Net Zero Emissions by 2050 scenario[139]. The uncertainty surrounding future demand is closely linked to the lack of clarity about certification and regulation, and the lack of infrastructure available to deliver hydrogen to end users. In order for this level of demand to be realised, accelerated policy action is required to unlock investment and accelerate production scale-up and deployment of infrastructure.	Barrier	High	Prioritise regions with strong policy support and infrastructure investment in emerging hydrogen applications to align with anticipated demand growth by 2030.
Political	National Strategies	A number of countries have included green hydrogen within their recovery plans following the pandemic. Several countries have also outline national plans and strategies, notably India which aims to become a global leader in production and supply of green Hydrogen. In	Enabler	High	Countries with National green hydrogen strategies in place will have clearer

[138] Green Hydrogen Supply, IRENA, 2021, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218

[139] Hydrogen, IEA, Accessed at: https://www.iea.org/energy-system/low-emission-fuels/hydrogen

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
		many cases, however, the pathway towards meeting certain targets and ambitions remains unclear[140].			production pathways and security of hydrogen supply
Political	Support for the scale-up of manufacturing capacity	Industrial policies often provide support through a specialized fiscal framework. For green hydrogen, policies that alleviate the financial burden associated with electrolyser investment will lower that cost component and enhance the business case[141].	Barrier	Medium	Prioritise locations with favourable regulatory environments supporting cost reduction for green hydrogen production.
Political	Shift away from support for hydrogen	With widespread elections globally, there is a risk that in certain key regions such as the US, policy shifts away from support for hydrogen production. This could undermine efforts to date, impacting momentum and investor confidence.	Barrier	Medium	Consider potential for high level changes in policy direction when selecting hub location.
Economic	High CapEx costs	Green hydrogen projects are capital intensive which makes financing a key factor. The capital cost of investment in electrolyser is closely linked to capacity, with cost per kwh potentially doubling for electrolysers below 1MW capacity. Green hydrogen can achieve cost parity with fossil-based hydrogen, however optimal conditions of low-cost renewable electricity are required[142]. There are expected to see cost reductions in very large plants as savings can be made across the balance of plant for production plants	Barrier	High	
Economic	High OpEx costs	The production cost of green hydrogen depends on the cost of electrolysers and their capacity factor. While the levelised cost of	Barrier	High	

[140] Green Hydrogen Market: Potentials and Challenges, 100re, 2023, Accessed at: https://100re-map.net/green-hydrogen-market-potentials-and-challenges/
[141] Green Hydrogen Supply, IRENA, 2021, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218
[142] Hydrogen costs in 2024, Wood Mackenzie, 2024, Accessed at: https://www.woodmac.com/news/opinion/hydrogen-costs-in-2024-what-you-need-to-know/#:~:text=The%20hydrogen%20market%20faces%20a,expensive%20to%20produce%20and%20transport.

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
		renewable electricity has fallen sharply, its variability impacts the utilisation of electrolysers, in turn driving up costs[143].			
Economic	High cost of transportation and storage	In line with the technical challenges outlined below, transportation and storage of hydrogen is face with: (1) high cost to upgrade existing pipeline infrastructure (2) high cost and efficiency losses of liquefaction and compression	Barrier	Medium	Avoid transportation of hydrogen, but if needed prioritise locations with existing pipeline infrastructure for longer distance transport
Economic	Opportunity for countries to play a role in future fuels	Green hydrogen production and then green hydrogen consumers/industries are going to be focused around geographies with access to renewables. This could see countries such as Morocco being a new energy exporter rather than consumer in years to come. Remembering it is easier to transport the derivatives of hydrogen this could see countries becoming fuel producers/exporters that aren't the traditional oil & gas exporters.	Enabler	Low	Explore opportunities to align with national ambitions surrounding E-fuel production.
Social	Safety - existing infrastructure and population density	Challenges regarding hydrogen safety include[144]: (1) Safe handling – hydrogen is highly flammable and therefore requires special equipment and procedures. (2) Transport safety: transporting over long distance can raise challenges due to hydrogen's low density (3) Hydrogen embrittlement: hydrogen can lead to metal embrittlement, leading to issues with structural integrity of equipment and infrastructure, particularly existing infrastructure when being converted[145].	Barrier	Medium	

[143] Green Hydrogen Supply, IRENA, 2021, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218

[144] Hydrogen Safety Challenges: A Comprehensive Review on Production, Storage, Transport, Utilization, and CFD-Based Consequence and Risk Assessment, Calabrese et al., 2024, Accessed at: https://www.mdpi.com/1996-1073/17/6/1350

[145] Issue Brief Outlines Hydrogen Transportation Barriers, Great Plan Institute, Accessed at: https://betterenergy.org/blog/issue-brief-outlines-hydrogen-transportation-barriers/#:~:text=This%20poses%20several%20challenges%2C%20like,subject%20to%20fluctuating%20pressure%20changes.

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
Social	Public awareness and acceptance	Public awareness and acceptance is a key issue when it comes to hydrogen. For example, hydrogen for heat projects have been stopped in the UK as a result of public disapproval.	Barrier	High	
Social	Risk of green hydrogen exports hindering decarbonization in developing countries	Sustainably produced green hydrogen is produced using additional renewable electricity. This aims to prevent the use of electrolysers increasing fossil fuel consumption elsewhere or displacing more efficient uses of renewable electricity. Green hydrogen should therefore only be produced from renewable energy capacity that would not otherwise be commissioned and electricity that would not otherwise be consumed. This becomes especially critical in developing countries. As demand for green hydrogen in developed countries increases, developing countries are at risk of developing renewables dedicated to green hydrogen for export potentially impacting the decarbonisation of their own electricity grid.	Barrier	Low	
Technological	Ease and costs of hydrogen transportation	A key barrier regarding transportation of hydrogen its low volumetric energy density, which results in higher costs of transportation for a given amount of energy when compared with carbon fuels. Each mode of hydrogen production, treatment, transport and storage has the potential to introduce inefficiencies into the end-to-end process. An option to mitigate this is by conversion to hydrogen-based fuels and derivatives, however many of the technology pathways to achieve this are not implemented at scale. For longer distance transport, shipping hydrogen in the form of a hydrogen carrier/derivative is more cost-competitive. However, the conversion to a hydrogen-based fuel such as green ammonia, to be converted back to hydrogen results in significant efficient losses in the end-to-end process[146]. In addition, hydrogen is currently mostly produced and consumed in the same location without need for transport infrastructure, and there is currently a lack of infrastructure to meet increasing demand. Pipelines are the most efficient and least costly way to transport hydrogen over longer distances, with small networks in place in Europe and the US	Barrier	High	Avoid transportation of hydrogen and prioritise hub location in proximity of hydrogen production. Alternatively, prioritise proximity to pipeline infrastructure to avoid high costs of liquefaction or compression.

[146] Green Hydrogen: the Holy Grail of Decarbonisation? An Analysis of the Technical and Geopolitical Implications of the Future Hydrogen Economy, Scita et al., 2020, Accessed at: https://www.jstor.org/stable/resrep26335

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
		which are mainly privately owned and used to connect industrial users[147].			
Technological	Storage	Irrespective of the application/sector, safe handling and storage of hydrogen are crucial. Two main options currently exist: tanks and underground geologic formations. Tanks are widely used in industry and are more suited to lower volumes. Hydrogen embrittlement is a challenge which leads to the deterioration of the cylinders raising safety concerns. Storing compressed hydrogen in tanks is at least 50% more expensive than storing methane due to its lower specific energy. The cost of storage is closely linked to how frequently the storage is used; additionally as more pressurised tanks are deployed costs are expected to decrease. Liquefied hydrogen storage requires maintain temperatures below -250 degrees Celsius. To liquefying the hydrogen is energy intensive, considerably more than compression, and once cool it needs active cooling to minimise losses from boil off[148]. Storage underground in salt caverns is also possible. However, the potential sites are limited geographically to those areas with suitable salt domes or bedded salt deposits in the rock strata below ground. Onshore in the UK this is the north east, Dorset and Cheshire. Other countries already investigating this are the USA, France and Germany. Crucially, it is best suited to larger volumes and long timeframes, and therefore most applicable for seasonal use. Another geological formation is former gas fields, such as Centrica's proposed Rough storage site. However, the hydrogen would be mixed with the existing gases and never be as 'clean' as salt caverns.	Barrier	Medium	Explore potential of production in regions with either more develop storage infrastructure, or favourable geological formations which enable longer term storage.
Technological	Availability of renewable electricity	Sustainably produced green hydrogen is produced using renewable electricity, either from dedicated renewable supply or sometimes otherwise curtailed power. i.e. electricity capacity that would not otherwise have been commissioned and electricity that would not have	Barrier	High	Identify locations with greater abundance of renewable

[147] Global Hydrogen Review 2023, IEA, Accessed at: https://www.iea.org/reports/global-hydrogen-review-2023
[148] Green Hydrogen Supply, IRENA, 2021, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
		been otherwise consumed. Wind and solar renewable electricity is variable, which sharply reduces electrolyser utilisation driving costs up. A potential solution to this is to connect to the local grid during renewables downtime, however this increases the carbon intensity of the hydrogen produced. Production sites can be optimised by utilising different renewable sources e.g. tidal and solar, or wind and solar. There is also the option to purchase 'renewable electricity' through the grid by means of a Power Purchase Agreement[149].			electricity generation.
Technological	Advancement in electrolyser technology	The electrolyser market is not yet fully developed and as the technology is further developed it is predicted there will be increases in conversion efficiency (majority 50-60%). Additionally, there are some early TRL technologies promising higher efficiencies (up to 90%)[150].	Enabler	Medium	
Legal	Hydrogen standards	Green hydrogen relates to hydrogen produced using renewable electricity and electrolysers, however it not linked to an agreed definition of embedded emissions - as such, generally governments talk about low carbon hydrogen which can include SMR with CCUS (blue hydrogen). The lack of international standards and regulation is a major obstacle affecting the development of the global green (or low carbon) hydrogen market. There are still no international standards addressing hydrogen production and use, with countries establishing their own standards and regulations[151]. A lack of common international framework may lead to unfair competition related to the ambiguity surrounding clean hydrogen, with carbon-free hydrogen being more expensive[152]. Definitions may also vary depending on the type of technology used.	Barrier	Medium	Prioritise production in locations with higher standards to ensure sustainability, and enable market entry to regions with stricter standards in place.
Legal	Lack of consistency across regions	Preferred electrolyser technologies vary by region and application. China dominates global manufacturing capacity (~68%). Alkaline electrolysers prefer a continuous electrical load to remain within safety limits. Proton	Barrier	Low	

[149] Green Hydrogen Supply, IRENA, 2021, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218

[150] Electrolysers, IEA, 2023 Accessed at: https://www.iea.org/energy-system/low-emission-fuels/electrolysers

[151] Environmental Defense Fund, 2023, Accessed at: https://blogs.edf.org/energyexchange/2023/05/09/lack-of-standards-could-undermine-global-hydrogen-market-before-it-gets-started/#:~:text=The%20main%20impetus%20behind%20hydrogen%27s,public%20support%20or%20market%20entry.

[152] Green Hydrogen Supply, IRENA, 2021, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
	in electrolyser standards	exchange membrane (PEM) technology, a newer technology, more typically produced by Western OEMs, allows hydrogen production to mirror renewable generation but at a higher CapEx cost. There is a risk that a two-tier global market develops, as Chinese OEMs push lower cost electrolysers, and carve out market shares in regions with less stringent rules on emissions			
Legal	Infrastructure and materials safety standards	Safety standards of materials for hydrogen production / storage / transport in Europe are covered under CE marking legislation. In the US it is the ASME stamp. However, in other regions, this is not the case and safety standards may vary.	Barrier	Medium	
Legal	Targets for E-fuels in sustainable fuel mandates	A number of fuel mandates contain targets for e-fuels, or hydrogen derived fuels, and this pivotal in driving the growth of hydrogen supply. These mandates set progressive targets, which in some cases are legally binding, for the adoption of low-carbon fuels, including e-fuels produced using green hydrogen[153]. As national governments and international bodies such as the European Union implement these targets, this provides greater certainty in demand. In turn, this stimulates investment in hydrogen production infrastructure and innovation.	Enabler	Medium	Regions with fuel mandates in place are more likely to have hydrogen production infrastructure in place, or planned.
Environmental	Water requirements	Water requirements for hydrogen production vary significantly by technology pathway. Water is required as an input for production and as cooling medium for production of all types of hydrogen. Green hydrogen relies on a relatively high share of water withdrawal for cool at 56%, however this is lower than blue hydrogen requirements (92%). Current freshwater withdrawals for hydrogen production could increase six-fold by 2050, and currently more than 35% of global green and blue hydrogen production capacity is located in water-stressed regions[154]. This has significant environmental impact. Larger plants may have such significant water requirements that they may have to rely on desalination plants.	Barrier	High	Prioritise hydrogen production in water-rich regions, and carefully evaluate water-related impacts and risks.

[153] ReFuelEU Aviation, European Commission, Accessed at: https://transport.ec.europa.eu/transport-modes/air/environment/refueleu-aviation_en

[154] Water for hydrogen production, IRENA, 2023, Accessed at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2023/Dec/IRENA_Bluerisk_Water_for_hydrogen_production_2023.pdf?rev=4b4a35632b6d48899eb02bc54fd1117f

Category	Factor	Detail	Enabler / barrier	Impact rating	Recommendation
Environmental	Land requirements	Green hydrogen requires significant amounts of renewable energy and water as inputs for electrolysers. This may place pressure on land use and water supplies[155]. In some developing countries with limited energy supplies, poorly designed green hydrogen production projects may exacerbate social imbalances by diverting electricity and water resources away from other essential needs. While water electrolysis plants likely won't occupy much space, the renewable energy systems supplying power to electrolysers require substantial land. Consequently, the installation of these renewable energy sources can lead to changes in land use, impacting social and ecological factors.	Barrier	Low	
Environmental	Conversion to green Ammonia	Green ammonia is highly toxic, and comes with significant safety risks and impacts on human health in cases of leaks. If converted for transportation purposes, this can also result in significant efficiency losses in the end-to-end process. Hydrogen itself is non-toxic, though is considered an indirect GHG[156].	Barrier	Low	Avoid conversion to Ammonia for transportation purposes to mitigate safety risks and losses in efficiency
Environmental	Lower environmental risk	Green hydrogen aims to displace the use of fossil fuels, with applications in a number of sectors. This reduces reliance on fossil fuels and therefore reduces the risk of associated environmental catastrophes	Enabler	Medium	

[155] Green Hydrogen Market: Potentials and Challenges, 100re, 2023, Accessed at: https://100re-map.net/green-hydrogen-market-potentials-and-challenges/

[156] The role of hydrogen and ammonia in meeting the net zero challenge, The Royal Society, 2022, Accessed at: https://royalsociety.org/-/media/policy/projects/climate-change-science-solutions/climate-science-solutions-hydrogen-ammonia.pdf

9.2.1.3 Case studies

There are several barriers that hinder the deployment of CCUS. Key challenges common to all sites include the high costs and logistical difficulties of transporting CO_2 to storage or utilisation facilities, which are influenced by the distance between the carbon capture site and the storage or utilisation location. Additionally, significant capital expenditures are required for the construction and installation of carbon capture equipment, compounded by the high energy penalties and operating and maintenance costs associated with running this equipment. The limited commercial deployment of CCUS technologies to date further underscores the challenges, and a limited policy support in many parts of the world exacerbates these issues by failing to provide a clear business model for CCUS adoption.

The development of CCUS hubs, defined as clusters of high-emission facilities that share CO_2 transportation and storage/utilisation infrastructure, has emerged as a strategic solution to these challenges. CCUS hubs offer several advantages, including:

- **Cost Reduction:** Economies of scale can be achieved when multiple facilities utilise shared transport, storage, and utilisation infrastructure, helping lower costs.
- **Risk Sharing:** By distributing the risks across multiple sites, no single facility bears all risks of the project.
- **Centralised Operations:** These hubs allow for improved coordination and optimisation of CCUS processes through centralised management.
- **Scalability and Flexibility:** Once the foundational infrastructure is established, it becomes easier to expand the network, connecting additional emitters and storage sites to increase carbon capture capacity.
- **Commercial Synergies:** CCUS hubs can also create opportunities for other commercial collaborations and innovations.
- **Economic Revitalisation:** By helping industries produce low-carbon goods, CCUS hubs can enhance regional competitiveness, positioning these areas for long-term economic success in a decarbonising world.

CCUS hubs, therefore, play a crucial role in overcoming the barriers to CCUS deployment and contribute to the broader goal of global decarbonisation. While the initial development of these hubs was slow, there has been a recent increase in their establishment as governments move towards large-scale CCUS deployment to meet net-zero targets. Notably, analysis by Wang identified 25 hubs worldwide that are expected to be operational by the end of this decade, with a combined capture capacity of 294 $MtCO_2$ per year[157].

In this report, we examine three case studies of CCUS hubs across the globe: the Louisiana Future Energy Cluster in the United States, the Antwerp Port Hub in Belgium, and the Junggar Basin Hub in China.

Case Study 1 (UK) – HyNet North West

HyNet is a CCUS and low-carbon hydrogen project based in North West England, supporting decarbonisation of industry across Liverpool, Manchester and North Wales. Significant emitters in the area cover a range of sectors, including major power producers, cement manufacturers, oil & gas, chemicals, food & drink and waste management. CO_2 from industrial emitters, alongside a blue hydrogen production facility planned at Stanlow refinery, will be transported for offshore storage in depleted Oil and Gas fields in Liverpool Bay.

The project plans to deploy a mixture of new-build and re-purposed existing pipelines to transport the CO_2. During initial deployment, where lower volumes of CO_2 are being transported, the transport system will operate with CO_2 in the gas phase[158]. Once the storage reservoir pressure increases, liquid phase flow will be required for the offshore leg of the pipeline and the system has been designed to accommodate this transition. The CO_2 pipeline is scheduled to take Final Investment Decision in September 2024, and be operational in the late 2020s. The initial capacity is expected to be 4.5 Mt CO_2/yr[159], with ambitions of scaling to 10Mt CO_2/yr in the

[157] Status and perspectives on CCUS clusters and hubs, Rui Wang, 2024, Accessed at: Status and perspectives on CCUS clusters and hubs - ScienceDirect

[158] HyNet CCUS Pre-FEED Key Knowledge Deliverable, Progressive Energy, 2022. Accessed at: HyNet CCUS pre FEED KKD WP1 - full chain basis of design (publishing.service.gov.uk)

[159] CCUS Track 1 Expansion Guidance, Department for Energy Security and Net Zero, 2023. Accessed at: CCUS Track-1 Expansion: HyNet process application guidance (publishing.service.gov.uk)

2030s. A key challenge faced by the project have been the complexity of the consenting process, for which they have need both planning permission for the pre-existing, repurposed pipe, as well as a Development Consent Order for the new-build element. However, the latter was granted in March 2024.

The HyNet CO_2 transport and storage network was selected by UK Government in 2021 to move into negotiations for support as one of the first major CCUS infrastructure projects in the UK. Five CO_2 emitters were selected in 2023 as first joiners to the network, covering capture from cement, energy from waste, lime production and blue hydrogen. More recently, an expansion process was launched to fill remaining capacity available within the network, with further selection of emitters awaiting announcement.

Alongside the development of the HyNet project, a wider cluster plan for the region has been developed to illustrate how wider industry in the region can decarbonise and also the benefits of the project for the local area. It highlights the potential for up to £30bn of near-term investment into decarbonisation projects with the potential to safeguard or create over 30,000 jobs in the local area[160].

Figure 9-9. HyNet Northwest overview

Case Study 2 (US) - Louisiana Future Energy Cluster

Louisiana, a state renowned for its refining and heavy industry, has emerged as a prime location for CCUS initiatives in the United States. Its extensive underground storage capacity and supportive state policies have positioned it as a leader in this field. The region's industrial corridor, centred around Baton Rouge and New Orleans, is a hub of chemical, petrochemical, refining, and ammonia production facilities—significant contributors to carbon emissions.[161] Louisiana has seized this opportunity, aiming to develop and expand both CCUS and low-carbon hydrogen networks.

The CCUS hub, known as the Liberty CCUS hub, which is spearheaded by Shell, is a cornerstone of these efforts. Initially focusing on decarbonising its own petrochemical units, the hub is open to partnering with other industrial companies in the region, including biomass, steel, paper, cement, and ammonia producers. The project is on track to commence operations in the mid-2020s, pending final CO_2 storage permitting.[161,162] While

[160]Net Zero North West Cluster Plan, 2023. Accessed at: NZNW_Cluster_Plan_Y2_Summary_FINAL_fcba0b7233.pdf (netzeronw.co.uk)

[161] A New U.S. Industrial Backbone: Exploring Regional CCUS Hubs for Small-to-Midsize Industrial Emitters, EFI Foundation, 2023, Accessed at: RegionalClusterFactSheets-1.pdf (efifoundation.org)

[162] Liberty Louisiana, The CCUS Hub, 2024, Accessed at: Liberty Louisiana - The CCUS Hub (ogci.com)

specific capture targets are not yet finalised, industry estimates suggest a potential of 12 million tons of CO_2 captured annually, representing approximately 12% of the state's industrial emissions.[161]

Key challenges facing the Liberty CCUS hub include complex land ownership issues and uncertainties surrounding regulatory frameworks for carbon dioxide storage. Additionally, the long-term viability of federal policies like 45Q and evolving carbon markets poses risks.[162] Technical challenges also arise from incorporating the multiple industrial facilities throughout the Baton Rouge and New Orleans area which have varying CO_2 purity levels, as impurities could impact transport efficiency. Stakeholder management challenges may also arise if multiple small to medium-sized industrial facilities join the CCUS network, as this can increase organisational complexity and potentially slow down deployment.

To complement its CCUS hub, Louisiana is also advancing a hydrogen hub, which includes both blue and green hydrogen production. This integration of hydrogen production and CCUS may help drive adoption of both technologies. A key project in this effort is the Louisiana Clean Energy Complex, led by Air Products, with an investment of US$4.5 billion. Located in Ascension Parish, this blue hydrogen project aims to capture and sequester 5 million tons of CO_2 annually, while supplying 750 million cubic feet per day of blue hydrogen to existing customers via a 700-mile pipeline that runs from Galveston Bay in Texas to New Orleans (see Figure 9-10 below[163]). Some of the blue hydrogen will also be bled from the pipeline and be used to produce blue ammonia for transportation and other markets. The captured CO_2 will be transported through an onshore pipeline up to 35 miles away, where it will be stored approximately one mile beneath the surface. The project is expected to be operational by 2026.[164] In addition to this, the H2theFuture project, funded by the US$50 million Build Back Better Challenge, will focus on green hydrogen production. This initiative will use offshore wind power to produce green hydrogen.

Recently, the Environmental Protection Agency (EPA) granted Louisiana primary enforcement authority ("primacy") to permit Class IV wells, which are required for permanent geological storage of CO_2[165]. This enables the Louisiana Department of Natural Resources to issue Underground Injection Control permits for geological sequestration facilities. The process to grant primacy took over 2 and a half years with Louisiana modifying its existing laws and regulations around CCS to be more consistent with federal requirements and with the aim to speed up the primacy approval. Key changes include a revision to the post-injection period of liability for operators to fifty years from ten, compared to ten years and twenty years in North Dakota and Wyoming respectively, which are the two other states that have been granted primacy[166]. Since the decision to grant Louisiana primacy, several groups have taken legal action against the EPA with the aim of overturning the determination which could halt development of CCS projects in the state.

---

[163] Louisiana Clean Energy Complex, Air Products, 2024, Accessed at: Landmark U.S. $4.5 Billion Louisiana Clean Energy Complex (airproducts.com)

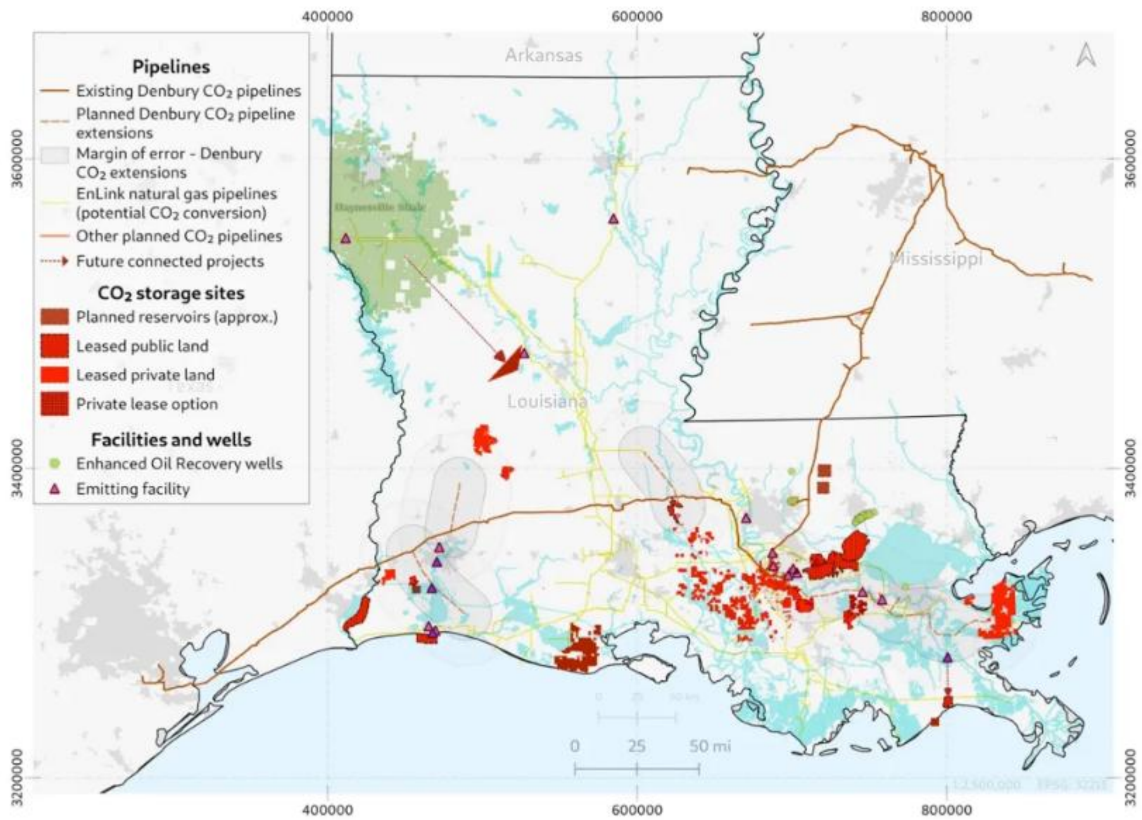
[164] Louisiana Governor Edwards and Air Products Announce Landmark U.S. $4.5 Billion Blue Hydrogen Clean Energy Complex in Eastern Louisiana, Air Products, 2021, Accessed at: Louisiana Governor Edwards and Air Products Announce Landmark U.S. $4.5 Billion Blue Hydrogen Clean Energy Complex in Eastern Louisiana

[165] State of Louisiana Underground Injection Control Program; Class VI Primacy. Accessed at: Federal Register :: State of Louisiana Underground Injection Control Program; Class VI Primacy

[166] CCS Permitting Roundup: EPA Grants Louisiana Permitting Primacy but Challengers Remain, Vinson & Elkins, 2024. Accessed at: CCS Permitting Roundup: EPA Grants Louisiana Permitting Primacy But Challenges Remain | V&E Environmental Update | Environmental | Insights | Vinson & Elkins LLP (velaw.com)

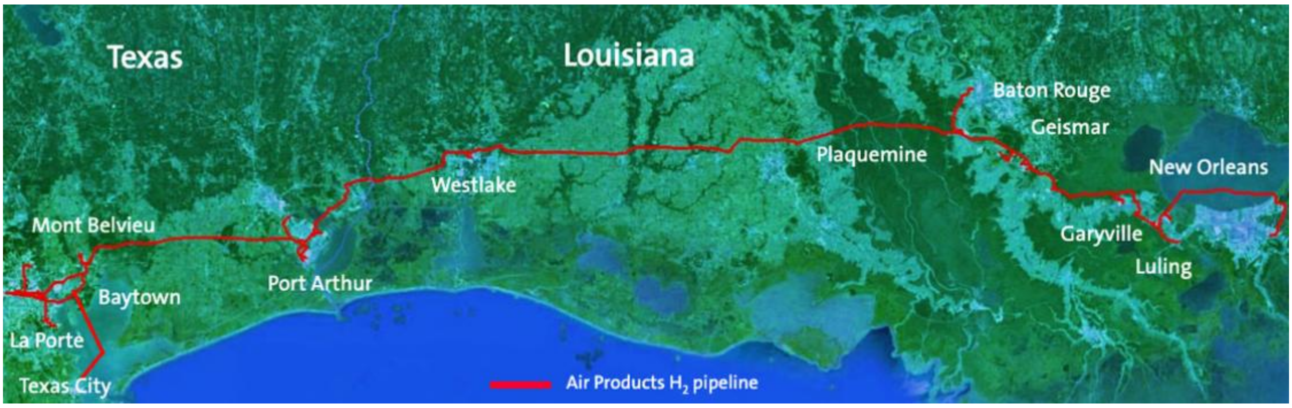
Figure 9-10. Carbon capture projects planned in Louisiana - the full route of CO_2 pipelines is yet to be defined with 10 potential pipeline projects proposed

Figure 9-11. Existing and proposed CO_2 pipeline infrastructure in Louisiana.[167]



[167] Originally cited as Carbon capture and sequestration in Louisiana (2023), accessed via https://capitalbnews.org/carbon-capture-louisiana/

Figure 9-12. The Air Products existing 700-mile-long hydrogen pipeline which will be transporting blue hydrogen from the Louisiana Clean Energy Complex to existing customers.[163]



Case Study 3 (EU) - Antwerp Port

The Port of Antwerp, located near Zandvliet, Antwerp, Belgium, is home to the largest integrated energy and chemicals cluster in Europe. The port is undertaking a major initiative to build a shared, open-access CO_2 transportation and export infrastructure aimed at reducing the port's emissions by 50% by 2030. This cross-border project, one of the world's largest multimodal open-access CO_2 export facilities, is being led by a consortium that includes Air Liquide, BASF, Borealis, ExxonMobil, INEOS, TotalEnergies, Fluxys, and the Port of Antwerp.[168]

The project is divided into two key phases. The first phase, known as Kairos, is spearheaded by BASF in collaboration with Air Liquide. This phase focuses on capturing CO_2 from two hydrogen facilities (enabling blue hydrogen production), two ethylene oxide production facilities, and one ammonia plant.[168] Supported by a substantial grant of EUR 356.8 million from the EU Innovation Fund, Kairos is expected to achieve annual reductions of 1.5 $MtCO_2$ starting in 2025.[169] The captured CO_2 will be transported via a pipeline network, which includes a central "backbone" pipeline extending throughout the Port of Antwerp's industrial zones on both banks of the River Scheldt.[170] This CO_2 will be directed to a shared liquefaction facility for temporary storage at the port, with Air Liquide and Fluxys forming a joint venture to construct and operate the CO_2 liquefaction and export terminal, which will have a capacity of 2.5 $MtCO_2$ per year.[171] From there, the CO_2 will be loaded onto ships and transported to the Northern Lights hub off the coast of Western Norway, considering additional storage options if necessary such as depleted gas fields in the North Sea, spanning sea boundaries in Norway, the Netherlands, Denmark, and the UK. By 2030, the project aims to expand the CCUS hub's capacity to capture 10 $MtCO_2$ per year, involving the construction of additional pipelines to connect industrial clusters in Belgium, northern France, and Germany to the Antwerp network, creating a scalable and modular infrastructure accessible to numerous industrial players.[168]

A key advantage of this CCUS hub is its direct sea access, which allows for the relatively straightforward shipping of CO_2 to various storage sites across Europe. This flexibility in CO_2 transport offers a more adaptable CO_2 storage supply chain compared to projects that rely solely on a single storage well. Furthermore, locating the hub near the port for shipping helps reduce the need for onshore and offshore pipeline transportation, helping reduce transportation costs. However, the project faces potential challenges, including the use of Air Liquide's proprietary CryocapTM technology for CO_2 liquefaction, which has not yet been deployed at an industrial scale.[172] This introduces the risk of technological failure and poses challenges in scaling up to meet

[168] Antwerp@C, The CCUS Hub, 2024, Accessed at: Antwerp@C - The CCUS Hub (ogci.com)

[169] CEF Energy: Antwerp@C CO2 Export Hub receives 144.6 million of EU funding for CO2 capture infrastructure, European Commission,2024, Accessed at: CEF Energy: Antwerp@C CO2 Export Hub receives 144.6 million of EU funding for CO2 capture infrastructure - European Commission (europa.eu)

[170] The Antwerp@C project takes a major next step towards halving CO2 footprint, INEOS Project One, 2022, Accessed at: The Antwerp@C project takes a major next step towards halving CO2 footprint - Ineos Project One

[171] Air Liquide, Fluxys Belgium and Port of Antwerp-Bruges awarded EU funding for building the Antwerp@C CO2 Export Hub, Air Liquide, 2022, Accessed at: Air Liquide, Fluxys Belgium and Port of Antwerp-Bruges awarded EU funding for building the Antwerp@C CO2 Export Hub | Air Liquide

[172] Kairos@c, 2024, Accessed at: Kairos@c (kairosatc.eu)

the demands of 2030. Additionally, effective collaboration among consortium members will be crucial, as aligning interests and coordinating efforts could become more complex as the project scales to include numerous cross-border industrial facilities.

Figure 9-13. Antwerp Port CO_2 pathways

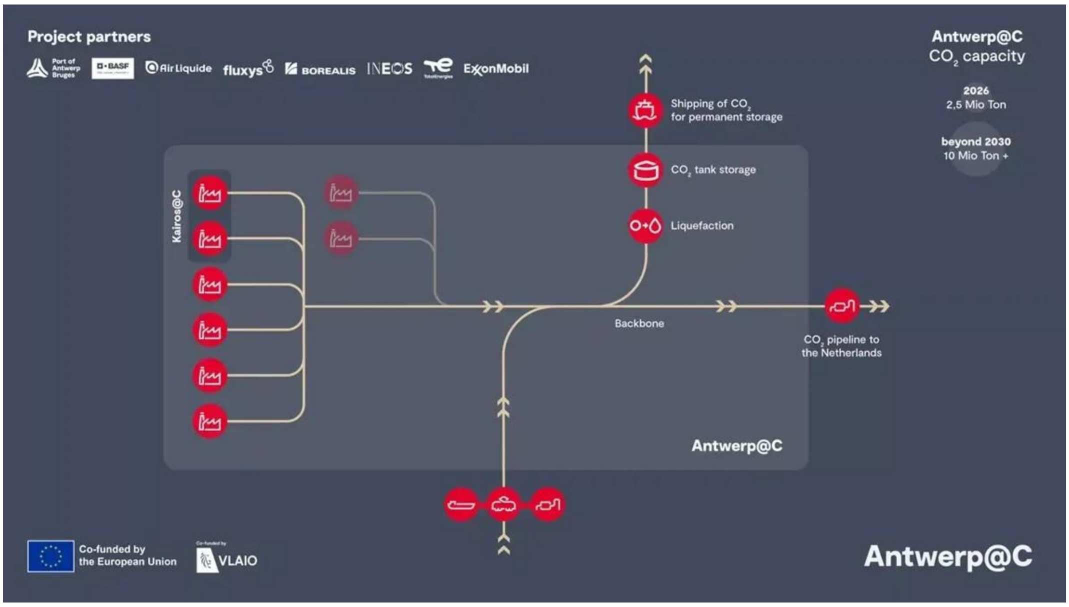
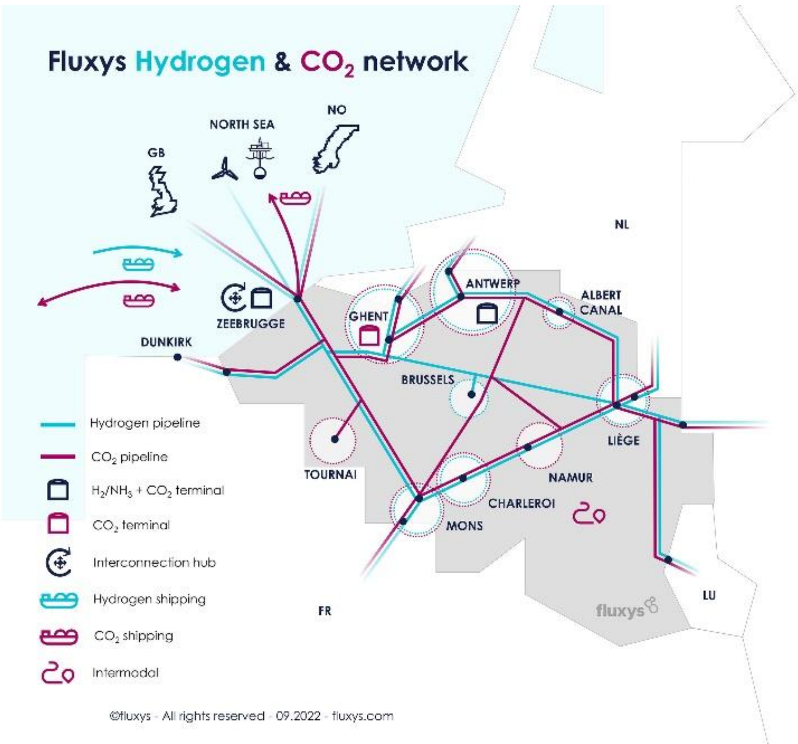


Figure 9-14. Complementary Hydrogen and CO_2 Infrastructure possibilities near Antwerp[173]



[173] Image taken from Sweco studies 70 km of hydrogen pipelines in Flemish ports for Fluxys Belgium - Sweco Belgium available at https://www.swecobelgium.be/en/insights/project-news/sweco-studies-70-km-of-hydrogen-pipelines-in-flemish-ports-for-fluxys-belgium/

Case Study 4 (Asia) – Junggar Basin Hub

The Junggar Basin Hub, located in Xinjiang, Northwestern China, represents a significant development as China's first major CCUS hub. The development of the hub and its transport and storage network, led by the China National Petroleum Corporation (CNPC) in collaboration with the OGCI, is primarily driven by the region's high concentration of large-scale emitters—mainly hydrogen production facilities, coal chemical plants, and refineries.[157,174] These sources produce relatively pure CO_2 streams, a favourable condition that enhances the economic viability of CO_2 capture.[157] Furthermore, the area offers substantial utilisation and storage potential, with estimated storage capacities of up to 90 $GtCO_2$, and the region's sparse population also helps alleviate societal concerns about the proximity of CCUS facilities to residential areas.[157,174,175]

The project is structured in two key phases. The first phase involves constructing CO_2 pipelines and storage systems to capture 1.5 $MtCO_2$ annually from a CNPC refinery by 2025. The second phase focuses on expanding the system to capture 3.0 $MtCO_2$ per year from additional hydrogen production facilities and other industrial sources, such as cement, steel, and power plants, with the ultimate goal of reaching a capture rate of 10 $MtCO_2$ per year by 2040. Initially, the captured CO_2 will be utilised for enhanced oil recovery (EOR) to improve the hub's commercial viability. However, the project plans to transition to long-term geological storage in depleted oil and gas reservoirs across the basin as it enters its second phase. While the initial transportation of CO_2 may involve truck transport, a shift t[176]o pipeline transport is anticipated as capacity grows, though the timing of this transition remains uncertain.

Despite the significant potential of the Junggar Basin, along with other basins in China like Bohai Bay, Songliao, and Ordos, the development of CCUS clusters in the country faces several unique challenges. Key issues include the need to explore viable business models and accelerate policy development, as EOR currently seems necessary to improve the economics of CCUS in the Junggar Basin.[157] Additionally, ongoing efforts to engage the public and secure their support are crucial for the success of this initiative and future CCUS projects.[157]

*5 (DAC) – South Texas DAC Huby*1PointFive, a subsidiary of energy company Occidental, are leading the development of a Direct Air Capture hub in South Texas, that is expected to have an initial capture capacity of 0.5$MtCO_2$/yr, scaling to 1$MtCO_2$/yr at full capacity[177]. The captured CO_2 will be geologically stored within a saline aquifer. The development will be deploying Carbon Engineering's DAC technology, which uses a potassium hydroxide solution as the capture agent before removing the salt formed containing the CO_2 within a pellet reactor for heating to release the CO_2 for onward processing and regenerate the capture agent[178]. The development is expected to use on-site, dedicated solar power to provide low-carbon energy for the capture process[179].The project was recently awarded US$50m by the U.S Department of Energy's Office of Clean Energy Demonstrations to support engineering design, initial equipment orders and permitting, with a total award of up to US$500m across all project phases. The facility is to be based at King Ranch in Kleberg County, with access to 106,000 acres sub-surface for development of geological storage and has applied for a Class VI well permit via the Environmental Protection Agency. It is anticipated that a geological storage volume of up to 3,000,000,000 tonnes of CO_2 could be accessed, which may also provide a sequestration facility for industrial emitters in the region. Stratigraphic test wells are currently being drilled to enabled further data collection on the subsurface geology to inform the storage site design and engineering[180]. Public engagement is a key focus of the project, with a community advisory board being established to enable input from communities and community groups that are impacted by the development. The project aims to support

---

[174] Road Map Update for Carbon Capture, Utilization, and Storage Demonstration and Deployment In The People's Republic Of China, Asian Development Bank, 2022, Accessed at: Road Map Update for Carbon Capture, Utilization, and Storage Demonstration and Deployment in the People's Republic of China (adb.org)

[175] Opportunities for CCS in Western China, Global CCS Institute, 2017, Accessed at: Opportunities for CCS in Western China - Global CCS Institute

[176] Junggar Basin, The CCUS Hub, 2024, Accessed at: Junggar Basin - The CCUS Hub (ogci.com)

[177] South Texas DAC Hub Factsheet, Office of Clean Energy Demonstrations, September 2024. Accessed at: Factsheet_DAC_SouthTexasDACHub_PhaseTwo_9.12.24.pdf (energy.gov)

[178] Carbon Engineering, Our Technology. Accessed at: Direct Air Capture Technology | Carbon Engineering

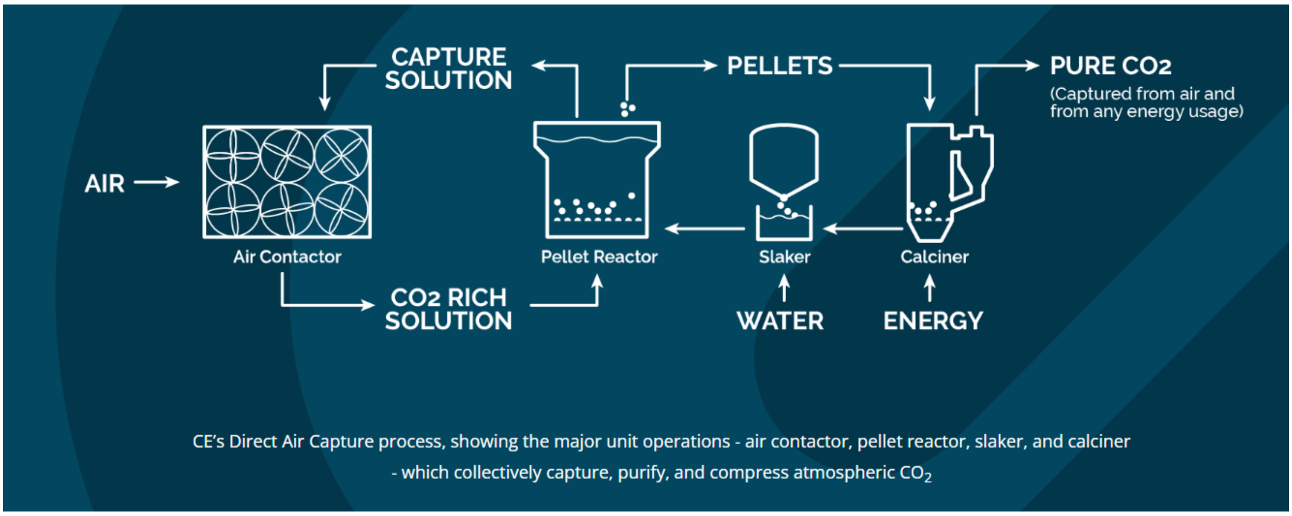
[179] The Economic Benefits of Direct Air Capture Hubs, The Rhodium Group, April 2024. Accessed at: https://rhg.com/wp-content/uploads/2024/04/The-Economic-Benefits-of-Direct-Air-Capture-Hubs.pdf

[180] South Texas DAC hub, OnePointFive. Accessed at: South Texas DAC Hub - King Ranch | 1PointFive

approximately 1,800 jobs throughout its lifecycle with the aim to support local and disadvantaged workers where possible.

Figure 9-15. Potential DAC Scheme[181]

Figure 9-16. Carbon Engineering DAC process[182]



[181] Carbon Engineering, Accessed at: Occidental, 1PointFive to Begin Construction of World's Largest Direct Air Capture Plant in the Texas Permian Basin - Carbon Engineering

[182] Carbon Engineering, Accessed at: Direct Air Capture Technology | Carbon Engineering

9.2.1.4 *Transport options*

CO_2 transport

Pipeline transport of CO_2 is generally the most suitable and lowest cost option when transferring large volumes of CO_2. As well as construction of new pipelines for the purpose of CO_2 transport, the option of repurposing natural gas pipelines for CO_2 transport is also being explored, thereby having the potential to result in significant cost savings when compared to construction of new pipelines. Pipeline transportation is a well-established method for gas transportation. The operation of CO_2 pipelines can be intricate, especially when handling varied CO_2 streams from multiple sources with fluctuating outputs. The optimisation of pipeline transport is therefore dependent on a range of factors including CO_2 pipeline specification, target transportation conditions and the location and size of compression and purification infrastructure.

Ship transport of CO_2 is one of the methods that can play an important role in transporting CO_2 from other regions for onward pipeline transportation. This can support in enabling a more dynamic CO_2 market, where CO_2 from countries without CO_2 pipeline transportation infrastructure can ship large volumes of CO_2 to a desired location elsewhere. There is existing expertise in CO_2 shipping, primarily stemming from the food industry, though this experience is on a smaller scale than what would be required for transporting CO_2 for the purpose of supporting decarbonisation targets. The process for shipping involves three main stages: liquifying the CO_2, intermediate storage at ports, and then transport using specialised, insulated vessels. When transporting CO_2 offshore over distances exceeding 350 km, depending on the scale of operations, shipping could potentially undercut the costs of pipeline methods. Additionally, low pressure CO_2 transport vessels may be used to improve the economics of ship transport.

Road and rail options are more suited for transporting smaller CO_2 quantities over relatively shorter distances. Although not suitable for large transport volumes, they offer a solution for transporting CO_2 captured from sites without readily available pipeline infrastructure. This method often necessitates on-site intermediate storage facilities.

Table 9-19. Methods of CO_2 transport

Transport method	Conditions	Cost, 2023US$ /tCO_2 [183]
Pipeline	5 – 20 MPa 283-307 K Supercritical phase	Onshore[184]: 0.275 – 102 [0.37 to 9.1 Mtpa] [25 to 500 km] Offshore[185]: 6.22 – 108 [0.5 to 5.0 Mtpa] [200 to 1000 km]
Ship	0.65 – 4.5 MPa 221 – 283 K Liquid phase	10.8 – 24.0 [186] [0.5 to 5.0 Mtpa] [200 to 1000 km]
Road	1.8 – 2 MPa 243 – 253 K Liquid phase	25.9 – 166 [187] [0.05 to 1.0 Mtpa] [16 to 800 km]

---

[183] Costs converted to a common basis using CEPCI escalation factors, where necessary.
[184] Solomon, M.D.; Scheffler, M.; Heineken,W.; Ashkavand, M.; Birth-Reichert, T. Pipeline Infrastructure for CO2 Transport: Cost Analysis and Design Optimization. Energies 2024, 17, 2911. https:// doi.org/10.3390/en17122911
[185] Durusut, E. and Joos, M. (2018) *Shipping CO2 - UK cost estimation study*. Available at: https://assets.publishing.service.gov.uk/media/5c07a24f40f0b67052a55bf9/BEIS_Shipping_CO2.pdf (Accessed: 30 August 2024).
[186] Durusut, E. and Joos, M. (2018) *Shipping CO2 - UK cost estimation study*. Available at: https://assets.publishing.service.gov.uk/media/5c07a24f40f0b67052a55bf9/BEIS_Shipping_CO2.pdf (Accessed: 30 August 2024).
[187] Corey Myers, Wenqin Li, Gregory Markham, The cost of CO2 transport by truck and rail in the United States, International Journal of Greenhouse Gas Control, Volume 134, 2024, https://doi.org/10.1016/j.ijggc.2024.104123.

Transport method	Conditions	Cost, 2023US$ /tCO_2 [183]
Rail	0.65 – 2.6 MPa 223 – 254 K Liquid phase	72.6 – 143 [188] [0.05 to 1.0 Mtpa] [16 to 800 km]

Hydrogen transport

Road: Tube trailers and tankers are specifically designed and can be used to transport all five forms of hydrogen by road, from production sites to utilisation sites.[189] It is more economical to transport compressed hydrogen via high-pressure tube trailers, especially if demand is low and the production plant lies near the distribution terminal or gas terminal. Otherwise, hydrogen, when liquefied and transported using high-insulated cryogenic tankers, is more economical for longer distances. These cryogenic tankers can carry 4,000 kg of liquid hydrogen over 4,000 km[190], which is 15-20 times the carrying capacity of steel tube trailers. The liquid hydrogen tanker is, however, not suitable for distance beyond 4,000km. The energy intensity of converting hydrogen to liquid H_2, LOHCs and other hydrogen carriers should also be considered, as it may ultimately increase the cost of transportation. Depending on the scale and infrastructure, other options for hydrogen transport may be more viable.

Pipeline: Hydrogen can be transported in gaseous form through existing natural gas pipeline or dedicated hydrogen pipeline, but doing so requires a significant capital investment, regulatory compliance, and surety of demand. Pipeline transport compressed hydrogen in the same manner as road transport for tube trailers, maintaining compression pressure differences throughout the process. Transporting hydrogen via existing gas pipeline without retrofitting is economically viable, but the safety and material compatibility of existing gas pipeline raise concerns and uncertainty. It's undeniable that the hydrogen pipeline is a mature technology, with existing infrastructure in Europe and the US.[191] It has a long lifespan, low operating costs, and can transport large volume of hydrogen to distances within national borders, benefiting users along the pipeline grid. Other flexible hydrogen transportation options, such as shipping, should be considered for large-scale hydrogen transportation over longer distances (remote or off-grid locations) where pipeline transport may not be feasible.

Shipping is a more flexible mode of transporting large-scale hydrogen over longer distance for international import and export. Liquid H_2, ammonia, and other hydrogen carriers (metal hydrides, LOHCs) can be transported via shipping. Different ship types can transport ammonia in specially designed liquefied hydrogen tankers. These tankers have a carrying capacity of between 30,000 m^3 and 87,000 m^3.[192] According to research, the cost of hydrogen transportation via ships may be more cost-effective than the construction of new dedicated pipelines for distances beyond 7000 km.[193] The cost of shipping hydrogen will also depend on the vessel, supporting infrastructure, and distance covered. Nevertheless, shipping hydrogen is a mature technology, given that more than 170 ports worldwide transport ammonia on a large scale. Shipping provides a more flexible international import and export of hydrogen compared to other transport technologies.

Rail: Currently, rail is not the primary route for transporting hydrogen, but it provides a connectivity option to locations where pipelines are not feasible. Rail transport can distribute ammonia and other hydrogen carriers from production sites to end users that are not located along a pipeline grid. Rail technology will continue to improve as the hydrogen market develops.

---

[188] Corey Myers, Wenqin Li, Gregory Markham, The cost of CO2 transport by truck and rail in the United States, International Journal of Greenhouse Gas Control, Volume 134, 2024, https://doi.org/10.1016/j.ijggc.2024.104123.
[189] *Hydrogen Transport and Storage Cost Report (publishing.service.gov.uk)
[190] https://www.anz.com/content/dam/anzcom/pdf/institutional/reports/hydrogen-transportation.pdf
[191] roland_berger_hydrogen_transport.pdf
[192] *Cost reduction pathways of green hydrogen production in Scotland – total costs and international comparisons (climatexchange.org.uk)
[193] A review of hydrogen storage and transport technologies, Yang et al., 2023, Accessed at: review of hydrogen storage and transport technologies | Clean Energy | Oxford Academic (oup.com)

Table 9-20. Hydrogen transport methods

Hydrogen Form	Transport Method	Distance (km)	Condition	Throughput	Cost (US$/kg$H_2$)[194]
Compressed hydrogen (CGH_2)	Road (Tube Trailers)	Up to 300	Pressure: 200–700 bar Temperature: Ambient	300 –1,300 kg per trailer	3.30 – 6.60
	Pipeline	Up to 1,500	Temperature: -253°C (20 K) Pressure: Slightly above atmospheric pressure	100 – 500 tons/day	0.10 – 0.30 per 100 km
Liquid hydrogen (LH_2)	Road (Cryogenic Tankers)	Up to 1,500		3,000–5,000 kg per tanker	3.90 – 7.90
	Shipping (Cryogenic Vessels)	Up to 10,000		15,000–60,000 tons per vessel	1.30 – 3.30
Ammonia (NH3)	Road (Tanker Trucks)	Up to 2,000	Temperature: -33°C @ atmospheric pressure or ambient with pressurization Pressure: 8–10 bar (for liquid form)	10,000–20,000 kg per truck	2.00 – 3.90
	Pipeline	Up to 1,500		-	2.00
	Shipping (Ammonia Carriers)	Up to 20,000		50,000–100,000 tons of per vessel	0.70 – 2.00
Liquid Organic Hydrogen carriers, (LOHCs)	Road (Tanker Trucks)	Up to 1,500	Temperature: Ambient Pressure: Slightly above atmospheric pressure	1,500–3,000 kg per truck (as LOHC)	2.60 – 5.30
	Shipping (LOHC Carriers)	Up to 10,000		10,000–50,000 tons per vessel (as LOHC)	1.00 – 2.60

[194] The cost ($/kgH2) has been converted from GBP based on an exchange rate of 1.31, is subject to regional regulatory differences, energy prices, exchange rates, scale and supporting infrastructure.

9.2.2 Global survey of CO_2 sources

9.2.2.1 Approach and methodology

Long-list of sub-sectors

The long list of sub-sectors can be found in Table 9-21 below.

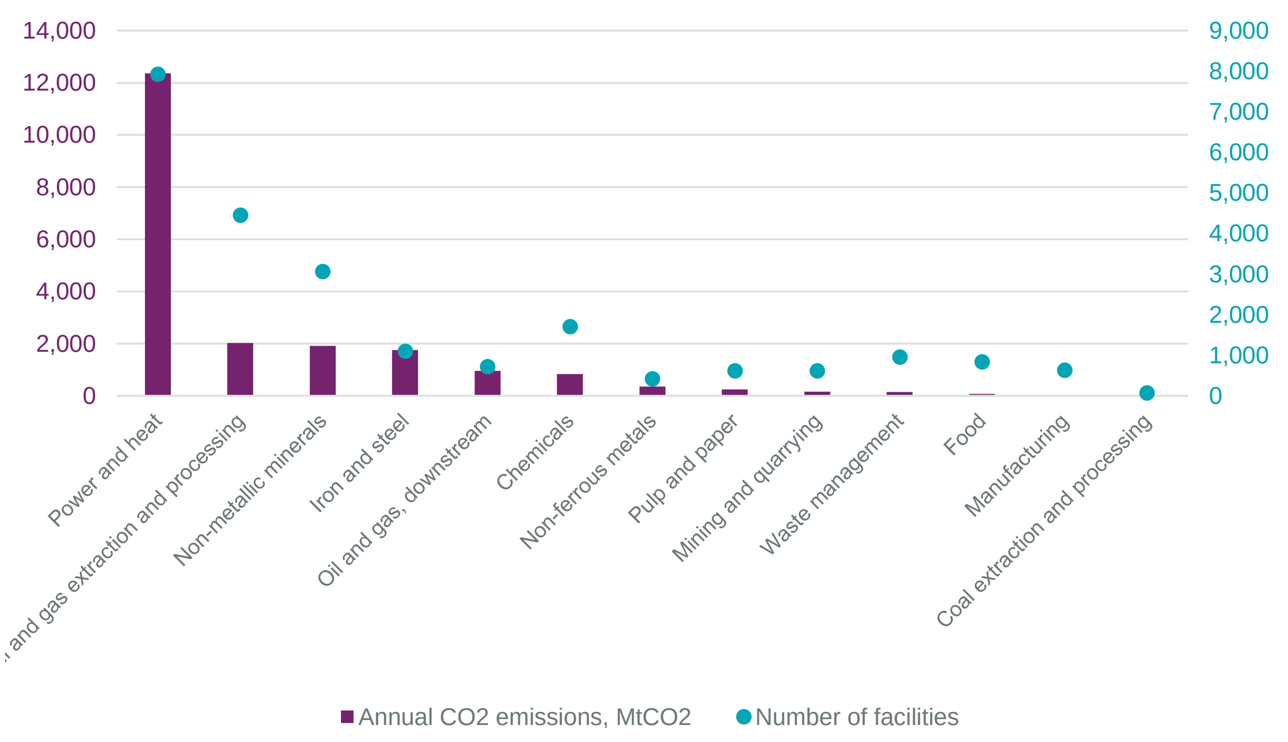
Table 9-21. Long-list of sub-sectors

Class	Sector	Sub-sector	
Energy	Power and heat	**Coal and lignite**	**Natural gas and other gases**
		Oil and liquid fuels	**Biomass and bioenergy**
		Peat	**Undefined/ other**
	Coal extraction and processing	**Coal and lignite processing**	**Coal and lignite mining**
	Oil and gas extraction and processing	**Upstream oil and gas**	**CO_2 removal**
		Support activities	**Midstream oil and gas**
		Gas compression and oil pumping	
Industry	Chemicals	**Ethylene oxide**	**Ammonia and other nitrogen fertilisers**
		Methanol	**Hydrogen and other gases**
		Ethanol	**Plastics**
		Pharmaceuticals	**Undefined/ other**
	Iron and steel	**Basic iron and steel**	**Smelting/ casting of iron and steel**
		Undefined/ other	
	Non-ferrous metals	**Aluminium**	**Aluminium oxide (alumina)**
		Copper	**Undefined/ other**
	Mining and quarrying	**Non-ferrous metals**	**Iron ores**
		Non-metallic minerals	**Undefined/ other**
	Food	**Milling**	**Sugar**
		Starch	**Alcohol**
		Oil	**Meat**
		Dairy	**Undefined/ other**
	Oil and gas, downstream	**Refinery**	**LNG terminals**
		Undefined/ other	
	Pulp and paper	**Pulp**	**Paper and board**

Class	Sector	Sub-sector	
	Manufacturing	**Wood products**	**Vehicles and machinery**
		Metal products	**Textile**
		Electrical/ electronics	**Undefined/ other**
	Non-metallic minerals	**Cement**	**Lime and plaster**
		Glass	**Ceramics**
		Mineral fibres	**Undefined/ other**
	Other/ undefined	**Data centres**	**Other/ undefined**
		Transport/ freight	
Waste management	Waste management	**Energy from waste**	**Hazardous waste incineration**
		WWT sludge incineration	**Landfill**
		Undefined/ other	

The distribution of CO_2 emissions and facilities in the long-list database can be seen in Figure 9-17 below. This shows that power and heat significantly account for the largest share of CO_2 and point sources. Oil and gas extraction and processing and non-metallic minerals account for the second and third largest share, respectively.

Figure 9-17. Annual CO_2 emissions and number of facilities in the long list, by sector



Screening of sub-sector long-list

An overview of the number of sub-sectors excluded due to each step, as well as the final number of sub-sectors in the short-list, is outlined in Figure 9-18 below.

Figure 9-18. Number of sub-sectors excluded after each step and final number of sub-sectors in short-list

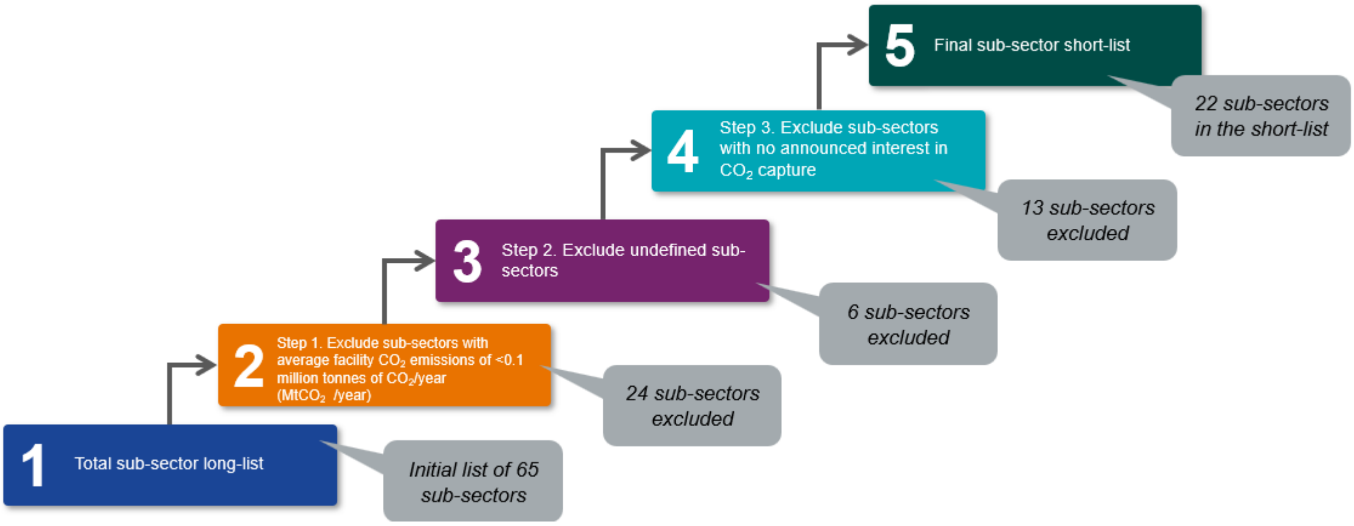


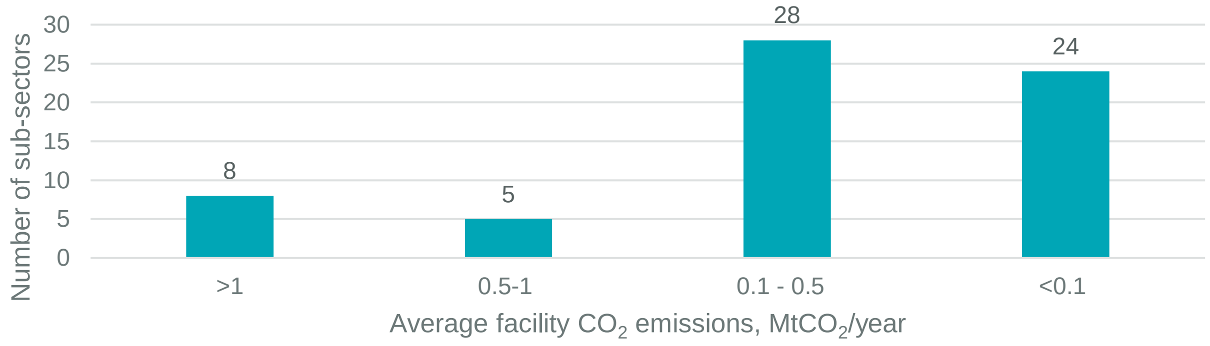
Table 9-22. Excluded sub-sectors and rationale for exclusion

Excluded sub-sectors	Reason for exclusion
Industry > Non-metallic minerals > Glass	Step 1 criterion
Industry > Manufacturing > Wood products	Step 1 criterion
Industry > Food > Undefined/Other	Step 1 criterion
Industry > Non-ferrous metals > Copper	Step 1 criterion
Industry > Food > Oil	Step 1 criterion
Industry > Non-metallic minerals > Ceramics	Step 1 criterion
Industry > Non-metallic minerals > Mineral fibres	Step 1 criterion
Waste and water > Waste management > WWT sludge incineration	Step 1 criterion
Energy > Oil and gas extraction and processing > Gas compression and oil pumping	Step 1 criterion
Industry > Non-metallic minerals > Undefined/Other	Step 1 criterion
Waste and water > Waste management > Landfill	Step 1 criterion
Industry > Manufacturing > Vehicles and machinery	Step 1 criterion
Energy > Coal extraction and processing > Coal and lignite mining	Step 1 criterion
Industry > Food > Meat	Step 1 criterion
Industry > Other / undefined > Data centers	Step 1 criterion
Industry > Manufacturing > Metal products	Step 1 criterion
Industry > Food > Dairy	Step 1 criterion

Excluded sub-sectors	Reason for exclusion
Industry > Chemicals > Pharmaceuticals	Step 1 criterion
Industry > Manufacturing > Undefined/Other	Step 1 criterion
Industry > Manufacturing > Textile	Step 1 criterion
Industry > Other / undefined > Transports / freight	Step 1 criterion
Industry > Manufacturing > Electrical / electronics	Step 1 criterion
Waste and water > Waste management > Undefined/Other	Step 1 criterion
Industry > Other / undefined > Other / undefined	Step 1 criterion
Industry > Iron and steel and of ferro-alloys > Undefined/Other	Step 2 criterion
Industry > Chemicals > Undefined/Other	Step 2 criterion
Energy > Power and heat > Undefined/Other	Step 2 criterion
Industry > Oil and gas, downstream > Undefined/Other	Step 2 criterion
Industry > Mining and Quarrying > Undefined/Other	Step 2 criterion
Industry > Non-ferrous metals > Undefined/Other	Step 2 criterion
Industry > Oil and gas, downstream > LNG terminals	Step 3 criterion
Energy > Coal extraction and processing > Coal and lignite processing	Step 3 criterion
Industry > Mining and Quarrying > Iron ores	Step 3 criterion
Industry > Food > Milling	Step 3 criterion
Energy > Power and heat > Oil and other liquid fuels	Step 3 criterion
Industry > Iron and steel and of ferro-alloys > Smelting / casting of iron and steel	Step 3 criterion
Industry > Non-ferrous metals > Aluminium oxide (alumina)	Step 3 criterion
Industry > Mining and Quarrying > Non-ferrous metals	Step 3 criterion
Energy > Power and heat > Peat	Step 3 criterion
Industry > Mining and Quarrying > Non-ferrous metals	Step 3 criterion
Energy > Power and heat > Peat	Step 3 criterion
Industry > Chemicals > Plastics	Step 3 criterion
Industry > Mining and Quarrying > Non-metallic minerals	Step 3 criterion

Figure 9-19 below shows the number of sub-sectors falling within a range of specified average facility CO_2 emissions. From this figure it can be seen that there are 24 sub-sectors with average facility CO_2 emissions of <0.1 $MtCO_2$/year, and hence excluded from further review. This figure also shows that the largest portion of sub-sectors, accounting for 43%, have an average facility CO_2 emissions between 0.1 and 0.5 $MtCO_2$/year.

Figure 9-19. Average facility annual emissions



Scoring of sub-sector short-list

Criteria influencing ease of capture

Table 9-23. Scoring criteria relevant to the prospects for CO_2 capture

Factor description	Score		
	3 (high score)	2 (med score)	1 (low score)
CO_2 concentration	>50%	20-50%	<20%
Deployment level	Operational CO_2 capture at relevant scale	Operational pilot/demonstration scale CO_2 capture, commercial scale plans	Interest announced in the sector
Integration with existing processes	CO_2 removal is already part of the process	CO_2 removal can be retrofit with some site adjustments	Significant barriers to retrofit CO_2 removal
Scale, $MtCO_2$/year	>1 .0	0.5-1.0	0.1-0.5

The overall calculation per sub-sector is therefore:

$$\begin{aligned}\boldsymbol{Overall\ score} = {} & (CO2\ concentration\ score\ x\ importance\ weighting) \\ & + (deployment\ level\ score\ x\ importance\ weighting) \\ & + (Integration\ with\ existing\ processes\ score\ x\ importance\ weighitng) \\ & + (scale\ score\ x\ importance\ weighting)\end{aligned}$$

Minimum CO_2 volume threshold

Table 9-24. Minimum volume threshold by CO_2 concentration

<table>
<tr><th>CO_2 concentration</th><th>Minimum threshold, $MtCO_2$/year</th><th colspan="2">Sub-sectors</th></tr>
<tr><td rowspan="6"><20%</td><td rowspan="6">1</td><td>Coal and lignite, power and heat generation</td><td>Basic iron and steel</td></tr>
<tr><td>Aluminium</td><td>Methanol</td></tr>
<tr><td>Natural gas and other gases, power and heat generation</td><td>Pulp</td></tr>
<tr><td>Upstream oil and gas</td><td>Paper and board</td></tr>
<tr><td>Lime and plaster</td><td>Energy from Waste</td></tr>
<tr><td>Hazardous waste incineration</td><td>Biomass and bioenergy power and heat ,generation</td></tr>
<tr><td rowspan="2">20-50%</td><td rowspan="2">0.5</td><td>Refinery</td><td>Cement</td></tr>
<tr><td>Hydrogen and other gases</td><td></td></tr>
<tr><td rowspan="3">>50%</td><td rowspan="3">0.1</td><td>Ethylene oxide</td><td>Ammonia and other nitrogen fertilisers</td></tr>
<tr><td>Alcohol</td><td>Ethanol</td></tr>
<tr><td>Midstream oil and gas</td><td>Sugar</td></tr>
</table>

Global CO_2 hotspots

Table 9-25. CO_2 hotspot scenarios

Scenario	E-fuels production	CO_2 quantity	Distance, radius, km
1 – Small scale e-fuels production	> 5 -10k barrels per day (bbl/day)	Single source, > 2 $MtCO_2$/year	N/A
2 – Medium scale e-fuels production	> 75 – 100k bbl/day	Multiple sources, > 20 $MtCO_2$/year	30 km
3 – Large scale e-fuels production	> 500k bbl/day	Multiple sources, > 100 $MtCO_2$/year	80 km

9.2.2.2 Results

Availability of CO_2 sources

CO_2 availability by capture score

The breakdown of the CO_2 availability and number of facilities by sub-sector against the ease of capture score is represented in Figure 9-20 and Figure 9-21 below. From these figures, the following can be determined:

- Power generation accounts for the largest share of available CO_2, with coal and lignite, and natural gas and other gases being the two largest sectors in terms of CO_2 availability.
- Coal and lignite power generation accounts for 76% of available CO_2 within the 15-20 score range and 48% of total available CO_2 from all sectors.
- After power generation (coal and lignite and natural gas and other gases), cement, upstream oil and gas and basic iron and steel account for the third to fifth largest sectors in terms of CO_2 availability.

Figure 9-20. Availability of CO_2 by sub-sector and ease of capture score

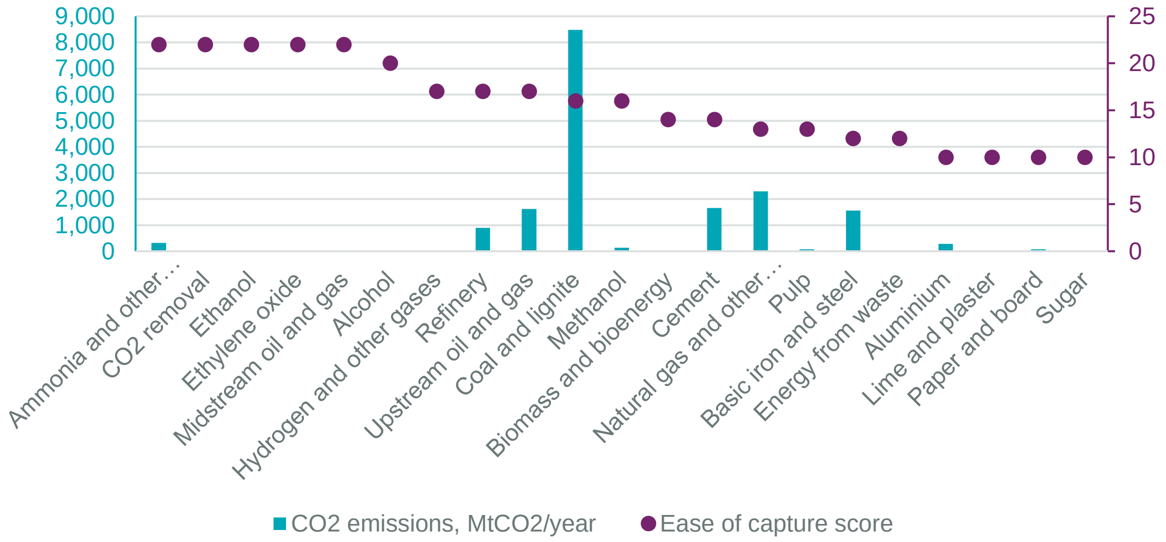
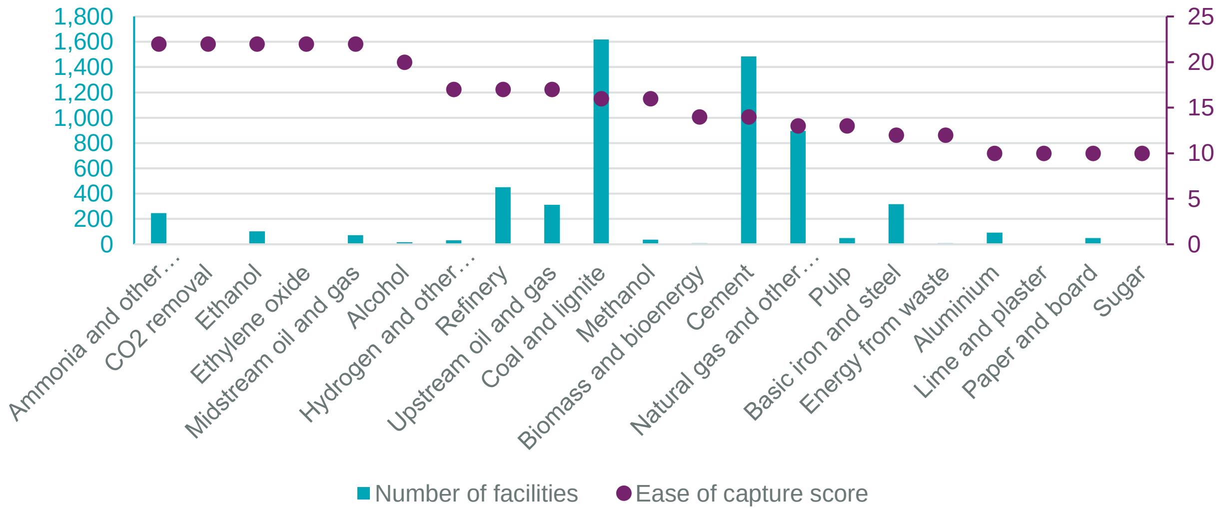


Figure 9-21. Number of facilities by sub-sector and ease of capture score



Regional CO_2 availability

Table 9-26. Countries included in each region

Region	Countries	
Africa	Algeria	Angola
	Benin	Botswana
	Cameroon	Congo
	Cote D'Ivoire	Egypt
	Equatorial Guinea	Ethiopia
	Ghana	Kenya
	Libya	Morocco
	Mozambique	Nigeria
	Senegal	South Africa
	South Sudan	Sudan
	Tanzania	Tunisia
	Uganda	Zambia
	Zimbabwe	
Central America	Bolivia	Costa Rica
	Cuba	Dominican Republic
	Guatemala	Honduras
	Nicaragua	Panama
Central Asia	Kazakhstan	Tajikistan
	Turkmenistan	Uzbekistan
Eastern Asia	China	Japan
	Mongolia	North Korea
	South Korea	Taiwan
Europe	Albania	Austria
	Belarus	Belgium
	Bosnia and Herzegovina	Bulgaria
	Croatia	Cyprus
	Czechia	Denmark
	Estonia	Finland
	France	Georgia
	Germany	Greece
	Hungary	Ireland
	Italy	Kosovo
	Latvia	Lithuania

Region	Countries	
	Moldova	Montenegro
	Netherlands	North Macedonia
	Norway	Poland
	Portugal	Romania
	Russia	Serbia
	Slovakia	Slovenia
	Spain	Sweden
	Switzerland	Ukraine
	United Kingdom	
Middle East	Bahrain	Iran
	Iraq	Israel
	Jordan	Kuwait
	Lebanon	Oman
	Saudi Arabia	Syrian Arab Republic
	United Arab Emirates	Yemen
North America	Canada	Mexico
	Trinidad and Tobago	United States
Oceania	Australia	New Zealand
	Papua New Guinea	
South America	Argentina	Brazil
	Chile	Colombia
	Ecuador	Guyana
	Peru	Venezuela
South-East Asia	Brunei Darussalam	Cambodia
	Indonesia	Lao People's Democratic Republic
	Malaysia	Myanmar
	Philippines	Singapore
	Thailand	Timor-Leste
	Vietnam	
Southern Asia	Bangladesh	Bhutan
	India	Nepal
	Pakistan	Sri Lanka
Western Asia	Armenia	Azerbaijan
	Turkey	

Global CO_2 hotspots

Figure 9-22. Small scale e-fuels production, > 5 – 10k bbl/day - CO_2 point sources above 2 $MtCO_2$/year

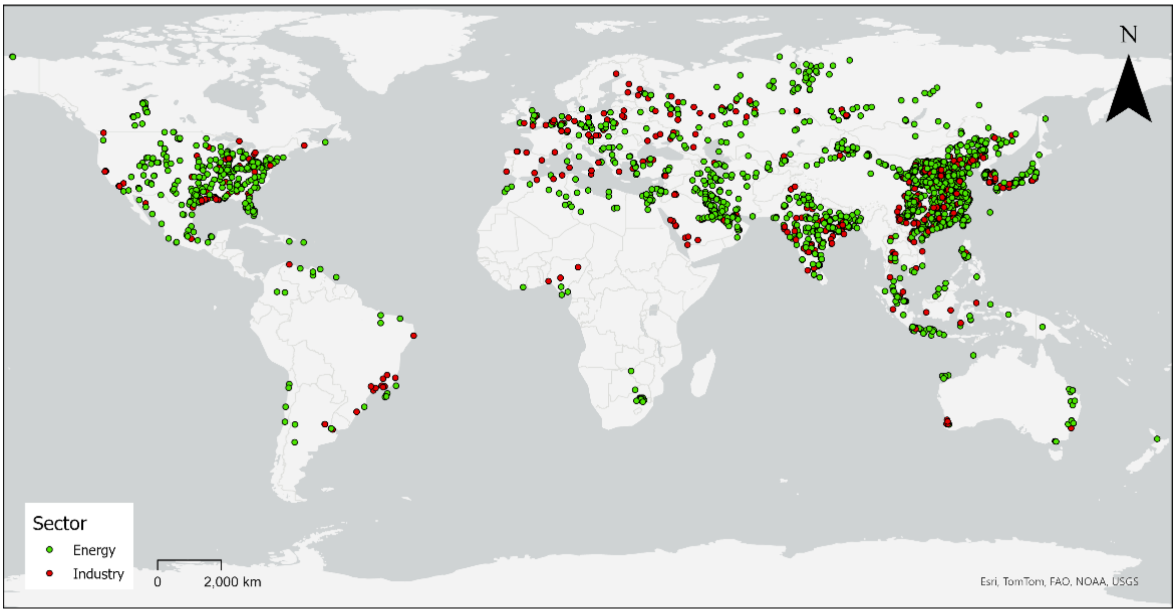


Figure 9-23. Medium-scale e-fuels production, > 75 – 100k bbl/day - CO_2 hotspots above 20 $MtCO_2$/year in a 30km radius

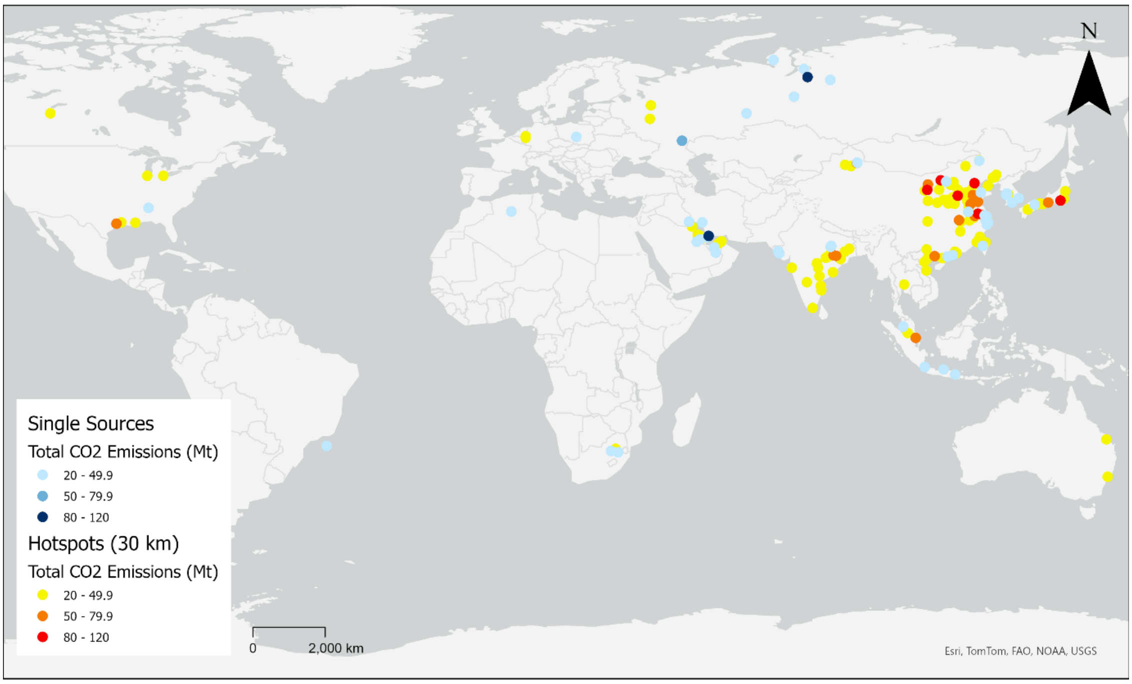
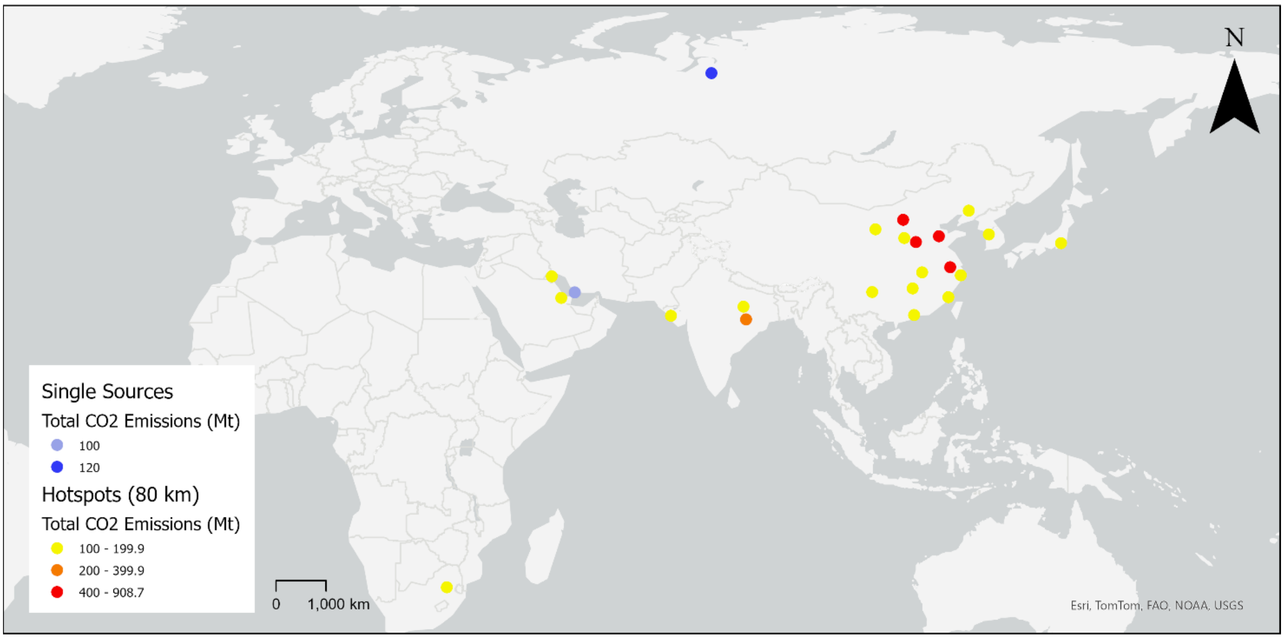


Figure 9-24. Large-scale e-fuels production, > 500k bbl/day - CO_2 hotspots above 100 $MtCO_2$/year in an 80km radius



Direct Air Capture

S-DAC technology utilises adsorbents that function effectively at ambient to low pressures and temperatures ranging between 80 – 120ºC.[195] In contrast, L-DAC systems employ aqueous basic solutions to capture CO_2. The captured CO_2 is subsequently released through a series of units operating at high temperatures of between 300 – 900ºC. L-DAC can be deployed at a large scale, operating continuously, whilst S-DAC can only operate in batch mode and has a modular design. The energy requirements for S-DAC are 7.2 – 9.5 GJ/tCO_2, which is slightly higher than L-DAC (5.5 – 8.8 GJ/tCO_2). However, the regeneration temperatures are significantly lower for S-DAC compared to L-DAC.

Three primary resources are essential for the establishment of a DAC plant: energy, land, and water. DAC technologies are highly energy intensive, therefore, to maximise net capture efficiency, energy sources need to be highly abundant, and zero- or very low-carbon. Hence, easy access to renewable energy is pivotal for DAC plants. L-DAC and S-DAC differ in their energy requirements due to varying operational temperature needs, however, for both systems the energy split is approximately 20% electricity and 80% heat. L-DAC plants require high temperatures (~900ºC) for CO_2 release, which are currently met using fossil fuels, such as natural gas. In contrast, S-DAC plants can utilise waste heat or renewable energy due to their medium to low temperature requirements.[196] DAC systems require a smaller land area per tonne of CO_2 removed compared to other prominent CO_2 removal methods, such as reforestation. The land footprint for large-scale DAC deployment varies based on the specific system and its energy sources, for example, if renewable energy is used, it will constitute a significant portion of the overall land requirement.[196] Ideally DAC plants would be in areas of cheap low-carbon electricity and heat in close proximity to CO_2 off takers, either for sequestration or utilisation.

---

[195] Direct Air Capture, Energy Systems, IEA, Accessed at: [Direct Air Capture - Energy System - IEA]

[196] 6 Things to Know About Direct Air Capture, Lebling et al., 2022, Accessed at: https://www.wri.org/insights/direct-air-capture-resource-considerations-and-costs-carbon-removal

Water plays an integral role in all steps of the DAC process, impacting energy requirements, material lifetime and productivity. Not only does water constitute a significant portion of absorption solvents, it also is a potential heating fluid for regeneration and a byproduct of the carbon capture process.[197] The location of the DAC plant plays a crucial role in its water usage, as local temperature and humidity are key influencing factors. Evaporation is the primary cause of water loss, making relative humidity and temperature the primary determinants of water consumption. Higher losses occur in hot, dry environments, consequently restricting the number of economically feasible locations for DAC plants. Water usage also depends on the system type, with L-DAC consuming substantially more water than S-DAC. L-DAC systems consume 1 – 7 tonnes of water per tonne of CO_2 captured, necessitating plant locations with easy access to large volumes of water. S-DAC water usage varies considerably based on the solid sorbent regeneration method employed. When indirect heating is utilised, it results in the net production of water, while direct heating systems using steam condensation result in approximately 1.6 tonnes of water losses per tonne of CO_2 captured.[196]

Globally, 27 Direct Air Capture plants have been commissioned of which 18 are completed[198]. These plants are all small-scale, with a combined capacity of almost 0.1 MtCO2/yr , and generally sell the captured CO_2 for use within chemicals and fuels (Power-to-X), beverage carbonisation and for use in greenhouses[199]. Emerging technologies and global DAC deployment are summarised in Table 9-27.

[197] Water management and heat integration in direct air capture systems, Holmes et al., 2024, Accessed at: https://www.nature.com/articles/s44286-024-00032-6

[198] Ozkan M, Atwood M, Letourneau C, Beuttler C, Jiménez Haertel C, Evanko J. The status quo of DAC projects worldwide. Chem. 2023; 9: 3381-3384. https://doi.org/10.1016/j.chempr.2023.11.004.

[199] Direct Air Capture, Energy Systems, IEA, Accessed at: Direct Air Capture - Energy System - IEA

Table 9-27. Summary of DAC deployment and emerging technologies[200].

Supplier	Country	TRL	Technology	Deployment status
Climeworks	Switzerland	8-9	Solid Sorbent (amine-functionalised solid)	Technology validated on small-scale at Hinwi (Switzerland), Orca and Mammoth (Iceland). 36 ktCO_2/year is the largest scale tested, but target size is 100 ktCO_2/year
Global Thermostat	USA	7-8	Solid sorbent (impregnated honeycomb sorbent)	Signed agreement with Exxon Mobil and HIF (commissioning started in 2022)
GreenCap Solutions	Norway	6-7	Solid sorbent (Zeolite)	Validated at 0.3 ktCO_2/year scale for CO_2 utilisation in greenhouse farming
Kawasaki	Japan	4	Solid sorbent (amine-impregnated porous material)	Small-scale piloting (5-6 kgCO_2/day)
Susteon	USA	4	Solid sorbent and catalyst (CO$_2$ methanation)	Still at prototype level produces methane for utilisation, not CO_2
Carbon Engineering	Canada	7-8	Liquid solvent (caustic solvent)	Suitable for large scale capture >1MtCO_2/year Currently validated below 0.5 MtCO_2/year Signed contract with 1PointFive for construction of a fleet of 70 DAC facilities of 1MtCO_2/year by 2035, including the South Texas DAC Hub.
Commonwealth Scientific and Industrial Research Organisation - CSIRO	Australia	4	Liquid solvent (Amino acid)	Partnership with Rolls-Royce has secured funding for 100 tCO_2/year demonstrator in Derby, UK
Mission Zero Technology - MZT	UK	4	Electrochemical separation membrane	Funding secured for 120tCO_2/year plant
Verdox	USA	3-4	Solid sorbent (Electro-swing adsorption)	Tested on lab-scale On-going prototyping and scale-up
Oy Hydrocell	Finland	3-4	Solid sorbent (Temperature-vacuum swing)	Prototype used in small CO_2-to-fuels application (1.3 tCO_2/year)
Infinitree	USA	5-6	Solid sorbent (ion-exchange moisture swing)	Tested for CO_2 utilisation in greenhouse farming at 100 tCO_2/year scale
Skytree	Netherlands	5-6	Solid sorbent (temperature swing)	Validated at 100 tCO_2/year for algal culture applications

[200] Bisotti F, Hoff K, Mathisen A, Hovland J. Direct Air capture (DAC) deployment: A review of the industrial deployment. *Chemical Engineering Science*. 2024; 283. https://doi.org/10.1016/j.ces.2023.119416.

9.3 PROSPECTS FOR E-FUELS PRODUCTION

9.3.1 High-level global review

9.3.1.1 Approach and methodology

Indicator data sources and original scoring style

Table 9-28. Indicator data sources and original scoring style

Theme	Indicator	Data source	Original scoring style
Policy and regulation	CCS policy	Legal & Regulatory - Global CCS Institute (co2re.co)	0 - 100
	CCS legal and regulatory	Legal & Regulatory - Global CCS Institute (co2re.co)	1 - 100
	National hydrogen policy	Irena, Green Hydrogen Strategy	No strategy Strategy in development/ roadmap published Strategy published
Financial incentives	CCUS financial incentives	BCG, Scaling Carbon Capture	US$/ton: 0-50 50-100 101-200 200+
	Hydrogen financial incentives	Funding guide - European Commission (europa.eu) Inflation reduction act Hydrogen Headstart Programme Key searches were used to determined details on countries not in the EU, US or Australia	National & external funding/incentives National funding/incentives EU funding
CO_2	Number and volume of biogenic sources - all sources, above 2 $MtCO_2$/year	CaptureMap	Number and volume of sources ($MtCO_2$/year)
	Number and volume of sources in top 50% scoring sub-sectors (16-22)	CaptureMap and D1 outputs	Number and volume of sources ($MtCO_2$/year)
	Number and volume of sources within 3 scenarios identified in WP1	CaptureMap and D1 outputs	Number and volume of sources ($MtCO_2$/year)
	CO_2 transport projects	IEA CCUS Projects Database	Number of projects
	CO_2 capture projects	IEA CCUS Projects Database	Number of projects
	CCU projects	IEA CCUS Projects Database	Number of projects
	DAC projects	IEA CCUS Projects Database	Number of projects
Hydrogen	Levelised cost of hydrogen	IEA, LCOH	Low - high

Theme	Indicator	Data source	Original scoring style
	Capacity of hydrogen production projects (electrolysis)	IEA Hydrogen Projects Database	Nm³ H_2/h (x10^6)
Business and innovation prospects	Global innovation index	Global Innovation Index	0 - 100
	Ease of doing business	Ease of Doing Business Index by Country 2024 (worldpopulationreview.com)	0 - 100
	Digital readiness score	Digital Readiness Index 2021 (cisco.com)	-2.5 to 2.5

Indicator ranking

Table 9-29. Indicator ranking style

		Rank and score				
Theme	Indicator	Low	Low-mid	Mid	Mid-high	High
		0	0.5	1	1.5	2
Policy and regulation	CCS policy	0	1 – 10	11 - 20	21 – 30	31 - 100
	CCS legal and regulatory	0	1 – 20	21 – 40	41 – 60	61 - 100
	National hydrogen policy	No strategy		Strategy in development/ roadmap developed		Strategy published
Financial incentives	CCUS financial incentives	Not assessed	0 – 50	51 – 100	101 – 200	200+
	Hydrogen financial incentives	No funding				Funding available
CO_2	Number of biogenic sources - all sources	0	1 – 3	4 – 6	6 – 9	10+
	Volume of biogenic sources - all sources, $MtCO_2$/year	0	1.5	1.5 – 2.5	2.5 – 10	10+
	Number of biogenic source - above 2 $MtCO_2$/year	0	1 – 3	4 – 6	6 – 9	10+
	Volume of biogenic source - above 2 $MtCO_2$/year, $MtCO_2$/year	0	1.5	1.5 – 2.5	2.5 – 10	10+
	Number of sources in top 50% scoring sub-sectors (16-22)	0	1 – 10	11 – 20	21 – 30	31+
	Volume of sources in top 50% scoring sub-sectors (16-22), $MtCO_2$/year, $MtCO_2$/year	0	0 - 10	10 – 50	50 – 200	200+

		Rank and score				
	Number of sources within 3 scenarios identified in WP1 – 2 $MtCO_2$/year	0	1 – 10	11 – 20	21 – 30	31+
	Volume of sources within 3 scenarios identified in WP1 - 2 $MtCO_2$/year, $MtCO_2$/year	0	0 - 10	10 – 50	50 – 200	200+
	Number of sources within 3 scenarios identified in WP1 – 20 $MtCO_2$/year points	0	1	2	3	4+
	Volume of sources within 3 scenarios identified in WP1 – 20 $MtCO_2$/year points, $MtCO_2$/year	0	0 – 25	25 – 50	50 – 75	75+
	Number of sources within 3 scenarios identified in WP1 – 20 $MtCO_2$/year hotspots	0	1 – 2	3 – 4	5 – 6	7+
	Volume of sources within 3 scenarios identified in WP1 – 20 $MtCO_2$/year hotspots, $MtCO_2$/year	0	0 – 10	10 – 50	50 – 200	200+
	Number of sources within 3 scenarios identified in WP1 – 100 $MtCO_2$/year points	0	1 – 3	4 – 6	7 – 9	10+
	Volume of sources within 3 scenarios identified in WP1 – 100 $MtCO_2$/year points, $MtCO_2$/year	0	0 – 10	10 – 50	50 – 200	200+
	Number of sources within 3 scenarios identified in WP1 – 100 $MtCO_2$/year hotspots	0	1	2	3	4+
	Volume of sources within 3 scenarios identified in WP1 – 100 $MtCO_2$/year hotspots	0	0 – 15	15 – 100	100 – 200	200+
	CO_2 transport projects	0	1	2	3	4+
	CO_2 capture projects	0	1 – 5	6 – 10	11 – 20	21+
	CCU projects	0	1	2	3 - 4	5+
	DAC projects	0	1	2	3	4+
Hydrogen	Levelised cost of hydrogen	High	Mid-high	Mid	Low-mid	Low
	Capacity of hydrogen production projects (electrolysis), Nm^3 H_2/h (x10^6)	0	0 – 1	1 – 5	5 – 10	10+
Business and innovation prospects	Global innovation index	No data	0 – 20	20 – 40	40 – 60	60+
	Ease of doing business	0 – 40	40 – 60	60 – 70	70 – 80	80+
	Digital readiness score	-2.5 to -1.5	-1.5 to -0.5	-0.5 to 0.5	0.5 to 1.5	1.5 to 2.5

Theme ranking

Table 9-30. Theme ranking style

Theme	Rank and score				
	Low	Low-mid	Mid	Mid-high	High
	0	0.5	1	1.5	2
Policy and regulation	0	0 – 1.5	1.5 – 3	3 – 4.5	4.5 - 6
Financial incentives	0	0 – 1	1 – 2	2 – 3	3 - 4
CO_2	0	0 – 6	6 – 11	11 – 16	16 - 32
Hydrogen	0 – 0.8	0.8 – 1.6	1.6 – 2.4	2.4 – 3.2	3.2 - 4
Business and innovation prospects	0	0 – 1.5	1.5 – 3	3 – 4.5	4.5 - 6

Overall score ranking

Table 9-31. Overall score ranking style

Theme	Rank and score				
	Low	Low-mid	Mid	Mid-high	High
Overall prospects for e-fuels	0 – 4	4 – 8	8 – 12	12 – 16	16+

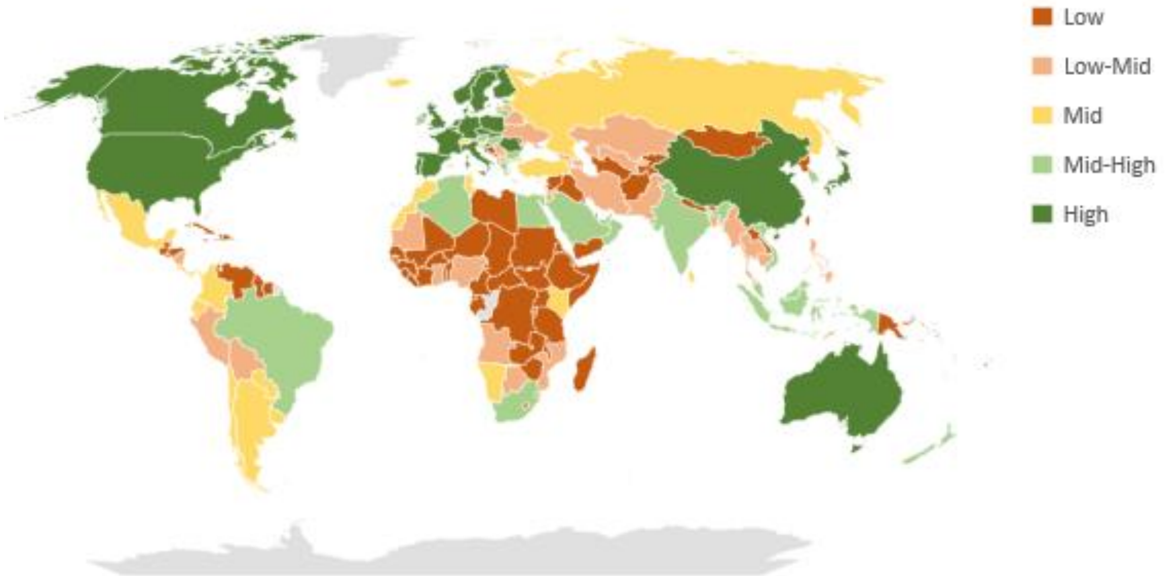
9.3.1.2 Results

Theme results

The overall scores for each country from low-high for each theme are represented in the figures below. These figures represent the rankings determined through summing the individual scores of the indicators within each theme.

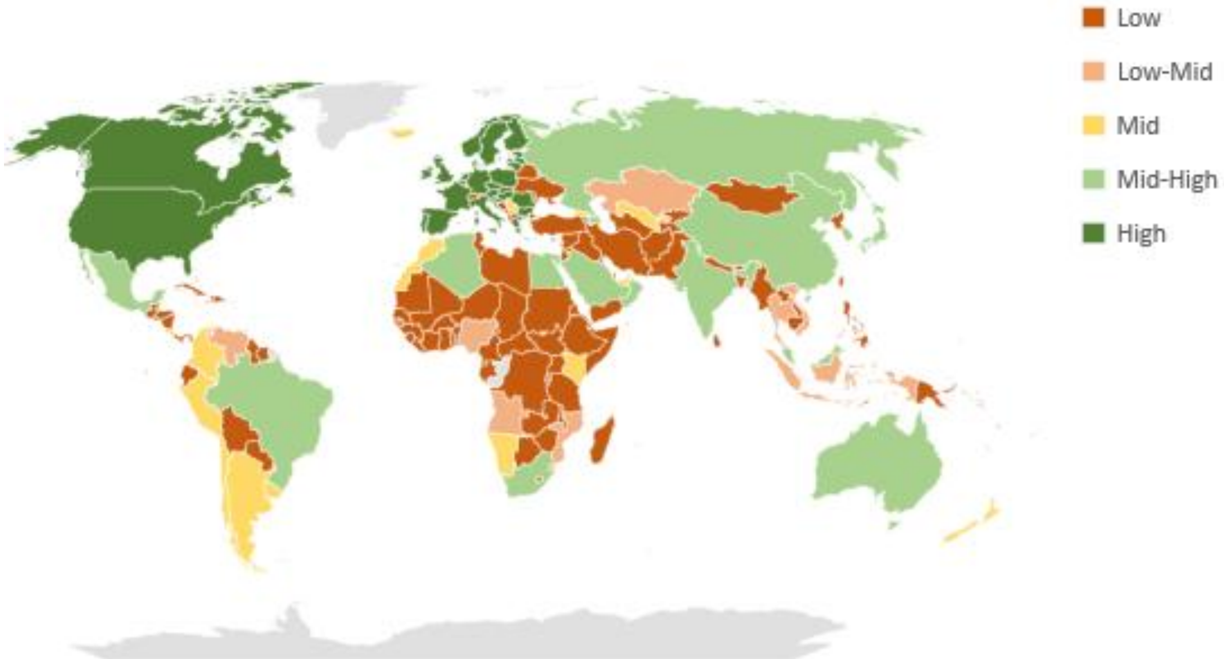
Policy and regulation

Figure 9-25. Policy and regulation theme: results



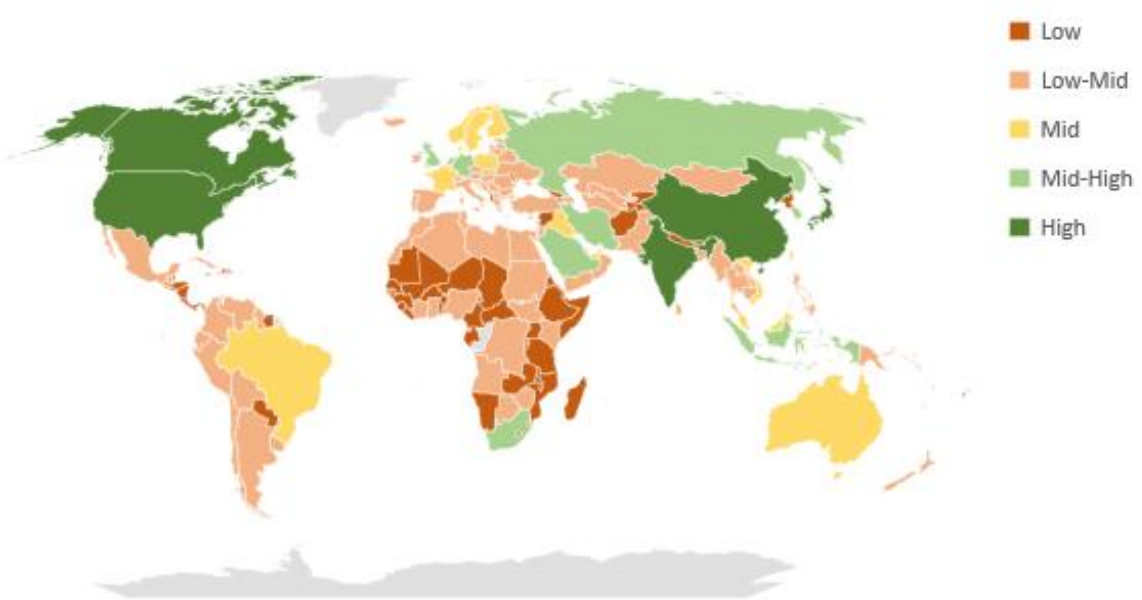
Financial incentives

Figure 9-26. Financial incentives theme: results



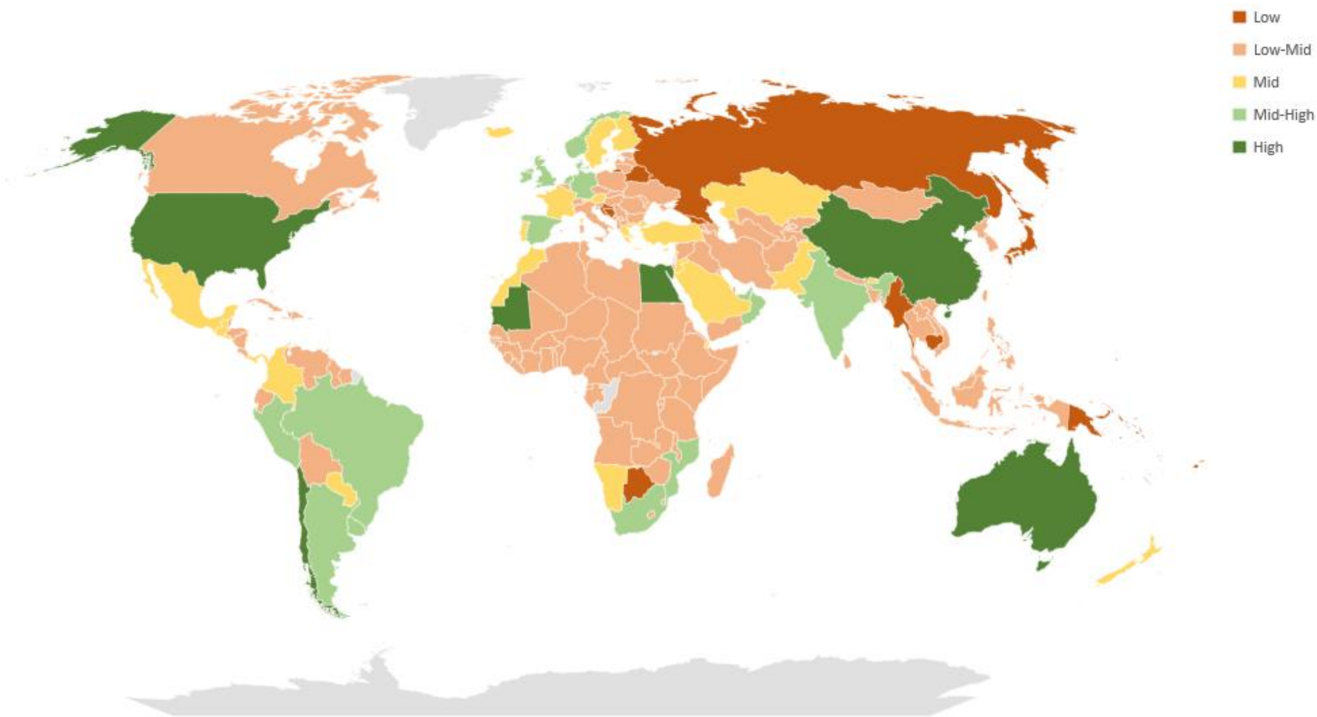
CO_2

Figure 9-27. CO_2 theme: results



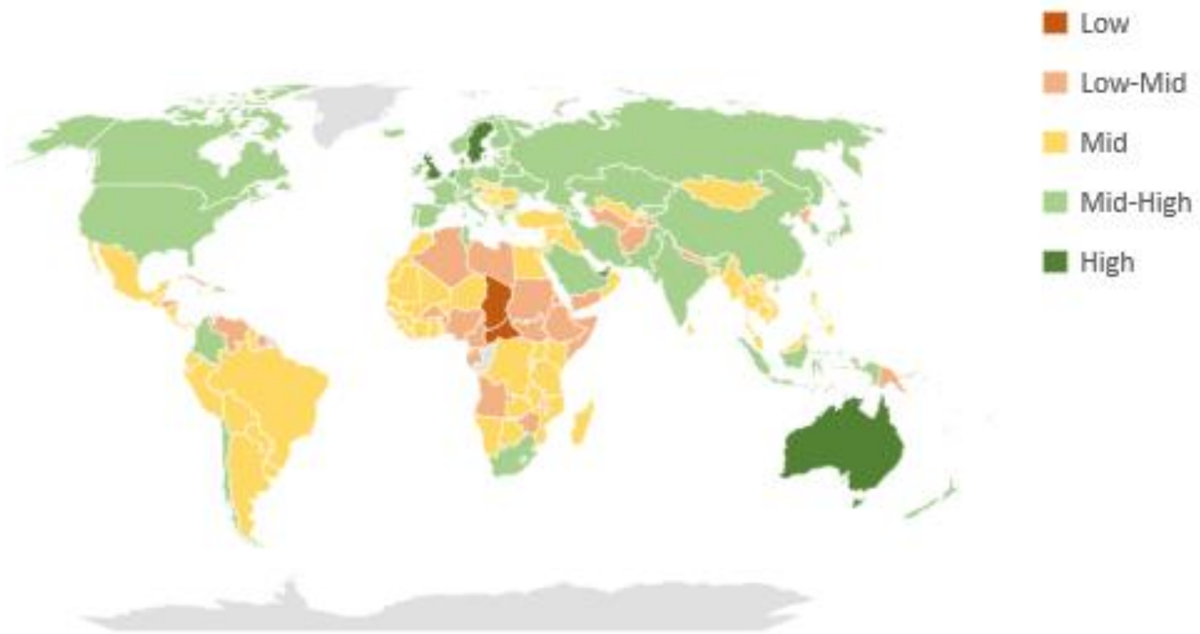
Hydrogen production

Figure 9-28. Hydrogen production theme: results



Business and innovation prospects

Figure 9-29. Business and innovation prospects theme: results



9.3.2 Selection of exemplar locations

The top-scoring countries were examined in greater detail, revealing strong prospects for e-fuel production in several cases. Seven countries received an overall rating of 'high,' although their scores varied across specific themes. While some countries performed consistently well across all themes, others excelled in particular areas. An overview of the score for each theme, as well as the overall score, for the top scoring countries, is outlined in Table 9-32 below.

Table 9-32. Scores per theme for top scoring countries in prospects for e-fuels production

Country	Region	Policy and regulation	Financial incentives	CO_2	Hydrogen	Business and innovation prospects
Australia	Oceania	High	Mid-High	Mid	High	High
China	Asia	High	Mid-High	High	High	Mid-High
Denmark	Europe	High	High	Mid	Mid-High	High
Germany	Europe	High	High	Mid-High	Mid-High	Mid-High
Netherlands	Europe	High	High	Mid-High	Mid-High	High
United Kingdom	Europe	High	High	Mid-High	Mid-High	High
United States of America	North America	High	High	High	High	Mid-High

Upon reviewing Table 9-32, the following rationale was concluded:

- There are four regions with countries exhibiting ‘high’ scores, namely Oceania, Asia, Europe, and North America. Hence the remaining regions (South America and Africa), are excluded moving forwards.
- Australia was excluded due to having a score of ‘Mid’ in the CO_2 theme. With Australia excluded, the regions of Asia, Europe, and North America are remaining.
- With only one country remaining in contention for each of North America and Asia, the United States and China were selected as two of the exemplar locations.
- Among the four-remaining high-scoring countries in Europe, Denmark was excluded due to a 'Mid' rating in the CO_2 theme. Germany, Netherlands, and the United Kingdom showed similar scores across the five themes, so the availability of CO_2 sources and planned e-fuel projects were examined more closely for these three countries. Germany emerged as the strongest option, with the highest availability of CO_2 sources and the greatest number of planned e-fuel projects. As a result, Germany was selected as the final country for further analysis.

9.4 PROSPECT FOR E-FUEL PRODUCTION IN USA, CHINA, AND GERMANY

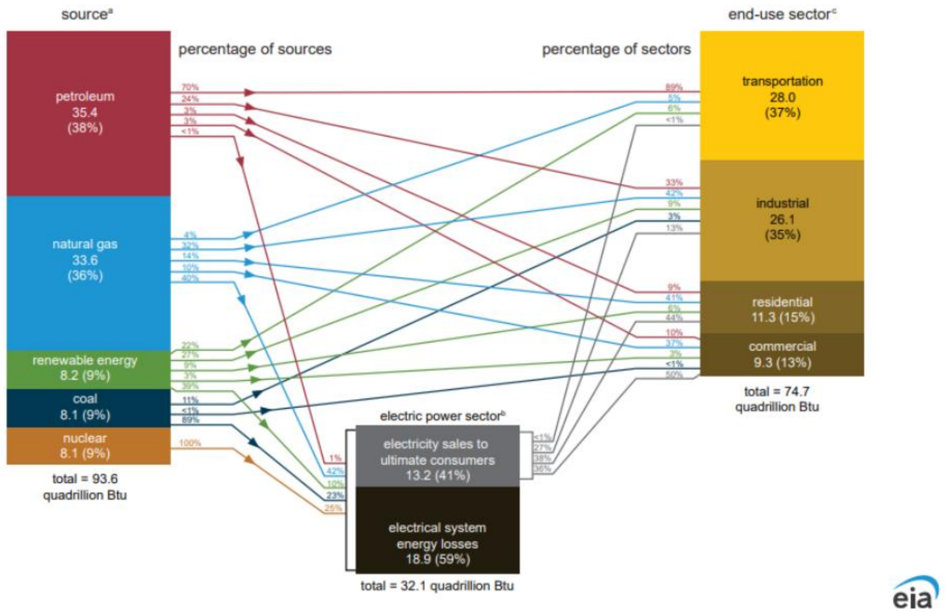
9.4.1 United States

9.4.1.1 Current energy landscape

Depending on how it is measured, the United States has the largest or second largest economy in the world, accounting for 25% of the global economy[201]. Importantly, the US plays a critical role in the world’s energy and climate economy. The US is the second largest energy producer and consumer as well as also the second largest CO_2 emitter globally.

The largest share of CO_2 emissions arises from the transport sector, followed by electricity generation and industry[202]. The current primary energy mix in the US is dominated by petroleum and natural gas. Coal, nuclear and renewable energy each account for approximately 9% of primary energy. An overview of the primary energy mix and subsequent end uses is outlined in Figure 9-30[203] below.

Figure 9-30. U.S energy consumption by source and sector, 2023 (quadrillion British thermal units)



201 United States 2024, Energy Policy Review, International Energy Agency

202 Inventory of Greenhouse Gas Emissions and Sinks, United States Environment Protection Agency

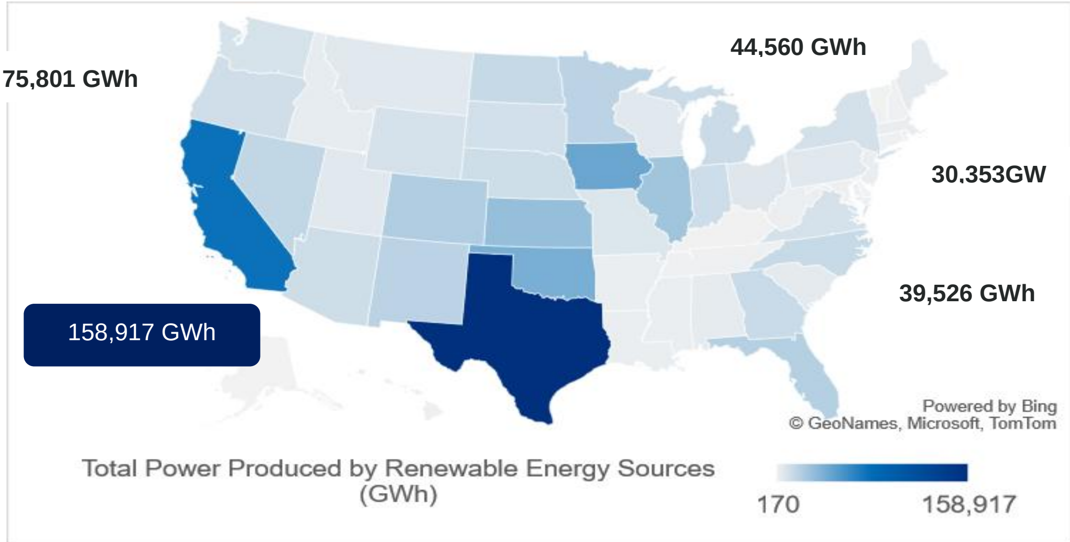
203 How has energy use changed throughout US history? U.S Energy Information Administration, Independent Statistics and Analysis, 2024

Hydrogen is not visible in Figure 9-30. At present the role of hydrogen for energy use, either directly or as an intermediate is negligible from a national scale – the vast majority of hydrogen produced and used today is produced from fossil fuels and used as an industrial feedstock, though smaller amounts of hydrogen are used as a fuel in transport (e.g. rockets or certain low carbon vehicles).

Green hydrogen, i.e., hydrogen produced utilising renewable electricity, is a key component of e-fuel production, therefore the availability of renewable energy currently, and in the future contributes to the potential scale of e-fuel deployment. Direct Air Capture (DAC) can also be utilised to source CO_2 as a feedstock for e-fuels production. DAC provides the greatest GHG reduction benefits when utilising low carbon energy sources, including renewable electricity. Hence, if utilising DAC to source CO_2, this further increases the importance of renewable electricity availability when considering development of an e-fuels facility.

Renewable energy production has nearly tripled in the past decade. Progress varies between states, but in all locations renewable electricity generation is likely set to grow further, as it is now cost competitive with other forms of power generation in many locations. Figure 9-31[204] illustrates the total power generated by renewable energy sources in the United States (October 2023 to September 2024), where it can be seen that Texas is by far the largest renewable energy producer, followed by California, Iowa, Oklahoma, and Kansas.

Figure 9-31. Renewable energy produced per state (GWh/yr) in the US, (2023 – 2024)



Nationally, wind energy's share of annual utility-scale electricity generation capacity in the US increased from less than 1% in 1990 to approximately 10% in 2023. The share of utility scale electricity generation capacity generated from solar was approximately 3.9% in 2023, up from less than 0.1% in 1990[205]. Wind power is therefore the dominant renewable energy source in the US, accounting for nearly half of the total renewable energy generation[206]. States in the Central and Midwest regions of the US, characterised by high and consistent wind speeds, are the primary contributors to the nation's wind energy generation.

In addition to the availability of renewable electricity, the selection of a suitable location for an e-fuels production plant is also influenced by the cost of industrial electricity. The cost of electricity is important to consider in the production of green hydrogen as it powers the electrolysis process. Moreover, it is one of the largest contributors to the cost of green hydrogen production, oftentimes accounting for more that 70% of the total cost. The cost of industrial electricity can vary considerably across different regions and states within the US. This variation arises from the decentralised nature of electricity regulation in the country, where each state has the autonomy to develop its own policies, rates, and utility regulations without direct federal oversight.

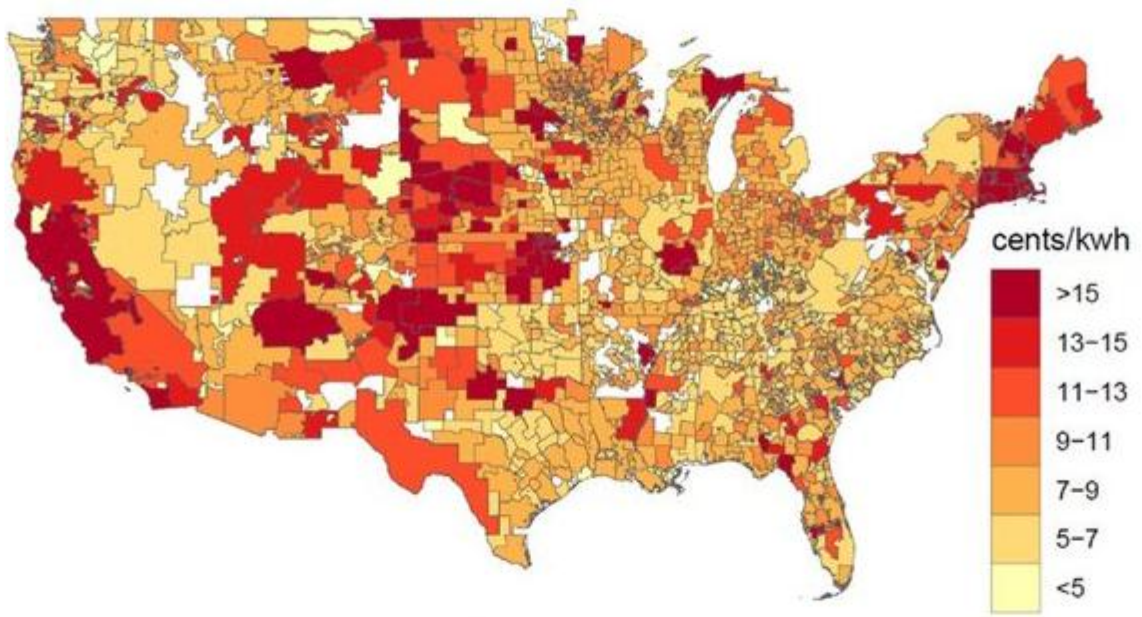
[204] Which states produce the most renewable energy? The Motley Fool, 2024

[205] Electricity generation, capacity, and sales in the United States, U.S Energy Information Administration, Independent Statistics and Analysis, 2024

[206] Which US state generates the most wind power? World Economic Forum, 2022

States including California, Alaska, Hawaii, Florida are characterised by relatively high costs of industrial electricity. In contrast, states such as New Mexico, Oklahoma, and many in the Gulf Coast Region (Texas, Alabama, Louisiana, and Mississippi), offer lower industrial electricity costs. Industrial electricity prices in the United States in 2023 are shown in Figure 9-32[207] below.

Figure 9-32. Industrial electricity prices in the United States, 2023



Gulf Coast Highlight

While Texas is actively developing its renewable energy sector, other Gulf Coast states are lagging in renewable energy deployment. Ten US states, primarily in the Southeast, including Mississippi, Alabama, Louisiana, and Florida, currently have no wind power generation facilities. Texas is the largest renewable energy producer in the Gulf Coast region and the entire United States. Mississippi, Louisiana, and Alabama produce relatively low amounts of renewable energy compared to the national average.

Policy priorities

The transition of the fuel sector hinges on various enabling policy and regulatory frameworks to drive the demand, development, and deployment of e-fuels. There is however little national policy consensus. In the United States, the Biden Administration set a goal of reaching net zero Greenhouse Gas emissions by 2050. Published in 2021, the Long-Term Strategy[208] of the United States contains pathways to net zero GHG emissions, involving five key transformations. These include:

- Decarbonising electricity
- Electrifying end uses and switching to other clean fuels
- Cutting energy waste
- Reducing methane and other non-CO_2 emissions, and
- Scaling up CO_2 removal.

Clean fuels, such as carbon-free hydrogen and sustainable biofuels, are highlighted to be prioritised in sectors that are harder to electrify, in particular, aviation, shipping and industrial processes. However, e-fuels are not specifically prioritised.

[207] Distributed clean energy opportunities for US oil refinery operations, Frontiers in Economic Research, Kathleen Krah et al, 2023

[208] The Long-Term Strategy of the United States, Pathways to Net-Zero Greenhouse Gas emissions by 2050, The United States Department of State and the United States Executive Office of the President, November 2021

To support the Strategy, a number of key laws were passed by the Biden Administration. In August 2022, the Inflation Reduction Act (IRA) increased action on clean energy and climate change[209]. The overarching outcomes expected from the IRA is to help the US become a global leader in clean energy technology, manufacturing and innovation, lowering energy costs, accelerate private investment in clean energy solutions, strengthen supply chains and boost economic opportunities[209].

The IRA builds on climate and clean energy actions under the Bipartisan Infrastructure Law (BIL), signed in November 2021. A selection of key aims of the BIL are to support in modernising the electricity grid, building a network of electric vehicle chargers, strengthening the battery supply chain and investing in new clean energy and emissions reduction technologies.

Decarbonising the electricity grid is amongst some of the key decarbonisation goals of the US, with a target of achieving 100% carbon free electricity generation by 2035[209]. The IRA builds on grid investments in the BIL.

There are diverse views on the extent to which hydrogen, particularly from renewable sources, is expected to play a role in decarbonisation in the US over the coming decades. Ongoing pilot projects and studies are exploring the production and blending of hydrogen into existing gas networks, which may inform a transition plan to upgrade the current infrastructure. In terms of renewable energy, the strategy emphasises the critical roles of solar, onshore wind, and offshore wind in creating a low-carbon future. The importance of investing in transmission infrastructure to support the integration of these renewable energy sources has also been recognised as essential for success.

Transport accounts for the largest share of greenhouse gas emissions in the US; a target has been set for at least 50% of all new passenger cars and light trucks sold in 2030 to be zero-emission vehicles, namely battery electric, plug-in hybrid or fuel cell electric vehicles[209]. Key priorities in the IRA also include incentivising and supporting the development and use of cleaner transport fuels. Incentives are provided for fuels for cars, trucks and the aviation sector, focusing on ethanol, biodiesel and sustainable aviation fuels (SAF).

The National Blueprint for Transportation Decarbonisation presents the three key strategies for decarbonising the transportation sector; one of the strategies involves the deployment of zero-emission vehicles and fuels. Large long-term opportunity was identified for hydrogen in rail, maritime, and long-haul heavy trucking, with additional opportunity for use as a feedstock for fuels. The Blueprint also advocates for supporting the development of sustainable drop-in fuels and their associated infrastructure, however, **with a greater emphasis overall on biomass synthetic fuels over e-fuels**. Moreover, the Blueprint expresses concerns regarding e-fuels, highlighting the need for additional research to verify their potential to reduce emissions and minimise life-cycle emissions.

9.4.1.2 *Resource availability*

Green hydrogen can be produced from grid electricity, produced from a variety of domestic resources, such as wind, solar, geothermal, and biomass. The amount of electricty produced from wind and solar has increased across the US, with wind power capacity having doubled this decade and solar power generation increasing 8 fold. Current and projected renewable energy production capacities, as well as grid expansion and decarboinsation progress, can provide insights not only into the grid readiness, but also its capacity, to support deployment of e-fuel production facilities[210].

Solar and wind

It is proposed that e-fuel production facilities be located in regions with abundant, low-cost renewable electricity. The United States possesses vast renewable energy resources from wind and solar, yet only a fraction of this potential is currently harnessed.

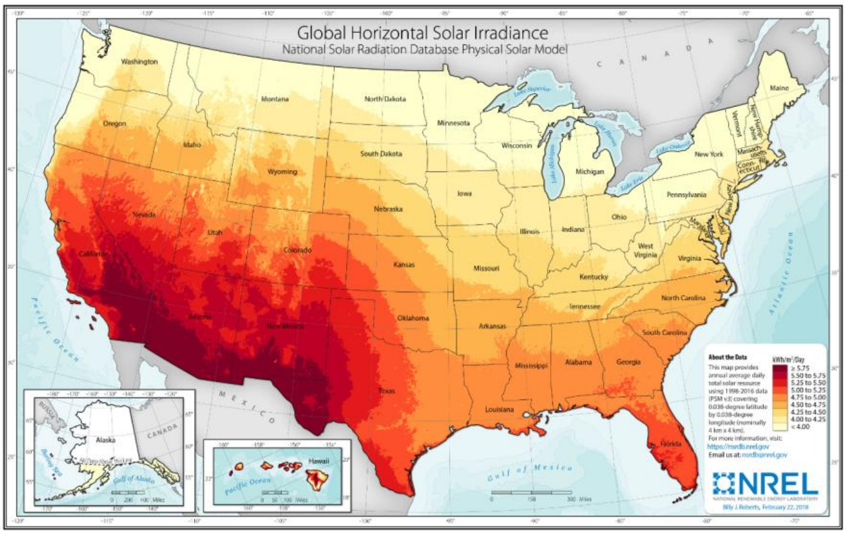
The Southwest and Gulf Coast regions experience the highest solar irradiance in the US, as illustrated in Figure 9-33[211], presenting significant theoretical potential for renewable energy production.

[209] Building a Clean Energy Economy, A Guidebook to the Inflation Reduction Act's Investment in Clean Energy and Climate Action, The White House, 2023

[210] A decade of growth in solar and wind power: Trends across the US, Climate Central, 2024

[211] Solar Resource Maps and Data, National Renewable Energy Laboratory

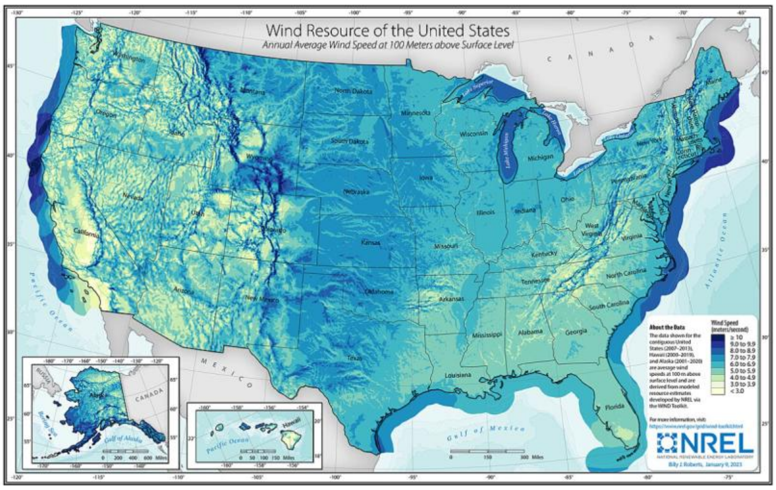
Figure 9-33. Solar Irradiance across the United States (1998 – 2016)



Wind power is the largest source of renewable energy in the US, contributing nearly half of the total renewable energy generated. Texas is the largest wind energy producer, followed by Iowa, Oklahoma, and Kansas. Notably, 10 states located in the southeast region have no wind power capacity. Figure 9-34[212] depicts the average wind speeds across the US.

According to estimates from the US Department of Energy, the country's land-based wind resource potential ranges from 2.2 – 15.1 TW; this wide range reflects the inherent uncertainties in assessing wind conditions. Like solar, the potential for wind power varies significantly across different states.

Figure 9-34. Average Wind Speed across the United States (2007 – 2013)



An e-fuels plant with a production capacity of 25,000 kt/year (525,000 bbl/day) is expected to require 11,250 kt/year of green hydrogen. To produce this amount of green hydrogen, 633TWh/year of renewable electricity is required. In 2023, the US produced 890TWh of renewable energy, enough to support only one large e-fuels production facility. There is relatively little constrained renewable generation at present[213]. Considerable additional renewable or other low carbon power generation would be required for the US to generate green hydrogen to support e-fuel production – multiples of current generation. Whilst the wind and solar resource maps show considerable untapped renewable potential, increasing the renewable capacity in a short timescale

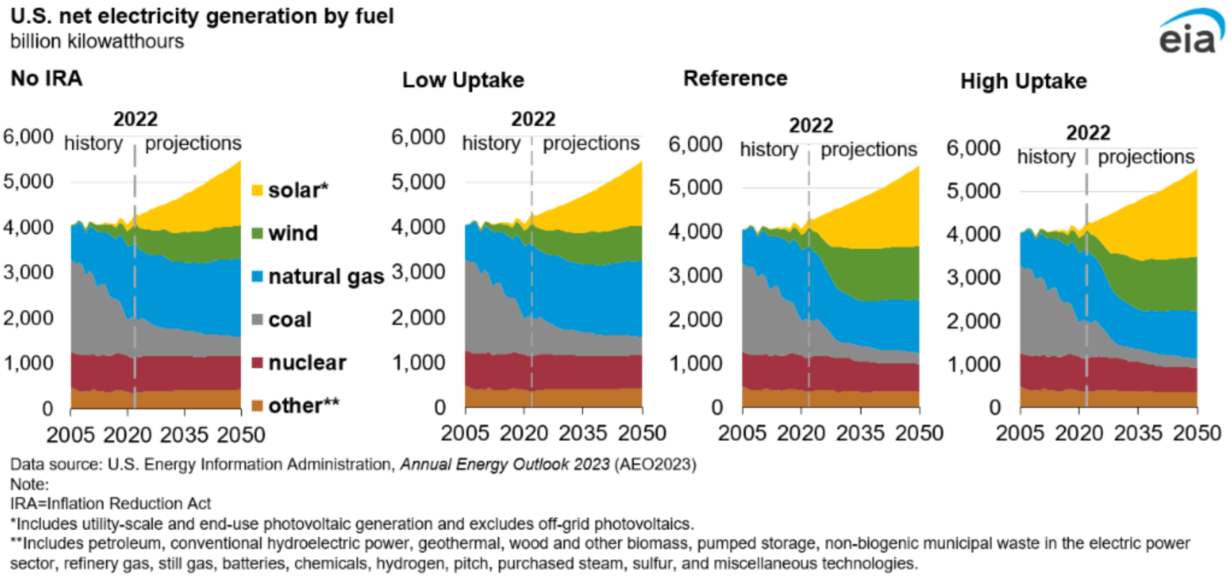
[212] Wind Resource Maps and Data, National Renewable Energy Laboratory

[213] Electricity explained, electricity generation, capacity and sales in the United States, US Energy Information Administration, 2024

would be a major undertaking and would require serious and sustained commitments and (re-)alignment across public bodies, industry, landowners, investors.

To facilitate the decarbonisation of the US electricity grid, the Inflation Reduct Act (IRA) offers tax credits to incentivise the deployment of solar and wind power generation[214]. The US Energy Information Administration modelled the potential impact of these tax credits on the nation's net electricity generation mix, as illustrated in Figure 9-35[214]. The analysis suggests that an increase in solar power deployment is likely, regardless of rate of uptake of the IRA incentives. In contrast, the growth of wind is more gradual, with a significantly increase only under a scenario of high uptake of the IRA.

Figure 9-35. U.S. net electricity generation by fuel



Water

Water may have several roles in e-fuel production. Water is needed for hydrogen production, as well as most carbon capture processes, and can potentially support some e-fuel production processes themselves (e.g. cooling water). As the production of green hydrogen involves water electrolysis, whereby water is split into hydrogen and oxygen, the availability of water is a factor in assessing the suitability of a region for e-fuels production. According to Concawe[215], approximately 3.7 – 4.5 litres of water is required to produce 1 litre of liquid e-fuels; this figure is comparable to the water footprint required to produce US conventional crude oil and gasoline, which is 3-7 litres/ litre of jet fuel and 1-3 litres/ litre of jet fuel, respectively[216].

The emergence of new water uses, especially in water-scarce areas, could lead to conflicts with other water users and ecosystem impacts. Water managers in at least 40 states across the US anticipate local, statewide, or regional water shortages within the next few years[217].

Some US Regions already experiencing significant water stress, such as California, are depicted in Figure 9-36[218].These regions may see increased competition for water resources, impacting their potential suitability for e-fuel production, unless the use of seawater, through desalination, can be scaled up without significantly increasing costs.

Locations such as those with a combination of freshwater constraints and high industrial electricity prices are unlikely candidates for cost-competitive green hydrogen production at scale.

---

[214] Annual Energy Outlook 2023, US Energy Information Administration, 2023

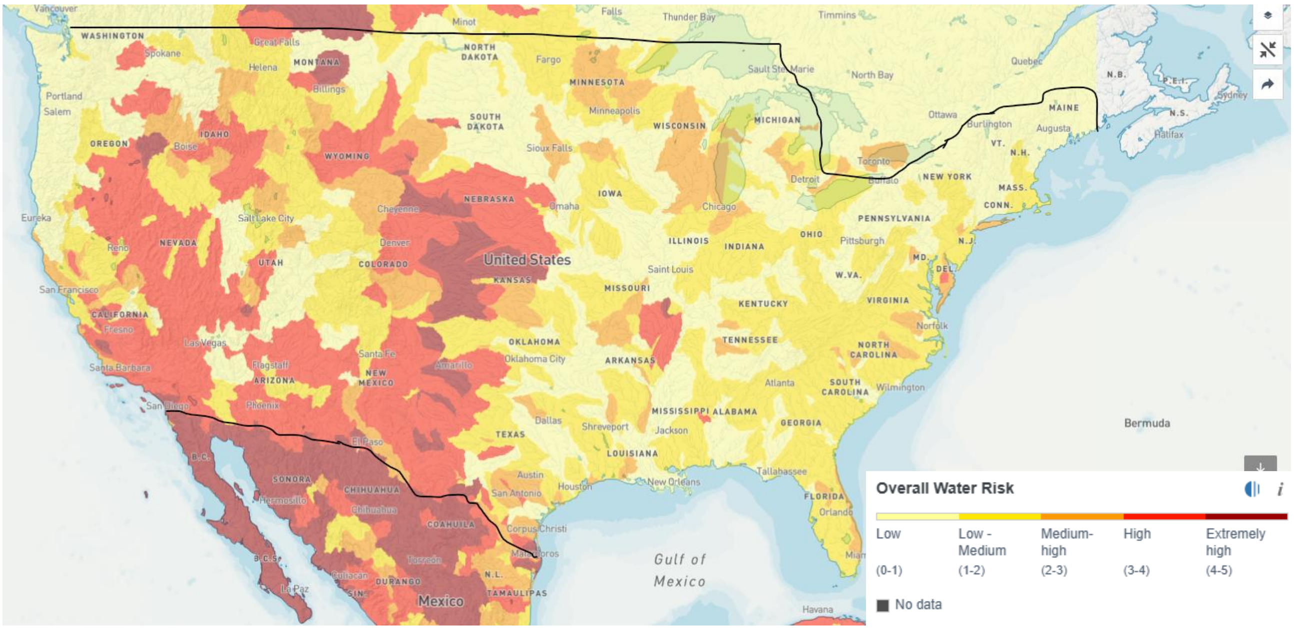
[215] A look into the role of e-fuels in the transport system in Europe (2030 – 2050), Concawe, 2019

[216] Water footprint and land requirement of solar thermochemical jet-fuel production, ACS Publications, Environmental Science and Technology, Christoph Falter and Robert Pitz-Paal, 2017

[217] Drought and Water Conservation, Gulf Coast Water Authority

[218] Aqueduct Water Risk Atlas

Figure 9-36. Overall water risk in the US



Gulf Coast Highlight

Texas faces some water supply constraints onshore; the state's water demand is projected to outpace supply, exacerbated by extreme weather events, increasing drought frequency, aging infrastructure, and overreliance on groundwater[219]. Given Texas's susceptibility to drought, future water shortages could impact agriculture, industry, and municipal water supplies, further complicating the state's water management challenges and creating uncertainty for industrial development. Options for integrating seawater would be remove the threat of this becoming a bottleneck for potential growth.

9.4.1.3 *CO_2 sources*

The availability of CO_2 is another factor to consider in the selection of a suitable location for an e-fuels production plant, as CO_2 constitutes the second primary component of the e-fuel synthesis process.

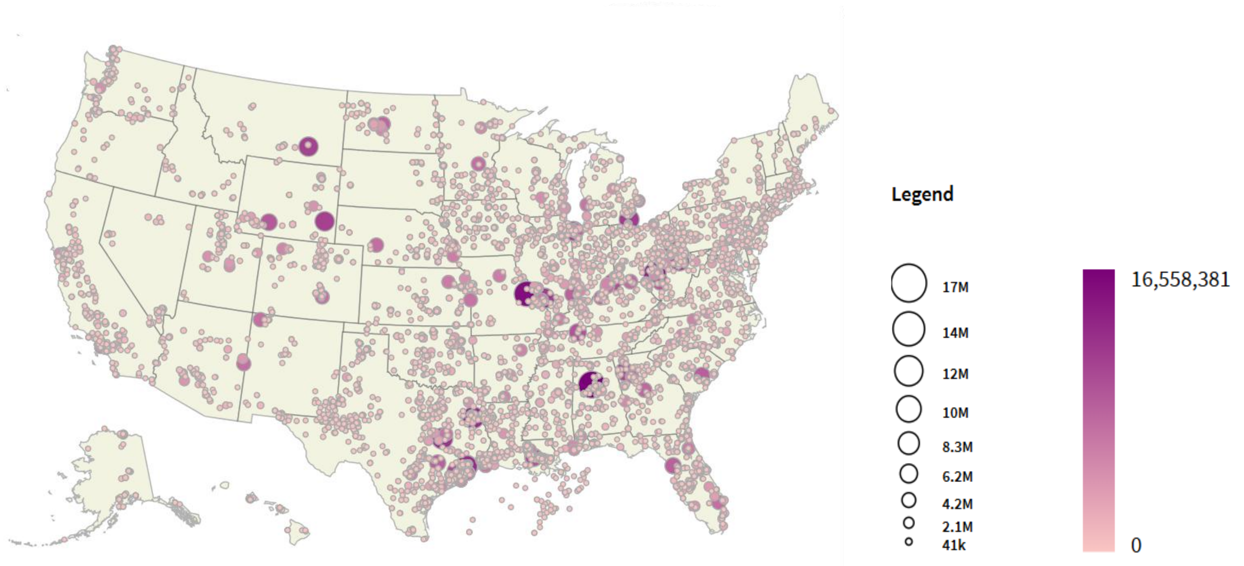
The US is the second largest CO_2 emitter in the world, and the largest on a per capita basis. In line with its current fossil energy consumption, the transport sector has the highest CO_2 emissions. Whilst this makes it an attractive sector to focus emissions reductions, the mobile nature of the emissions makes transport a difficult and expensive sector to source CO_2 from.

Carbon capture involves chemically separating CO_2 from the outputs of a process, often via a specialist chemical process involving the use of chemicals (e.g. solvents) and complex equipment combined with large industrial processes at specific locations.

Clusters of industrial facilities can facilitate the development of Carbon Capture, Utilisation and Storage (CCUS) hubs, reducing costs and risks whilst enabling larger-scale deployment of CCUS. Locating an e-fuel production facility near or within these hubs can offer the advantage of utilising captured CO_2 and leveraging shared CO_2 transportation infrastructure. Figure 9-37[20] illustrates the location and total reported emissions from facilities which are part of the Greenhouse Gas Reporting Program. Emissions are concentrated in the Southern, Northeastern, and Midwestern regions of the United States. In contrast, the Western region, excluding California, has a lower concentration of facilities and, consequently, lower emissions.

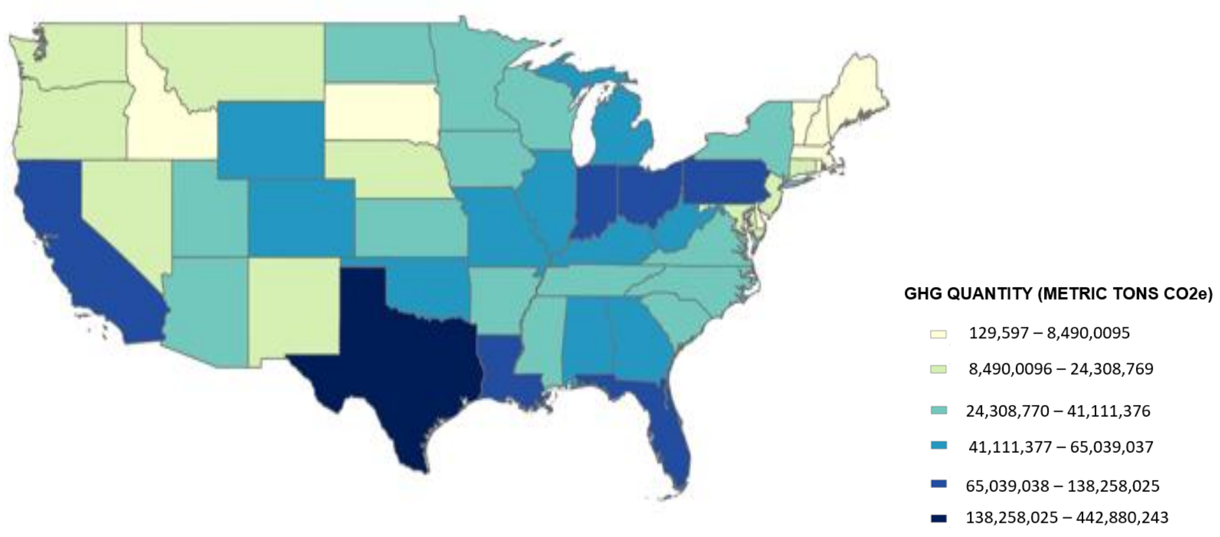
[219] Does Texas have a water issue? AUC Group, 2024

Figure 9-37. Location and Total Reported Emissions from Greenhouse Gas Reporting Program (GHGRP) Facilities (2023)



In 2023, Texas, California, Florida, and Louisiana were the top CO_2 emitting states in the US, whereas Vermont, New Hampshire, and Maine were the least, as illustrated in Figure 9-38 [220] below.

Figure 9-38. Annual reported CO_2 emissions from stationary sources reporting to the GHGRP in the United States, 2023

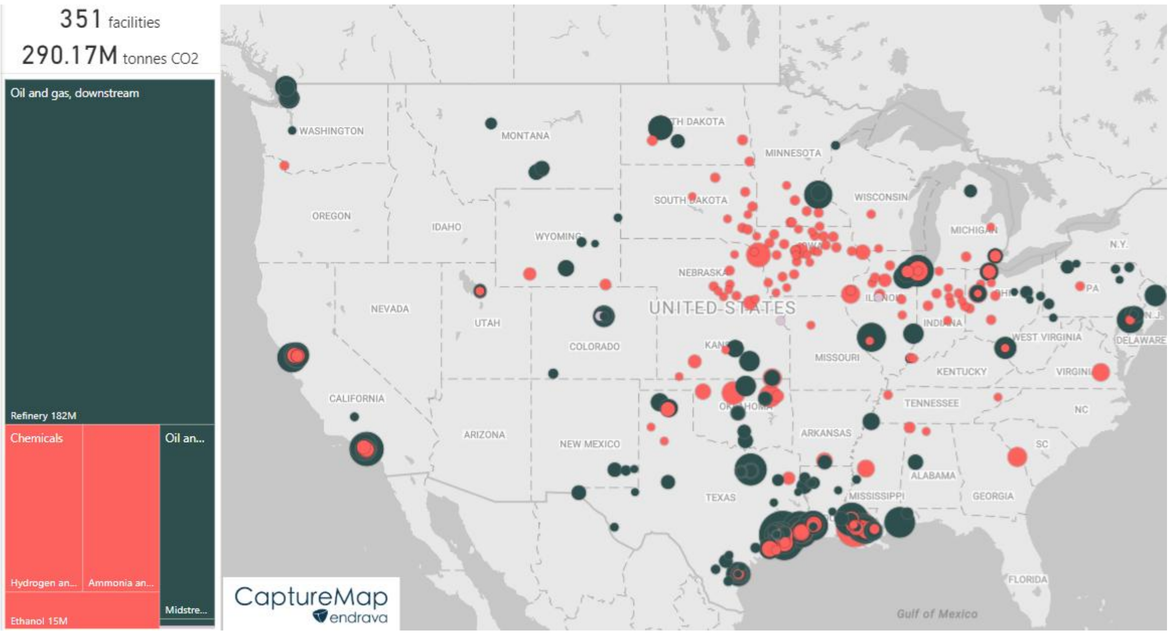


**This chart reflects total CO_2 emissions from stationary sources reported to the GHGRP. Approximately half of total US emissions are reported to the GHGRP by these emitters. This chart does not include emissions from the transportation or agricultural sectors and facilities where emissions are below the 25,000 metric ton CO2e reporting threshold.*

[220] Greenhouse Gas Reporting Programme (GHGRP) Emissions by Location, United States Environmental Protection Agency, 2024

This study previously reviewed a range of different power and industrial sectors providing a source of CO_2, to determine which may provide the most opportunity to capture CO_2 as a feedstock for e-fuels production. A selection of priority sectors consisted of ammonia, ethanol, oil and gas, alcohol, and refineries, primarily due to the higher CO_2 concentration in the stream to be separated from, and hence lower capture costs. Facilities in these sectors are represented in Figure 9-39 [221] below, where it can be see that there are over 351 point sources of CO_2 greater than 1000 $ktCO_2$/year from these priority sectors, emitting a combined total of over 290 $MtCO_2$/year.

Figure 9-39. Point sources of CO_2 in the US >1000 $ktCO_2$/year from priority sectors



Gulf Coast Highlight

Approximately one-quarter of the total US energy-related Greenhouse Gas (GHG) emissions originate from the Gulf Coast region, primarily due to its substantial industrial activity which includes several large oil and gas refining and chemicals manufacturing sites. The high availability of CO_2 across multiple sources in close proximity creates the potential for an e-fuel hub to emerge in the Gulf Coast region. In 2022, industry, particularly energy-intensive industries, accounted for approximately 52% of energy consumption in the Gulf Coast and South-Central region, significantly higher than the 33% national average[222]. Despite considerable renewable energy capacity, the region's energy mix remains over 90% fossil fuels.

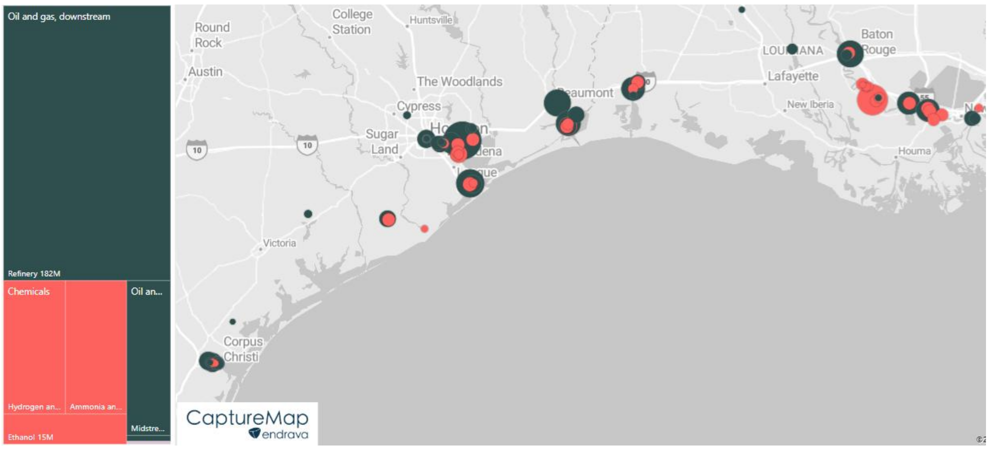
In the Gulf Coast region, clusters of high priority CO_2 sources are located near Houston, Corpus Christi, Port Arthur and New Orleans, as shown in Figure 9-40[223] below.

[221] CaptureMap, Endrava

[222] Gulf Coast and South-Central Region report, Building a Clean Energy and Industrial Economy and the supporting role of the US Department of Energy's Office of Fossil Energy and Carbon Management, US Department of Energy, 2024

[223] CaptureMap, Endrava

Figure 9-40. Point sources of CO_2 in the Gulf Coast region >100 ktCO_2/year from priority sectors



9.4.1.4 *Carbon capture*

The availability of captured CO_2 for further utilisation is influenced by several factors, including supportive policies and regulations, as well as financial incentives like grants and tax credits. The goal of these initiatives is to stimulate the deployment of carbon capture technologies, thereby creating a market for CO_2.

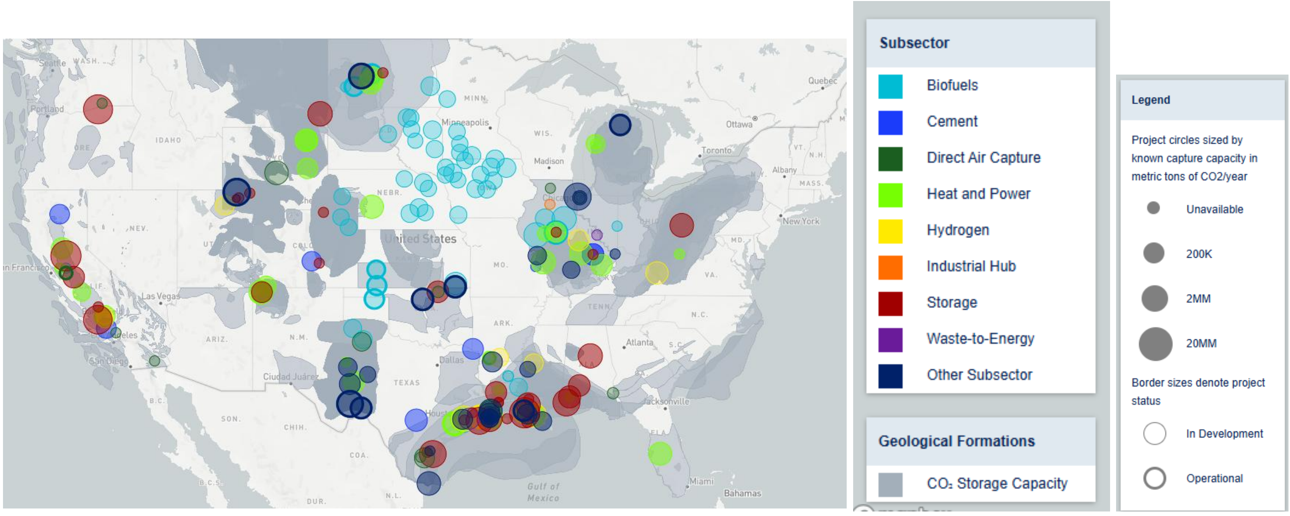
This section provides an overview of the current state of CCUS activities across the country, encompassing CCUS projects, CCUS hub developments, and the deployment of related transportation infrastructure. A mature CCUS environment is more conducive to e-fuel development, as it enhances the availability of captured CO_2 as a feedstock and facilitates its transportation for utilisation. Furthermore, this section covers CCUS-related policies, regulations, and financial incentives, as these can either accelerate or hinder the deployment of CCUS technologies.

Carbon capture activity

The US has experience in developing and deploying many of the components of CCUS technologies, and several integrated CCUS systems. Figure 9-41[224] highlights the progress in CCUS project development across the US; Texas, Louisiana, California, and Wyoming, are particularly noteworthy states showcasing significant CCUS activity. According to the project pipeline, the US's CO_2 capture capacity is projected to reach 335.2 MtCO_2 by 2030, however, 136.3 MtCO_2 of this capacity is still in the planning stage and subject to potential changes[225].

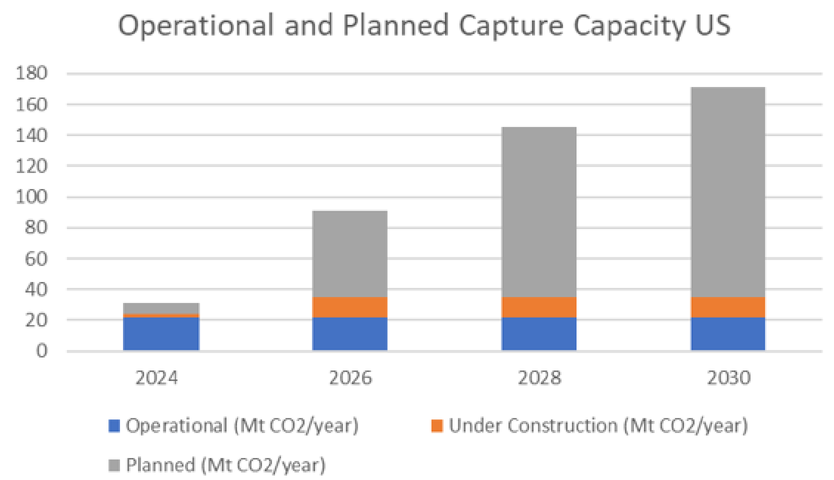
[224] US Carbon Capture Activity and Project Map, Clean Air Task Force
[225] CCUS Projects Explorer, International Energy Agency, 2024

Figure 9-41. US carbon capture activity and project map



As illustrated in Figure 9-42[226], storage projects contribute the greatest to the overall CO_2 capture capacity in the US from 2026 onwards. Among the approximately 300 CCUS projects identified by the IEA for the US, 221 have dedicated geological storage or are proposed for Enhanced Oil Recovery (EOR), whilst the fate of CO_2 for 66 projects are unknown or unspecified. Only 6 projects involve non-EOR utilisation of the captured CO_2

Figure 9-42. Operational and planned capture capacity in the US at various development stages



The majority of CCUS hub developments utilise Direct Air Capture (DAC), technology with individual CCUS projects being adopted to a wider range of industries. A selection of CCUS projects and hubs in the US are outlined in Table 9-33 below.

[226] CCUS Projects Database, International Energy Agency, 2024

Table 9-33. CCUS projects and hub across the US at various stages of deployment

Project	State	Description	Status	Capture Capacity
Bayou Bend CCS Hub[227]	Texas	The hub is designed to provide transportation and storage solutions for industrial emitters in the Houston Ship Channel and Beaumont/Port Arthur region.	Expected operating year 2026	To be determined
SEDAC Hub[228]	Alabama	Supports the deployment of DAC in Mobile County. Pursuit of a variety of CO_2 use cases beyond permanent storage in subsurface reservoirs (e.g., CO_2 to fuels).	Planning	1 Mt CO_2/ year
California DAC Hub	California	DAC hub with geological storage.	Planning	To be determined
Midwest CCUS Network	Illinois, Iowa	Aims to connect ethanol plants and other industrial facilities to saline storage sites.	Planning	12 MtCO_2/ year
Starwood Energy Elysian Ventures project	Not published	Carbon capture retrofit to an existing gas-fired power station. The captured CO_2 is proposed to be used for EOR.	Planning	1.7 MtCO_2/year
The Red Trail Energy CCS project	North Dakota	Ethanol producer operating a retrofit CO_2 capture facility, with the aim to permanently store the captured CO_2.	Operational	1.80 Mt CO_2/ year
Chevron CCS Project	California	Decarbonisation of oil and gas production facility through deployment of CCS. Results in permanent storage of CO_2.	Planning	300,00 tonnes CO_2/year
GE Gas Power CCS Project	Alamaba	Carbon capture retrofit to a natural gas power plant.	Planning	Approx. 1.6 Mt CO_2/year
Carbon America	Nebraska	CCS project at the Bridgeport Ethanol plant to capture CO_2 produced during the fermentation process.	Planning	175,000 tons CO_2/ year

[227] Bayou Bend CCS, The CCUS Hub, OGCI
[228] SEDAC Hub, Southern States Energy Board

Gulf Coast Highlight

CCUS developments in the Gulf Coast region are concentrated in Texas and Louisiana, with numerous CCUS projects having been announced and implemented in the region. CCUS projects in the Gulf Coast region are presented in Figure 9-43[25] and Figure 9-44[229] below.

Figure 9-43. CCUS projects at various stages in the value chain in the Gulf Coast Region

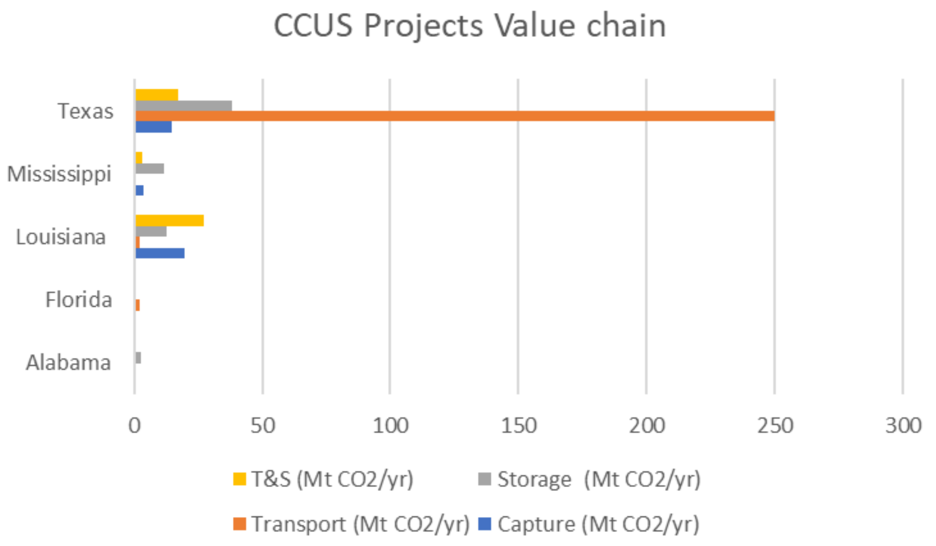
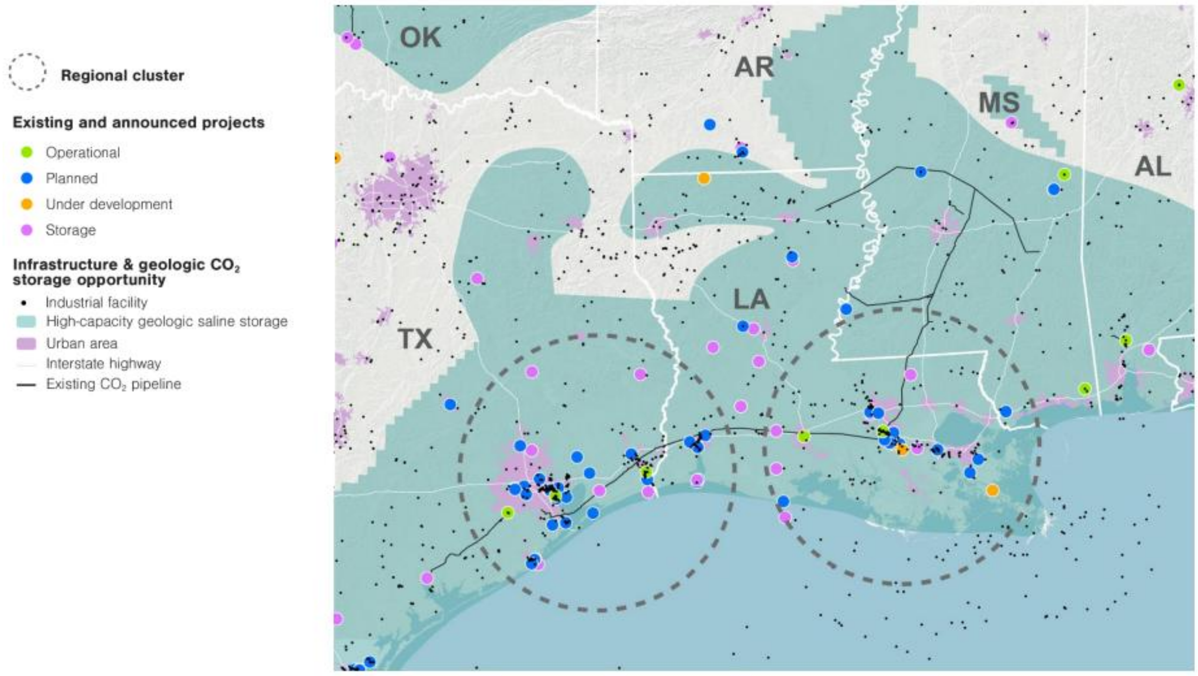


Figure 9-44. Existing and announced CCUS projects in the Gulf Coast regions



The Gulf Coast region has been labelled as a possible location for CCUS hub development due to its energy infrastructure, favourable geologic conditions for CO_2 storage, and proximity to industrial centres.

[229] A New U.S. Industrial Backbone Exploring Regional CCUS Hubs for Small-to-Midsize Industrial Emitters, EFI Foundation & Horizon Climate Group, 2023

Louisiana recently achieved a significant milestone by obtaining primary enforcement authority (primacy) over Class VI underground injection wells. This is expected to accelerate the permitting process for CCS projects, fostering growth in the state's CCS industry. One notable example is the Liberty CCUS hub, which is facilitating decarbonisation across multiple industrial sectors. Additionally, the state is actively developing a hydrogen hub. The presence of both hydrogen and CCUS hubs in the region creates opportunities for co-locating an e-fuel production facility, which could access key feedstocks.

Liberty Louisiana CCUS Hub

Shell is leading the development of the Liberty CCUS hub in Louisiana. Initially aimed at decarbonising Shell's own petrochemical operations, the hub is open to partnerships with other regional industries, including biomass, steel, paper, cement, and ammonia producers.

There are 43 proposed carbon capture projects in Louisiana, as depicted in Figure 9-45[230], including nine hydrogen/ ammonia plants, four Liquefied Natural Gas (LNG) terminals, and one gas processing plant. The project is expected to commence operations in the mid-2020s, pending final CO_2 storage permits. While specific capture targets are still being finalised, industry estimates suggest a potential annual capture of 12 million tonnes of CO_2.

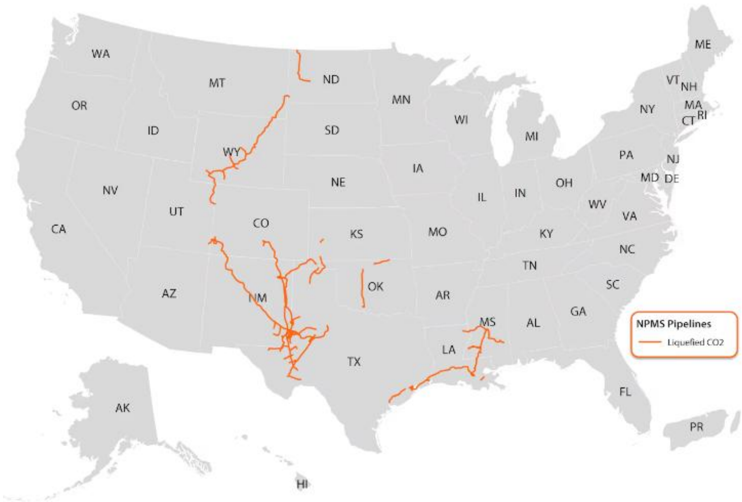
Figure 9-45. Locations of carbon capture projects in the Liberty CCUS Hub

[230] Carbon Capture and Storage in Louisiana, Oil&Gas Watch, 2023

CO_2 transport infrastructure

The United States has an existing CO_2 pipeline network primarily used for EOR operations, spanning over 5,000 miles and facilitating the transport of approximately 68 million metric tons of CO_2 annually, as shown in Figure 9-46[231] below.

Figure 9-46. Existing CO_2 pipelines in the US



This pipeline network would require significant expansion to meet the expected growth in demand from broader CCUS applications.

Estimated of the CO_2 pipeline infrastructure required to support future large-scale CCS projects in the US range from 20,000 to 96,000 miles. Achieving this huge expansion of the current pipeline network would require considerable investment in the face of uncertainties and is unlikely to be quick or simple.

Since 2021, four major CO_2 pipeline projects have been proposed in the Midwest, as depicted in Figure 9-47[32], collectively totalling over 4,000 miles of additional pipeline infrastructure[232]. However, recent high-profile CO_2 pipeline projects in the US have faced cancellations or delays due to community opposition and permitting challenges[233].

[231] US Department of Transportation Pipeline and Hazardous Material Safety Administration, RaboResearch, 2024

[232] Siting challenges for carbon dioxide pipelines, Congressional Research Service, 2023

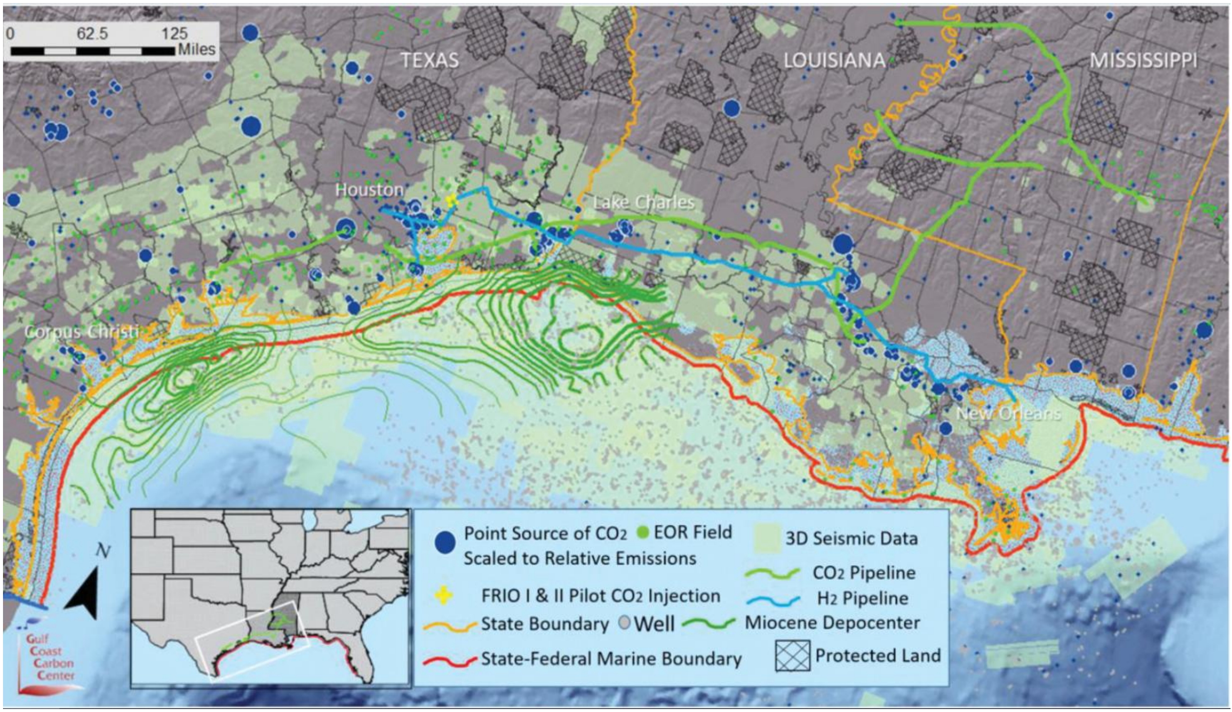
[233] Building our way to net-zero: Carbon dioxide pipelines in the United States, Global CCS Institute, 2024

Figure 9-47. Proposed CO_2 pipeline projects in the Midwest

Gulf Coast Highlight

CO_2 pipelines developed in the Texas Permian Basin and along the Gulf Coast in the 1970s, largely due to the availability of sub-surface CO_2 and the opportunity to use this to enhance oil recovery by injecting this into depleting oilfields. These pipelines are understood to have a good safety record. The existing experience gives the region flexibility in siting of a potential e-fuel facility, and a head start in terms of future CO_2 transport infrastructure investment. Energy and petrochemicals are some of the largest industries in the region, supported by CO_2 pipelines initially established primarily to support EOR. Existing CO_2 pipeline infrastructure in the Gulf Coast region is represented in Figure 9-48 below.

Figure 9-48. Existing CO_2 pipeline infrastructure in the Gulf Coast region



Carbon capture market drivers and barriers

Policy and regulation

Policies and regulation vary across the different states in the US, with each state implementing their own measures, resulting in a varying landscape for carbon capture. A selection of the key policies and regulations relevant to carbon capture in the US are outlined in Table 9-34 below.

Table 9-34. Carbon capture policy and regulation in the US

Policy/ regulation	Location	Key points
Infrastructure Investment and Jobs Act	US-wide	• Provides specific provisions for the development of protocols and standards to ensure the adoption of CCUS, facilitating their integration into existing and future energy and industrial frameworks.
Clean Air Act	US-wide	• Stringent emission reduction targets across all sectors.
Carbon Sequestration: Carbon Capture, Removal, Utilization, and Storage Program[234]	California	• Establishes a regulatory foundation to govern the safe deployment of carbon dioxide capture, removal, utilisation, and sequestration, including rules for monitoring, permitting, and reducing GHGs and co-pollutants.
Carbon Dioxide Removal Market Development Act[t234]	California	• Proposed legislation (introduced in 2023 and passed Senate; currently on hold). • Require emitting entities to purchase increasing amounts of negative emission credits to counterbalance their emissions.
2023 Pipeline Safety and Expansion Act	US-wide	• Enhances the construction, operation, and safety standards for CO_2 pipelines, ensuring they align with the growing needs of the CCUS sector.

Financial incentives

Federal and State grants, tax incentives, and business models support the deployment and scaling of CCUS technologies. These support both the capital and operational phases, enabling wide-scale deployment of CCUS. A selection of key financial incentives are outlined in Table 9-35 below. These legislative measures are designed to integrate CCUS within broader economic and environmental frameworks, reflecting a strategic approach to carbon management.

[234] Lessons from California's Carbon Dioxide Removal Policies, World Resources Institute, 2023

Table 9-35. Carbon capture financial incentives in the US

Financial incentive	Support mechanism	Location	Key points
Infrastructure Investment and Jobs Act	45Q tax credit	US-wide	• Funding for the development and scale-up of CCU infrastructure, emphasising the enhancement of facilities to implement these technologies efficiently and at scale. • The 45Q tax credit is aimed at reducing industrial CO_2 emissions through CCUS technologies by providing financial incentives for each metric ton of CO2 that is captured and either sequestered or utilised.
Inflation Reduction Act (IRA)	Tax credit	US-wide	• Introduces enhanced tax credits for carbon sequestration and utilisation, establishing economic incentives that facilitate the broader adoption and scaling of CCUS technologies.

The Infrastructure Investment and Jobs Act of 2021, alongside complementary legislative measures and state-level initiatives, marks a significant step towards advancing CCUS technologies in the United States, with a notable emphasis on storage infrastructure. The Infrastructure Investment and Jobs Act (IIJA) of 2021 significantly enhances U.S. commitments to the CCUS sector by allocating approximately US$12 billion through 2026, aimed at accelerating the integration of these technologies into the national energy infrastructure.

Modifications to the 45Q influence the motivation behind choosing between CO_2 storage and utilisation pathways based on the incentives provided, with the current structure providing greater incentives for CO_2 storage over CO_2 utilisation pathways. This difference in fiscal benefits can directly impact the decision-making process regarding whether to store or utilise captured CO_2. Importantly, utilisation pathways also enable revenue generation from the sale of end products, which is an opportunity not available to entities focusing solely on CO_2 storage. A summary of the 45Q credit levels is provided in Table 9-36 below.

Table 9-36. 45Q tax credit levels for projects beginning construction during 2023-2032 following IRA modifications

Minimum Size of Eligible Carbon Capture plant by type (tCO_2/year)[235]		Dedicated secure geologic storage of CO_2 (US$/t CO_2)	Storage via EOR or Utilisation (US$/t CO_2)
Power plant (e.g., coal, natural gas, and biomass fired power plants)[236]	18,750*	US$85	US$60
Other industrial facility (e.g., ethanol, steel, cement, and chemicals)	12,500	US$85	US$60
Direct Air Capture	1,000	US$180	US$130

Indexed to inflation after 2026. **and capture capacity not less than 75% baseline emissions.*

[235] A new US Industrial backbone, Exploring regional CCUS hubs for small-to-midsize industrial emitters, EFI Foundation, Horizon Climate Group, 2023

[236] Primer: 45Q tax credit for carbon capture projects, Carbon Capture Coalition

The Infrastructure Investment and Jobs Act (IIJA) has allocated US$2.1 billion under the Carbon Dioxide Transportation Infrastructure Finance and Innovation Program to support large-capacity, common-carrier carbon dioxide transport projects. These projects, which include pipelines, rail, and shipping, must exceed US$100 million in scale and facilitate CCUS and hydrogen production initiatives. Annual funding is allocated through to 2026, but no projects have been announced to date.

Over US$131 million of funding was announced to support both power production and industrial emissions reduction in 2024, encouraging deployment of CCS, however, funding is focussed on CO_2 storage. The US Department of Energy (DoE) have released several funding initiatives, including US$131 million in 2024. There is a noticeable strategic focus on storage over utilisation; this emphasis is reflected in targeted investments such as the US$98 million allocated to support BP's large-scale carbon storage hub in Indiana.

9.4.1.5 *Hydrogen production*

Green hydrogen – hydrogen produced by renewably powered electrolysis - is the other key feedstock for e-fuel production. Like captured CO_2, the availability of green hydrogen is influenced by several factors, including supportive policies and regulations, as well as financial incentives, and resource availability.

This section provides an overview of the current state of green hydrogen production across the country, encompassing green hydrogen projects, hydrogen hub developments, and the deployment of related transportation infrastructure. Furthermore, this section covers green hydrogen-related policies, regulations, and financial incentives, as these can either accelerate or hinder the deployment of green hydrogen production.

Hydrogen activity

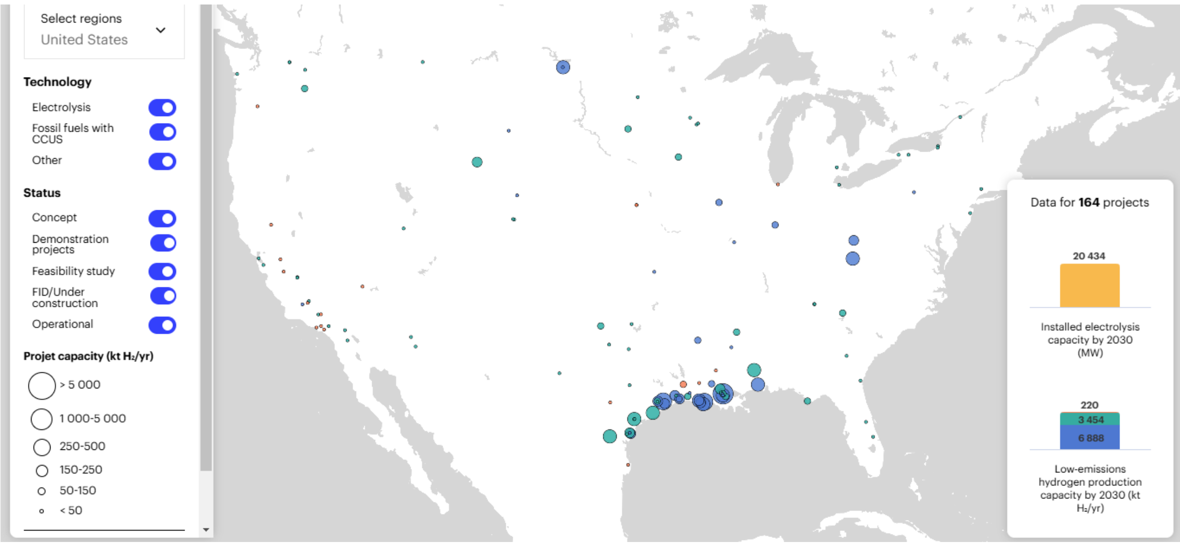
Whilst the US, like the rest of the world, currently relies heavily on fossil fuel-based hydrogen production (without carbon capture), the landscape is evolving due to federal investments from the DoE's Hydrogen Hub initiative and the provisions of the IRA.

As of 2024 there were over 30 operational green hydrogen facilities across North America. Market sentiment is changing rapidly on hydrogen due to challenging use cases at current hydrogen prices. It is possible though that in the next five years, the US may undertake 30 more green hydrogen projects. Mississippi, California, Louisiana, and Texas are expected to be at the forefront of investment in green hydrogen projects.

Hydrogen production from fossil fuels with carbon capture forms the majority of hydrogen projects proposed for 2030, with hydrogen produced via electrolysis accounting for a smaller portion of the overall market – green hydrogen totalling 172 MW of installed capacity, theoretically capable of producing up to ~26,000 tons/year, compared with the current fossil fuel based capacity of 10 million tons/year. Figure 9-49 [237] depicts hydrogen production facilities that are operational, as well as those at various stages of development across the US. Hydrogen production projects are concentrated in the Gulf Coast and California, however, there are projects proposed throughout the country, including in Florida, New Jersey, New York, North Carolina, Ohio, South Carolina, Georgia, Utah, and Virginia.

[237] Hydrogen production projects interactive map, International Energy Agency, 2023

Figure 9-49. Hydrogen production facilities (operational and at various stages of development) across the US



Fossil fuels with CCUS (Blue), Electrolysis (Green), Other (orange)

A sample of green hydrogen projects across the US are outlined in Table 9-37 below.

Table 9-37. Sample of Green hydrogen projects across the US

Project	State	Description	Status	Hydrogen production capacity
St Gabriel Green Hydrogen plant	Louisiana	Plug Power Inc. and Olin Corporation launched a joint venture called Hidrogenii to produce green hydrogen.	Planned	15 tonnes/day
Kingsland Green Hydrogen plant	Georgia	Largest liquid green hydrogen site in the US. 40 MW of Plug's PEM electrolysers.	Operational	15 tonnes/day
Casa Grande Green Hydrogen plant	Arizona	Air Products will build, own and operate the green hydrogen plant.	In construction	10 tonnes/day
Donaldsonville Green Hydrogen project	Louisiana	20 MW alkaline water electrolysis plant to produce green hydrogen. The plant will be integrated into existing ammonia synthesis loops.	Planned	(Ricardo calculated) up to 8 tonnes/day

Seven regional clean hydrogen hubs are to be developed nationwide, driving supply and demand of hydrogen across the country[238]. The seven selected clean hydrogen hubs may potentially receive a combined US$7 billion in funding from the Bipartisan Infrastructure Law. If related investments are included and materialise the total would be around US$50 billion. Two-thirds of this investment is allocated to green hydrogen production. Collectively, the hubs aim to produce over 3 million tons of clean hydrogen annually, though demand for this is still uncertain and evolving. A map of the proposed seven clean hydrogen hubs are outlined in Figure 9-50[239] below.

[238] Regional Clean Hydrogen Hubs to Drive Clean Manufacturing and Jobs, The White House, 2023

[239] Regional Clean Hydrogen Hubs selections for award negotiations, US Department of Energy, Office of Clean Energy Demonstrations, 2023

Figure 9-50. Selected Regional Clean Hydrogen Hubs

The Hydrogen Hubs program timeline indicates that "Phase 4: Ramp up and operate" will occur between 2030 and 2037[240]. In November 2024, the Department of Energy's Office of Clean Energy Demonstrations awarded initial funding to the Gulf Coast Hydrogen Hub and Midwest Hydrogen Hub, two of the seven Regional Clean Hydrogen Hubs, enabling them to commence Phase 1 of their project plans[241].

Table 9-38. Description of two regional clean hydrogen hubs

Hub name[239]	State	Description
Heartland Hydrogen Hub	Minnesota, North Dakota, South Dakota	• Decarbonise agricultural fertiliser production • Reduce regional costs of clean hydrogen • Promote clean hydrogen use in electricity generation • Advance clean hydrogen applications in cold climate space heating
Mid-Atlantic Hydrogen Hub	Pennsylvania, Delaware, New Jersey	• Develop renewable hydrogen production facilities using renewable and nuclear electricity • Expand hydrogen applications to: ○ Heavy transportation (trucks, buses, refuse trucks) ○ Manufacturing and industrial process improvements ○ Combined heat and power • Repurpose historic oil infrastructure and utilise existing rights-of-way

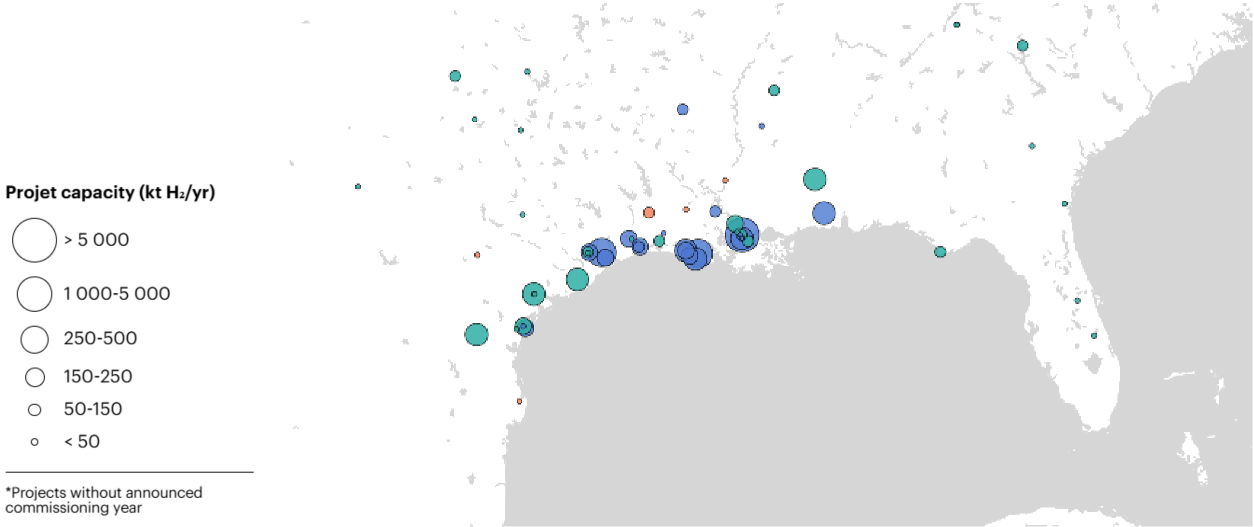
[240] US Hydrogen Hubs: What comes next? Clean Air Task Force, 2023

[241] Department of Energy announces initial funding tranches for Gulf Coast and Midwest Regional Clean Hydrogen Hubs, US Department of Energy, 2024

Gulf Coast Highlight

The Gulf Coast is currently the US's leading hydrogen producer, generating 3.5 Mt annually, primarily from natural gas; this output constitutes one-third of the nation's total hydrogen production. Recent supportive policies, initiatives and funding programs, including the Regional Hydrogen Hubs Program, is spurring the development of several clean hydrogen production facilities along the Gulf Coast**,** as illustrated in Figure 9-51 below.

Figure 9-51. Hydrogen production facilities (operational and at various stages of development) in the Gulf Coast Region



Fossil fuels with CCUS (Blue), Electrolysis (Green), Other (orange)

Gulf Coast Hydrogen Hub

The Gulf Coast HyVelocity Hub is one of the seven regional hydrogen hubs planned across the country as part of the Regional Clean Hydrogen Hubs Program and is expected to be one of the largest[242]. The project will receive up to US$1.2 billion from the Infrastructure Investment and Jobs Act.

The Gulf Coast Hydrogen Hub's industry partners are currently evaluating potential sites and facility configurations throughout the region[243]. Proposed locations are concentrated in the Houston area and extend across Texas and the Gulf Coast. Seven specific projects are under consideration; a selection of these projects include:

- **Star E-Methanol (Ørsted):** Clean hydrogen production utilising either proton exchange membrane or alkaline electrolysis, powered by 1.5 GW of solar and land-based wind. It is proposed that this hydrogen is used to create e-methanol for fossil fuel reliant industries.
- **Crescent Bayou (Chevron):** Clean hydrogen production facility utilising natural gas as feedstock, with a plan to capture >95% of CO_2 emissions. Captured CO_2 will be transported and stored in nearby geologic formations. The project aims to produce up to 700 MTPD of clean hydrogen, which would be converted to 4,000 MTPD of lower-carbon ammonia.
- **Hydrogen Pipeline (Exxonmobil):** ExxonMobil is assessing the feasibility of low-carbon hydrogen pipeline infrastructure to connect production facilities to demand centres produced in the greater Houston area.

[242] Why the US Gulf Coast is ideal for clean hydrogen production, Pipeline & Gas Journal, 2024
[243] Regional Clean Hydrogen Hubs Program, Gulf Coast Hydrogen Hub (HyVelocity), Office of Clean Energy Demonstrations, 2024

Hydrogen transport infrastructure

Approximately 1,600 miles of hydrogen pipelines are currently operational in the United States[244]. Owned by merchant hydrogen producers, these pipelines are concentrated in regions with significant hydrogen demand, such as the Gulf Coast, where large-scale consumers, such as petroleum refineries and chemical plants are located.

To support the hydrogen hub and other domestic hydrogen production initiatives, the expansion of hydrogen transport infrastructure is required[245]. As hydrogen produced through clean pathways can be injected into existing natural gas pipelines, the US Department of Energy (DOE) launched the HyBlend initiative to address technical obstacles and facilitate hydrogen blending in natural gas pipelines. This effort aligns with the DOE's H2@Scale vision, promoting the widespread adoption of clean hydrogen across various sectors of the economy.

Gulf Coast Highlight

The Gulf Coast region is home to the country's largest hydrogen pipeline network, which spans over a thousand miles[246]. Over 90% of the US hydrogen pipeline network is concentrated in Texas and Louisiana due to the existing hydrogen market in the region[247]. Hydrogen City in South Texas exemplifies an integrated production and distribution hub, with a 75-mile pipeline connecting to local industries and a 1 million tonne per annum ammonia production facility. The existing hydrogen infrastructure network in the Gulf Coast region is outlined in Figure 9-52 below.

Figure 9-52. Existing hydrogen infrastructure network in the Gulf Coast region[248]

[244] Hydrogen Pipelines, US Department of Energy
[245] HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines, US Department of Energy
[246] US Gulf Coast a natural fit for clean hydrogen industry, Reuters, 2024
[247] Hydrogen isn't new – at least not in the Gulf Coast, EFI Foundation, 2022
[248] Transforming Texas into a global hydrogen hub, Gulf Energy, 2021

Hydrogen production market drivers and barriers

Policies and regulation vary across the different states in the US, with each state implementing their own measures, resulting in a varying landscape for green hydrogen production. A selection of the key policies and regulations relevant to green hydrogen in the US are outlined in Table 9-39 below.

Policy and regulation

Table 9-39. Hydrogen policy and regulation

Policy/ regulation	Support mechanism	Location	Key points
National Clean Hydrogen Strategy and Roadmap	Framework	US-wide	• Comprehensive framework encompassing the full hydrogen value chain. • Establishes targets, market-driven metrics, and tangible actions. • Presents a strategic framework for achieving large-scale production and deployment of clean hydrogen, exploring scenarios for 2030, 2040, and 2050.
Infrastructure Investment and Jobs Act	Legislation	US-wide	• This legislation includes a suite of hydrogen-specific provisions that will drive large-scale deployment and investment for the hydrogen industry.
Clean Hydrogen Production Standard	Guidance	US-wide	• Guidance document • Establishes a target of 4.0 $kgCO_2e/kgH_2$ for life cycle (defined here as "well-to-gate") GHG emissions associated with hydrogen production
Hydrogen for Industry Act[249]	Act	US-wide	• Amends the Energy Policy Act (2005) to establish a Hydrogen Technologies for Heavy Industry Demonstration Program.

Financial

Production of clean hydrogen has become economically favourable in the US policy environment, due to frameworks and funding initiatives, increasing the deployment of hydrogen production facilities. The DoE is actively involved in hydrogen development, with several offices contributing to this effort. In 2022, the Present's Fiscal Year Budget Request included US$400 million in funding for these initiatives.

[249] Hydrogen for Industry Act, American Institute of Physics, 2024

Table 9-40. Hydrogen financial incentives

Financial incentive	Support mechanism	Location	Key points
Hydrogen Shot Initiative	Grant funding	US-wide	• Aims to reduce the cost of clean hydrogen to US$1/kg by 2031. • Support for critical demonstration projects. • Establishes a comprehensive framework for the deployment of clean hydrogen.
IRA: Clean Hydrogen Tax Credit (45V)	Tax credit	US-wide	• 10-year incentive offering up to US$3/kg of clean hydrogen produced.
Regional Clean Hydrogen Hubs program (H2Hubs)	Grant funding	US-wide	• US$7 billion initiative funded by the Infrastructure Investment and Jobs Act (IIJA). • Aims to establish regional clean hydrogen hubs nationwide, contributing to a broader $8 billion hydrogen hub program enabled by the IIJA.

The Inflation Reduction Act introduced the Clean Hydrogen Tax Credit (45V), a 10-year incentive offering up to US$3 per kg of clean hydrogen produced. This significant tax credit aims to enhance the financial viability of clean hydrogen production, stimulating investment and accelerating its deployment. The Clean Hydrogen Tax Credit is a performance-based incentive, with the credit amount varying based on the carbon intensity of the hydrogen production process. Lower-carbon hydrogen production pathways, emitting up to 4kg of CO_2-equivalent per 1 kg hydrogen, qualify for the maximum credit. This tiered incentive structure encourages the development and deployment of increasingly low-carbon hydrogen technologies.

9.4.1.6 *E-fuels*

Market for e-fuels

The demand for e-fuels in the United States is projected to rise significantly as the country prioritises renewable energy integration and ambitious decarbonisation goals. By 2032, the US e-fuel market is expected to reach a value of US$ 31 billion. In particular, the heavy-duty on-road, light-duty on-road, and aviation segments represent critical areas of focus for e-fuel adoption.

The aviation sector is poised to be a dominant consumer of e-fuels in the US, driven by initiatives like the 2030 SAF Grand Challenge, which targets the production of 3 billion gallons of sustainable aviation fuel (SAF) annually by 2030. Globally, North America is projected to account for about 25% of jet fuel consumption by 2030, highlighting the region's significance in e-fuel deployment and potential leadership in SAF projects. The Midwest is likely to play a pivotal role in this effort, leveraging its renewable energy surplus to produce e-fuels that align with the country’s goal of meeting most or all domestic jet fuel demand with e-fuels by 2050. This strategic focus underscores the aviation sector's reliance on low-carbon fuels as a decarbonisation strategy, especially given its limited alternatives to reduce GHG emissions.

Despite the push for electrification, the US road transport sector, particularly heavy-duty and light-duty segments, offers substantial opportunities for e-fuels. Light-duty internal combustion engine vehicles (ICEVs) are expected to remain a significant part of the vehicle stock through 2040, given uncertainties around achieving the 50% Electric Vehicle (EV) sales target by 2030 and existing infrastructure challenges. E-fuels, compatible with ICEVs, present a flexible solution for decarbonising these segments during the transition to full electrification. Similarly, in the heavy-duty on-road sector, where electrification faces technical and operational barriers, e-fuels can serve as a near-term and complementary option to reduce emissions. Regional production hubs, inter-sector competition, and alignment with renewable energy resources will be critical in shaping the e-fuel landscape in the coming decades.

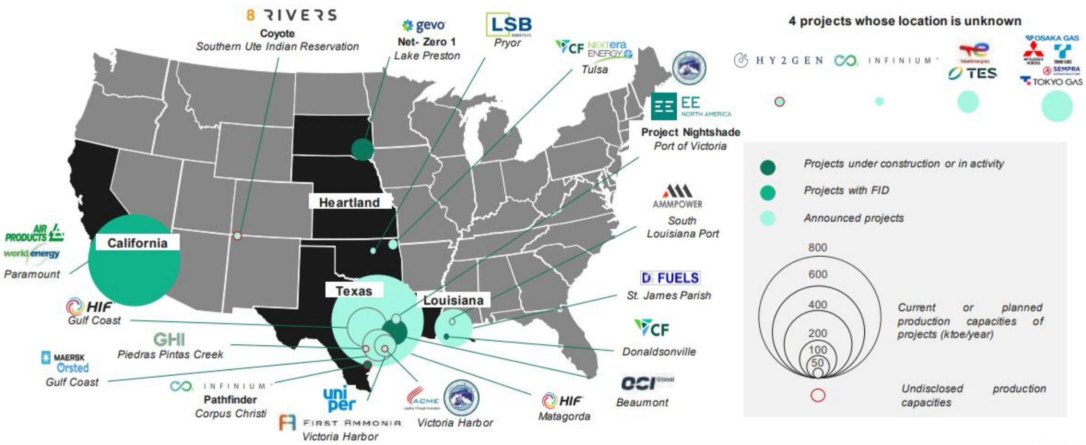
E-fuels activity

Production of e-fuels in the US is growing, with over 20 projects currently at various stages of development across the country. A significant portion of e-fuel projects remain in the study phase, reflecting substantial early-stage activity within the sector but highlighting a limited number of advanced-stage demonstration initiatives. 11 projects remain in the study phase, and only 5 projects have progressed beyond the FID stage, including the four that are either in construction or operational.

Projections suggest that all active projects could be commissioned between 2025 and 2026, although eight projects have yet to disclose an expected timeline for completion. This timeline highlights both the momentum and the uncertainties associated with the growth of the e-fuel market in the US.

Figure 9-53 illustrates that e-fuel projects in the US are concentrated in 4 primary hub locations: the California Hub, Texas Hub, Louisiana Hub, and the Central Hub (Heartland).

Figure 9-53. Map of e-fuel projects at various stages of development in the US



Gulf Coast Highlight

Numerous e-fuel production facilities are operational or in development in the Gulf Coast region, highlighting the region's growing opportunities and market for e-fuels. A sample of e-fuel production projects in the Gulf Coast region are outlined in Table 9-41 below.

Table 9-41. Sample of e-fuel production projects in the Gulf Coast Region

Project	State	Description	Status	Capacity
HIF Matagorda e-fuels Facility	Texas	E-methanol production utilising green hydrogen produced by renewable energy and captured CO_2 from site.	Operational by 2027	1.4 million tons/ year
Ørsted Star e-methanol project	Texas	Project involves the construction of new onshore wind and solar to power the electrolysis of green hydrogen. Biogenic CO_2 will be captured from an industrial facility and synthesised with the green hydrogen to produce e-methanol.	Operational by 2025	300,000 tons/ year
Pathfinder	Texas	Production of e-fuels through captured CO_2 and green hydrogen. E-fuels include SAF, e-diesel, and e-naptha.	Operational since 2023	Not disclosed
Roadrunner	Texas	E-fuels production through the conversion of waste CO_2 currently being vented to atmosphere, and renewable power. Conversion of an existing browfield gas-to-liquids project.	In construction	Not disclosed

E-fuels market drivers and barriers

Policy and regulation

Despite the absence of e-fuel or SAF mandates, the US has set an ambitious SAF production target of 3 billion gallons/year by 2030, and several States have enacted policies that indirectly support SAF. **The US does not have a medium-term SAF or e-fuels blending mandate to boost demand, instead, the growth of the market relies mainly on policy incentives**, namely the Inflation Reduction Act (IRA). In addition to the IRA, California has included SAF in its Low-Carbon Fuel Standard (LCFS) trading system and Washington State has proposed to integrate SAF into its Clean Fuels Program. A selection of policies and regulations relevant to e-fuels are outlined in Table 9-42 below.

Table 9-42. Policies and regulations in the US relevant to e-fuels

Policy/ regulation	Support mechanism	Location	Key points
Low-Carbon Fuel Standard	Regulation/ Standard	California	• Aims to reduce the amount of GHG emissions and air pollution from transportation. • Sets declining targets. • Promotes the production of renewable alternatives, such as hydrogen, renewable diesel, and biofuels.

Sustainable Aviation Fuel Grand Challenge Roadmap[250]	Roadmap	US-wide	• Outlines a whole-of-government approach to support industry achieve the targets set in the SAF Grand Challenge.
			    ○ 50% reduction in life cycle GHG emissions compared to conventional fuel.
			    ○ 3 billion gallons/year of domestic SAF production by 2030.
			    ○ >35 billion gallons/year of domestic SAF production to satisfy 100% of domestic demand by 2050.
			• Coordinated policies and actions

Clean Fuel Standard[251]	Regulation/ Standard	Oregon	• Encourages reductions in carbon intensity of fuels. • Sets declining targets for the level of carbon intensity of transportation fuels used in Oregon. • Fuels that are cleaner than the annual limit generate credits, whilst higher carbon intensity fuels create deficits.

E-fuels produced from CO_2 and hydrogen are currently not classified as renewable fuels under the Renewable Fuel Standard (RFS) program. The RFS is a US federal program mandating the inclusion of a minimum volume of renewable fuels in transportation fuels. Established by the Energy Policy Act of 2005 and expanded by the Energy Independence and Security Act of 2007, the RFS encompasses four renewable fuel categories, all of which rely on biomass as a feedstock. This federal policy limitation could hinder the development of the e-fuels market, making it reliant on state-level initiatives to specifically include these e-fuels.

[250] Sustainable Aviation Fuel Grand Challenge, US Department of Energy
[251] Clean Fuels Program Overview, Oregon.gov

Financial

State-level initiatives, such as California's Low Carbon Fuel Standard (LCFS), offer financial incentives that make the utilisation of CO_2 in fuel production more economically attractive. Similarly, Oregon has implemented its own Clean Fuel Standard in conjunction with the Climate Commitment Act to target the state's largest emission source[252]. This market-based policy incentivises the adoption of low-carbon fuels and is funded by an annual participation fee[253]. A selection of key financial incentives relevant to e-fuels in the US are outlined in Table 9-43 below.

Table 9-43. Financial incentives in the US relevant to e-fuels

Financial incentive	Support mechanism	State	Key points
Inflation Reduction Act (Build Back Better Agenda)	SAF tax credit	US-wide	• Tax credit valued at US$1.25 per gallon for SAF produced that reduces lifecycle GHG emissions by at least 50% compared to conventional jet fuel. ○ Tax credit value increases by an additional 1 cent per gallon for each percentage point of emissions reductions beyond this threshold.
H2@Scale initiative	Grant funding	US-wide	• US$8 million funding dedicated to 9 cooperative projects.
Low Carbon Fuel Standard	Tax Credit	California	• Credit price is determined by market forces of supply and demand. • approximately US$71 per credit.
Sustainable Aviation Fuel Grand Challenge	Grant funding	US-wide	• Federal funding amounting to US$4.3 billion to support SAF production

The aviation sector is receiving significant attention with the introduction of the Sustainable Aviation Fuel Grand Challenge, which seeks to significantly boost SAF production to at least 3 billion gallons per year by 2030. This initiative is supported by federal funding opportunities amounting to up to US$4.3 billion, demonstrating a concerted effort to reduce the aviation industry's carbon footprint through innovative fuel solutions. The proposed SAF tax credit within the Build Back Better Agenda further incentivises the reduction of lifecycle greenhouse gas emissions, promoting the rapid scaling of domestic SAF production.

Barriers

- E-fuels present a promising alternative for decarbonising the transport sector; however, their adoption in the US will face significant barriers.
- The most important is likely to be high cost, in absolute terms but particularly in relation to low conventional fossil fuel prices. Related there is little demand in the US for e-fuels (at plausible production prices).
- In the short term, these higher costs can be partially mitigated by financial incentives such as tax credits or grant funding but this is unlikely to be sustainable over the long-term. In the long term either carbon pricing or regulatory measures may be more effective in supporting e-fuel economics and demand.
- Incumbency, wherein decision-making favours the status quo, results in high system inertia.

[252] Hydrogen Laws and Incentives in Oregon, US Department of Energy

[253] Clean Fuel Standard, Department of Ecology, State of Washington

- Existing fuel standards and certification processes are often geared towards traditional fuels, requiring revisions to accommodate e-fuels.
- Regulatory and carbon accounting complexities further inhibit e-fuels. Accurately tracking and verifying the lifecycle emissions of e-fuels is challenging but critical for ensuring environmental benefits.
- There is currently a lack of demand for e-fuels. Building demand requires concentrated efforts, including public awareness, financial incentives, and mandates for hard-to-decarbonise sectors.
- Public perception of technologies, particularly regarding their benefits, risks, and acceptability, significantly influences their development and deployment. This is especially true for emerging technologies like carbon capture and utilisation (CCU) and e-fuels, where public engagement and support are crucial for successful implementation.[254]
- While there is a growing body of research on public perceptions of CCU, studies specifically focused on e-fuels in the United States are currently lacking. However, existing research on CCU provides valuable insights. Overall, the US public holds a moderately positive view of CCU, albeit with important nuances. Notably, public sentiment is less favourable towards CCU facilities located in local communities compared to CCU-derived products.
- CCU products, such as e-fuels, are perceived to offer significantly more benefits than CCU in general. Public support for CCU products and processes is generally positive, with perceived benefits slightly outweighing risks. While CCU may be perceived more favourably than carbon capture and storage (CCS), these findings suggest that CCU developers may encounter greater public resistance when proposing local facilities compared to promoting CCU-derived products.
- Overcoming these barriers will require coordinated efforts from governments, industries, and the broader society.

9.4.2 Germany

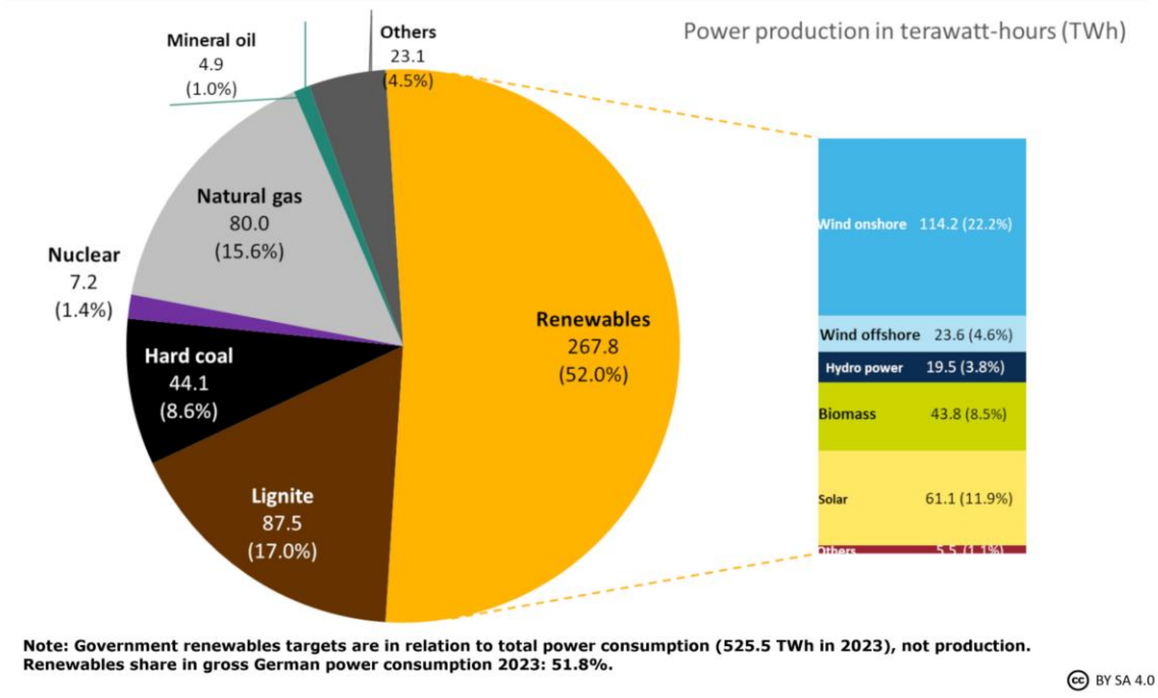
9.4.2.1 Current Energy Landscape

Germany, the largest energy consumer in Europe, has the continent's largest economy and ranks as the third largest economy globally, following the United States and China[255,256]. Germany is a member of the European Union. Among European Union nations, Germany produces the highest levels of CO_2 emissions, with the energy industry being the lead contributor, followed by the industrial and transportation sectors [257,258]. The country's primary energy mix comprises of oil (34%), natural gas (26%), coal (18%), and renewables (22%).

Germany is a net energy importer. In 2023, Germany imported 69.8% of its total energy supply, a 13% decrease in energy imports since 2000[259]. Domestically, coal and biofuels/waste are the dominant energy sources, accounting for 27% and 39% of total domestic energy production, respectively. An overview of the generation mix for power production is outlined in Figure 9-54.[260]

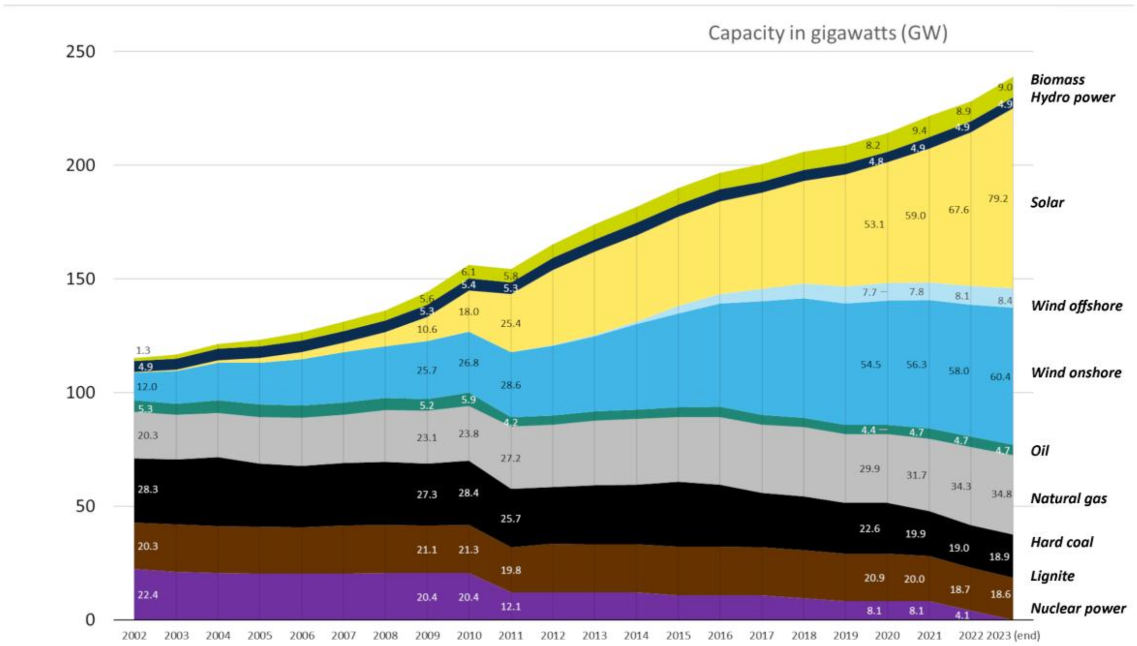
[254] Exploring public perceptions of carbon capture and utilization in the U.S, 2024
[255] Economic Facts about Germany, KPMG
[256] Germany - Country Commercial Guide, International Trade Administration
[257] Carbon dioxide emissions from energy in the European Union in 2000, 2010 and 2023, by country, Statista
[258] Distribution of greenhouse gas emissions in Germany in 2023, by sector, Statista
[259] Germany Energy Mix, International Energy Agency
[260] Germany's energy consumption and power mix in charts, Clean Energy Wire

Figure 9-54. Share of energy sources in gross German Power production in 2023



Germany's energy transition has enabled renewables to become the cheapest and fastest growing power source in the country. Renewable energy production has thus experienced a steady growth over the last decade, as depicted in Figure 9-55, and is likely to continue to follow this trend [261].

Figure 9-55. Installed net power generation capacity in Germany 2002 – 2023 [260]



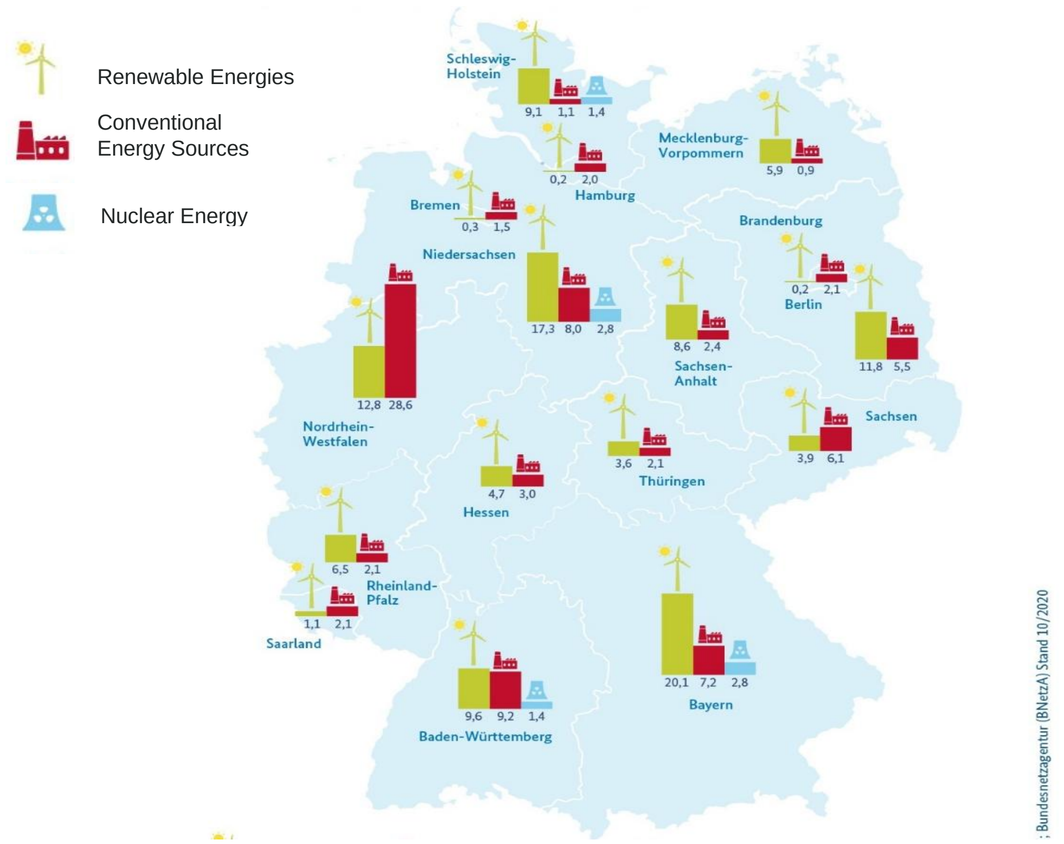
[261] How will Germany support the expansion of renewables in future?, Clean Energy Wire

The share of renewable electricity generation in Germany has seen significant growth, rising from 3.6% in 1990, when the first feed-in-law was introduced, to approximately 57% of the nation's gross electricity consumption in the first half of 2024[261]. Wind power is Germany's leading renewable energy source, with the country possessing the largest onshore wind capacity in Europe and ranking third globally. By the end of 2023, Germany had a cumulative wind capacity of 61GW in operation. Whilst the annual expansion has fluctuated in recent years, approximately 4GW of new wind turbine capacity was added in 2024[262].

Germany also ranks among the global leaders in solar energy, holding the fifth position worldwide in installed capacity. By the close of 2023, the country's solar power capacity reached approximately 61GW, closely mirroring its wind power output. In 2023, solar PV systems generated around 12% of the nation's new power consumption, contributing significantly to the overall renewable energy share of 52% that year. Business confidence in Germany's solar sector has grown steadily in recent years, further strengthened by the government's 2022 commitment to achieving 100% renewable power by 2035. In 2023, solar expansion significantly outpaced expectations, with over 14GW of new capacity installed. This exceeded the planned 9GW and nearly doubled the previous years' additions[263].

In 2019, renewable energy dominated the installed power plant capacity in 10 of Germany's 16 federal states, though regional differences were significant, as illustrated in Figure 9-56[264]. Bavaria led with 20.1 GW of renewable capacity, over 65% of which came from solar installations. Lower Saxony followed with 17.3 GW, where onshore wind turbines accounted for roughly 65% of the renewable capacity. Measured by total installed capacity, Mecklenburg-Western Pomerania (87%), Schleswig-Holstein (78%), and Saxony-Anhalt (78%) had the highest shares of renewables. In these states, as well as Rhineland-Palatinate, renewables formed the largest portion of installed capacity.

Figure 9-56. Power plant capacities distributed across the individual federal states in Germany, 2019



[262] German onshore wind power – output, business and perspectives, Clean Energy Wire

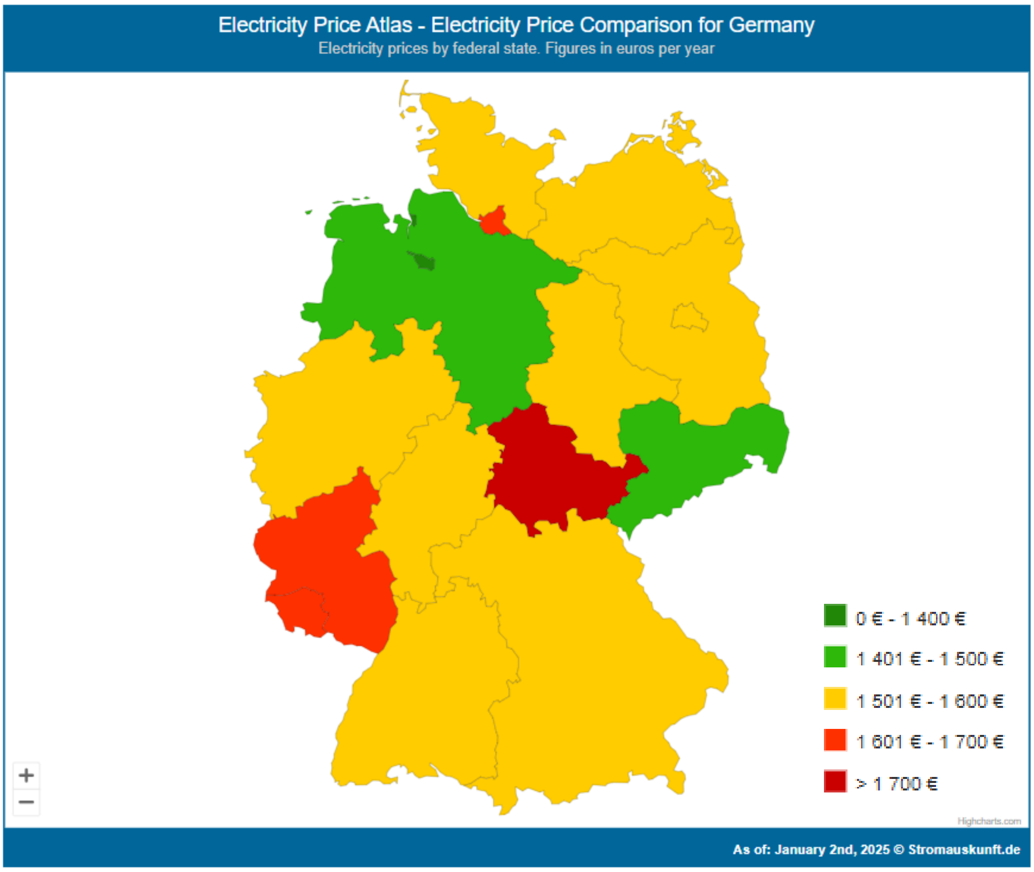
[263] Solar power in Germany – output, business & perspectives, Clean Energy Wire

[264] Renewables leading in ten federal states, Bundesministerium fur Wirtschaft und Klimaschutz

Despite the growth and robust nature of Germany's renewable energy sector, the country faces notable challenges. Transmission infrastructure remains insufficient to fully utilise the expanding renewable capacity. Electricity generation frequently exceeds demand during peak solar output. Integrating renewable energy into the grid has become increasingly costly; grid stabilisation measures (re-dispatch costs) totalled €3.1 billion in 2023, while €13 billion was spent on grid fees to mitigate the impact on electricity prices. Low wholesale electricity prices have also significantly increased federal funding requirements for guaranteed feed-in tariffs, with projections for 2024 rising to €23 billion, which is more than double the initially planned amount[261].

In addition to the availability of renewable electricity, the selection of a suitable location for an e-fuels production plant is also influenced by the cost of industrial electricity. The cost of electricity is important to consider in the production of green hydrogen as it powers the electrolysis process. Moreover, it is one of the largest contributors to the cost of green hydrogen production, oftentimes accounting for more than 70% of the total cost. Industrial electricity prices in Germany are not uniform across all regions; overall, whilst the base cost of electricity is influenced by national policies and markets, regional factors create variability. Several factors contribute to the regional price difference, including grid fees, renewable energy supply, transmission infrastructure, taxes and levies, and contract negation[265]. It can be seen from Figure 9-57[265] that Saxony, Lower Saxony, and Bremen experience the lowest industrial electricity prices, whilst Thuringia, Hamburg, Saarland, and Rhineland-Palatinate are characterised by higher prices.

Figure 9-57. Electricity prices comparison for Germany



[265] Electricity Price Atlas: Regional Electricity Prices in Germany, StromAuskunft

Policy priorities

Germany's transition to a low-carbon energy system relies on a robust policy and regulatory framework designed to drive the demand, development, and deployment of e-fuels and renewable energy technologies. These efforts align closely with national and EU-wide climate objectives, supported by a range of ambitious policies and initiatives.

Under the Federal Climate Protection Act, Germany has set a goal of achieving greenhouse gas (GHG) neutrality by 2045, with interim targets of reducing emissions by 65% by 2030 and 88% by 2040 compared to 1990 levels. Beyond 2050, the country aims to achieve net-negative emissions, aligning with the Paris Agreement's 1.5°C target. These commitments are underpinned by significant milestones, including the planned phase-out of coal-fired power generation by 2030 and a transition to a renewable energy-dominated mix. The Renewable Energy Sources Act (EEG) targets renewable energy sources to account for at least 80% of electricity consumption by 2030, supported by specific expansion goals for wind and solar capacities of 115 GW and 215 GW, respectively.

Since the introduction of the EEG in 2000, the share of renewables in Germany's power consumption has grown significantly, reaching 52% in 2023. This growth is complemented by Germany's National Hydrogen Strategy, which targets an electrolysis capacity of at least 10 GW and more than 1,800 km of hydrogen pipelines by 2030. Hydrogen and renewable fuels are expected to play a critical role in decarbonising hard-to-abate sectors such as transport, industry, and energy storage.

Germany's energy transition has been bolstered by policy reforms such as the "Easter Package" introduced in 2022. This package outlines a roadmap to achieve 100% renewable electricity by 2035, requiring annual renewable energy expansion volumes to exceed 20 GW to meet the 215 GW installed capacity target by the end of the decade. These national efforts are closely tied to the European Union's overarching climate policies, including the European Green Deal and the Fit for 55 package, which aim to reduce EU-wide GHG emissions by 55% by 2030 and achieve climate neutrality by 2050. Germany has committed to even more ambitious targets, with its Climate Action Plan aiming for a 65% reduction in GHG emissions by 2030 and climate neutrality by 2045.

Germany's climate strategy is also influenced by key EU policies, such as the EU Emissions Trading System (EU ETS), which applies a cap-and-trade mechanism to 40% of EU emissions from power generation, energy-intensive industries, and civil aviation. From 2027, the EU ETS will expand to cover fuel distribution for road transport, buildings, and additional industrial sectors under a separate system (EU ETS II or ETS2).

Meanwhile, the Effort Sharing Regulation governs emissions from transport, buildings, waste, agriculture, and smaller industries not covered by the EU ETS, requiring member states to contribute reductions based on their relative wealth. Germany, with its higher responsibilities, is tasked with a 50% emissions reduction by 2030 compared to 2005 levels. Transport and maritime sectors are also central to the decarbonisation efforts; as part of the Fit for 55 package, the EU launched initiatives such as ReFuelEU Aviation and FuelEU Maritime. ReFuelEU Aviation sets targets for sustainable aviation fuel (SAF) use, starting at 2% by 2025 and rising to 63% by 2050, with a mandate for 1.2% e-fuels in aviation by 2030, increasing to 35% The FuelEU Maritime aims to reduce the carbon intensity of maritime fuels by 6% by 2030, progressing to 75% by 2050.

Moreover, Germany is developing a Carbon Management Strategy to achieve negative emissions by 2060. This strategy includes setting specific targets for technical carbon sinks, such as direct air capture and underground CO_2 storage. Germany's National Energy and Climate Plan further details its energy transition goals, including CO_2 capture, transport infrastructure, and storage capacities.

Resource availability

Green hydrogen can be produced from grid electricity, produced from a variety of domestic resources, such as wind, solar, geothermal, and biomass. The amount of electricity produced from wind and solar has increased in Germany, with solar power capacity increasing by approximately 750% since 2017 and electricity generated from wind power increasing 25% in 2023 compared to 2018 [263, 266]. Current and projected renewable energy production capacities, as well as grid expansion and decarboinsation progress, can provide insights not only into the grid readiness, but also its capacity, to support deployment of e-fuel production facilities.

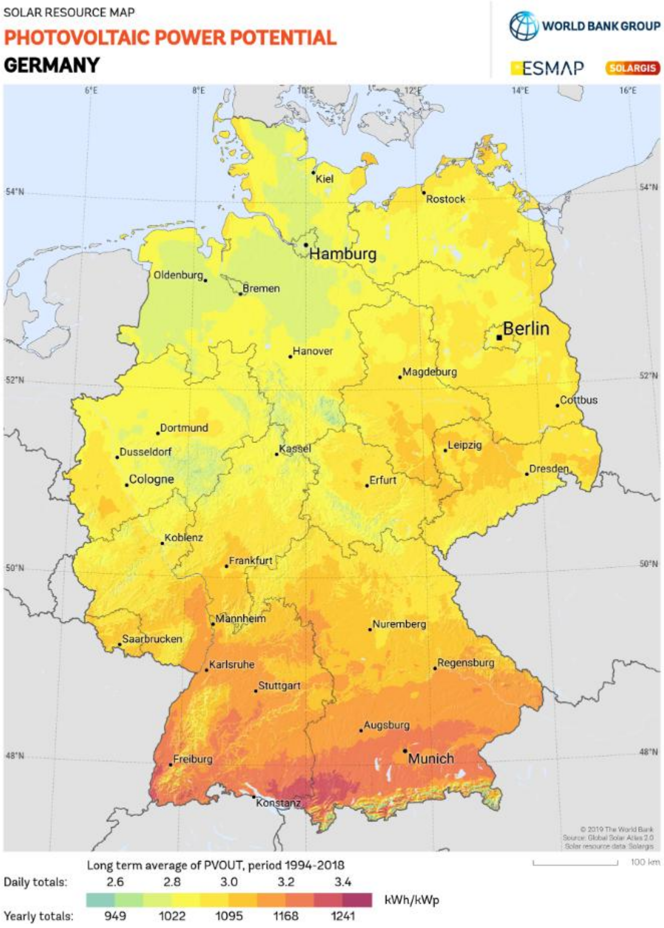
Solar and wind

To minimise electricity or hydrogen transmission costs, e-fuel production facilities should be located in regions with abundant, low-cost renewable electricity. Germany has significant renewable energy resource potential and remains a leader in wind and solar PV deployment.

Despite experiencing some of the least sunshine hours, Germany is one of the largest solar power producers globally, having a total installed solar capacity of approximately 82GW by the end 2023. Bavaria led Germany in new solar capacity installations in 2023, contributing 3.5GW[267].

To achieve the national target of 215GW by 2030, an annual increased of 19GW in solar capacity will be required moving forward, a value greater than previous years expansion. Southern Germany, namely Bavaria and Baden-Württemberg, has the highest PV power potential, as illustrated in Figure 9-58. Photovoltaic power potential Germany[268], presenting significant theoretical potential for renewable energy production[267].

Figure 9-58. Photovoltaic power potential Germany



[266] Wind power turbine fleet's output grows 25 percent in Germany over five years, Clean Energy Wire

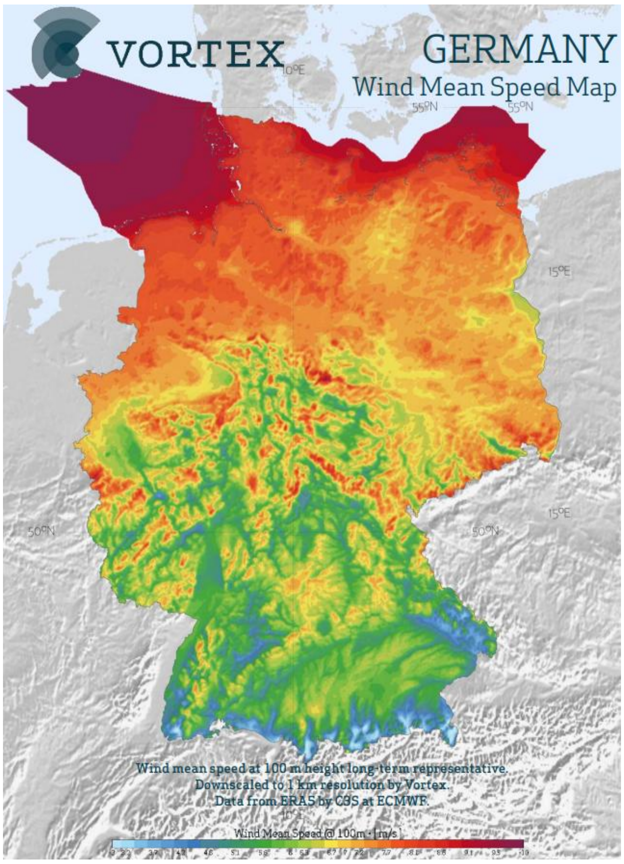
[267] Growth in renewable energy in 2023, Bundesnetzagentur

[268] Germany, Global Solar Atlas

Wind power is the largest renewable energy source in Germany, contributing approximately 27% of total power production, and half of the total generated by renewables. Germany's installed onshore wind capacity reached 60.9 GW by the end of 2023, with Schleswig-Holstein, Bavaria, and Baden-Württemberg, having contributed most significantly.

The national target for 2030 is 115 GW of installed onshore wind capacity; to meet this goal, an annual addition of 7.7 GW is required[267].

Figure 9-59. Mean wind speed across Germany[269]



Renewable energy contributed over 50% in 2023 of Germany's gross electricity consumption, with installed capacity expanding by 17GW to reach a total of 166GW. This robust growth potentially creates opportunities, as periods of high wind and solar generation now result in surplus electricity. From January to October 2024, Germany experienced over 430 hours of negative wholesale electricity prices, reflecting an abundance of renewable power available on the grid. This surplus presents an opportunity to channel excess renewable energy for the production of e-fuels.

Illustratively, an e-fuels plant with a production capacity of 25,000 kt/year (525,000 bbl/day) might require ca. 11,250 kt/year of green hydrogen. To produce this amount of green hydrogen, approx. 633TWh/year of renewable electricity would be required. In 2024, Germany produced 275.2 TWh of renewable energy, i.e. under half of what is required to support one large e-fuels production facility. Considerable additional renewable or other low cost, low carbon power generation would be required for Germany to generate enough green hydrogen to support e-fuels production. Whilst the wind and solar resource maps show considerable untapped renewable potential, particularly for wind, increasing the renewable capacity in a short timescale would be a major undertaking and would require serious and sustained commitments. Interestingly the resource availability for wind is in the north, whereas for solar resource increases as you go south.

[269] Germany Wind Map, Vortex

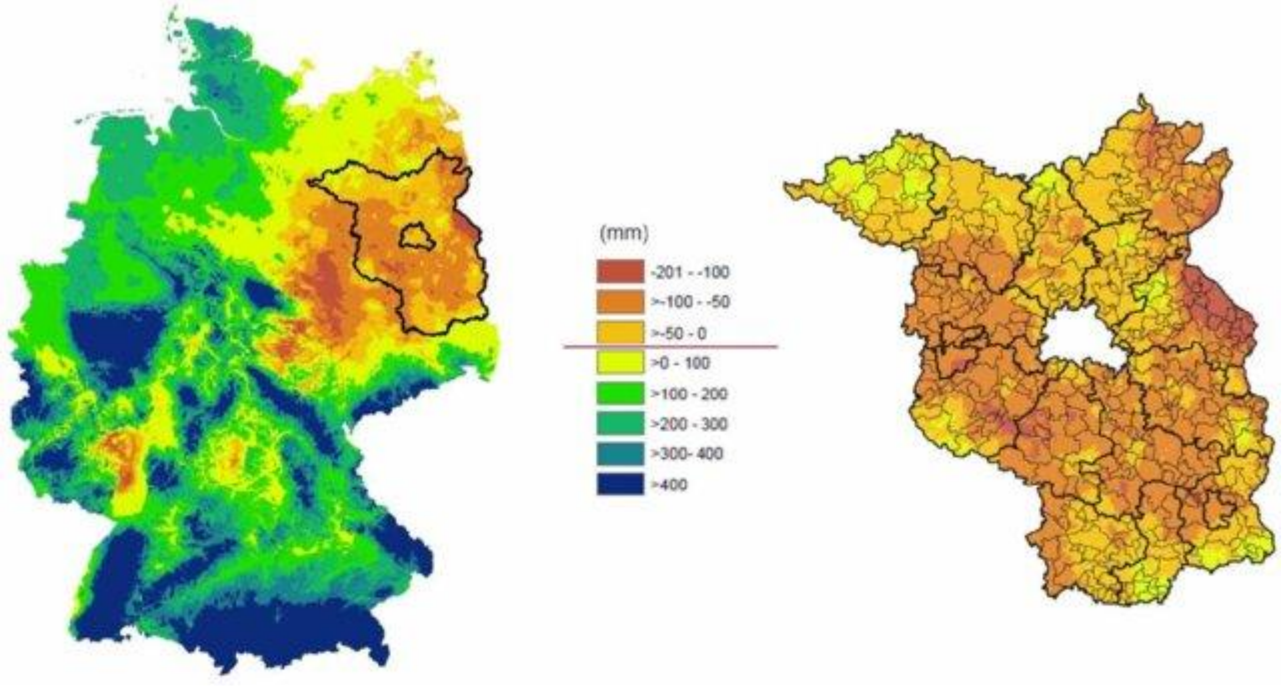
Water

Water may have several roles in e-fuel production. Water is needed for hydrogen production, as well as most carbon capture processes, and can potentially support some e-fuel production processes themselves (e.g. cooling water). As the production of green hydrogen involves water electrolysis, whereby water is split into hydrogen and oxygen, the availability of water is a factor in assessing the suitability of a region for e-fuels production. According to Concawe, approximately 3.7 – 4.5 litres of water are required to produce 1 litre of liquid e-fuels.

The emergence of new water uses, especially in water-scarce areas, could lead to conflicts with other water users and ecosystem impacts. National water stress rankings compiled by the World Resources Institute list Germany as being subject to 'medium to high water stress', utilising 20%-40% of their available supply[270]. Germany has not historically been a region where water stress has been an issue, however, in recent years the country has experienced long dry seasons and heatwaves, draining the water levels of the Rhine River[271].

Water stressed areas includes the country's northeast, as well as along the Lower Rhine River[272]. These regions may see increased competition for water resources, impacting their potential suitability for e-fuel production, unless the use of seawater, through desalination, can be scaled up without significantly increasing costs. Locations such as those with a combination of freshwater constraints and high industrial electricity prices are unlikely candidates for cost-competitive green hydrogen production at scale.

Figure 9-60. Annual climatic water balance of Germany (left) and the state of Brandenburg (right) over the period from 1991 to 2021.[273]



[270] WRI: Four European countries are subject to extreme water stress, Water News Europe

[271] Germany introduces national water strategy as climate change forces action, Reuters

[272] Auswirkung des Klimawandels auf die Wasserverfügbarkeit − Anpassung an Trockenheit und Dürre in Deutschland, Umwelt Bundesamt

[273] Potential and risks of water reuse in Brandenburg (Germany) – an interdisciplinary case study

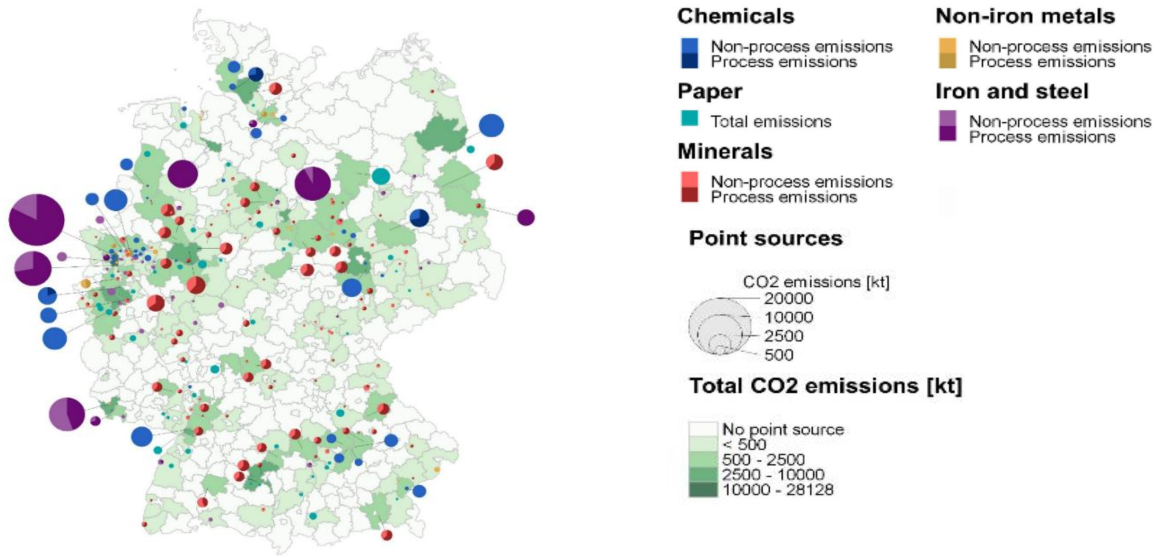
CO_2 sources

The availability of CO_2 is another factor to consider in the selection of a suitable location for an e-fuels production plant, as CO_2 constitutes the second primary component of the e-fuel synthesis process. Therefore, our next focus is large point sources of CO_2.

Germany is the largest CO_2 emitter in the European Union (EU), emitting more than the combined emissions of Italy and Poland, the next two largest emitters in the EU[274,275]. The energy industry is the largest source of CO_2 emissions, accounting for 30% of Germany's total emissions in 2023. Heavy industry is the second largest emitter, followed by the transportation sector, accounting for 23% and 22% of emissions in 2023, respectively[275]. Certain subsectors within the energy industry and industrial sector are conducive with the deployment of carbon capture, such as ethylene oxide, ammonia, ethanol, and oil and gas.

Clusters of industrial facilities can facilitate the development of Carbon Capture, Utilisation and Storage (CCUS) hubs, reducing costs and risks whilst enabling larger-scale deployment of CCUS. Locating an e-fuel production facility near or within these hubs can offer the advantage of utilising captured CO_2 and leveraging shared CO_2 transportation infrastructure. Figure 9-61[276] illustrates the distribution of CO_2 emissions from various industrial sectors in Germany in 2017. A concentration of point sources can be seen in the Ruhr area (North Rhine-Westphalia), which is the largest urban area in Germany, and the third in the EU. The Ruhr area is characterised by a relatively large proportion of industry, namely integrated steel mills and chemical production facilities. In contrast, Mecklenburg-Vorpommern (northeastern Germany), Hesse (central Germany), and Thuringia (central Germany), have a lower concentration of facilities, and hence CO_2 emissions.

Figure 9-61. Distribution of CO_2 emissions from different industries in Germany in 2017



This study previously reviewed a range of different power and industrial sectors providing a source of CO_2, to determine which may provide the most opportunity to capture CO_2 as a feedstock for e-fuels production. A selection of priority sectors consisted of ammonia, ethanol, oil and gas, and refineries, primarily due to the higher CO_2 concentration in the stream to be separated from, and hence lower capture costs. Facilities in these sectors are represented in Figure 9-62, where it can be seen that there are 30 point sources of CO_2 greater than 100 ktCO_2/year from these priority sectors, emitting a combined total of over 24 MtCO_2/year. A large majority of these CO_2 point sources are refineries, contributing to 80% of emissions, followed by ammonia production (10%). Ethanol only contribute 1.5% and 0.5%, respectively. When the CO_2 threshold is increased to 500 ktCO_2/year, there are only 15 CO_2 point sources, which emit a combined total of approximately 21

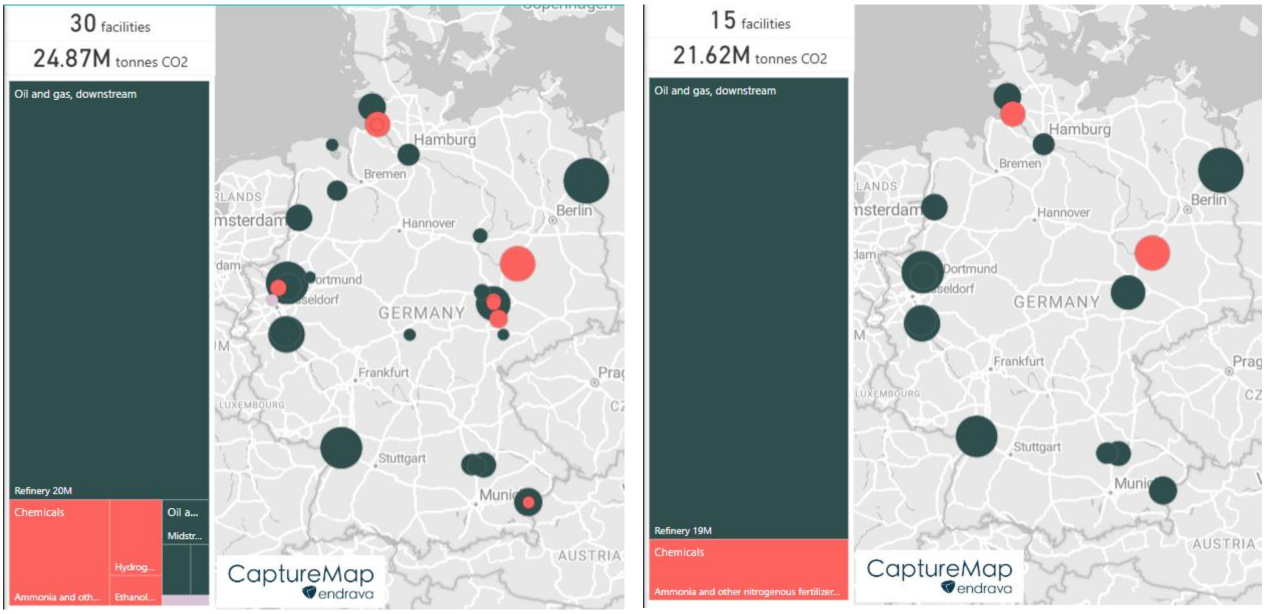
[274] Climate change in Europe: facts and figures, European Parliament

[275] Carbon dioxide emissions from energy in the European Union in 2000, 2010 and 2023, by country, Statista

[276] Analysis of the German Industry to Determine the Resource Potential of CO2 Emissions for PtX Applications in 2017 and 2050

$MtCO_2$/year. These emissions are entirely made up by two sectors; refineries (88%) and ammonia production (12%).

Figure 9-62. Point Sources in Germany >100 ktCO2/year (left), >500 ktCO2/year (right)



Carbon Capture

The availability of captured CO_2 for further utilisation is influenced by several factors, including supportive policies and regulations, as well as financial incentives like grants and tax credits. The goal of these initiatives is to stimulate the deployment of carbon capture technologies, thereby creating a market for CO_2.

This section provides an overview of the current state of CCUS activities across Germany, encompassing CCUS projects, CCUS hub developments, and the deployment of related transportation infrastructure. A mature CCUS environment is more conducive to e-fuel development, as it enhances the availability of captured CO_2 as a feedstock and facilitates its transportation for utilisation. Furthermore, this section covers CCUS-related policies, regulations, and financial incentives, as these can either accelerate or hinder the deployment of CCUS technologies.

Carbon capture activity

At present, Germany does not have significant experience in deploying large-scale CCS technologies. However, experience and capabilities are poised to grow, as here are 23 CCUS projects proposed, with five CCUS projects that may become operational before 2030[277].

As it is currently not permitted to develop underground CO_2 storage sites in Germany, the focus of CCUS projects is on CO_2 capture with transport and/or utilisation, as evidenced in Table 9-44. It can also be seen in this table that there is a focus on deploying carbon capture technologies to support decarbonisation of the cement, lime, and waste incineration industries[277].

[277] CCS in Germany's Decarbonisation Pathway: State of play and way forward, March 2024, Global CCS Institute

Table 9-44. CCUS projects across Germany at various stages of development.

Project	Location	Description	Status	Capture capacity (tCO_2/ year)
CAP2U[278]	Lengfurt (Bavaria)	Heidelberg Materials and Linde have established a joint venture to build a large-scale CCU facility at a cement plant. The captured CO_2 is proposed to be utilised in food and/or chemical industries.	In construction. Operational by 2025	70,000
GeZero[279]	Geseke (North Rhine-Westphalia)	Heidelberg Materials plants to deploy a carbon capture system at its existing cement production facility. The captured CO_2 is proposed to be stored permanently.	Construction to begin in 2026, commissioning 2029	700,000
Everest[280]	Wülfrath (North Rhine-Westphalia)	Carbon capture system to be installed at Europe's largest lime plant.	Operational by 2029	1.4 million
CO_2LLECT[281]	Rüdersdorf (Brandenburg)	Consortium of Cemex and Linde to deploy a CCUS system at Cemex's cement production site.	Operational by 2030	1.3 million
H_2GE Rostock[282]	Rostock (Mecklenburg-Vorpommern)	Partners VNG AG and Equinor AS are investigating the production and distribution of blue hydrogen and ammonia in Rockstock. It also proposes the storage and/or use of the captured CO_2.	Under evaluation	Not published

[278] Groundbreaking ceremony for the world's first large-scale carbon capture and utilisation facility in the cement industry, Heidelberg Materials
[279] GeZero: on the path to Germany's first fully decarbonised cement plant, Heidelberg Materials
[280] Lhoist
[281] EU backs pioneering CO_2 capture project at Cemex's Rüdersdorf cement plant, Cemex
[282] H2GE Rostock project, VNG

CO_2 transport infrastructure

Although Germany does not yet currently have any CO_2 pipeline infrastructure that can transport large quantities of CO_2, there are several transport infrastructure projects in development. These are planned to connect with international CO_2 storage, for example in the North Sea, as shown in Table 9-45 below.

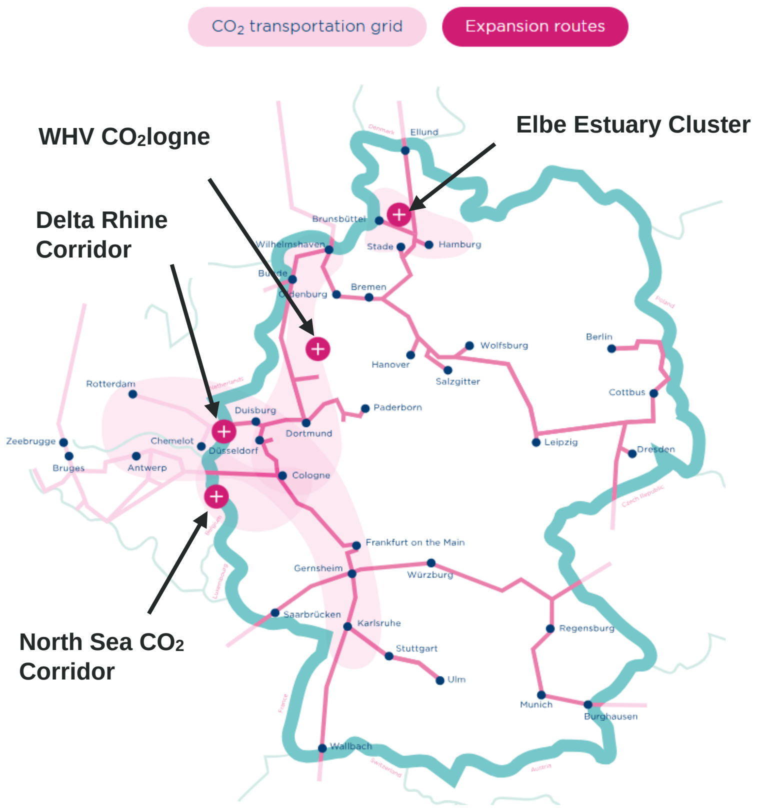
Table 9-45. CO_2 transport and storage infrastructure projects in Germany.

Project	Location	Description
WHV CO_2logne[283]	From Cologne region to Wilhelmshaven	• The WHV CO_2 Corridor, developed by OGE, aims to link Wilhelmshaven's future energy hub with the Ruhr region via a western route. • This project will connect East Westphalia's "cement region" and the Ruhr area's industrial hubs, including Dortmund, Duisburg, Düsseldorf, and Cologne. • Enabling approximately 30% of Germany's residual CO_2 emissions to access export options in Wilhelmshaven.
Delta Rhine Corridor[283]	Between Netherlands and Germany (North Rhine-Westphalia)	• BASF, Gasunie, OGE, and Shell have signed a cooperation agreement to advance the Delta Rhine Corridor project. • Aims to transport CO_2 to storage facilities off the Dutch coast, primarily via the Aramis system, in collaboration with potential customers.
NOR-GE[284]	Between Germany and Norway	• Partnership between Wintershall Dea and Equinor. • Comprehensive CCS project connecting Germany and Norway. • CO2 transportation from continental Europe and storage on the Norwegian Continental Shelf. • Estimated pipeline capacity of 20 to 40 million tonnes per year by 2037.
CO_2peline[285]	From Rohrdorf, Germany, to Burghausen, Germany, to Linz, Austria	• The cross-border "co₂peline" project connects important emitters of unavoidable CO_2 emissions in Bavaria and Upper Austria with industrial centres in South East Bavaria and includes potential CO_2 interim storages.

Open Grid Europe GmbH (OGE) is leading Germany's most advanced transmission system grid plans. The company aims to develop a nationwide CO_2 transportation network spanning Belgium, the Netherlands, northern Germany, Denmark, and the North Sea. Key components include the WHVCO_2logne and Delta Rhine Corridor, along with clusters in the Elbe estuary and Rhine district. This network is designed to facilitate CO_2 export from Wilhelmshaven, Rotterdam, and Antwerp/Zeebrugge for storage in the North Sea. The collection network is being designed north-to-south, incorporating anticipated CO_2 volumes from southern Germany and transit volumes from neighbouring countries into the northern pipelines. Connection to southern Germany is targeted for the mid-to-late 2030s[286].

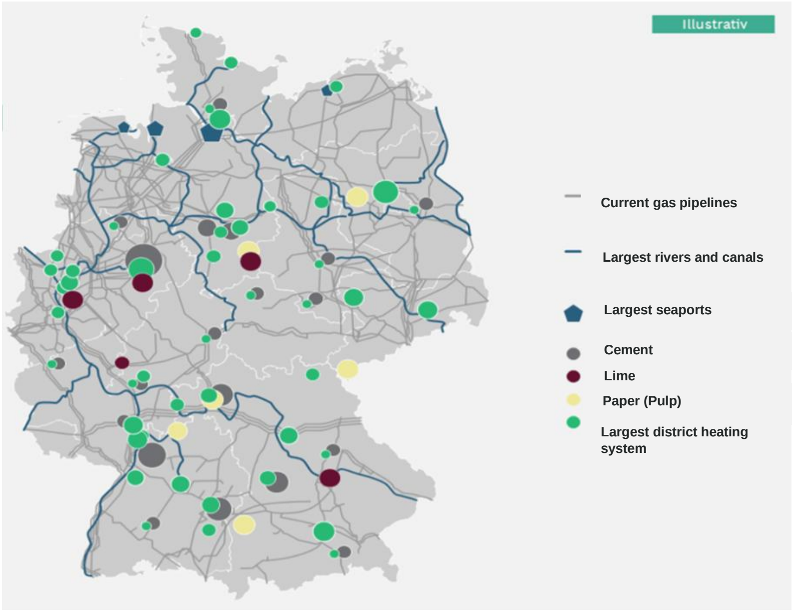
[283] Our CO2 transportation grid starts, OGE
[284] Wintershall Dea and Equinor partner up for large-scale CCS value chain in the North Sea, Wintrshall Dea
[285] Co2peline, Bayernets
[286] Series of articles Carbon Management: How can CO2 be transported?, FFE

Figure 9-63. Proposed CO_2 pipeline transport expansion routes by OGE[30]



The high costs associated with CCUS technology in Germany stem from the dispersed locations of concentrated CO_2 point sources, often far from potential storage sites[287]. Figure 9-64[287] illustrates the challenges faced by isolated industrial sites in capturing CO_2 without an established transportation network. With no domestic CO_2 storage capability, even large emitters aiming to implement CCUS lack the infrastructure to transport and store the captured CO_2.

Figure 9-64. Overview of the largest potential carbon capture users in Germany



[287] Why Germany needs a carbon management strategy, Clean Air Task Force

Carbon capture market drivers and barriers

Policy and regulations

Germany has drafted a Carbon Management Strategy, however, has not yet established specific targets for CCS and CCU, and CCU policy remains in its early stages. Current policy prioritises to decarbonise hard-to-abate, emission intensive sectors, particularly cement and lime production, basic chemical manufacturing, and waste management. These sectors are expected to receive government support for CCUS adoption. By contrast, electricity generation using gaseous fossil fuels may deploy CCUS technologies and utilise developing CO_2 transport networks but will not benefit from state support. Furthermore, CO_2 streams from coal-fired power plants are explicitly excluded from both transport and storage infrastructure[277].

A selection of key policies and regulations relevant to carbon capture in Germany are outlined in Table 9-46 below. These include those at a federal, regional state, and European Union level.

Table 9-46. Carbon capture policy and regulation in Germany

Policy/ regulation	Location	Key points
Carbon Management Strategy *(draft)*[288]	Germany	• Establish a robust foundation for the use of carbon capture technologies, including the transport and storage of CO_2. • Planned strategy will include fields of application for CCUS, public funding, ensuring climate neutrality in 2045, CO_2 transport infrastructure, CO_2 storage infrastructure.
Carbon Management strategy	North Rhine-Westphalia (Germany)	• Includes provisions for advancing the CO_2 infrastructure in North Rhine-Westphalia.
Carbon Dioxide Storage Act (KSpG)	Germany	• Implements the EU Directive on geological storage of carbon dioxide. • Currently only allows the implementation of CCS technologies for research, testing and demonstration purposes. • Draft update proposed: permanent CO_2 storage will only be permitted offshore and not onshore. ○ a legal basis in the KSpG allowing Federal States to opt-in for onshore storage could be considered, upon request of Federal States during the legislative process.

EU Industrial Carbon Management strategy (COM/2024/62)[289]	EU	• proposes a comprehensive framework to address all facets of the CO_2 value chain, fostering an enabling environment for the adoption of carbon management technologies across the EU.
		• Defines the CO_2 capture targets required for achieving the EU's 90% net emissions reduction goal by 2040 and its climate neutrality objective by 2050.
		• Identifies necessary actions at both the member state and EU levels to:
		    ○ Develop a unified European CO_2 market for carbon management.
		    ○ Create a favourable investment climate for industrial carbon management technologies.

[288] Key principles of the Federal Government for a Carbon Management Strategy, Federal Ministry for Economic Affairs and Climate Action
[289] Germany Unveils the Key Points of its Carbon Management Strategy, Marking a Crucial Step in the Country's Decarbonisation Pathway, Global CCS Institute

Policy/ regulation	Location	Key points
CCS Directive (Directive 2009/31/EC)[290]	EU	• Establishes a legal framework for the environmentally safe geological storage of CO_2 in the EU. • Applies to commercial scale facilities with a capacity of >100ktCO_2/year.
The Net Zero Industry Act, Regulation (EU) 2024/1735	EU	• Seeks to enhance the EU's capacity in clean technologies, including CCUS, to facilitate a seamless transition to clean energy. • Promotes the establishment of regional clusters by member states for the manufacturing of specific net-zero technologies, while simplifying administrative processes to support these initiatives.

The 2009 **Carbon Storage Directive** remains the cornerstone of the EU's regulatory framework for CCS; however, it has a limited scope and degree of harmonisation. The directive minimally addresses the capture and transport of CO_2, focuses on a precautionary approach to geological storage, and grants significant discretion to member states in its implementation. Notably, EU member states retain the right to prohibit CO_2 storage in parts or all of their territory and have flexibility in designing liability regimes. Member States were required to transpose the Directive into national law by 2011 and retain the option to permit or prohibit geological CO_2 storage in their jurisdictions, exclusive economic zones, and continental shelves. For those permitting storage, compliance with the Directive necessitates assessing and exploring storage capacity within their territories.

At the EU level, Directive 2009/31/EC governs the environmentally safe geological storage of CO_2, supported by other regulations such as the EU Environmental Impact Assessment Directive, the Environmental Liability Directive, the TEN-E Regulation, the Revised EU ETS Directive, and the Net Zero Industry Act (NZIA).

Adopted in 2024, the NZIA introduces an injection capacity target of 50 Mtpa of CO_2 by 2030, necessitating the development of permanent geological storage to support CCS deployment. It mandates EU oil and gas producers, with certain exemptions, to contribute proportionally to establishing the required storage sites. A Delegated Act outlining these contributions is expected in 2025. Recognised storage projects located on EU territory may qualify as Net-Zero Strategic Projects under the NZIA. The NZIA also emphasises transparency and reporting by Member States, particularly regarding geological data, to ensure the EU meets its injection capacity target. By driving CO_2 storage development, the Act aims to support widespread CCS implementation across the EU[291].

9.4.2.2 Financial incentives

Federal and State grants, tax incentives, and business models support the deployment and scaling of CCUS technologies. These support both the capital and operational phases, enabling wide-scale deployment of CCUS. A selection of key financial incentives are outlined in Table 9-47 below[277,292].

[290] CCS Directive, Carbon Gap
[291] CO2 Storage Permitting Process in The European Union: A Guide, Global CCS Institute
[292] CCS IN EUROPE REGIONAL OVERVIEW, November 2023, Global CCS Institute

Table 9-47. Carbon capture financial incentives in Germany.

Financial incentive	Support mechanism	Location	Key points
Carbon Contract for Difference (CCfD) Scheme	Contract for difference	Germany	• Aim is to accelerate the phase-out of fossil fuels in energy intensive industries. • Applicable to energy-intensive industries • Companies reducing CO_2 emissions and converting their production to climate-friendly production will be able to receive grants. • Compensates companies for the additional costs of adoption low-carbon technologies over 15 years.
The EU Innovation Fund	Grant funding	EU	• Utilises revenue generated by the EU Emissions Trading System (ETS). • Decarbonisation of hard-to-abate industries. • Supports CCUS projects with a potential of approximately 10 $MtCO_2$/year which will become operational by 2027. • Approximately €40 billion for the period 2020-2030. ○ €1 billion allocated to CCUS
Projects of Common Interest (PCIs)	Grant funding	EU	• PCI projects must have a significant impact on at least two EU countries. • Several CCUS projects have been funded as a PCI, including 6 CO_2 transport projects.
The European Interconnection Mechanism (EIM)	Grant funding	EU	• Supports development of cross-border energy and transport infrastructure projects. • €680 million has been granted to CO_2 PCIs. • In 2023, the EU allocated €480 million to four CO_2 transportation and storage projects.
Horizon Europe	Grant funding	EU	• Funding program for research and innovation • Budget of €95.5 billion for the 2021-2027 • CCS and CCU projects can receive support from 2 clusters under the second pillar of Horizon Europe on "Global challenges and European industrial competitiveness".

Hydrogen production

Green hydrogen – hydrogen produced by renewably powered electrolysis - is the other key feedstock for e-fuel production. Like captured CO_2, the availability of green hydrogen is influenced by several factors, including supportive policies and regulations, as well as financial incentives, and resource availability.

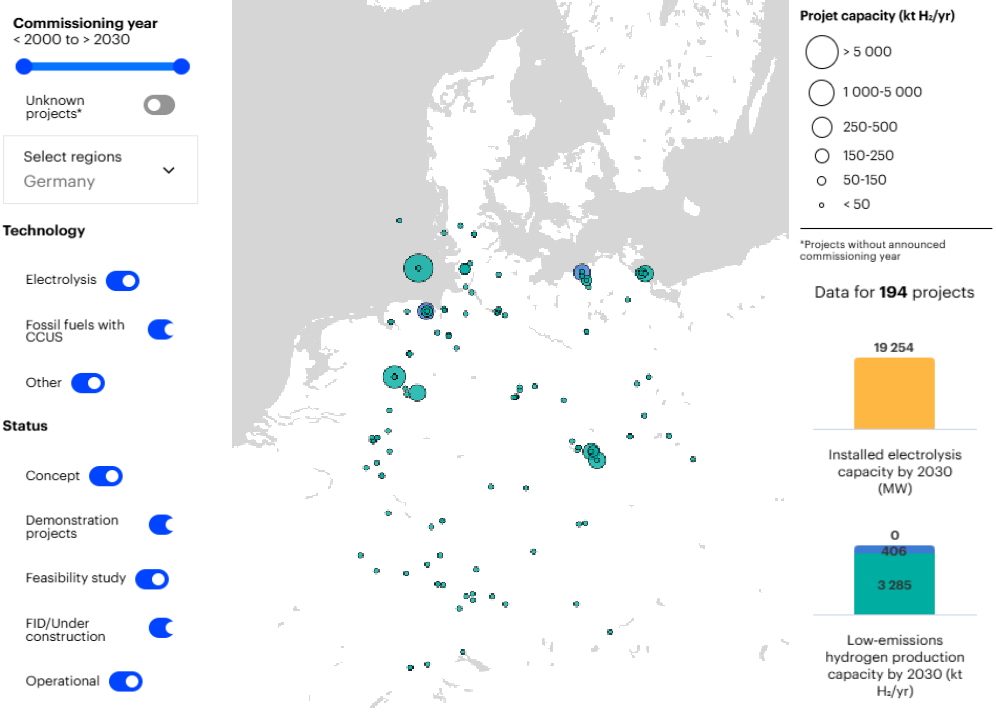
This section provides an overview of the current state of green hydrogen production across Germany, encompassing green hydrogen projects, hydrogen hub developments, and the deployment of related transportation infrastructure. Furthermore, this section covers green hydrogen-related policies, regulations, and financial incentives, as these can either accelerate or hinder the deployment of green hydrogen production.

Hydrogen activity

Germany leads Europe in hydrogen production, boasting a capacity of 2.15 Mt/year, with 81% of its hydrogen utilised domestically. In 2022, 86% of Germany's hydrogen production was derived from reforming, 13.5% came as a by-product of ethylene and styrene manufacturing, and only 0.5% originated from water electrolysis. Despite the dominance of fossil fuel-based production, Germany leads Europe in water electrolysis capacity, contributing 38% of the total installed capacity in Europe; equivalent to 64.12 MW[293].

Currently, Germany operates approximately 24 green hydrogen facilities using water electrolysis, with over 100 renewable hydrogen production projects planned. As shown in Figure 9-65[294], by 2030, electrolysis-based hydrogen is projected to dominate, contributing 3,285 kt/year, compared to 406 kt/year from fossil fuels with carbon capture. These projects are distributed nationwide, with notable concentrations in the western, northwestern, and northern regions.

Figure 9-65. Hydrogen production facilities (operational and at various stages of development) across Germany.



Fossil fuels with CCUS (blue), Electrolysis (green)

A sample of green hydrogen projects across Germany are outlined in Table 9-48.

[293] The European Hydrogen Market Landscape, November 2023, European Hydrogen Observatory

[294] Hydrogen production projects interactive map, IEA

Table 9-48. Sample of Green hydrogen projects across Germany[295]

Project	Location	Description	Status	Hydrogen production capacity
Green Wilhelmshaven project	Wilhelmshaven (Lower Saxony)	• Project includes the construction of an ammonia terminal and a 1GW electrolysis green hydrogen plant. • Includes the construction of a hydrogen pipeline and an Etzel salt carven for storage.	Operational by 2028	300 kt/year
GET H2 Nukleus	Lingen (Lower Saxony)	• 300MW electrolyser to be installed at the Emsland gas-fired power plant by a consortium of BP p.l.c, Evonik, Nowega, OGE and RWE. • Project is to be completed in 3 stages, the first to come online in 2025. • Aims to supply green hydrogen to industry in Lower Saxony and North Rhine-Westphalia. • Includes construction of hydrogen distribution network.	Operational by 2027	49 kt/year *(estimated)*
HyTech Hafen Rostock[296]	Rostock (Mecklenburg-Vorpommer)	• Green hydrogen to be produced by a 100MW electrolyser. • Planned hydrogen storage facility.	Operational by 2027	6.5 kt/year
HydrOxy Hub Walsum Project	Duisburg-Walsum (North Rhine-Westphalia)	• Total electrolyser capacity of 520MW will be installed in 3 phases, with the first phase operational in 2027. • Green hydrogen produced will be exported to be used in green steel production.	Operational by 2031	75 kt/year
TES Green Energy Hub	Wilhelmshaven (Lower Saxony)	• Planned to serve as a central hub for the distribution of e-Natural gas. • Will be connected to the German natural gas grid. • Electrolyser capacity of 500MW, eventually expanding to 1GW	Operational by 2028	To be confirmed.

[295] Top 5 Upcoming Green Hydrogen Projects in Germany (2024), Blackridge Research and Consulting
[296] HyTechHafen Rostock – Green Hydrogen for the Energy Transition, EnergyPort

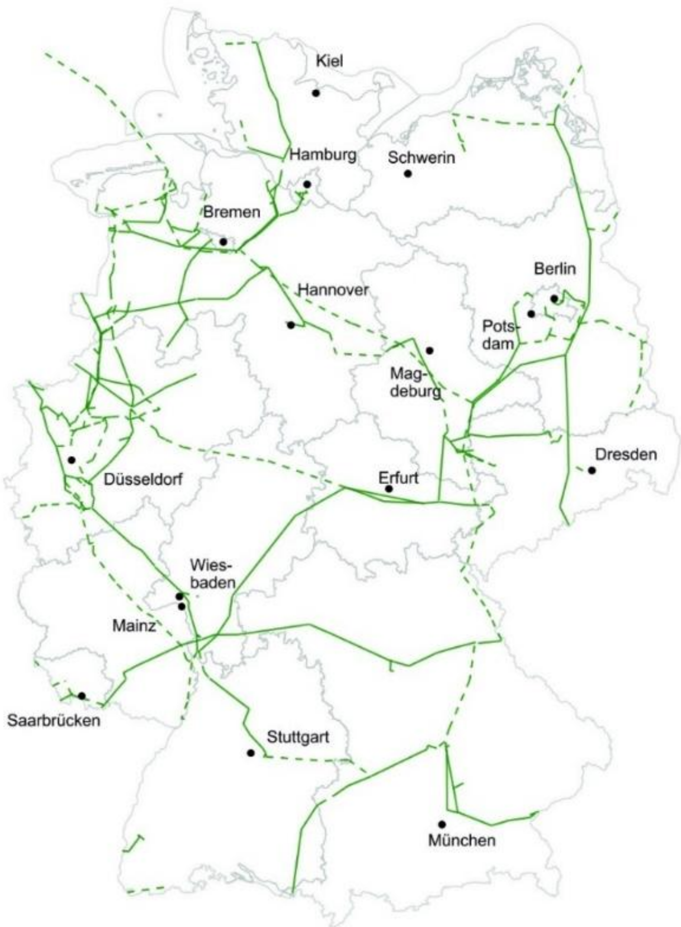
Hydrogen transport infrastructure

Hydrogen pipelines have been in use for decades in Germany, particularly in the Ruhr area and the Central German chemical triangle. The Ruhr area hosts the country's longest dedicated hydrogen pipeline, a 240 km network connecting the Marl Chemical Park to Castrop-Rauxel and Leverkusen. In the Central German chemical triangle, encompassing Bitterfeld, Schkopau, and Leuna, approximately 3.6 billion m^3 of hydrogen is consumed annually, supported by a 150 km pipeline network. Schleswig-Holstein also features a 30 km pipeline from Heide to Brunsbüttel[297 298].

These existing hydrogen networks are central to Germany's plans to establish model regions for a green hydrogen economy, integrating production, storage, transport, and multi-sector use. The transformation extends to the entire gas network, aligning with the National Hydrogen Strategy to replace fossil natural gas with green hydrogen, synthetic methane, and biogas. The Association of Gas Transmission System Operators (FNB Gas) has outlined the "H2 Start Network 2030," proposing a 1,200 km hydrogen network based on existing natural gas infrastructure, with only 100 km requiring new construction[297 298].

Initial gas pipeline conversions began in late 2022, with the first hydrogen flows expected in 2025. If original expectations are met, by 2032, the €19 billion hydrogen "core grid" would connect all federal states, linking key hydrogen production, consumption, storage, and import hubs.

Figure 9-66. Approved hydrogen core pipeline network in Germany[297]



[297] Hydrogen to start to flow in pipelines in Germany in 2025, Clean Energy Wire
[298] Existing hydrogen pipelines in Germany, TUV Nord

Hydrogen market drivers and barriers

The Federal Government projects national demand for hydrogen and its derivatives to reach between 95 and 130 TWh by 2030. Of this demand, an estimated 50% to 70% (approximately 45 to 90 TWh) will need to be met through imports. The reliance on imported hydrogen products is expected to grow further beyond 2030[299].

Preliminary estimates indicate that by 2045, demand for hydrogen and its derivatives could rise significantly, reaching between 360 and 500 TWh for hydrogen and approximately 200 TWh for hydrogen derivatives[299]. However, the costs for hydrogen, whether by domestic production or import are currently high, and it is not clear the extent to which early ambitions of scale are likely to be reduced or delayed.

Policy and regulations

Table 9-49[300] below highlights a selection of key policies and regulations shaping the development of green hydrogen in Germany.

Table 9-49. Hydrogen policy and regulation

Policy/ regulation	Location	Key points
EU Hydrogen Strategy	EU	• Serves at a long-term policy declaration. • Proposing a strategic roadmap for hydrogen uptake. • Sets 2030 objective of 10 million tonnes of renewable hydrogen produced in the EU.
National Hydrogen Strategy[299]	Germany	• Sets out first-phase plans for launching the market ramp-up of hydrogen. • Includes an action plans detailing specific measures. • Lays out the basis for private investment in the production, transportation, and use of hydrogen.
Net Zero Industry Act	EU	• Seeks to strengthen and scale up EU manufacturing of net-zero technologies. • Sets a 2030 benchmark of 40% domestic production of these technologies. • Includes hydrogen provisions: electrolysers and fuel cells identified as net-zero technologies; therefore, they are eligible for administrative support and faster permitting procedures.
Renewable Energy Directive	EU	• Sets a legal framework for the development of clean energy across all sectors of the EU economy. • Two Delegated Acts focus on the definition of what is renewable hydrogen. • Will impact the supply and demand of hydrogen in industry and transport. • Defines under which conditions hydrogen, hydrogen-based fuels or other energy carriers can be considered as Renewable Liquid and Gaseous Fuels of Non-Biological Origin (RFNBOs).
RefuelEU Aviation	EU	• Objective is to increase both demand and supply of sustainable aviation fuel (SAF). • Sets SAF volumes and rules on the blending on fuels. • Hydrogen provisions: supports the adoption of RFNBO.

[299] The National Hydrogen Strategy, The Federal Government
[300] 2024 State of the European Hydrogen Market Report, Oxford Institute for Energy Studies

Policy/ regulation	Location	Key points
FuelEU Maritime	EU	• Objective is to boost the demand for renewable and low-carbon fuels in the shipping sector to reduce its GHG emissions. • Applies to ships above 5000 gross tonnages arriving and departing from ports under the jurisdiction of the EU Member States and European Economic Area (EEA) countries. • Hydrogen provisions: supports the adoption of RFNBO.
Hydrogen and Decarbonised Gas Market package[301]	EU	• Consists of Directive (EU) 2024/1788 and Regulation (EU) 2024/1789 • integration of renewable and low-carbon gases into the existing gas network • establishment of dedicated cross-border hydrogen infrastructure and competitive hydrogen market.
EU Taxonomy	EU	• Includes hydrogen provisions which states that the production of hydrogen other hydrogen-based fuels can be considered sustainable as long as the product achieves a 70% reduction in life cycle GHG emissions compared to the fossil fuel comparator of 94 g CO2e/MJ (28.2 g CO2e/MJ).

Financial incentives

Germany offers a wide range of funding opportunities for advancing low-carbon hydrogen production and associated infrastructure. These initiatives are supported by both the federal government and the European Union, aimed at accelerating the country's transition to hydrogen-based energy systems.

The German federal government and states have committed €7 billion to support hydrogen generation, infrastructure development, and its application. Additionally, Germany will allocate €350 million through the Hydrogen Bank's "Auctions-as-a-Service" mechanism for domestic hydrogen projects[300].

At the European level, the EU Innovation Fund, one of the largest global funding programs for demonstrating low-carbon technologies, provides substantial support for hydrogen-related projects across the value chain. To date, over €4 billion has been allocated to hydrogen projects throughout Europe. Furthermore, the EU's Hydrogen Bank, designed to establish a comprehensive hydrogen value chain across Europe, launched its second auction in December 2024[302]. This initiative offers approximately €1.2 billion for renewable hydrogen projects, complementing the €720 million awarded to seven renewable hydrogen projects in April 2024[303].

[301] The EU Gas and Hydrogen package, Norton Rose Fulbright
[302] Second European Hydrogen Bank Auction and Innovation Fund Call 2024 launched, Hydrogen Europe
[303] European Hydrogen Bank auction provides €720 million for renewable hydrogen production in Europe, EC

Table 9-50. Hydrogen financial incentives

Financial incentive	Support mechanism	Location	Key points
EU Innovation Fund	Grant funding	EU	• €4.8 billion to 85 innovative projects, with hydrogen projects making up one third of total awards. • Hydrogen projects distributed across Europe (Germany is a recipient).
Horizon Europe[304]	Grant funding	EU	• EU's key funding program for research and innovation. • Supports hydrogen projects across all stages of the project life cycle. • Clean Hydrogen Partnership: €113.5 million will be made available through Horizon Europe for projects across the whole hydrogen value chain.
EU ETS	Tax credit	EU	• Objective: to reduce GHG emissions by establishing a cap-and-trade system that incentivises emission reductions and the adoption of clean technologies. • Includes hydrogen provisions: eligibility for free allocation of EU Allowances has expanded to encompass hydrogen production processes beyond fossil fuels, including through electrolysis.
Important Projects of Common European Interest (IPCEI Hydrogen)[305]	Grant funding	EU/ Germany	• €4.6bn to finance 23 green hydrogen projects which are part of the third Hy2Infra wave. • Projects cover the entire value chain. • 1.4 GW of green hydrogen production capacity powered by renewable energies. • storage of up to 370 GWh of hydrogen. • construction of a 2,000 km pipeline to transport hydrogen.

NOW GmbH[306]	Grant funding	Germany	• initiates a wide range of funding schemes through its ministries, with a focus on green hydrogen and fuel cell technologies.
			• Funding programmes include:
			  ○ National Innovation Programme Hydrogen and Fuel Cell Technology (NIP)
			  ○ Development of Renewable fuels (RK)

[304] Horizon Europe, EC
[305] Clean Hydrogen Partnership launches € 113.5 million call for projects across the whole hydrogen value chain, Clean Hydrogen Partnership
[306] NOW-GMBH

E-fuels

Market for e-fuels

By 2050, hydrogen and synthetic energy carriers might constitute approximately 24% of Germany's final energy demand, amounting to roughly 480 TWh annually[307]. This figure is the mean demand based on several scenarios, covering business as usual and various emissions reduction target pathways. In the aviation sector, achieving the ReFuelEU targets under the assumption of constant air traffic and no energy efficiency improvements would require approximately 960 million litres (797 ktoe) of sustainable aviation fuel (SAF) by 2030, increasing to 4 billion litres (3,320 ktoe) by 2035[308]. These figures illustrate the potential role hydrogen and synthetic fuels might play in decarbonising hard-to-electrify sectors of the economy.

Germany's draft National Energy and Climate Plan (NECP) references a demand for renewable hydrogen of approximately 0.95 Mt by 2030. Notably, 64.3% of this renewable hydrogen is expected to be imported to meet domestic needs. This aligns with projections for renewable liquid and gaseous fuels of non-biological origin (RFNBO), which estimate a sub-target of 20–25 TWh, or 0.6–0.75 Mt, of renewable hydrogen for industrial applications by the same year[309].

Germany also plans to electrify or use electrically produced fuels for about one-third of its heavy road haulage by 2030. Hydrogen and synthetic fuels, more specifically synthetic methane and hydrogen-derived fuels, are expected to play a key role in decarbonising the transport sector[310]. The German Aerospace Center estimates that synthetic fuels could meet up to 30% of Germany's transport energy needs by mid-century, particularly in sectors where direct electrification is challenging, such as aviation, maritime shipping, and heavy-duty road transport[311].

In aviation, e-fuels, especially e-kerosene, are seen as crucial for achieving the nation's climate goals. By 2030, e-kerosene could power the equivalent of 70,000 transatlantic flights, potentially avoiding 4.6 million tonnes of CO_2 emissions. These fuels are central to Germany's strategy to decarbonise transport sectors where alternatives to liquid fuels are limited[312].

E-fuels activity

E-fuel production in Germany is already underway, with several facilities operational and numerous projects at various stages of development nationwide. As depicted in Figure 9-67[313], a few of these projects are either under construction or have planned commissioning dates. However, many remain in the early stages of development, with considerable uncertainty on whether they will proceed and associated timelines.

---

[307] Future role and economic benefits of hydrogen and synthetic energy carriers in Germany: a systematic review of long-term energy scenarios

[308] The global race for efuels is on, International e-fuels Observatory.

[309] National Energy And Climate Plan Analysis: Germany, E3G

[310] Germany launches electric truck charging network, Reuters

[311] E-fuels for the Energy Transition in the Transport Sector –Properties and Application: Current State of Research

[312] E-fuels for planes: with 45 projects, is the EU on track to meet its targets?, T&E

[313] Synthetic fuels from Germany: Currently 19 power-to-liquid plants in planning and operation, PtX Lab

Figure 9-67. Announced and operational e-fuel plants in Germany.

Figure 9-67 also highlights the distribution of e-fuel projects, showing a relatively dispersed network across Germany. Notably, there is a higher concentration of these projects in the northwest and eastern regions, reflecting regional dynamics and infrastructure considerations driving e-fuel development in these areas.

A sample of e-fuel production projects in Germany are outlined in Table 9-51[313] below.

Table 9-51. Sample of e-fuel production projects in Germany

Project	Location	Description	Status	Capacity (tonnes/year)
Solarbelt	Werlte (Lower Saxony)	Production of e-kerosene utilising captured CO_2 from the onsite biogas (biomethane) plant. Organisation: Solarbelt FairFuel gGmbH	Operational since 2021	360
NextGate	Hamburg (Hamburg)	Production of e-fuels utilising green hydrogen produced via electrolysis and biogenic CO_2. Organisation: joint venture of the two partner companies Mabanaft and H&R.	Operational since 2022	200
Ineratec	Frankfurt (Hesse)	Production of e-fuels at the industrial park Frankfurt Höchst. CO_2 feedstock originates	Operational since 2024	3,500

Project	Location	Description	Status	Capacity (tonnes/year)
		from a biogas plant on site and green hydrogen. Organisation: Ineratec		
Shell Rheinland Refinery	Cologne (North Rhine-Westphalia)	The refinery will produce e-kerosene. Green hydrogen will be produced from a 100MW PEM electrolyser (10MW currently commissioning). Organisation: Shell Deutschland GmbH	Operational by 2025	100,000
HyKero	Lippendorf (Saxony)	The site will commercially produce e-kerosene, green naptha and green hydrogen utilising CO_2 from biogas (biomethane). Organisation: XFuels GmbH	Operational by 2026	42,000
Jangada	Drewitz (Brandenburg)	Production of green hydrogen and e-fuels for use in aviation. Organisation: Hy2gen	Operational by 2028	34,000

E-fuels market drivers and barriers

Policy and regulations

Germany's renewable energy policy framework adopts EU policies whilst tailoring amendments to address national priorities. Policies targeting various renewable fuels, including RFNBOs and e-fuels, have been introduced to support decarbonisation efforts.

Renewable fuels are increasingly recognised as clean alternatives for reducing GHG emissions, and consequently have been integrated into both EU and national fuel planning strategies. A cornerstone of EU efforts is the Renewable Energy Directive (RED) III, which plays a pivotal role in promoting the adoption of renewable energy across the EU and within Germany. Under the European Union's Renewable Energy Directive II (RED II), Renewable Fuels of Non-Biological Origin (RFNBOs) must achieve at least a 70% GHG emissions savings compared to the conventional fuels they replace. A critical factor in meeting this criterion is the source of CO_2 used in e-fuel production[314].

The Second Delegated Act under RED II specifies permissible CO_2 sources for e-fuels to qualify as RFNBOs:

1. **Industrial Emissions:** CO_2 captured from specific industrial activities listed in Annex I of the EU Emissions Trading System (EU ETS), such as oil refining, steel production, cement manufacturing, and certain combustion installations. This CO_2 must be accounted for under an effective carbon pricing system (e.g., carbon tax or emissions allowances) and incorporated into e-fuels before January 1, 2041 (or January 1, 2036, for CO_2 from fuel combustion for electricity generation).
2. **Biomass Combustion**: CO_2 captured from the combustion or decomposition of biomass.
3. **Ambient Air:** CO_2 directly captured from the ambient air through technologies like Direct Air Capture (DAC).

The Fit for 55 package is a collection of proposals from the EU to update legislation and create new initiatives to reduce the EU's GHG emissions by at least 55% by 2030. This package identifies aviation and maritime transport as contributors to approximately 28% of GHG in the EU transport sector. To address this, the EU launched ReFuelEU Aviation and FuelEU Maritime initiatives aimed at accelerating the deployment of renewable fuels in these sectors.

These initiatives underscore the EU's commitment to leveraging renewable fuels as a critical pathway for achieving long-term GHG emission reductions.

[314] Avoided CO2 emissions – Renewable hydrogen and "green" e-fuels in the EU, Global Energy Blog

Table 9-52. E-fuels policy and regulation[315]

Policy/ regulation	Location	Key points

Renewable Energy Directive	EU	• Sets a legal framework for the development of clean energy across all sectors of the EU economy.
		• Defines under which conditions hydrogen, hydrogen-based fuels or other energy carriers can be considered as RFNBOs.
		• Measures include:
		  ○ Achieving at least a 42.5% share of renewable energy in the EU's final energy consumption.
		  ○ A minimum of 29% share of renewables for transport sector.
		  ○ Increase in share of RFNBOs by 5.5%.

National Platform for Future Mobility[316]	Germany	• Aim to develop cross-modal and interlinking pathways for a GHG neutral transport system.
		• Measures include:
		  ○ A minimum share of 21% share of renewable fuels including e-fuels.
		  ○ Increasing national electrolysers capacity to 20 GW and importing 20 GW.

Mobility and Fuels Strategy (MFS)	Germany	• Central platform for shaping the energy transition in the transport sector.
		• Measures include:
		  ○ Increasing share of renewable energies (fuels) to 18% of gross final energy consumption by 2030.
		  ○ Increasing share of renewable energies (fuels) to 60% of gross final energy consumption by 2045.

Alternative Fuels Infrastructure Regulation[317]	EU	• Aims to ensure minimum infrastructure to support the required uptake of alternative fuel vehicles across all transport modes in the EU. • Sets mandatory national targets for the deployment of alternative fuels infrastructure. • Enhances infrastructural capacities for recharging & refuelling of hydrogen and renewable fuels.
RefuelEU Aviation*	EU	• Sets a target for SAF use of 2% by 2025 and 6% by 2030, increasing to 63% by 2050. • Establishes a minimum share of 1.2% e-fuels in aviation by 2030, rising to 35% by 2050.
FuelEU Maritime*	EU	• Aims for a 6% reduction in the carbon intensity of maritime fuels by 2030, progressing to a 75% reduction by 2050.

[315] Market diffusion of Power-to-X fuels in Germany: A cognitive approach with robust reasoning for policy support
[316] The National Platform Future of Mobility, VDA
[317] Alternative Fuels Infrastructure, EC

Financial incentives

In Germany, the government has allocated €1.9 billion to promote the development of e-fuels and advanced biofuels by 2026. This funding aims to reduce greenhouse gas emissions in the transport sector by supporting the rollout of these alternative fuels.

Additionally, the German government has approved a €350 million state aid package to support Concrete Chemicals in producing synthetic aviation fuels. This initiative is part of Germany's commitment to advancing sustainable aviation technologies.

Moreover, the European Union's Innovation Fund provides financial support for innovative low-carbon technologies, including those related to synthetic fuels. This support can include grants, subsidies, tax incentives, and regulatory frameworks that promote the adoption of Power-to-X technologies.

A selection of key financial incentives relevant to e-fuels in Germany are outlined in Table 9-53 below.

Table 9-53. E-fuels financial incentives

Financial incentive	Support mechanism	Location	Key points
The Energy Tax Directive (ETD)	Tax rate	EU	• EU framework for the taxation of energy products. • Currently treats e-fuels and fossil fuels equally. • Proposed revision to tax fuels based on energy content and environment impact, potentially lowering e-fuel tax rate to the minimum.
EU ETS[318]	Cap-and-trade	EU	• Covers emissions from power generation, energy-intensive industries, and civil aviation. • Incentivises e-fuels by increasing costs for carbon-intensive fuels. • ETS II (from 2027) will cover fuel combustion from road transport and buildings.
EU Innovation Fund	Grants and subsidies	EU	• One of the world's largest funding programs for innovative low-carbon technologies. • Provides financial support for the demonstration of e-fuel technologies.

Barriers

E-fuels present a promising alternative for decarbonising the transport sector; however, their adoption in Germany will face significant barriers.

One key obstacle is the Germany's reliance on imports for e-fuel production feedstocks, as domestic production alone will not meet demand. Due to limited land and less favourable conditions for green electricity production, Germany will remain an energy-importing region. Therefore, the importation of green hydrogen and its derivatives, such as green ammonia and methanol, will be essential to meet future demand. Ensuring security of supply is another challenge, as Germany will need to engage in trade relations to import a substantial portion of its e-fuel needs[319].

Additionally, the high cost of e-fuels is a major barrier to their adoption. These fuels exceed the price of conventional fossil fuels. Falling renewable energy prices are expected to lower production costs in the future, and rising carbon prices or regulation may improve economic competitiveness. Government incentives and

[318] ETS2: buildings, road transport and additional sectors, EC

[319] CHALLENGES AND OPTIONS FOR EFUEL SUPPORT IN THE EU IN THE LIGHT OF THE US IRA, Frontier Economics

regulations may also help reduce costs and improve market competitiveness. In the short term, e-fuels are produced on a small scale, limiting economies of scale. Larger facilities are anticipated as technology advances and demand grows, however at large scale there may also be diseconomies of scale if sources of CO_2 and hydrogen (or its precursor low-cost electricity) are difficult to bring together in Germany. Aviation and maritime sectors, in particular, are expected to rely on e-fuels to reduce GHG emissions[319].

The success of e-fuels depends on addressing high costs and risks for producers in the EU. Market incentives, such as the SAF quota under the ReFuelEU Aviation regulation and the renewable energy target for the transport sector in the Renewable Energy Directive (RED), currently support demand. However, regulatory uncertainty remains a major hurdle. The quota levels for 2030 have been reduced, and no post-2030 targets have been set. Given the long planning and construction timelines for e-fuel projects, the future regulatory environment will be crucial to the viability of plants that are in the early stages of development.

9.4.3 China

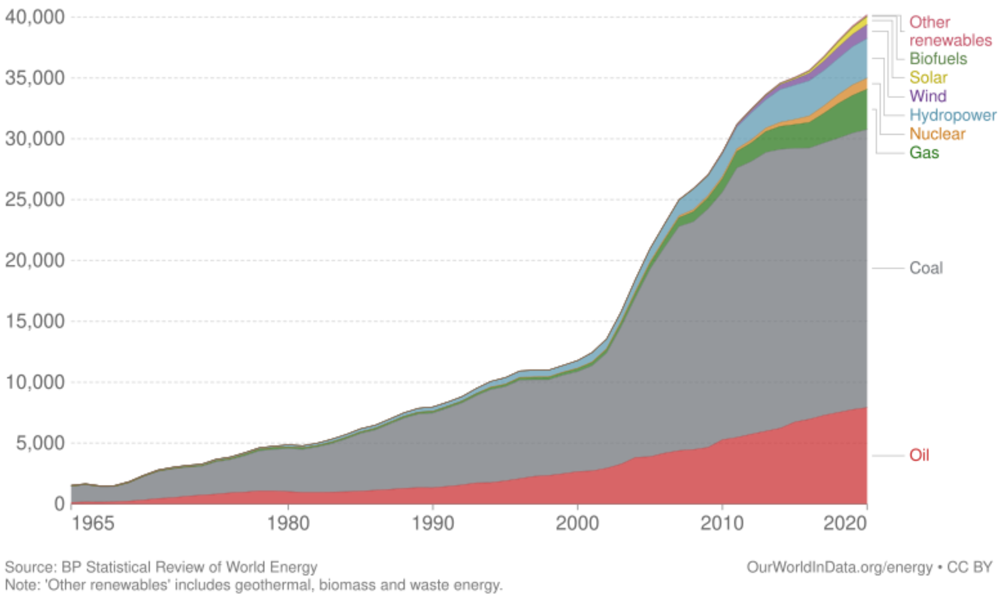
9.4.3.1 Current energy landscape

China is the world's second-largest economy (or largest based on PPP), accounting for approximately 19% of global GDP in 2023[320]. It plays a pivotal role in the global energy and climate economy, being the largest energy producer and consumer, as well as the largest CO_2 emitter globally[321,322].

The country's energy mix is dominated by coal, which remains the most prominent fuel source, despite significant investments in renewable energy[1,3], accounting for approximately 56% of total energy consumption as of 2023. This reflects China's reliance on coal for electricity generation, industrial processes, and heating. Petroleum and natural gas follow, contributing 19% and 9%, respectively, to the energy mix. Renewable energy sources, including hydropower, wind, and solar, have seen rapid growth and now account for 15% of primary energy, while nuclear energy makes up a smaller share at 2% [1,3].

An overview of China's primary energy mix is detailed below in Figure 9-68. This highlights the country's reliance on coal and the growing contribution of renewables to its energy landscape.

Figure 9-68. Primary energy consumption in TWh by source in China (1965 – 2023)



[320] International Energy Agency (IEA). (2024). *World Energy Investment 2024: China*. Retrieved January 9, 2025, from https://www.iea.org/reports/world-energy-investment-2024/china

[321] International Energy Agency. (n.d.). *China: Emissions*. Retrieved January 9, 2025, from https://www.iea.org/countries/china/emissions

[322] Ritchie, H., & Roser, M. (n.d.). *China: Energy Country Profile*. Our World in Data. Retrieved January 9, 2025, from https://ourworldindata.org/energy/country/china

China's renewable energy sector has undergone a transformative expansion over the past decade, with installed capacity nearly tripling since 2013. This growth has been driven by a combination of aggressive government policies, technological advancements, and massive investments in clean energy infrastructure. Between 2023 and 2028, renewable energy in China is expected to account for 56% of global renewable electricity capacity growth, deploying almost four times more capacity than the European Union and five times more than the United States[323]. This is further emphasised by the fact that in 2023 alone, China commissioned as much solar photovoltaic (PV) capacity as the entire world did in 2022, and its wind capacity additions grew by **66% year-on-year**, underscoring China's commitment to diversifying its energy mix.

The country's renewable energy growth is supported by strong government policies, including subsidies, feed-in tariffs, and ambitious targets under the **14th Five-Year Plan**. China has also become a major exporter of renewable energy technologies, with solar panels, lithium batteries, and EVs, which saw a **30% increase in exports** in 2023. Despite these advancements, coal remains a critical part of China's energy strategy, with coal production reaching a record high in 2023. This reflects the country's emphasis on energy security and the challenges of balancing economic growth with emissions reduction.

Hydropower remains the largest source of renewable energy in China in terms of total installed capacity, reflecting its long history of development and significant infrastructure. However, the growth of solar and wind power has been the primary driver of recent expansion in the country's renewable energy sector. Since 2013, solar power capacity has increased more than 180 times, while wind power capacity has grown sixfold. Together, solar and wind account for **95% of the country's growth in renewable energy capacity** over this period[324] [325] [326]. Despite this rapid growth, hydropower's established base means it constitutes a larger share of the overall renewable energy mix. This highlights two key trends: hydropower's continued dominance in total capacity and the accelerating expansion of solar and wind.

Renewable energy in China is cost-competitive with fossil fuel power generation, particularly in regions with abundant solar and wind resources. The levelised cost of electricity (LCOE) for solar and wind has declined significantly due to economies of scale, technological innovation, and government support. Key factors include:

- **Solar PV costs**: in 2023, the cost of solar photovoltaic (PV) modules in China declined by an estimated 42% compared to 2022, reaching approximately US$0.15/W. Alongside this, the LCOE for solar energy in China was estimated at US$0.039/kWh (3.9 cents/kWh). These developments reflect significant cost reductions in solar energy, positioning it as a competitive electricity source in the region[327] [328].
- **Wind energy costs**: Onshore wind energy costs have also declined, with the LCOE reaching **US$0.03 per kWh** in regions with high wind speeds. Offshore wind remains more expensive but is expected to **become cost-competitive by 2030.**
- **Policy support**: Government policies, including feed-in tariffs, subsidies, and renewable energy quotas, have played a critical role in driving down costs and accelerating deployment.

---

[323] **International Energy Agency (IEA).** (2023). *Renewables 2023: Electricity*. Retrieved from https://www.iea.org/reports/renewables-2023/electricity.

[324] State Council of the People's Republic of China. (2024, December 20). *Statistics Archive*. Retrieved from https://english.www.gov.cn/archive/statistics/202412/20/content_WS67657149c6d0868f4e8ee2bf.html.

[325] State Council of the People's Republic of China. (2024, December 16). *Statistics Archive*. Retrieved from https://english.www.gov.cn/archive/statistics/202412/16/content_WS675f5ed4c6d0868f4e8edfa4.html.

[326] Rystad Energy. (n.d.). *China's solar capacity surges, expected to top 1 TW by 2026*. Retrieved from https://www.rystadenergy.com/news/china-s-solar-capacity-surges-expected-to-top-1-tw-by-2026.

[327] DNV. (2024). Energy Transition Outlook 2024: A global and regional forecast of the energy transition. Høvik, Norway: DNV. Available at: https://www.dnv.com [Accessed 14 Jan. 2025].

[328] Mercom India. (n.d.). *China's solar module production in 2023*. Retrieved January 10, 2025, from https://www.mercomindia.com/chinas-solar-module-production-in-2023

Electricity costs

The cost of industrial electricity is a critical factor in the production of green hydrogen and e-fuels, as electricity accounts for **over 70% of the total cost** of electrolysis. In China, industrial electricity prices vary by region, influenced by local policies, grid infrastructure, and energy mix. Key trends include:

1. **Eastern Provinces (e.g., Jiangsu, Zhejiang)**:
    - **Higher electricity prices**: These regions have relatively higher industrial electricity prices due to high demand and limited renewable energy integration. Prices range from **0.10 to 0.13 US$/kWh** for large-scale industrial users [329,330].
    - **Green hydrogen potential**: Despite higher costs, these provinces are investing in green hydrogen projects to decarbonise industrial processes[331]. For instance, coastal provinces including Jiangsu and Guangdong at the end of 2024 have cut electricity prices by 8.9% and 16%, respectively, to support local industries, including green hydrogen projects[332].
2. **Western and Northern Provinces (e.g., Xinjiang, Inner Mongolia)**:
    - **Lower electricity prices**: These regions benefit from lower electricity prices, often below **0.08 US$/kWh**, due to abundant renewable energy resources and lower demand[333].
    - **Green hydrogen hubs**: Xinjiang and Inner Mongolia are emerging as green hydrogen hubs, leveraging their low electricity costs and renewable energy potential[333].
3. **Time-of-Use (TOU) pricing**:
    - **Incentivising off-peak consumption**: Many provinces have implemented TOU pricing to incentivise energy consumption during off-peak hours. For example, in Guangdong, peak electricity rates can reach **0.23 US$/kWh**, while off-peak rates drop to **0.04 US$/kWh**.
    - **Impact on green hydrogen**: TOU pricing can significantly reduce the cost of green hydrogen production by enabling electrolysers to operate during periods of low electricity prices, typically when renewable energy generation (such as solar and wind) is high and electricity demand is low. By aligning electrolyser operation with these low-cost periods, TOU pricing can reduce the variable costs of hydrogen production, making green hydrogen more economically competitive. However, this approach also introduces several challenges and trade-offs that require careful consideration[334] [335]:
        1. **Technology constraints**: The operational flexibility and efficiency profile of alkaline electrolysers (AEL) and proton exchange membrane electrolysers (PEMEL) differ, for example PEMEL are more adaptable to dynamic operation due to faster ramp-up and ramp-down capabilities compared to AEL. This allows them to respond at an improved rate to changes in electricity pricing and operate with increased efficiency during low-cost periods.
        2. **Operating at low load factors**: Operating at a lower load factor due to being only active during specific low-cost periods can lead to underutilisation of the electrolyser

---

[329] CEIC Data. (n.d.). *China Electricity Price: 36 City*. Retrieved January 9, 2025, from https://www.ceicdata.com/en/china/electricity-price-36-city

[330] China Briefing. (2024). *China's Industrial Power Rates: A Guide for Investors*. Retrieved January 9, 2025, from https://www.china-briefing.com/news/chinas-industrial-power-rates-category-electricity-usage-region-classification/

[331] Zheng, X. (2024, December 6). *Hydrogen energy forecast to see rapid development in nation*. *China Daily*. Retrieved January 9, 2025, from https://www.chinadaily.com.cn/a/202412/06/WS675252d5a310f1265a1d1764.html

[332] Bloomberg. (2025, January 8). *China's richest regions cut electricity prices to protect industries*. Retrieved January 10, 2025, from https://www.bloomberg.com

[333] China Briefing. (n.d.). *China's industrial power rates: Category, electricity usage, and region classification*. Retrieved January 10, 2025, from https://www.china-briefing.com/news/chinas-industrial-power-rates-category-electricity-usage-region-classification/

[334] Brandt, J., Iversen, T., Eckert, C. et al. Cost and competitiveness of green hydrogen and the effects of the European Union regulatory framework. Nat Energy 9, 703–713 (2024). https://doi.org/10.1038/s41560-024-01511-z

[335] Zun, M.T.; McLellan, B.C. Cost Projection of Global Green Hydrogen Production Scenarios. *Hydrogen* **2023**, *4*, 932-960. https://doi.org/10.3390/hydrogen4040055

capacity. Increasing the fixed cost per unit of hydrogen produced. Since the levelised cost for hydrogen production is sensitive to capacity utilisation, a low load factor can keep the overall levelised cost high, offsetting some of the savings from cheaper electricity.

3. **Infrastructure and storage**: In order to maximise the benefits of TOU pricing, green hydrogen production may require additional infrastructure, such as energy storage systems or hydrogen storage facilities to balance supply and demand. These added costs can partially negate the savings from low-cost electricity, particularly if storage solutions are expensive or inefficient.
4. **Grid integration and stability**: While TOU pricing incentivises the use of excess renewable energy, it also raises concerns regarding grid stability. Large-scale electrolyser operation during low-price periods could lead to sudden spikes in electricity demand. If a significant portion of electrolysers are programmed to operate simultaneously during low-price periods, this could create localised or system-wide spikes in electricity demand. Even if overall grid demand is low, a sudden surge in electrolyser operation could strain specific parts of the grid, especially in regions with high concentrations of hydrogen production facilities.

Challenges and opportunities

1. **Grid integration**:
   - **Curtailment rates**: Despite rapid growth, China faces challenges in integrating renewable energy into the grid. Curtailment rates for wind and solar power remain between **5% and 15%** in some regions, highlighting the need for grid modernisation and energy storage solutions,
   - **Transmission infrastructure**: Expanding transmission infrastructure to connect remote renewable energy hubs with high-demand industrial centres is critical. To address these disparities, China has invested heavily in long-distance, ultra-high-voltage (UHV) transmission lines, which enable renewable-rich regions to supply electricity to demand centres in the east and south[336].
2. **Energy security**:
   - **Coal dependency**: China continues to rely on coal for energy security, with coal production reaching a record high in 2023. Balancing renewable energy growth with coal dependency remains a key challenge.
   - **Energy storage**: Investments in energy storage, including battery storage and pumped hydro, are essential to address intermittency and ensure grid stability.
3. **Export pressures**:
   - **Trade tensions**: China's dominance in renewable energy manufacturing, particularly in solar panels and wind turbines, has led to increasing scrutiny and trade tensions in international markets. Countries like the US and EU are implementing protectionist policies, such as the Inflation Reduction Act (IRA) and anti-subsidy investigations, to reshore their own green manufacturing capabilities. These measures could result in higher tariffs, export restrictions, and reduced market access for Chinese clean energy products. Such trade barriers not only threaten China's export-driven growth model but also risk exacerbating domestic overcapacity issues, potentially leading to the risks of job losses and pressures on industry, which may challenge progress toward climate goals[337].
   - **Domestic market growth**: To mitigate export risks and sustain growth, China is focusing on expanding its domestic market for renewable energy technologies. By increasing domestic

[336] State Grid Corporation of China (SGCC). (n.d.). Retrieved January 10, 2025, from http://www.sgcc.com.cn/

[337] Atlantic Council. (n.d.). *China's manufacturing overcapacity threatens global green goods trade*. Retrieved from https://www.atlanticcouncil.org/blogs/econographics/sinographs/chinas-manufacturing-overcapacity-threatens-global-green-goods-trade/.

adoption of solar, wind, and other clean energy solutions, China can absorb excess production capacity, reduce reliance on volatile international markets, and support its dual carbon goals (peaking emissions by 2030 and achieving carbon neutrality by 2060). This strategy also aligns with broader economic objectives, such as stimulating local demand, creating jobs, and fostering innovation in green technologies. However, success will depend on addressing challenges like low domestic consumption, regional economic disparities, and the need for robust infrastructure and policy support.

4. **Policy and regulatory framework**:
    - **Renewable energy targets**: China's 14th Five-Year Plan sets ambitious targets for renewable energy deployment, including **1,200 GW of wind and solar capacity by 2030**.
    - **Carbon trading**: The expansion of China's carbon trading market provides additional incentives for renewable energy adoption and emissions reduction.

Policy priorities

China's policy priorities in the energy and climate sectors are shaped by its dual objectives of achieving carbon neutrality by 2060 and maintaining sustainable economic growth. These priorities are closely linked to the current energy landscape, which is dominated by coal but increasingly diversified through rapid renewable energy deployment. The policy framework focuses on key technologies, sectors, and targets that align with the country's long-term decarbonisation goals. These include the expansion of renewable energy, the development of Carbon Capture, Utilisation, and Storage (CCUS), the scaling up of hydrogen production, and the advancement of e-fuel technologies. These priorities are embedded in China's broader energy transition strategy, which seeks to balance energy security, economic growth, and environmental sustainability.

The **2024-2025 Energy Conservation and Carbon Reduction Action Plan** further underscores and emphasises these priorities and targets including[338,339]:

- Increase the share of non-fossil energy consumption to **18.9% in 2024** and **20% by 2025.**
- Raise the proportion of non-fossil energy in power generation to **39% by 2025**, driven by large-scale wind, solar, hydropower, and nuclear projects.
- Reduce carbon dioxide emissions by **130 million tonnes annually** in 2024 and 2025.
- Accelerate the construction of large wind and photovoltaic bases in deserts, Gobi, and barren lands, alongside offshore wind farms.
- **Expand UHV transmission lines** to connect renewable-rich regions with high-demand industrial centres.
- Increase pumped storage capacity to **62 GW** and new energy storage capacity to **40 GW by 2025**.
- Strengthen energy conservation reviews for new investment projects and integrate carbon emission evaluations into environmental impact assessments.

China's commitment to achieving carbon neutrality by 2060 has catalysed the development of comprehensive policy frameworks supporting CCUS, hydrogen production, and e-fuel technologies, which may enable China to decarbonise hard-to-abate sectors such as heavy industry, aviation, and shipping. These technologies are seen as complementary to renewable energy expansion, addressing gaps where direct electrification is challenging. These initiatives, embedded in the nation's policy and regulatory frameworks, seek to align decarbonisation efforts with sustainable economic growth and industrial transformation. These frameworks as outlined in Table 9-54 below, establish specific targets, implementation guidelines, and monitoring mechanisms across various sectors of the economy.

[338] China.org.cn, 2024. *China accelerates efforts to decarbonise its power grid*. Published May 29, 2024. Available at: http://www.china.org.cn/china/Off_the_Wire/2024-05/29/content_117222105.htm. Accessed January 9, 2025.

[339] SCIO (State Council Information Office), 2024. *China advances grid decarbonisation to achieve carbon neutrality goals*. Published May 30, 2024. Available at: http://english.scio.gov.cn/topnews/2024-05/30/content_117223269.htm. Accessed January 9, 2025.

Interestingly recent focus has been on blue hydrogen production from fossil fuel hydrocarbons with CCUS, which is chemically the opposite process to e-fuel synthesis from hydrogen and CO_2. Thus, hydrogen and CCUS technologies are viewed as complementary tools to help China meet its carbon neutrality targets. In November 2022, the International Energy Agency (IEA) and China's Administrative Centre for China's Agenda 21 (ACCA21) co-published the report "Opportunities for Hydrogen Production with CCUS in China." The report identifies coal-based hydrogen production with CCUS retrofitting as a near-term opportunity to reduce emissions from China's existing hydrogen facilities. The report also highlights the strategic need for developing CO_2 transport and storage infrastructure, particularly in industrial clusters where hydrogen production and consumption are concentrated. Without this infrastructure, the scale-up of CCUS technologies would face significant logistical and economic barriers.

Policy and financial incentives are necessary to scale low-carbon hydrogen and CCUS adoption. The report calls for integrating CCUS into China's emissions trading schemes and introducing subsidies or other financial mechanisms to lower investment risks. Additionally, it emphasises the importance of large-scale demonstration projects to validate CCUS technologies in hydrogen production settings. Such projects are expected to showcase the feasibility of these technologies while addressing uncertainties that deter private investment.

However, the report notes that these measures alone may not be sufficient to overcome broader challenges, such as market readiness and international competition in the hydrogen sector.

China's hydrogen strategy reflects both opportunities and challenges in achieving decarbonisation at scale. While initiatives like the 2023 guidelines and the IEA-ACCA21 report signal strong intent, practical implementation will require addressing issues related to infrastructure, costs, and international competitiveness

China's "1 + N" carbon neutral policy, introduced in May 2021, represents a structured approach to achieving carbon neutrality by 2060, with a focus on reducing emissions across ten critical sectors. The "1" component outlines overarching guidelines for carbon reduction, while the "N" refers to detailed implementation plans tailored to specific industries and regions. A key emphasis of the policy is on transforming the energy structure, given that the energy sector accounts for a significant share of China's emissions. Renewable energy development plays a central role in this transformation, with China achieving its 2030 target of 1,200 gigawatts of solar and wind capacity by July 2024—six years ahead of schedule.

This milestone reflects the rapid deployment of large-scale renewable projects and centralised energy policies but also raises challenges regarding grid integration, energy storage, and regional disparities in capacity utilisation. By embedding renewable energy within the broader "1 + N" framework, China seeks not only to decarbonise its power generation but also to align energy system reforms with industrial and economic restructuring, underlining the complex interplay of technological advancement and policy enforcement required to achieve long-term climate goals.

The following table provides a detailed overview of China's key renewable energy laws and policies, outlining their specific provisions, objectives, and contributions to the country's energy transition.

Table 9-54. China's key renewable energy laws and policies

Policy/Law	Key provisions	What it does	Significance in promoting renewable energy
China's First Comprehensive Energy Law (2025)	• Energy planning and development. • Market systems and utilisation. • Energy reserves and emergency response. • Hydrogen energy recognition. • Advanced technologies (e.g., smart microgrids, energy storage).	• Provides a legal framework for national energy planning and market operations. • Ensures energy security through reserves and emergency systems. • Promotes green hydrogen and advanced energy technologies.	• Legally recognises hydrogen as an energy source, supporting green hydrogen production. • Encourages investment in renewable energy technologies like smart grids and energy storage.
Guiding Opinions on Renewable Energy Substitution (2024)	• Renewable energy consumption targets (1.1 billion tonnes SCE by 2025, 1.5 billion tonnes by 2030). • Sectoral integration (industry, transport, buildings, rural areas). • Infrastructure upgrades and demand management.	• Sets specific targets for renewable energy adoption. • Promotes renewable energy in key sectors like steel, petrochemicals, EVs, and green buildings. • Modernises energy infrastructure and optimises energy use.	• Drives renewable energy adoption across industries and regions. • Supports the development of renewable energy infrastructure, such as grid upgrades and energy storage systems.
14th Five-Year Plan (2021-2025)	• Renewable energy targets (1,200 GW wind and solar by 2030). • Grid modernisation. • Energy storage systems. • UHV transmission lines.	• Sets ambitious renewable energy capacity goals. • Upgrades grid infrastructure to handle renewable energy integration. • Expands UHV lines to connect renewable-rich regions with industrial centres.	• Achieved 1,200 GW wind and solar target six years early (2024). • Enhances grid capacity to integrate more renewable energy, reducing curtailment rates.
Renewable Energy Law and Amendments	• Comprehensive energy planning. • Market regulation. • Sustainable energy utilisation. • Supported by Cleaner Production Promotion Law and Circular Economy Promotion Law.	• Provides a legal basis for renewable energy development and market operations. • Promotes efficient use of renewable energy and clean technologies.	• Forms the backbone of China's renewable energy legal system. • Ensures consistent prioritisation of renewable energy development and clean energy transition.

Policy/Law	Key provisions	What it does	Significance in promoting renewable energy
Market Mechanisms and Pricing Reforms	• Time-of-Use (TOU) pricing. • Tiered electricity pricing. • Green certificates.	• Encourages off-peak energy consumption and optimises renewable energy use. • Incentivises energy efficiency in energy-intensive industries. • Establishes a market for renewable energy trading.	• Reduces grid strain and optimises renewable energy use. • Encourages renewable energy adoption through financial incentives like green certificates.
International Collaboration and Green Development	• Belt and Road Initiative (BRI) renewable energy cooperation. • Global trade in renewable energy technologies. • Green development partnerships.	• Expands renewable energy cooperation with BRI countries. • Strengthens China's role as a global leader in renewable energy manufacturing and exports. • Advances global green development and climate goals.	• Positions China as a global leader in clean energy technologies. • Drives global GDP growth and clean energy investments through international collaboration.
2024-2025 Energy Conservation and Carbon Reduction Action Plan	• Reduce energy consumption per unit of GDP by 2.5% in 2024. • Increase non-fossil energy consumption to 20% by 2025. • Save 50 million tonnes of standard coal annually. • Reduce CO_2 emissions by 130 million tonnes annually.	• Sets specific targets for energy efficiency and emissions reduction. • Promotes renewable energy adoption in key sectors like steel, cement, and construction. • Modernises energy infrastructure and optimises energy use.	• Drives renewable energy adoption across industries and regions. • Supports the development of renewable energy infrastructure, such as grid upgrades and energy storage systems.
National Carbon Trading Market Expansion	• Expand carbon market to cover steel, aluminium, and cement by 2024. • Introduce free allowances for new sectors (2024-2026). • Strengthen data verification and oversight. • Explore international carbon market mechanisms.	• Incentivises emissions reductions in high-emission industries. • Encourages low-carbon technologies like electric arc furnaces (EAFs) in steel production. • Improves data accuracy and transparency.	• Creates financial incentives for industries to adopt renewable energy and low-carbon technologies. • Supports the transition to a total emissions cap after 2030, aligning with China's dual carbon goals.

9.4.3.2 Resource availability

The establishment of e-fuel production facilities necessitates substantial inputs of renewable energy, water, hydrogen (H_2), and carbon dioxide (CO_2). Assessing China's capacity to support such developments requires a comprehensive analysis of its renewable energy potential, water availability, grid decarbonisation plans, and infrastructure readiness. These resources must also account for competing demands from other industrial and energy sectors, which could impact the scalability of e-fuel hubs.

Renewable energy

China's substantial renewable energy capacity positions it well for e-fuel production, but resource allocation challenges remain significant. With the world's largest installed capacity of solar and wind power[340], China has the technical potential to produce large volumes of green hydrogen, a critical input for e-fuel synthesis. Regions such as Inner Mongolia, Qinghai, and Xinjiang, with abundant renewable resources, are strategically positioned to serve as e-fuel production hubs[341] [342] [343]. However, competition for renewable electricity, and for green hydrogen across sectors, including ammonia production, steelmaking, and methanol synthesis, may limit its availability for e-fuel production.

China leads the world in renewable energy capacity however, the scalability of e-fuels and other advanced energy solutions could be constrained by competing demands for renewable electricity. As industries, transportation, and households increasingly rely on clean energy, the allocation of renewable power will become a critical challenge. In 2023, China's renewable energy capacity reached 1.45 terawatts, representing over 50% of the global total and surpassing the combined capacity of the next three leading nations. For instance, China's solar PV installations alone exceed the combined solar capacity of the United States and the European Union.

The distribution of renewable energy generation varies significantly across provinces, reflecting differences in resource availability, policy support, and infrastructure development. Key regions include:

1. **Xinjiang**:
    - **Solar power**: Xinjiang is the largest solar power producer in China, with an installed capacity of **38,117 MW**. Its vast deserts and high solar irradiance make it a hub for large-scale solar farms[342].
    - **Wind energy potential**: Xinjiang also has significant wind energy potential, with wind farms contributing to its renewable energy mix.
    - **Challenges**: Despite its renewable energy potential, Xinjiang faces challenges in grid integration and transmission due to its remote location.
2. **Inner Mongolia**:
    - **Wind energy hub**: Inner Mongolia is a leader in wind energy, benefiting from consistent wind speeds and expansive land areas suitable for wind farms. It accounts for **20% of China's total wind energy capacity** and **57% of China's total wind energy potential**, with an exploitable capacity of **1.46 billion kilowatts[343].**

[340] Global Energy Monitor. (n.d.). *China continues to lead the world in wind and solar with twice as much capacity under construction as the rest of the world combined*. Retrieved from https://globalenergymonitor.org/report/china-continues-to-lead-the-world-in-wind-and-solar-with-twice-as-much-capacity-under-construction-as-the-rest-of-the-world-combined/.

[341] Stockholm Environment Institute (SEI). (2024). *Solar and wind power in Mongolia: 2024 policy overview (SEI2024-046)*. Retrieved from https://www.sei.org/wp-content/uploads/2024/10/solar-and-wind-power-in-mongolia-2024-policy-overview-sei2024-046.pdf.

[342] International Energy Agency. (2024). *Renewables 2024: Executive Summary*. Retrieved January 9, 2025, from https://www.iea.org/reports/renewables-2024/executive-summary

[343] State Council of the People's Republic of China. (2024, June 8). *News*. Retrieved from https://english.www.gov.cn/news/202406/08/content_WS6663bb5fc6d0868f4e8e7efd.html.

   - **Coal dependency**: Despite its renewable energy growth, Inner Mongolia remains heavily reliant on coal for electricity generation, highlighting the region's dual energy profile.

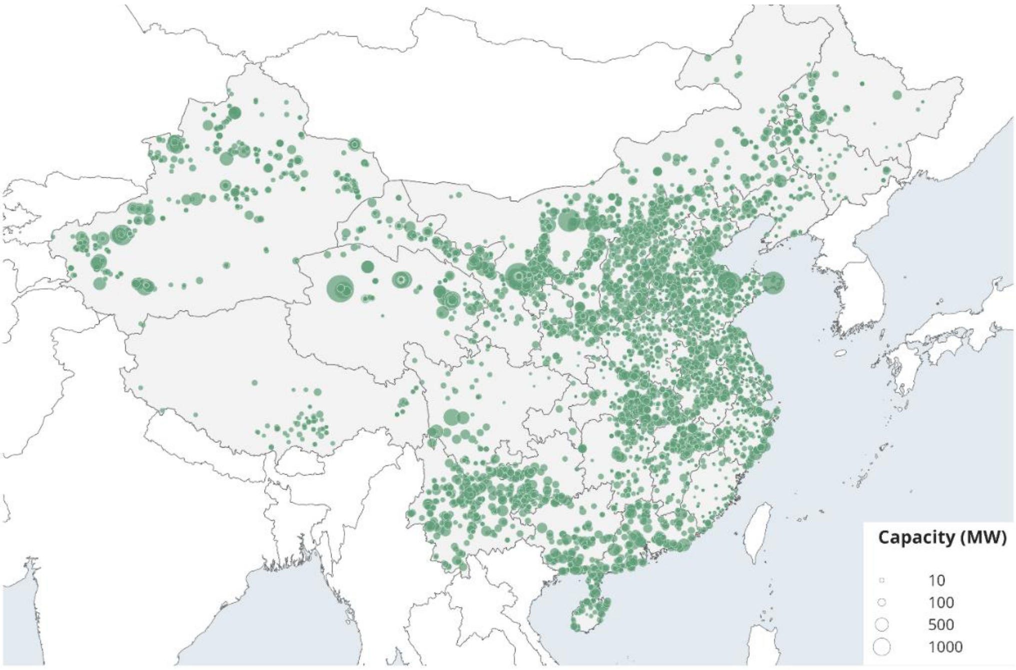
3. **Jiangsu and Shandong**:
   - **Coastal wind power**: These coastal provinces are major contributors to both onshore and offshore wind energy, leveraging their proximity to high-demand industrial centres.
   - **Solar expansion**: Both provinces have also seen significant growth in solar PV installations, driven by favourable policies and high electricity demand.

4. **Sichuan and Yunnan**:
   - **Hydropower dominance**: These provinces are rich in hydropower resources, which remain a significant component of China's renewable energy mix. Hydropower accounts for over **70% of Sichuan's electricity generation**[344].
   - **Seasonal variability**: Hydropower generation in these regions is subject to seasonal variability, with lower output during dry seasons.

5. **Tibet**:
   - **Emerging solar hub**: Tibet has emerged as a key region for solar energy development, with its high altitude and clear skies providing ideal conditions for solar PV installations.
   - **Grid challenges**: Similar to Xinjiang, Tibet faces challenges in grid integration and transmission due to its remote location.

Solar

Figure 9-69. Operating solar farms in China (2024)



Note: Data includes solar project phases with a capacity of 1 megawatt (MW) or more

Source: Global Solar Power Tracker, Global Energy Monitor

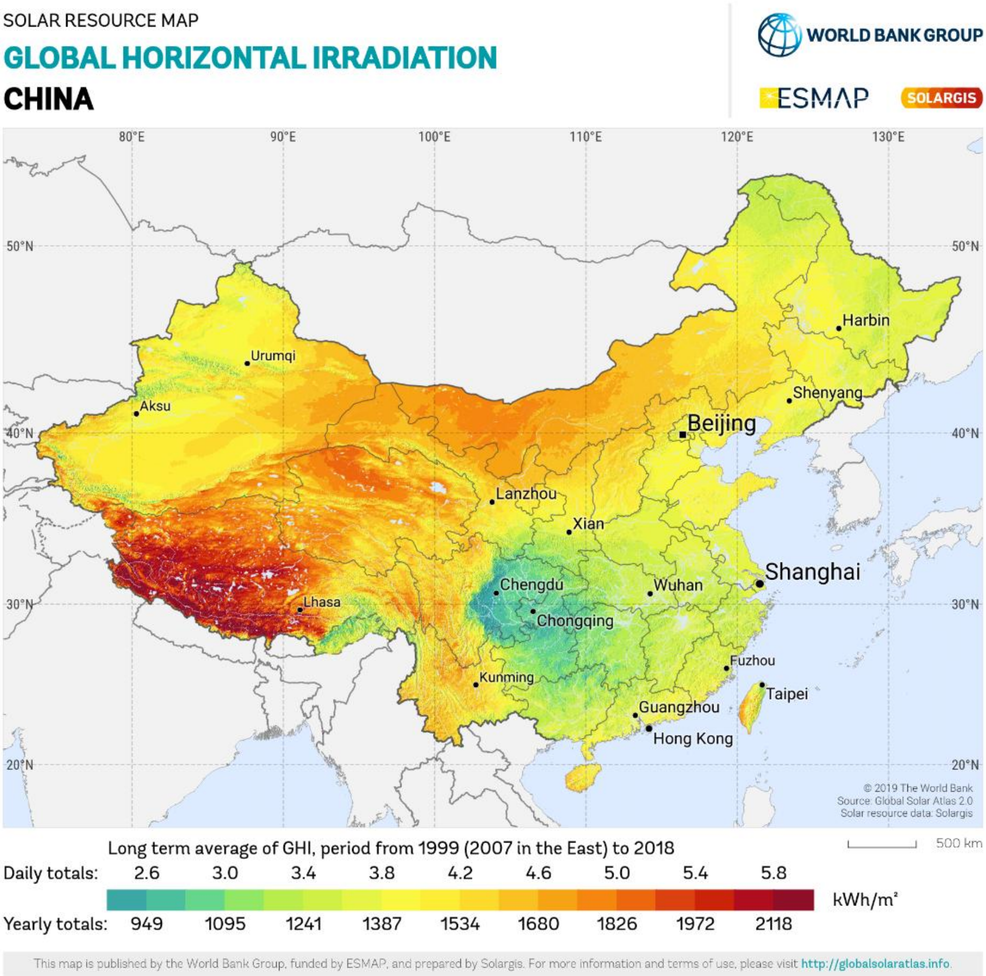
[344] Dialogue Earth. (n.d.). *China's power system needs to modernise*. Retrieved from https://dialogue.earth/en/energy/chinas-power-system-needs-to-modernise/.

As shown in Figure 9-69, Provinces in the east of China such as Shandong, Jiangsu, and Anhui have driven solar PV deployment, benefiting from high solar irradiance and supportive policies accounting for 30% of China's total solar capacity in 2024[345,346].

These regions have become key hubs for solar energy development due to their proximity to industrial centres, high electricity demand, and favourable government incentives. However, despite their significant contributions, their solar irradiance levels are lower compared to regions like **Tibet**, which boasts one of the highest solar irradiances in the world.

As shown in Figure 9-70, Tibet's solar irradiance is exceptionally high due to its high altitude, thin atmosphere, and clear skies, which allow for greater solar radiation penetration. For instance, the daily averaged spectral irradiance in Lhasa, Tibet, reaches 1.12 $W \cdot m^{-2} \cdot nm^{-1}$ at its peak, with summer solstice values exceeding 1.13 $W \cdot m^{-2} \cdot nm^{-1}$, more than double the winter solstice values[347].

Figure 9-70. Solar Irradiation across China



[345] State Council of the People's Republic of China, 2024. *China's renewable energy capacity and grid decarbonisation progress*. Published December 16, 2024. Available at: https://english.www.gov.cn/archive/statistics/202412/16/content_WS675f5ed4c6d0868f4e8edfa4.html. Accessed January 9, 2025.

[346] China Daily, 2024. *China strengthens renewable energy infrastructure to accelerate decarbonisation*. Published March 5, 2024. Available at: https://www.chinadaily.com.cn/a/202403/05/WS65e67805a31082fc043baa34.html. Accessed January 9, 2025.

[347] GPXYGPFX, 2024. *Decarbonisation pathways for China's grid: Renewable energy integration and infrastructure development*. Published 2024. Available at: https://www.gpxygpfx.com/EN/10.3964/j.issn.1000-0593(2024)02-0460-07. Accessed January 9, 2025.

In contrast, eastern provinces like Shandong, while benefiting from strong industrial demand and policy support, experience lower solar irradiance due to higher levels of air pollution, frequent cloud cover, and lower altitudes. These factors reduce the efficiency of solar PV systems compared to the conditions of Tibet. Therefore, Tibet's vast renewable resources are increasingly being harnessed for large-scale projects, such as the Caipeng Solar-Storage Power Station, which operates at an altitude of 5,228 meters and is the world's highest-altitude solar installation. The project, with a total capacity of 150 MW, features 170,000 solar panels and a 20 MW/80 MWh energy storage system. It is expected to generate 247 million kWh of electricity annually, addressing central Tibet's seasonal power shortages during winter and spring.

Wind

Wind power also plays a significant role in China's renewable energy landscape, with an installed capacity of **around 300 GW as of 2023**. Operating wind farms in China in 2024 are shown in Figure 9-71 below. The majority of this capacity is concentrated in **northern and western regions**, such as **Inner Mongolia and Xinjiang**, where wind resources are particularly abundant due to their vast open landscapes and consistent wind speeds. Inner Mongolia alone contributes **20% of the national total** [12,348], making it a cornerstone of China's wind energy strategy. These regions benefit from **average wind speeds of 6-8 meters per second**, which are ideal for both onshore and offshore wind farms, and their remote locations provide ample space for large-scale wind projects.

Figure 9-71. Operating wind farms in China (2024)

Note: Data includes wind project phases with a capacity of 10 MW or more

Source: Global Wind Power Tracker, Global Energy Monitor

[348] State Council of the People's Republic of China, 2024. *China's renewable energy capacity and grid decarbonisation achievements*. Published December 16, 2024. Available at: https://english.www.gov.cn/archive/statistics/202412/16/content_WS675f5ed4c6d0868f4e8edfa4.html. Accessed January 9, 2025.

The development of wind power in these regions is supported by **government policies and infrastructure investments**, including the expansion of **UHV transmission lines** to connect wind-rich areas with high-demand industrial centres in the east. For example, Inner Mongolia's wind farms are linked to major cities like Beijing and Shanghai, ensuring that the electricity generated can be efficiently transported and utilised. Additionally, the **14th Five-Year Plan** has set ambitious targets for wind energy, aiming to increase capacity to **400 GW by 2025**, with a focus on both onshore and offshore projects.

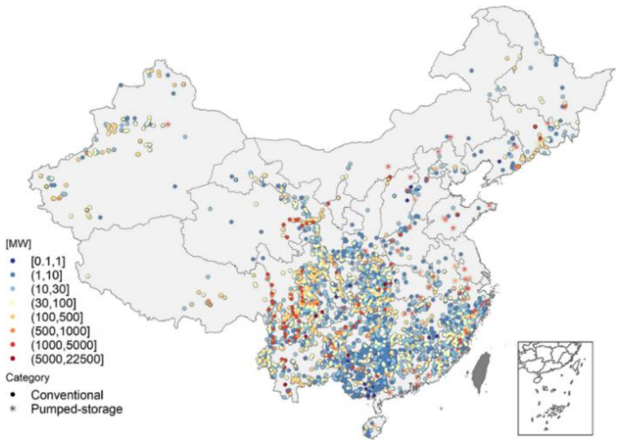
Despite the advantages, challenges remain. **Grid integration** is a significant issue, as the intermittent nature of wind energy requires robust energy storage solutions and grid modernisation to ensure stability. Curtailment rates in some regions, such as Xinjiang, have historically been as high as **15%**, highlighting the need for improved infrastructure and demand-side management. Potential solutions include the development of green hydrogen production and the adoption of e-fuels as versatile energy carriers. Furthermore, the **environmental impact** of large-scale wind farms, particularly in ecologically sensitive areas, has raised concerns about habitat disruption and land use conflicts. However, these impacts are significantly lower compared to fossil fuel-based energy sources like coal or natural gas plants for example the lifecycle carbon footprint of wind energy is approximately 20-30 times lower than that of coal and 10-15 times lower than natural gas[349].

To address curtailment, China is implementing measures such as expanding ultra-high-voltage (UHV) transmission lines to connect wind-rich regions with high-demand areas, enhancing grid flexibility through smart grid technologies, and promoting energy storage systems like battery storage and pumped hydro. Additionally, policies such as TOU pricing are being introduced to incentivise real-time energy consumption and reduce mismatches between supply and demand.

Hydro

Hydropower remains a major component of China's renewable strategy, with over 350 GW of capacity, making it the largest source of renewable electricity in the country. The majority of this capacity is concentrated in the **resource-rich southwestern provinces of Sichuan and Yunnan**, which together contribute **70% of China's total hydropower capacity**[12 13]. These regions are endowed with abundant water resources, steep terrain, and significant river systems, such as the **Yangtze, Mekong, and Salween rivers**, which provide ideal conditions for large-scale hydropower development. Figure 9-72 below represents the hydropower plants operating in China in 2022.

Figure 9-72. Hydropower plants operating in China (2022)[350]



Hydropower plays a critical role in China's energy mix, not only as a reliable source of electricity but also as a key enabler of grid stability and energy storage through **pumped hydro storage systems**.

[349] Galparsoro, I., Menchaca, I., Garmendia, J.M. et al. Reviewing the ecological impacts of offshore wind farms. npj Ocean Sustain 1, 1 (2022). https://doi.org/10.1038/s44183-022-00003-5

[350] Wan, W., Doell, P., & Zheng, H. (2022). Risk of Climate Change for Hydroelectricity Production in China Is Small but Significant Reductions Cannot Be Precluded for More Than a Third of the Installed Capacity. *Water Resources Research*, 58(8). DOI: 10.1029/2022WR032380. License: CC BY-NC 4.0.

For example, the **Baihetan Dam** in Sichuan, the world's second-largest hydropower plant, has a capacity of **16 GW** and generates over **60 billion kWh of electricity annually**, significantly reducing reliance on coal-fired power plants. Similarly, the **Xiluodu Dam** in Yunnan, with a capacity of **13.86 GW**, is another major contributor to China's renewable energy goals.

However, hydropower generation is subject to **seasonal variability**, as water flow fluctuates between wet and dry seasons. During the dry season, hydropower output can drop significantly, leading to potential energy shortages. These fluctuations underscore the importance of **diversifying energy sources** to ensure a consistent electricity supply, particularly for energy-intensive applications like **e-fuel production hubs**, which require stable and reliable power. For instance, in 2022, Sichuan experienced severe droughts that reduced hydropower output by **50%**, forcing the province to rely on coal-fired power and ration electricity to industries.

To address these challenges, China is investing in **complementary renewable energy sources**, such as solar and wind, as well as **energy storage systems** to balance supply and demand. For example, the integration of **floating solar farms** on hydropower reservoirs, such as the **Huaneng Power International's project in Yunnan**, enhances energy generation by utilising existing infrastructure and mitigating the impact of seasonal water variability. Additionally, the expansion of **pumped hydro storage** facilities, which store excess energy during periods of low demand and release it during peak times, is supporting the stabilisation of the grid and improves renewable energy integration.

Despite its advantages, large-scale hydropower development has raised **environmental and social concerns**, including the displacement of communities, disruption of ecosystems, and impacts on downstream water availability. For instance, the construction of the **Three Gorges Dam**, the world's largest hydropower project, displaced over **1.4 million people** and significantly altered the local environment.

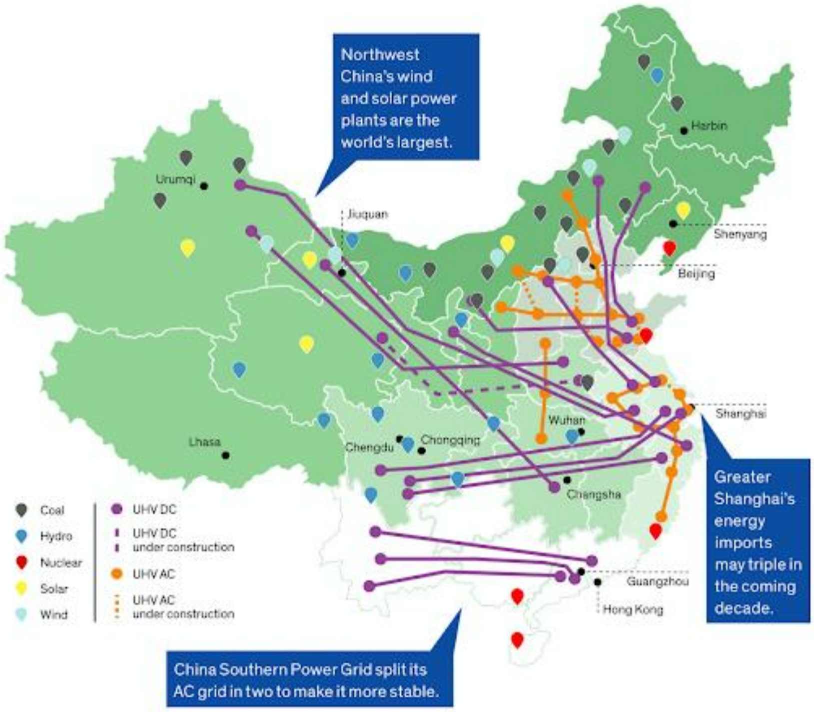
Ultra-high voltage transmission lines

Ultra-high voltage (UHV) transmission lines play a significant role in enabling large scale use of renewables via balancing regional energy demands and supports the development of **e-fuel hubs**. These advanced transmission systems, which operate at voltages of **800 kV or higher**, are designed to efficiently transport electricity over long distances with minimal losses. They play a critical role in connecting **renewable-rich western provinces**, such as **Inner Mongolia and Xinjiang**, where wind and solar resources are abundant, to **high-demand industrial and urban centres in the east**, such as Beijing, Shanghai, and Guangdong [351,352]. China's UHV transmission grid is represented in Figure 9-73 below.

[351] Rethink Research, 2024. *China's UHV transmission to more than double by 2025 to 105 GW*. Available at: https://rethinkresearch.biz/articles/chinas-uhv-transmission-to-more-than-double-by-2025-to-105-gw/. Accessed January 9, 2025.

[352] China Daily, 2024. *China accelerates development of clean energy infrastructure to meet decarbonisation goals*. Published January 10, 2024. Available at: https://www.chinadaily.com.cn/a/202401/10/WS659e528fa3105f21a507b9c7.html. Accessed January 9, 2025.

Figure 9-73. China's ultra-high voltage grid (2018)[353].



China's UHV grid is extensive, spanning over **30,000 kilometres** with a transmission capacity of **240 GW**, equivalent to powering **80 million households** annually[351,352]. This infrastructure is essential for mitigating regional energy disparities, as it enables the transfer of surplus renewable energy from resource-rich but less populated areas to energy-hungry industrial hubs. For example, the **Zhundong-Wannan UHV line**, which stretches **3,324 kilometres**, transmits electricity from Xinjiang's vast wind and solar farms to Anhui province, reducing the need for coal-fired power in the east[354]. Similarly, the **Shanghaimiao-Shandong UHV line** connects Inner Mongolia's wind farms to Shandong, one of China's most energy-intensive provinces[354].

For e-fuel hubs, reliable electricity delivery from renewable energy centres is critical to ensure consistent hydrogen production, therefore UHV transmission lines are essential. By linking e-fuel production facilities to renewable energy centres, UHV infrastructure helps stabilise the energy supply, reducing the risk of interruptions caused by localised weather variability or grid instability. For instance, the **Xinjiang e-fuel hub**, which is under development, will rely heavily on UHV lines to transport electricity from nearby solar and wind farms, ensuring a stable energy supply for large-scale hydrogen production [352].

Despite its advantages, the UHV grid faces several challenges. **Transmission losses**, although lower than conventional high-voltage systems, still account for **5-7% of the electricity transported**, particularly over extremely long distances [355]. Additionally, the **high infrastructure costs** of UHV projects, which may exceed **US$2 billion per line**, pose a significant barrier to further expansion [354,356]. These costs include not only the construction of transmission lines but also the development

[353] Nextrends Asia. (n.d.). *Advancing climate goals with ultra-high voltage power lines*. Retrieved from https://nextrendsasia.org/advancing-climate-goals-with-ultra-high-voltage-power-lines/.

[354] CYG Insulator, 2024. *China's advancements in ultra-high voltage (UHV) transmission for renewable energy integration*. Available at: https://www.cyginsulator.com/article/83.html. Accessed January 9, 2025.

[355] Baidu Xueshu, 2024. *China's energy transition and the role of UHV transmission in decarbonisation efforts*. Available at: https://xueshu.baidu.com/usercenter/paper/show?paperid=435d4c5bbc393fa859b39f2bb198e450. Accessed January 9, 2025.

[356] Enerdata, 2024. *China completes 880 km 750 kV UHV transmission project in Xinjiang*. Available at: https://www.enerdata.net/publications/daily-energy-news/china-completes-880-km-750-kv-uhv-transmission-project-xinjiang.html. Accessed January 9, 2025.

of **converter stations**, which are necessary to transform alternating current (AC) into direct current (DC) for long-distance transmission and back again[355].

To address these challenges, China is investing in **technological advancements** to improve the efficiency and reduce the costs of UHV systems. For example, the development of **next-generation UHV lines** with higher voltage levels (up to **1,100 kV**) and advanced materials is expected to lower transmission losses and increase capacity [354]. Additionally, the integration of **smart grid technologies**, such as real-time monitoring and AI-driven load balancing, is enhancing the reliability and flexibility of the UHV network [357].

The UHV grid also plays a crucial role in reducing **renewable energy curtailment**, which occurs when excess electricity generated by wind and solar farms cannot be absorbed by the grid. In regions like Xinjiang and Inner Mongolia, curtailment rates have historically been as high as **15%**, but UHV lines have supported the reduction of these rates by enabling the export of surplus energy to other regions[358] .

Water

Seasonal water variability and energy reliability directly affect e-fuel production potential in hydropower-reliant regions. As the dominant source of renewable electricity in China's energy mix, hydropower plays a critical role in supporting e-fuel production during peak renewable energy downtimes. However, seasonal water variability poses significant challenges. During periods of drought, such as those experienced in 2022, hydropower generation in Sichuan fell by nearly 20%, disrupting energy supplies to industrial hubs. Conversely, excess rainfall risks overloading dam infrastructure, requiring emergency water releases. These fluctuations necessitate diversified energy sources and advanced grid management to maintain reliable electricity for e-fuel hubs.

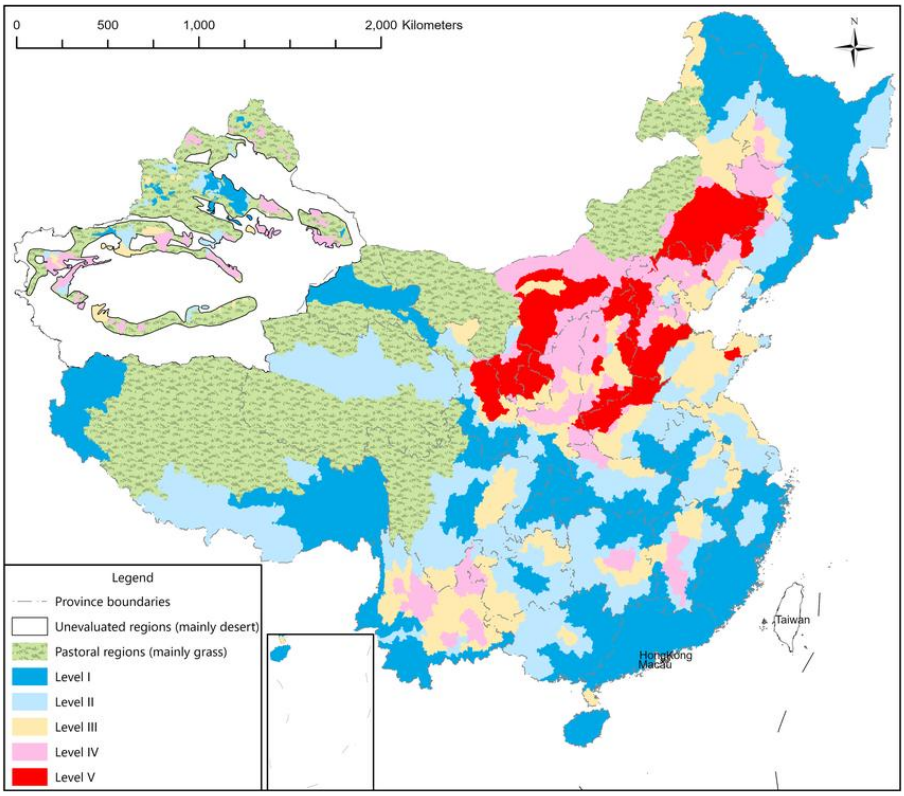
Water is a critical input for e-fuel production, but existing water demands create significant competition. Producing 1 kg of hydrogen via electrolysis requires approximately 9 litres of water, a modest figure compared to agricultural uses but significant in industrial contexts. However, when scaled to industrial levels, the water demand becomes substantial. For example, a large-scale e-fuel hub producing **100,000 tonnes of hydrogen annually** would require **900 million litres of water**, equivalent to the annual water consumption of a mid-sized city.

This water demand creates significant competition in regions already facing water stress. Figure 9-74 depicts water stress levels in China in 2017. For instance, **thermal power plants**, which are still a major part of China's energy mix, consume **2-3 litres of water per kWh of electricity generated**, further exacerbating water scarcity in regions like **Inner Mongolia and Xinjiang**. These regions, targeted for renewable energy development, face heightened competition between **agriculture, urban development, and industrial applications**, making water management a critical issue for sustainable e-fuel production.

[357] State Council of the People's Republic of China, 2022. *China promotes green energy to achieve sustainable development goals*. Published May 21, 2022. Available at: https://english.www.gov.cn/news/topnews/202205/21/content_WS628823b8c6d02e533532b154.html. Accessed January 9, 2025.

[358] State Council of the People's Republic of China, 2022. *China promotes green energy to achieve sustainable development goals*. Published May 21, 2022. Available at: https://english.www.gov.cn/news/topnews/202205/21/content_WS628823b8c6d02e533532b154.html. Accessed January 9, 2025.

Figure 9-74. Spatial distribution of water stress levels in China (2017)[359]



China's annual water consumption for energy production is estimated at **140 billion cubic metres**, highlighting the scale of competition for resources. In water-stressed regions like **Inner Mongolia**, where renewable energy projects are expanding rapidly, the competition for water is particularly acute. For example, Inner Mongolia's plans to develop **1,000,000 tonnes of green hydrogen production capacity by 2028** will require significant water resources, potentially conflicting with agricultural and urban needs. Similarly, in **Xinjiang**, where large-scale solar and wind projects are being developed, water scarcity remains a pressing concern, with the region already experiencing overexploitation of its groundwater resources.

To address these challenges, strategic investments in **water-efficient technologies** and **alternative water sources** will be critical. Key solutions include:

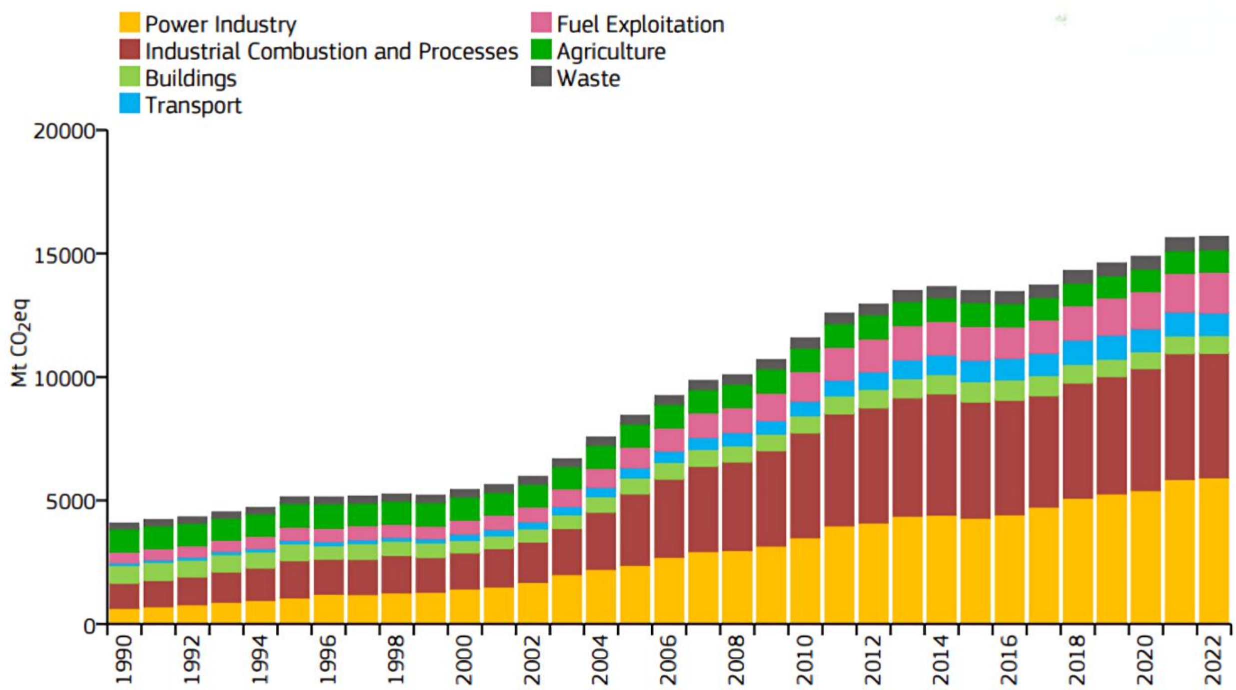
1. **Desalination**: Expanding desalination infrastructure in coastal regions can provide an additional water source for industrial applications, reducing reliance on freshwater resource.
2. **Wastewater recycling**: Implementing advanced wastewater treatment and recycling systems can help meet industrial water demands without exacerbating regional shortages.
3. **Efficient water use**: Promoting water-saving technologies in agriculture, industry, and urban areas can free up resources for e-fuel production. For example, Inner Mongolia's plans to expand **efficient water-saving irrigation** from **34.03 million mu to 38 million mu** by 2025 are expected to save **3.5 billion cubic metres of water annually**, which could be redirected to industrial uses.

[359] Kong, Mengyuan & Wang, Gaoxu & Wu, Yongxiang & Liu, Guodong & Gu, Ying & Wei, Wu. (2021). A Nationwide Analysis of Water Scarcity and Cloud Seeding Demand Levels From Analyzing Water Utilization Data, Agricultural Drought Maps, and Local Conditions in China Mainland. Earth and Space Science. 8. 10.1029/2020EA001477.

9.4.3.3 CO_2 sources

The availability of CO_2 is another factor to consider in the selection of a suitable location for an e-fuels production plant, as CO_2 constitutes the second primary component of the e-fuel synthesis process. China is the world's largest emitter of CO_2, accounting for approximately **31.9% of global CO_2 emissions** in 2020[360]. This dominance is driven by the country's rapid industrialisation, urbanisation, and reliance on coal, which constitutes over **60% of its energy mix**. In 2023, China's total CO_2 emissions were estimated at **12.6 billion metric tons**, with energy-related emissions contributing the majority. The distribution of GHG emissions by sector in China is represented in Figure 9-75.

Figure 9-75. GHG emissions by sector in China[361].



The largest share of China's CO_2 emissions comes from the **power sector**, which accounts for **57% of total energy-related emissions** in 2022[360]. This is primarily due to the country's heavy reliance on coal-fired power plants, which remain the backbone of its electricity generation.

The **industrial sector** is the second-largest contributor, responsible for **28% of emissions**. Energy-intensive industries such as steel, cement, and chemicals drive this share, reflecting China's role as the world's manufacturing hub[360]. The **transport sector** accounts for **10% of emissions**, with road transportation being the dominant source. While China has made significant strides in promoting electric vehicles (EVs), the sector's emissions remain substantial due to the continued use of fossil fuels in freight and aviation[362].

---

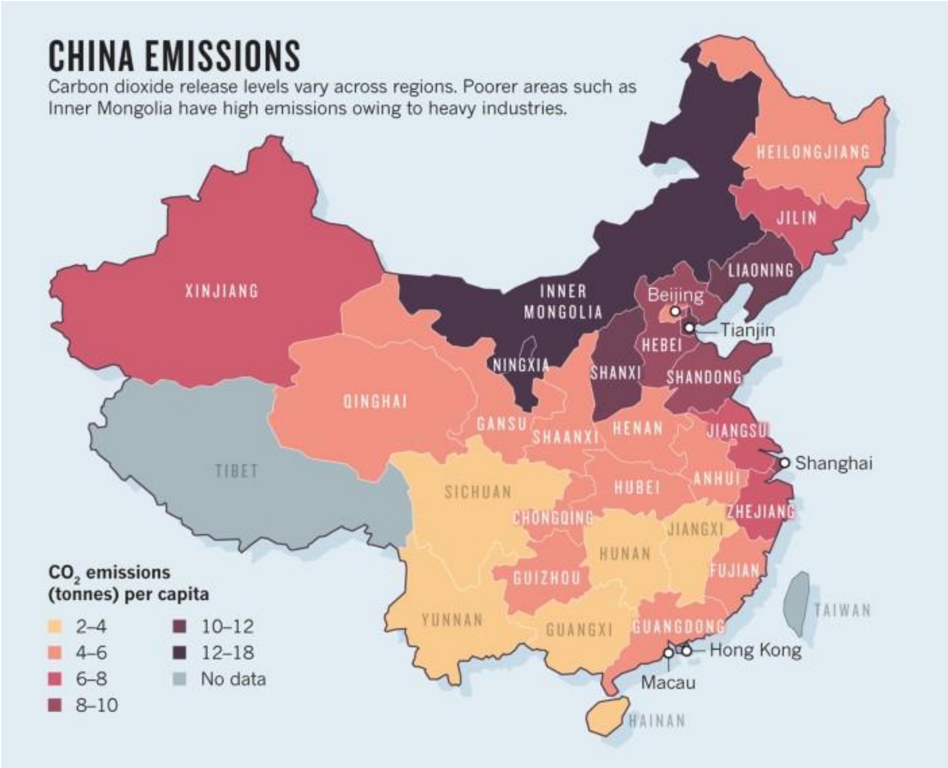
[360] Hu, L., Hu, X., Li, B. *et al.* Carbon dioxide emissions from industrial processes and product use are a non-ignorable factor in China' s mitigation. *Commun Earth Environ* **5**, 800 (2024). https://doi.org/10.1038/s43247-024-01951-1

[361] Crippa, M., Guizzardi, D., Pagani, F., Banja, M., Muntean, M., Schaaf, E., Monforti-Ferrario, F., Becker, W.E., Quadrelli, R., Risquez Martin, A., Taghavi-Moharamli, P., Köykkä, J., Grassi, G., Rossi, S., Melo, J., Oom, D., Branco, A., San-Miguel, J., Manca, G., Pisoni, E., Vignati, E. and Pekar, F., GHG emissions of all world countries, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/4002897, JRC138862

[362] Crippa, M., Guizzardi, D., Pagani, F., Banja, M., Muntean, M., Schaaf E., Becker, W., Monforti-Ferrario, F., Quadrelli, R., Risquez Martin, A., Taghavi-Moharamli, P., Köykkä, J., Grassi, G., Rossi, S., Brandao De Melo, J., Oom, D., Branco, A., San-Miguel, J., Vignati, E., GHG emissions of all world countries, Publications Office of the European Union, Luxembourg, 2023, doi:10.2760/953322, JRC134504.

China's CO_2 emissions are highly concentrated in specific regions due to the uneven distribution of industrial activity and energy production, as shown in Figure 9-76 below.

Figure 9-76. China regional carbon footprint[363]



The following regions are particularly significant[360]:

- **Eastern China**:
  - Provinces like **Shandong, Jiangsu, and Hebei** are among the top emitters due to their heavy industrial bases.
  - Shandong alone contributes over **10% of China's total CO_2 emissions**, driven by its large-scale cement, steel, and chemical production facilities.
  - Jiangsu and Zhejiang are also major contributors, with emissions from manufacturing, power generation, and transportation.
- **Northern China**:
  - **Inner Mongolia** and **Shanxi** are key coal-producing regions, with emissions primarily from coal-fired power plants and coal-to-chemicals industries.
  - Inner Mongolia has seen rapid growth in coal-to-liquids and coal-to-olefins projects, which produce high-purity CO_2 as a byproduct.
- **Southern China**:
  - **Guangdong** and **Zhejiang** have significant emissions from manufacturing and transportation, though these regions are also leading in renewable energy adoption.
- **Central and Western China**:

[363] Liu, Z., Guan, D., Crawford-Brown, D. *et al.* A low-carbon road map for China. *Nature* **500**, 143–145 (2013). https://doi.org/10.1038/500143a

- Provinces like **Henan** and **Sichuan** have growing industrial sectors, but their emissions are lower compared to the eastern and northern regions.

The following sectors are particularly relevant for e-fuel production due to their high CO_2 emissions and concentrated streams[360]:

- Cement production: China produces over 50% of the world's cement, with major facilities in Shandong, Guangdong, and Jiangsu. Cement flue gas typically contains 14-33% CO_2, making it suitable for capture.
- Steel and iron production: China produces over 50% of the world's steel, with emissions concentrated in Hebei, Liaoning, and Jiangsu. Blast furnace gas contains 20-27% CO_2, providing a viable source for capture.
- Coal-to-Chemicals: This sector has grown rapidly, particularly in Inner Mongolia and Shaanxi, producing high-purity CO_2 streams exceeding 90% concentration.
- Ammonia and ethanol Production: Significant CO_2 sources, with emissions concentrated in Shandong, Henan, and Sichuan[13].
- Power generation: Coal-fired power plants are the largest source of energy-related CO_2 emissions, with flue gas containing 10-15% CO_2.

The concentration of industrial facilities in specific regions creates opportunities for developing CCUS hubs, which can support large-scale e-fuel production. Key regions with potential include[360]:

- **Yangtze River Delta**: Encompassing Shanghai, Jiangsu, and Zhejiang, this region hosts numerous chemical plants, refineries, and manufacturing facilities. Its access to renewable energy, particularly offshore wind and solar, makes it an ideal location for e-fuel production.
- **Pearl River Delta**: Centred around Guangdong Province, this region is a major hub for manufacturing and technology. The proximity of industrial facilities and access to renewable energy resources create favourable conditions for CCUS and e-fuel production.
- **Northern China (Inner Mongolia and Shanxi)**: These regions have abundant coal resources and a growing coal-to-chemicals industry. The high concentration of CO_2 sources and availability of renewable energy (particularly wind) make them potential candidates for e-fuel hubs.
- **Bohai Bay Rim**: Including Shandong, Hebei, and Tianjin, this region is a major centre for heavy industry and petrochemicals. The clustering of industrial facilities and access to ports for e-fuel export enhance its potential as a hub.

9.4.3.4 *Carbon Capture*

The availability of captured CO_2 for further utilisation is influenced by several factors, including supportive policies and regulations, as well as financial incentives like grants and tax credits. The goal of these initiatives is to stimulate the deployment of carbon capture technologies, thereby creating a market for CO_2.

This section provides an overview of the current state of CCUS activities across the country, encompassing CCUS projects, CCUS hub developments, and the deployment of related transportation infrastructure. A mature CCUS environment is more conducive to e-fuel development, as it enhances the availability of captured CO_2 as a feedstock and facilitates its transportation for utilisation. Furthermore, this section covers CCUS-related policies, regulations, and financial incentives, as these can either accelerate or hinder the deployment of CCUS technologies.

Carbon capture activity

China's goal of achieving carbon neutrality by 2060 has driven significant development in CCUS technologies. Backed by government policies and private sector investment, China has emerged as a prominent player in expanding these technologies. By 2022, China had initiated approximately 100 CCUS demonstration projects at various scales and phases of development, with a combined annual CO_2 capture capacity of around 4 million tonnes. Over 40 of these projects have a capture capacity exceeding 100,000 tonnes per year, and more than 10 exceed 500,000 tonnes annually.[364]. A selection of carbon capture projects in China are outlined in Table 9-55 below.

Table 9-55. Five of the largest CCUS projects across China at various stages of deployment.

Project Name	Location	Description	Status	Capacity (tCO_2/year)
Sinopec Qilu Petrochemical CCUS[365]	Shandong Province	Captures CO_2 from chemical production processes for enhanced oil recovery (EOR).	Operational	1,000,000
China Energy's Ningdong Base CCUS Project[366]	Ningxia Hui Autonomous Region	Phased project capturing CO_2 from coal plants, with storage in Changqing Oilfield for EOR.	Under Construction	500,000 (First Phase), 3,000,000 (full capacity)
China National Petroleum Corporation (CNPC) Jilin Oilfield CCUS[367]	Jilin Province	Captures CO_2 from natural gas processing for EOR.	Operational	600,000
Taizhou Coal Power Plant CCUS[368]	Jiangsu Province	Demonstrates post-combustion CO_2 capture for coal-fired power.	Under Construction	500,000
Guangdong Offshore Storage Project[369]	South China Sea	China's first offshore CO_2 storage project integrated with CCUS.	Pilot Stage	300,000

A portfolio of these projects illustrates China's efforts to deploying full-chain CCUS solutions. For instance, the Sinopec Qilu Petrochemical CCUS project in Shandong Province captures 1 million tonnes of CO_2 annually from industrial sources for CO_2-Enhanced Oil Recovery (EOR)[366]. Similarly, the CNPC Jilin Oilfield CCUS separates 600,000 tonnes of CO_2 annually associated with natural gas processing[367].

[364] Global CCS Institute, 2023. *CCUS Progress in China*. Published March 2023. Available at: https://www.globalccsinstitute.com/wp-content/uploads/2023/03/CCUS-Progress-in-China.pdf. Accessed January 9, 2025.

[365] Sinopec Group, 2024. *Sinopec advances CCUS and hydrogen technologies to support China's carbon neutrality goals*. Available at: http://www.sinopecgroup.com/group/en/000/000/065/65137.shtml. Accessed January 9, 2025.

[366] China Energy Investment Corporation (CEIC), 2024. China Energy advances carbon capture and renewable energy projects to meet decarbonisation goals. Published January 2024. Available at: https://www.ceic.com/gjnyjtwwEn/xwzx/202401/4d90d45cab074fb8b4b810c61d51052c.shtml. Accessed January 9, 2025.

[367] China National Petroleum Corporation (CNPC), 2022. *CNPC's role in advancing CCUS technologies and sustainable energy development*. Published July 7, 2022. Available at: http://center.cnpc.com.cn/sysb/system/2022/07/07/030073119.shtml. Accessed January 9, 2025.

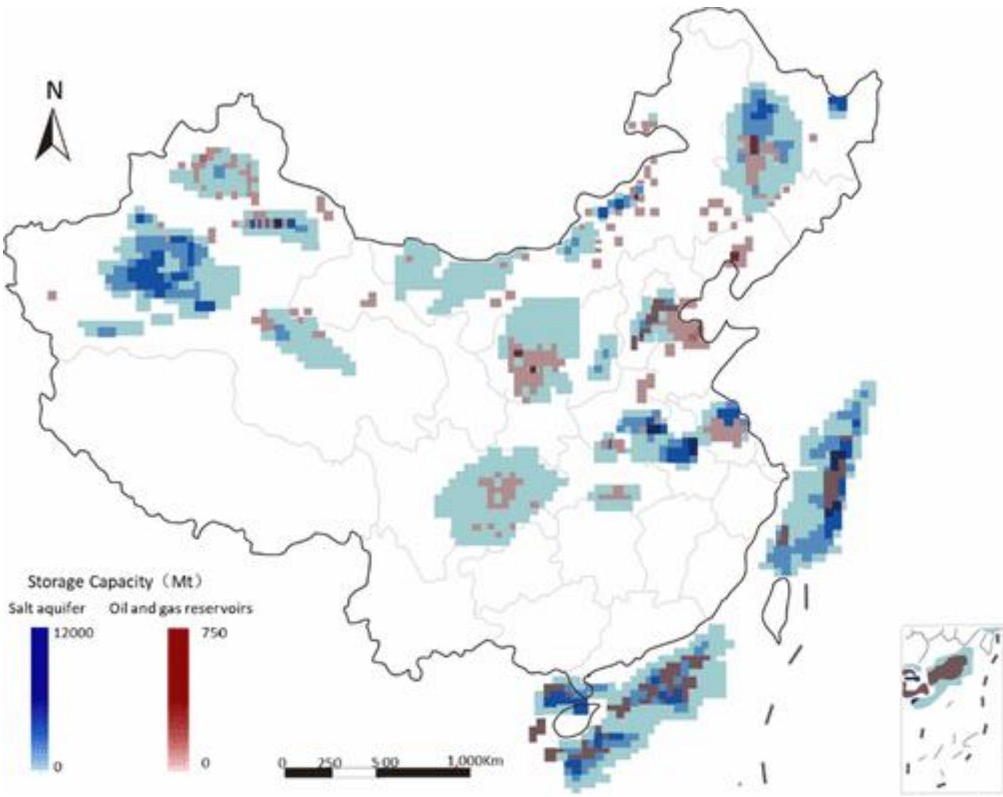
[368] China Energy Investment Corporation (CHN Energy), 2023. *CHN Energy's initiatives in renewable energy and CCUS technology deployment*. Published June 2023. Available at: https://www.chnenergy.com.cn/gjnyjtwwEn/xwzx/202306/b14014c59e7748d9a4f570ebb850429f.shtml. Accessed January 9, 2025.

[369] China Energy Investment Corporation (CHN Energy), 2025. *CHN Energy's advancements in renewable energy projects and carbon neutrality goals*. Published January 2025. Available at: https://www.chnenergy.com.cn/gjnyjtwwEn/xwzx/202501/bafe37ba8f6241938641c751349788be.shtml. Accessed January 9, 2025.

Large-scale initiatives target emissions from high-impact sectors, diversifying CCUS applications. Projects such as the Taizhou Coal Power Plant CCUS project focus on post-combustion CO_2 capture, with a planned capacity of 500,000 tonnes annually. Offshore projects, such as the Guangdong Offshore Storage Project, pilot innovative methods by integrating CO_2 transport with offshore geological storage.

China's CCUS deployment primarily focuses on geological storage through enhanced oil recovery (EOR) and is gradually diversifying applications to decarbonise multiple sectors. China's geological storage capacity provides vast opportunities for CO_2 sequestration, yet uneven geographic distribution creates logistical challenges for its utilisation. With an estimated storage potential of over 2,400 gigatonnes, concentrated in sedimentary basins such as the Ordos, Songliao, and Sichuan Basins, these regions are primed for CCUS development. Potential CO2 storage capacity in China is represented in Figure 9-77 below.

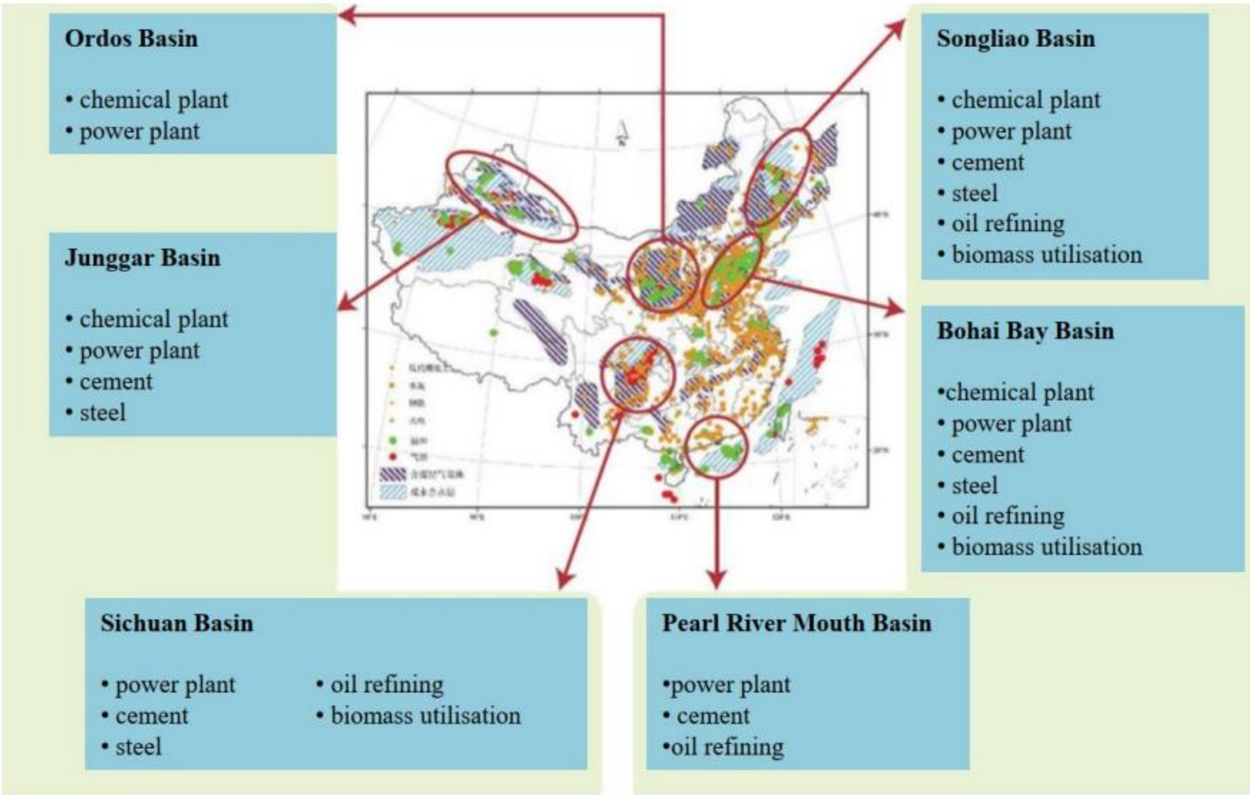
Figure 9-77. Potential CO_2 storage capacity[364]



EOR operations in these basins already utilise CO_2, though the volume remains limited to around 3 million tonnes annually. This focus on EOR restricts the availability of captured CO_2 for alternative applications, such as the production of sustainable aviation fuels (SAF) or synthetic methanol. For instance, the Ordos Basin's proximity to major industrial emitters highlights its importance, but its utilisation requires better pipeline integration. Infrastructure planning must prioritise CO_2 delivery to industrial hubs and e-fuel facilities to maximise its utility and decarbonisation impact.

China's deployment of CCUS infrastructure is structured around regional coordination and industrial clustering through established hubs, as represented in Figure 9-78 below. The Junggar Basin CCUS Hub in northwest China, operated by CNPC, has set capture targets of 1.5 million tonnes per annum (Mtpa) of CO_2 from refinery hydrogen production units by 2025, with plans to increase to 3 Mtpa by 2030 and 10 Mtpa by 2040. The hub utilises existing industrial infrastructure with high-purity CO_2 streams, incorporating pipeline networks and storage systems for potential capacity increases.

Figure 9-78. Potential CCUS hubs in China[370]



The East China CCUS Hub represents a collaboration between Sinopec, Shell, China Baowu, and BASF, with projected capture capacity of 10 Mtpa. This initiative combines international expertise with domestic industrial capabilities through public-private partnership arrangements.

The Guangdong offshore CCUS hub, located at the Dayawan Petrochemical Industrial Park in Huizhou, involves CNOOC, ExxonMobil, Shell, and the Guangdong Provincial Development & Reform Commission. The project scope includes assessment and implementation of large-scale CCUS systems, incorporating offshore storage capabilities.

CO_2 transport infrastructure

China's current CO_2 transport infrastructure is underdeveloped, heavily reliant on road transport and limited pilot pipelines, making large-scale CCUS projects unviable. The only existing pipeline infrastructure includes the Sinopec Shengli pipeline in Shandong, which spans 109 kilometres and a maximum transmission capacity of 1.7 million tonnes of CO_2 annually for EOR purposes and a 53 km pipeline in the Jilin oilfield[371]. Although this demonstrates the feasibility of CO_2 pipeline systems, the current reliance on trucking CO_2 is inefficient and unsuitable for the volumes needed to meet China's CCUS targets[371]. A major expansion of dedicated pipeline networks is essential to enable cost-effective transport from emission sources to storage or utilisation sites reducing logistical complexity and

[370] UK Carbon Capture and Storage Research Centre (UKCCSRC), 2021. *CCUS Development in China and Guangdong Carbon Capture Technology Centre*. Presentation by Xi Liang. Published September 2021. Available at: https://ukccsrc.ac.uk/wp-content/uploads/2021/09/Xi-Liang-CCUS-Development-in-China-and-Guangdong-Carbon-Capture-Technology-Centre_v3.pdf. Accessed January 9, 2025.

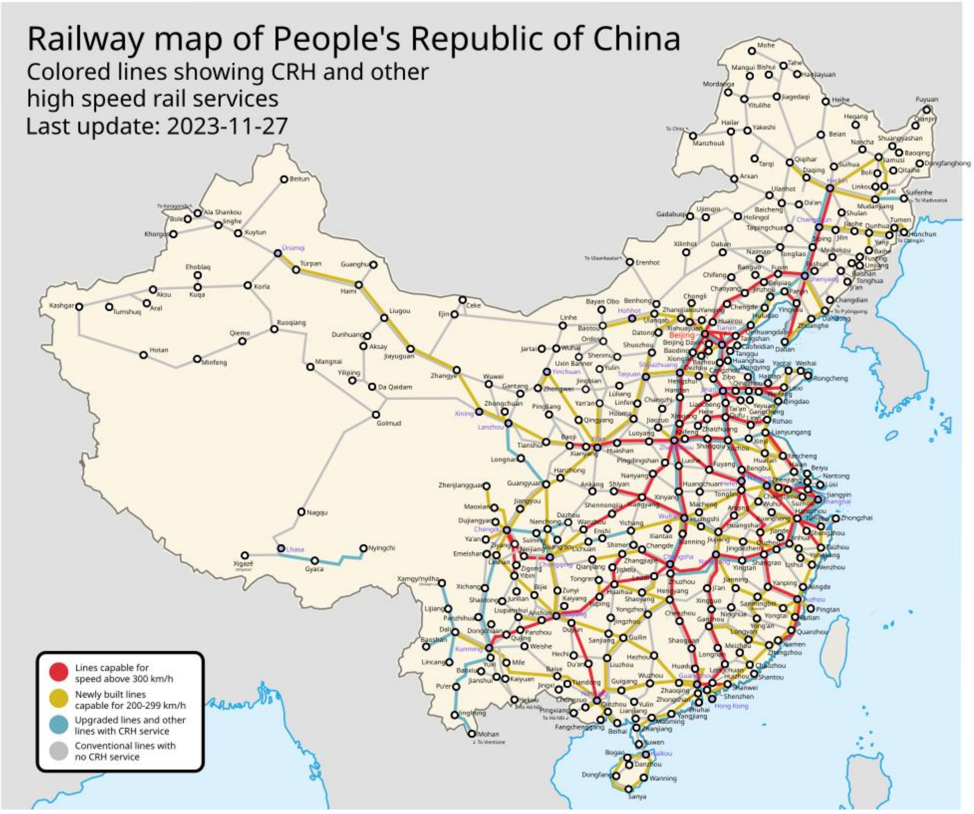
[371] Oxford Institute for Energy Studies (n.d.). *Carbon Capture, Utilization, and Storage*. Available at: https://chineseclimatepolicy.oxfordenergy.org/book-content/domestic-policies/carbon-capture-utilization-and-storage/ (Accessed: 9 January 2025).

production costs for these facilities with an estimated over 17,000 km of CO_2 pipelines being needed nationwide to achieve targets[372].

While plans to expand CO_2 transport infrastructure are under discussion, there are no publicised, large-scale pipeline development projects as of now. Instead, the focus is on establishing regional hubs, which may eventually integrate pipeline networks. Key projects include the East China CCUS Hub, designed to connect chemical and power plants in Jiangsu and Zhejiang provinces with offshore saline aquifer storage in the East China Sea. The Ordos Basin is also a focal point for infrastructure development, with plans to link industrial emitters to storage sites via a network of pipelines. Additionally, the Sichuan Basin aims to integrate cement and chemical industries with nearby geological storage.

China's extensive rail network, represented in Figure 9-79, spans over 162,000 kilometres, and can provide additional flexibility for CO_2 transport. While limited at present, rail transport could become a viable option for remote areas if equipped with specialised systems and safety measures. Coastal projects, such as the Guangdong Offshore Storage Project, utilise shipping for CO_2 transport to offshore storage sites, highlighting flexibility in transport methods to accommodate regional needs.

Figure 9-79. Railway network in China



The establishment of CCUS hubs and clusters is a transformative aspect of China's carbon capture infrastructure. These hubs act as regional centres, connecting multiple industrial facilities via shared pipelines and transport systems. For example, the Shaanxi Yanchang Petroleum CCUS cluster integrates CO_2 capture across sources and uses extensive pipelines to streamline transport and storage processes. This model leverages economies of scale by integrating efforts across multiple facilities to address emissions.

[372] **ECNS.** (2023, July 13). *China's population sees negative growth in 2022 for first time in 60 years: NBS*. Retrieved January 9, 2025, from https://www.ecns.cn/news/cns-wire/2023-07-13/detail-ihcrchef5347273.shtml

Eastern China emerges as a key area for CCUS hub development due to its dense industrial activities. Projects in Shandong and Jiangsu Provinces form a regional hub interconnected by pipelines, reducing industrial emissions efficiently. The Sinopec Qilu Petrochemical CCUS project anchors this hub, exemplifying the benefits of integrating advanced capture systems with coordinated infrastructure.

Carbon capture market drivers and barriers

Policy and regulation

CCUS has been a consistent element of China's national carbon mitigation strategies since the 12th Five-Year Plan (2011-2015). An overview of key policies and regulations in China relevant to CCUS are outlined in Table 9-56 below.

Table 9-56. Policies and regulations in China relevant to CCUS

Policy/ regulation	Location	Key points
"30/60" Targets	Nationwide	• Carbon peaking by 2030 and neutrality by 2060. • CCUS recognised as a critical tool for mitigating industrial emissions.
NDRC and NEA Implementation Guidelines	Nationwide	• Establish safety protocols for CCUS operations.
National Key R&D Program (2016–2020)	Nationwide	• Consolidated 973 and 863 programs. • Funded advanced capture materials, geological storage methods, and utilisation techniques.
14th Five-Year Plan (2021–2025)	Nationwide, focus on industrial clusters	• Targets emissions from power generation, cement production, and chemicals. • Emphasises R&D for capture efficiency and cost reduction.

Initially, policies concentrated on demonstration and pilot projects aimed at developing foundational technologies and methodologies. However, with the introduction of the "30/60" targets—carbon peaking by 2030 and carbon neutrality by 2060—there has been an expansion in the scope of CCUS-related policies. By October 2022, China had issued 70 national-level CCUS policies, including plans, standards, roadmaps, and technology catalogues. These documents outline strategies for future CCUS research, development, investment, and international technology cooperation, indicating an ongoing integration of CCUS into the country's carbon neutrality plans. This strategic inclusion reflects China's recognition of CCUS as a critical tool in mitigating industrial emissions and achieving long-term environmental sustainability.

China's CCUS policy framework involves multiple government departments, ensuring a comprehensive approach to its development and implementation. More than ten central government departments have included CCUS in their policy agendas, with significant contributions from the State Council, the National Development and Reform Commission (NDRC), the Ministry of Science and Technology (MOST), and the Ministry of Ecology and Environment (MEE). Each department addresses different aspects of CCUS, such as technological innovation, environmental standards, economic incentives, and regulatory measures. This multi-departmental involvement aims to provide a broad policy support system that covers various dimensions of CCUS from research and development to practical application and compliance with environmental regulations. Such a coordinated approach facilitates the alignment of CCUS initiatives with broader national objectives, promoting synergy across different sectors and enhancing the effectiveness of policy implementation.

China has developed a multifaceted policy framework to advance CCUS technologies, addressing critical components of supply, environment, and demand, though gaps in integration and scalability remain. Supply-side policies focus on fostering technological innovation and supporting pilot projects to establish the feasibility of CCUS technologies. The National Key R&D Program for CCUS (2016–2020) consolidated previous initiatives like the 973 and 863 Programs, directing funding towards research on advanced capture materials, geological storage methods, and utilisation techniques. Major projects like the Shenhua Ordos CCS Demonstration Project, which captures CO_2 from a coal-to-liquid plant in Inner Mongolia and stores it in saline aquifers, and the China Huaneng Group's GreenGen Project, which integrates CCUS with advanced energy systems, demonstrate China's technical capabilities. However, supply-side policies lack sufficient focus on scaling technologies for high-emission sectors like steel, cement, and chemicals, which limits their impact on large-scale decarbonisation.

Environmental policies form the regulatory backbone for CCUS deployment, but they often lack specificity and comprehensive enforcement mechanisms. These policies include China's National Standards for Geological Storage of CO_2, issued by the Ministry of Natural Resources, which provide guidance on site selection, risk assessment, and monitoring for storage projects. Tax incentives for low-carbon technologies, offering a 50% reduction in corporate income tax for companies investing in CCUS and similar initiatives, encourage enterprise-level engagement. Policies promoting CO_2 use in EOR, such as Sinopec's Shengli Oilfield project, integrate CCUS into industrial processes by utilising captured CO_2 to boost oil recovery while reducing emissions. The Action Plan for Carbon Dioxide Peaking Before 2030 highlights CCUS as a critical technology for achieving carbon neutrality, setting goals for sector-specific regulatory frameworks and pilot projects. However, many of these environmental policies lack detailed implementation strategies, leaving room for improvement in terms of practical applicability and alignment with international standards.

Demand-side policies remain underdeveloped despite their importance in creating market pull for CCUS technologies. Initiatives like Sinopec's Green Procurement Mandate, which incentivises supply chains to integrate low-carbon technologies, and direct subsidies for CCUS applications, such as methanol production at Yanchang Petroleum, demonstrate preliminary steps toward creating market demand. Additionally, proposals like the Green Building Certification, which rewards developers using CCUS-produced materials such as low-carbon cement, indicate potential growth areas.

An integrated example of policy alignment is the Guangdong Province CCUS Industrial Development Plan, which combines supply and demand-side measures. This plan promotes CCUS-specific standards, funds research and development, and provides financial support to industries, fostering the growth of low-carbon industrial clusters. Such coordinated efforts demonstrate the potential of aligning policies across different domains to accelerate the adoption of CCUS technologies.

The 14th Five-Year Plan (2021-2025) establishes the foundational policy architecture for China's low-carbon development strategy. This plan articulates specific measures for integrating decarbonisation technologies across industrial sectors while promoting economic growth. For CCUS, the plan emphasis deployment in key industrial clusters, particularly targeting emissions from power generation, cement production, and chemical manufacturing. The plan also outlines provisions for research and development funding, with a focus on improving capture efficiency and reducing operational costs.

Financial

China has integrated CCUS development into its national climate strategy, particularly through its 14th Five-Year Plan (2021-2025). The Ministry of Science and Technology (MOST) and (NDRC have established several key funding mechanisms for CCUS development. The China Clean Development Mechanism Fund provides significant support for CCUS projects, while provincial governments offer additional funding through local environmental protection funds. Key financial incentives in China relevant to CCUS are outlined in Table 9-57 below.

Table 9-57. Financial incentives in China relevant to CCUS

Financial incentive	Support mechanism	Location	Key points
Inclusion in Green Bond Endorsed Projects Catalogue	Investment Instruments for Green Projects	Nationwide	• Attracts green financing for CCUS technologies. • Highlights carbon capture and storage as eligible projects.
Carbon Emission Reduction Facility (CERF)	Concessional Finance via PBOC	Nationwide	• Covers 60% of loans at 1.75% interest. • Mobilised £65 billion in re-lending, reducing 100 Mt CO_2 annually.
Trading via National Emissions Trading System (ETS)	Market-Based Carbon Pricing	Nationwide	• Covers 2,000 facilities accounting for 40% of emissions. Enables CCUS to participate in emissions reduction.
Trading via China Certified Emission Reduction (CCER)	Voluntary Carbon Credit Offset Mechanism	Nationwide	• Allows ETS participants to offset 5% of emissions obligations. • Links compliance and voluntary carbon markets.
State-Owned Enterprises (SOEs)	Direct Operational Investment	Nationwide	• Major projects by Sinopec, CNPC, and CNOOC. • Focus on large-scale implementation and innovation.

China's national emissions trading system (ETS), implemented in July 2021, functions as a key mechanism within the nation's carbon pricing framework. The system is obligatory for the encompassed entities which includes 2,000 power generation facilities that collectively account for 4.5 billion tonnes of CO_2 emissions annually, representing approximately 40% of China's total emissions. This initial scope establishes the foundation for a market-based approach to emissions reduction.

The ETS utilises an intensity-based allocation methodology, whereby emission allowances are distributed according to sector-specific benchmarks linked to production output. This framework incorporates both ex-ante allocation based on historical data and ex-post adjustments reflecting actual production levels. Trading mechanisms enable the transfer of allowances between entities, with prices stabilising at approximately 60 yuan per tonne of CO_2 in 2024, establishing a reference point for investment decisions in emissions reduction technologies.

The Ministry of Ecology and Environment has outlined a two-phase expansion programme for the ETS. The initial phase (2024-2026) focuses on incorporating high-emission industrial sectors, including steel, cement, and aluminium manufacturing. This phase emphasises data quality improvement and system familiarisation. The subsequent phase, commencing post-2026, introduces more stringent quotas and enhanced compliance mechanisms, with the objective of encompassing 60% of national greenhouse gas emissions.

The regulatory framework has been further strengthened through integration with the national ETS, which now recognizes CCUS as an eligible emissions reduction methodology. This integration provides indirect financial incentives through carbon market mechanisms.

In January 2024 the CCER scheme was reinstated following its suspension in 2017. The CCER framework permits the generation and trading of carbon credits from verified emission reduction projects. Under current regulations, ETS participants may utilise CCER credits to offset up to 5% of their emissions obligations, establishing a linkage between compliance and voluntary carbon markets. This mechanism creates additional pathways for emissions reduction while maintaining system integrity through verification requirements and usage limitations.

The People’s Bank of China (PBOC) has introduced the CERF, a structural monetary policy instrument designed to advance China’s carbon peaking and neutrality goals. This initiative mobilises social capital to support low-carbon development in clean energy, energy conservation, environmental protection, and carbon reduction technologies. Under CERF, the PBOC offers low-cost funding to financial institutions, covering 60% of qualified carbon reduction loans at a rate of 1.75%, incentivising lending at rates close to the Loan Prime Rate (LPR). Eligible institutions must disclose lending details, including supported emission reductions, which are verified by third-party auditors and subjected to public scrutiny. The CERF highlights the government’s commitment to fostering financial institutions' awareness of green transitions, directing investments into low-carbon industries, and promoting green production, circular economy principles, and sustainable living. This facility sends a strong policy signal, aiming to accelerate China’s transition to a green and low-carbon economy.

Unlike the U.S. 45Q tax credit system, China's financial support for CCUS primarily comes through direct government funding and subsidies. The National Key R&D Program has allocated substantial funding for CCUS demonstration projects, with particular emphasis on industrial applications. Major demonstration projects receive up to 30% of their capital costs from central government funding, with additional support from provincial governments.

Financial mechanisms are integral to the advancement of CCUS projects in China. CCUS initiatives have been included in the updated Green Bond Endorsed Projects Catalogue (2021 Edition), which may attract green investments. SOEs have played a significant role in funding CCUS, aligning their investments with national carbon neutrality objectives. The People’s Bank of China has allocated approximately £32.5 billion in concessional finance to Chinese financial institutions to encourage re-lending for green projects. This Carbon Emission Reduction Facility has enabled around £65 billion in re-lending by the end of 2022, contributing to a reduction of 100 Mt of carbon emissions that year. The specific allocation of these funds to CCUS projects remains unclear, but these financial instruments support the development and scalability of CCUS technologies.

State-owned enterprises (SOEs) in China have been central to funding and developing CCUS projects in response to government carbon neutrality targets. Major SOEs, including Sinopec, CNPC and China National Offshore Oil Corporation (CNOOC), have initiated several large-scale CCUS demonstration projects. For example, Sinopec launched China's first 1 Mt per annum-scale CCUS project in a coal gasification unit in August 2022. Additionally, projects such as the Xinjiang cluster, projected to capture 10 Mt of CO_2 annually by 2030, and the first offshore storage project in the Pearl River Mouth Basin, expected to store over 300,000 tonnes of CO_2 per year, illustrate the involvement of SOEs in CCUS development. Local governments have also increased their support for CCUS, with ten subnational governments implementing CCUS research and development (R&D) and promotion programmes by late 2022. Guangdong Province, for instance, has provided incentives for CCUS demonstration projects in the power plant sector. This support from both central and local governments, along with participation from SOEs, contributes to the infrastructure necessary for CCUS initiatives in China. The active role of SOEs not only provides financial resources but also leverages their extensive operational capacities to implement and scale CCUS technologies effectively.

The national and provincial governments in China have invested approximately £110 million in CCUS development, primarily targeting research and innovation. This financial investment is supplemented by contributions from the People’s Bank of China, which has facilitated significant funding through concessional finance mechanisms. The inclusion of CCUS in green financial instruments, combined with funding from SOEs and supportive local government policies, aims to enhance China's capacity to scale CCUS technologies. As policies continue to develop and financial support mechanisms expand, China is positioned to further advance its CCUS capabilities, which are integral to its long-term carbon neutrality goals. However, the effectiveness of these investments will depend on the continued alignment of financial incentives with technological advancements and market needs, as well as the ability to overcome technical and economic barriers to widespread CCUS deployment.

The 2024 edition of the Green and Low-Carbon Transformation Industry Guidance Catalogue continues and expands upon the policies established in the 2021 edition[373]. Issued by the NDRC and other relevant departments, the 2024 catalogue provides detailed guidelines to support the transition to green and low-carbon industries. For CCUS, the catalogue outlines specific measures for carbon dioxide capture, utilisation, and storage, highlighting its role in controlling greenhouse gas emissions. It identifies key areas for technological advancement and infrastructure development to support CCUS deployment across various industrial sectors.

9.4.3.5 Hydrogen production

Green hydrogen – hydrogen produced by renewably powered electrolysis - is a key feedstock for e-fuel production. The availability of green hydrogen is influenced by several factors, including supportive policies and regulations, as well as financial incentives, and resource availability.

This section provides an overview of the current state of green hydrogen production across the country, encompassing green hydrogen projects, hydrogen hub developments, and the deployment of related transportation infrastructure. Furthermore, this section covers green hydrogen-related policies, regulations, and financial incentives, as these can either accelerate or hinder the deployment of green hydrogen production.

Hydrogen activity

China's total hydrogen production, as of 2024, was approximately 33 million tonnes annually[374]. Most of this hydrogen is produced through coal gasification and natural gas reforming, both of which are carbon intensive. Green hydrogen—produced through water electrolysis powered by renewable energy—accounts for less than 0.1% of the total hydrogen production in China[375]. The Hydrogen Energy Development Plan (2021-2035) includes targets to increase green hydrogen's share to 10% by 2030 and 15% by 2035, supported by investments in renewable energy and hydrogen infrastructure[376].

Developments in green hydrogen production, infrastructure, and industrial integration across China leverages the diverse regional renewable energy resources and logistics infrastructure. Key projects in different regions align with local renewable energy capacities and industrial requirements. Strategic pilot projects in China are demonstrating innovative solutions to competing resource demands by leveraging renewable energy for hydrogen production. These projects highlight the growing distinction between blue hydrogen and green hydrogen. This differentiation is critical for understanding the pathways to decarbonization and the scalability of hydrogen as a clean energy carrier.

A selection of hydrogen projects in China are outlined in Table 9-58, and depicted in Figure 9-80.

Table 9-58. Selection of hydrogen projects in China

Project Name	Region	Description	Status	Capacity (tH_2/year)
Sinopec Kuqa Green Hydrogen Plant	Xinjiang	Solar-powered green hydrogen production.	Operational	20,000

[373] National Development and Reform Commission (NDRC) of China. (2024, February 29). *Notice on Issuing the "Green Low-Carbon Transition Industry Guidance Catalogue (2024 Edition)" (Fa Gai Huan Zi [2024] No. 165)*. Retrieved from https://www.ndrc.gov.cn/xxgk/zcfb/tz/202402/t20240229_1364291.html.

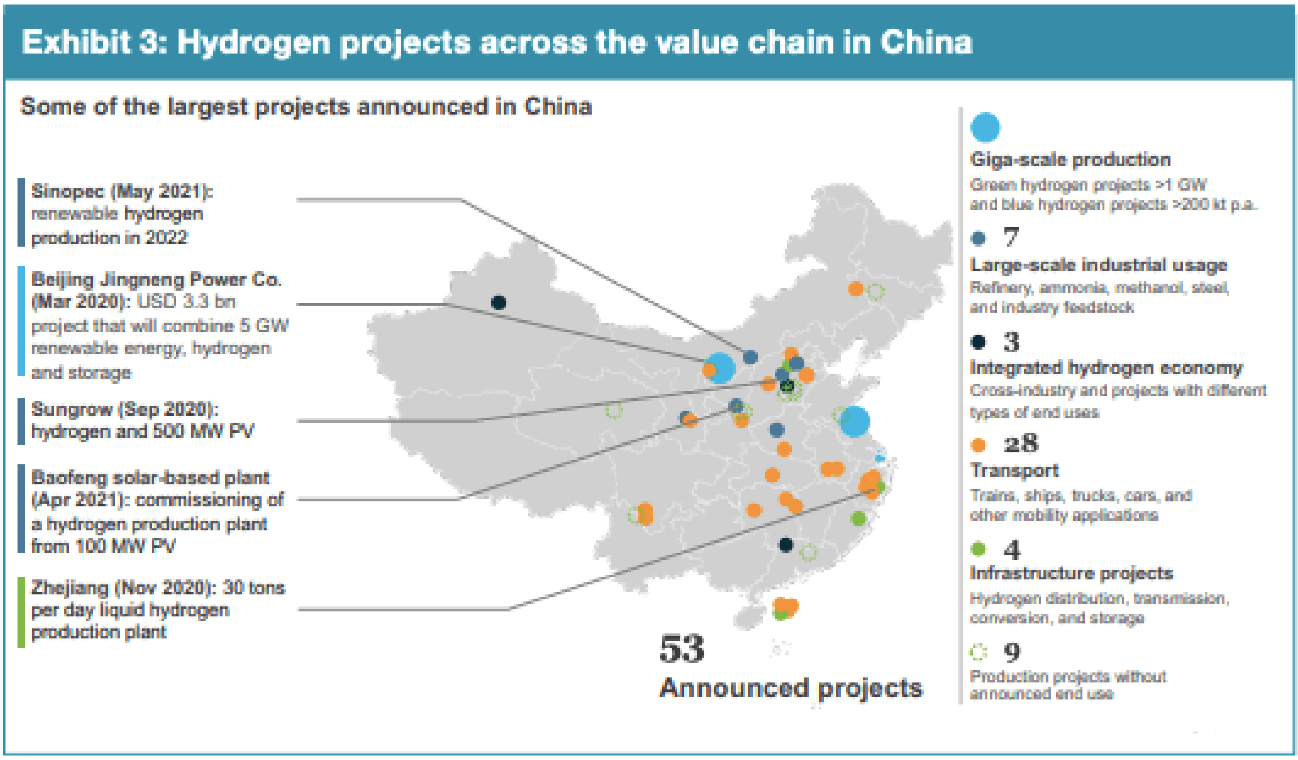
[374] International Energy Agency (IEA). (2024). *Global Hydrogen Review 2024*. Retrieved January 10, 2025, from https://www.iea.org/reports/global-hydrogen-review-2024

[375] World Economic Forum (WEF). (2023). *Green hydrogen in China: A roadmap for progress*. Retrieved from https://www3.weforum.org/docs/WEF_Green_Hydrogen_in_China_A_Roadmap_for_Progress_2023.pdf

[376]The State Council of the People's Republic of China. (2022, March 23). *China promotes green development in civil aviation industry*. Retrieved January 10, 2025, from https://english.www.gov.cn/statecouncil/ministries/202203/23/content_WS623ac568c6d02e53353282a4.html

Project Name	Region	Description	Status	Capacity (tH_2/year)
Baofeng Energy Project	Ningxia	Utilises a 150 MW electrolyser for hydrogen production.	Operational	21,000
Ordos Green Hydrogen Plant	Inner Mongolia	Integrates wind and solar power for hydrogen generation.	Planning	30,000
SPIC Hydrogen Demonstration	Qinghai	Hydropower-based green hydrogen production.	Pilot Stage	10,000
Guangdong Green Hydrogen Hub	Guangdong	Aims to establish a regional green hydrogen supply chain.	Planning	50,000

Figure 9-80. Hydrogen value chain projects in chain[377]



Green hydrogen projects, driven by renewable energy, are scaling up across China:

- **Xinjiang's Sinopec Kuqa Green Hydrogen Plant**: Operational since 2023, this facility capitalises on Xinjiang's solar irradiance of over 2,500 hours annually to produce 20,000 tonnes of green hydrogen per year, transported via a dedicated pipeline to Sinopec's Tahe refinery. Plans to expand capacity to 30,000 tonnes annually by 2028 further emphasise the scalability of solar-powered green hydrogen.
- **Ningxia Baofeng Energy Project**: Launched in 2021, this initiative uses a 150 MW alkaline electrolyser powered by a 200 MW solar array, producing 27,000 tonnes of hydrogen annually. This hydrogen is primarily used to replace coal in methanol production, demonstrating how

[377] **REGlobal**. (n.d.). *Investment trends and recent developments in China's hydrogen market*. Retrieved January 10, 2025, from https://reglobal.org/investment-trends-and-recent-developments-in-chinas-hydrogen-market/

green hydrogen can decarbonise industrial processes. The project serves as a replicable model for other regions.

- **Inner Mongolia's Ordos Green Hydrogen Plant**: Set to begin production by 2026, this project aims to generate 30,000 tonnes of green hydrogen annually using wind and solar power. Plans include hydrogen storage and pipeline construction to support the steel and chemical sectors.
- **SPIC Hydrogen Demonstration Project in Qinghai**: Exploring hydropower for green hydrogen production, this pilot project produces 10,000 tonnes annually, with applications in transportation such as fuel cell-powered buses and trucks.

Large-scale green hydrogen hubs are also under development, to bolster regional and national hydrogen supply chains:

- **Guangdong Green Hydrogen Hub**: This initiative aims to produce 50,000 tonnes annually, integrating production, storage, and distribution. Dedicated pipelines and connections to a future national hydrogen network position Guangdong as a leader in hydrogen technology and logistics.
- **Sinopec's ¥20 Billion Green Hydrogen Project**: Located in Inner Mongolia, this ambitious project will produce 100,000 tonnes of hydrogen annually, transported through a new 400 km pipeline to Beijing.

China is also actively exploring hydrogen as an energy source for various transportation applications. Since 2016, Rugao in Jiangsu Province has served as a pilot site for hydrogen economy initiatives. Designated as a "Hydrogen Featured Town," Rugao has implemented hydrogen fuel cell technologies, including fuel cell buses, and has hosted international fuel cell vehicle congresses to promote research and collaboration. Another significant hydrogen initiative is Sinopec's Xinjiang Kuqa Green Hydrogen Project, which was completed in August 2023. This facility, the largest photovoltaic-based green hydrogen production site in China, has an annual capacity of 20,000 tonnes and supplies green hydrogen to the Sinopec Tahe Petrochemical plant, replacing fossil fuels in hydrogen production processes.

Hydrogen-powered buses and trams are also gaining traction, with cities like Hefei and Foshan deploying hydrogen-powered buses on select routes. These projects aim to test operational efficiency and environmental benefits, highlighting the role of hydrogen as a key energy carrier in public transportation. However, the adoption of synthetic e-fuels in public transport remains limited, due to a greater focus on electrification and hydrogen technologies.

China is actively trialling hydrogen fuel cell technology in its public transportation systems to reduce urban emissions and assess the feasibility of hydrogen as an alternative energy source. In May 2024, Beijing introduced 50 hydrogen fuel cell buses into operation within the Daxing International Hydrogen Energy Demonstration Zone, enhancing the Beijing-Tianjin-Hebei hydrogen demonstration city cluster.

These buses are equipped with fuel cell systems developed by companies such as Innoreagen and Yuchai Xingshunda. Innoreagen's 115kW hydrogen fuel cell system has been installed in 20 Higer hydrogen fuel cell buses operating in Beijing's Economic Development Zone, providing commuting services. Similarly, Yuchai Xingshunda's 82kW and 125kW hydrogen fuel cell systems have been deployed in 50 Suzhou King Long 12-meter hydrogen fuel cell buses, a significant step in the commercial operation of hydrogen-powered public transport.

Hydrogen transport infrastructure

Infrastructure development is critical for scaling green hydrogen in China. The first dedicated hydrogen pipeline, spanning 400 km, connects the Sinopec Kuqa plant to refineries in Xinjiang[378]. Other proposed pipelines in Ningxia and Inner Mongolia aim to link production facilities with industrial clusters. Hydrogen clusters in provinces like Shandong and Jiangsu are attempting to promote collaboration among

[378] Carbon Credit Markets. (n.d.). *China's first long-distance hydrogen pipeline*. Retrieved January 10, 2025, from https://www.carboncreditmarkets.com/en/single-post/china-s-first-long-distance-hydrogen-pipeline

producers, consumers, and technology providers. In Shandong Province, efforts are underway to establish a hydrogen industry cluster. Shandong has been designated as China's only pilot zone for hydrogen's wider application, aiming to become a testing ground for fuel cells, batteries, pipelines, and business models essential for a nationwide rollout.

Tangshan, in Hebei Province, is also advancing hydrogen infrastructure development with a major project. Tangshan Haitai New Energy Technology Co., Ltd. ("Haitai Solar") is leading the Zhangjiakou-Tangshan hydrogen pipeline initiative, currently in the geological investigation stage. Construction is anticipated to commence shortly, with the pipeline, spanning 737 kilometres, expected to be operational by 2027 and is designed to operate at 63 bar pressure, exceeding China's current standard of 40 bar[379]. This pure hydrogen pipeline underscores China's ambitions to decarbonise its iron and steel industry through hydrogen metallurgy, a pivotal approach to mitigating emissions in hard-to-abate sectors and aims to facilitate renewable hydrogen exports and bolster the hydrogen economy across regions.

In addition to pure hydrogen pipelines, there is an increasing focus on hybrid pipelines capable of transporting hydrogen alongside other gases. Such pipelines are being explored as versatile and cost-effective solutions, particularly in regions where existing infrastructure can be adapted for hydrogen transport.

Hydrogen pipeline infrastructure in China is depicted in Figure 9-81 below.

Figure 9-81. Operational Hydrogen pipeline infrastructure in China[380].

Hydrogen clusters in provinces such as Shandong and Jiangsu are fostering collaboration among producers, consumers, and technology providers. By consolidating stakeholders, these clusters aim to accelerate innovation and integrate hydrogen into industrial and commercial applications efficiently. Shandong, in particular, is emerging as a key hub for hydrogen technology, focusing on pilot projects that could serve as benchmarks for other regions.

[379] TankTerminals. (n.d.). *China to build world's longest hydrogen pipeline to transport green hydrogen*. Retrieved January 10, 2025, from https://tankterminals.com/news/china-to-build-worlds-longest-hydrogen-pipeline-to-transport-green-hydrogen/

[380] China Hydrogen. (n.d.). The hydrogen transportation pipeline. Substack. Retrieved January 14, 2025, from https://chinahydrogen.substack.com/p/the-hydrogen-transportation-pipeline

The Jiangsu Provincial Development and Reform Commission recently identified Zhangjiagang, a county-level city of Suzhou, as a pilot city for the hydrogen industry. Zhangjiagang hosts over 40 hydrogen enterprises, featuring an extensive industrial chain encompassing hydrogen production, storage, transportation, and fuel cells. Furthermore, the city has integrated hydrogen technology across multiple sectors, including public transportation, port operations, combined heat and power, and logistics. Economically, the hydrogen industry in Zhangjiagang has already generated an annual output value exceeding 10 billion yuan (US$1.4 billion), with ambitious plans to double this figure to 20 billion yuan by 2025[381]. This growth is driven by strong local government policies, robust industrial collaboration, and targeted applications that align with the city's industrial strengths.

Zhangjiagang's achievements demonstrate that hydrogen can work effectively in specific contexts, particularly when supported by a conducive ecosystem of policy incentives, technological innovation, and market demand. However, its success may not be easily replicable in regions lacking similar resources, infrastructure, or government backing.

Hydrogen transport logistics face challenges due to hydrogen's low density. Efforts are underway to explore liquefied hydrogen and ammonia as carriers. A pilot project in Guangdong focuses on transporting liquefied hydrogen by rail, which could establish cost-effective, long-distance transport solutions.

Integration of rail and port infrastructure into hydrogen logistics is ongoing. Ports in Guangdong and Shandong are being upgraded for hydrogen export capabilities, while rail lines in Qinghai and Inner Mongolia are being adapted for hydrogen transport. Such infrastructure is crucial for connecting inland production sites to coastal markets and export hubs.

Hydrogen production market drivers and barriers

Policy and regulation

Key policies and regulations in China relevant to hydrogen are outlined in Table 9-59 below.

Table 9-59. Policies and regulations in China relevant to hydrogen production

Policy/ regulation	Location	Key points
14th Five-Year Plan	Nationwide	○ Focus on hydrogen energy development. Targets include: • Deployment of 50,000 fuel cell vehicles (FCVs). • Construction of hydrogen refuelling stations. • Annual production of 100,000–200,000 tonnes of renewable hydrogen by 2025. • Aim to reduce CO_2 emissions by 1–2 million tonnes annually.
Medium- and Long-Term Plan for Hydrogen Industry (2021-2035)	Nationwide	• Phased approach to hydrogen development: • By 2025: Establish a hydrogen supply system based on industrial by-products and renewable energy. • By 2030: Develop a comprehensive hydrogen industry technology innovation system. • By 2035: Widespread hydrogen applications across sectors with increased contribution from renewable hydrogen.
NDRC and NEA Implementation Guidelines	Nationwide	• Define technical standards for hydrogen production.

381 HEIE Expo. (n.d.). Zhangjiagang: A pilot city for hydrogen industry development. Retrieved January 14, 2025, from https://www.heieexpo.com/english/628.html

Policy/ regulation	Location	Key points
Regional Hydrogen Plans (14th Five-Year Plans)	18 provincial regions	• Tailored strategies based on local resources and strengths: • Guangdong/Shandong: Prioritise hydrogen fuel cell vehicle development. • Inner Mongolia: Focus on green hydrogen production using renewable energy.
Hydrogen Pipeline Network Initiative	Nationwide (Resource-rich west to demand centres in east/south)	• Planned 6,000-km pipeline network by 2050 to connect western production to eastern/southern demand centres. • Initial 400-km Sinopec pipeline (2023): • Links Inner Mongolia to Beijing-Tianjin-Hebei region. • Annual capacity of 100,000 tonnes. • Serves as a test case for long-distance hydrogen transport.
Guidelines for Establishing the Standards System on Hydrogen Energy Industry (2023)	Nationwide	• Comprehensive framework regulating hydrogen production, storage, transport, and usage. • Divided into five subsystems: fundamentals and safety, preparation, storage and transport, filling, and applications. • Aim to establish 30+ national and industrial standards by 2025.

The 14th 5-year plan is reinforced by the Medium- and Long-Term Plan for the Development of the Hydrogen Industry (2021-2035), which presents a phased approach to hydrogen development. By 2025, the plan targets establishing a hydrogen energy supply system primarily based on industrial by-product hydrogen and renewable energy hydrogen production. Targets include the deployment of approximately 50,000 FCVs, the construction of hydrogen refuelling stations, and achieving an annual production of 100,000 to 200,000 tonnes of hydrogen from renewable sources, which is likely to be exceeded[382]. Additionally, this phase aims to reduce carbon dioxide emissions by 1 to 2 million tonnes annually. The 2030 milestone aims to create a complete hydrogen industry technology innovation system and clean energy hydrogen production network. Furthermore by 2035, the strategy envisions widespread hydrogen application across various sectors, with a significant increase in renewable energy hydrogen's contribution to terminal energy consumption.

The Hydrogen Medium- and Long-Term Plan is supported by specific implementation guidelines released by the NDRC and National Energy Administration (NEA). These guidelines establish technical standards for hydrogen production, define safety protocols for CCUS operations, and outline requirements for synthetic fuel production facilities. Financial support mechanisms are detailed within these guidelines, including provisions for subsidies up to 20 million yuan for hydrogen projects in regions like Dalian, with similar incentive structures being implemented in Weifang and Sichuan provinces.

These coordinated policies create a comprehensive framework that addresses both technological development and market creation, while ensuring alignment with China's broader carbon neutrality goals. The emphasis on regional implementation allows for adaptation to local conditions while maintaining consistency with national objectives.

China's approach to hydrogen development is characterised by significant regional initiatives. Out of the 34 provincial-level regions, 18 have independently introduced their own hydrogen industry plans as part of their 14th Five-Year Plans, tailoring strategies to local resources and industrial strengths. For instance, provinces like Guangdong and Shandong have prioritised hydrogen fuel cell vehicle

[382] Rystad Energy. (2024, December 31). China set to smash national hydrogen targets, solidifying lead in global electrolyser market. https://www.rystadenergy.com/news/china-hydrogen-targets

development, while regions such as Inner Mongolia focus on green hydrogen production utilising abundant renewable energy resources.

The government has implemented substantial support mechanisms for hydrogen infrastructure, exemplified by the planned 6,000-kilometer national hydrogen pipeline network. This initiative aims to connect hydrogen production in resource-rich western regions with demand centres in the east and south by 2050. The network aims to address geographical disparities between hydrogen production capabilities and industrial demand. National Pipeline Development Initial implementation of this network has commenced with Sinopec's 400-kilometer pipeline project, announced in April 2023. This pipeline will transport hydrogen from Inner Mongolia to the Beijing-Tianjin-Hebei region with a designed capacity of 100,000 tonnes annually. The project serves as a test case for long-distance hydrogen transportation infrastructure in China and will inform future expansion of the national network.

China is taking steps to establish a national standards system for the hydrogen energy industry to address its low-carbon development goals. In July 2023, six government departments, led by the State Administration for Market Regulation (SAMR), released the "Guidelines for Establishing the Standards System on Hydrogen Energy Industry (2023)." This framework outlines a comprehensive approach to regulating hydrogen production, storage, transport, and utilisation. It is divided into five key subsystems: fundamentals and safety, hydrogen preparation, hydrogen storage and transport, hydrogen filling, and energy applications. These categories are further refined into 20 second level and 69 third-level subsystems to address technical, safety, and quality standards across the value chain. The guidelines aim to establish over 30 national and industrial standards by 2025, reflecting an effort to unify and improve the fragmented regulatory landscape currently governing hydrogen.

Financial

Key financial incentives in China relevant to hydrogen are outlined in Table 9-60 below.

Table 9-60. Financial incentives in China relevant to hydrogen

Financial incentive	Support mechanism	Location	Key points
Subsidies	Direct funding for infrastructure	Dalian Municipality	• Up to 20 million yuan subsidy for hydrogen infrastructure projects, focusing on transportation and distribution facilities; requires minimum project scale and technology verification.
Direct Funding and Tax Provisions	Financial and operational support	Weifang Municipality	• Direct funding mechanisms and tax incentives for qualifying projects; includes established technical criteria and operational requirements for financial support.
Green Bonds and Concessional Financing	Investment instruments	Nationwide	• Financial support through green bonds, concessional financing, and investment tools; supports scaling hydrogen and renewable energy projects while incentivising private sector participation.

Hydrogen similarly to CCUS, is given significant attention in the 2024 Green and Low-Carbon Transformation Industry Guidance Catalogue[373], with a focus on the entire hydrogen value chain, including production, storage, transportation, and utilisation. The catalogue emphasises the need for developing comprehensive hydrogen infrastructure and promoting the integration of hydrogen technologies with other low-carbon systems. This holistic approach aims to establish a robust hydrogen economy in China, facilitating its use in diverse applications such as energy storage, industrial processes, and transportation. By addressing the full spectrum of the hydrogen value chain, the policy framework seeks to eliminate bottlenecks and enhance the efficiency and effectiveness of hydrogen deployment, thereby supporting China's transition to a low-carbon economy.

The 2024 guidance also integrates renewable energy advancements, covering the manufacturing and construction of equipment for wind, solar, biomass, hydro, geothermal, and ocean energy. It underscores the importance of transitioning to cleaner energy sources and enhancing energy efficiency across various sectors. The document promotes the development of new energy facilities and the upgrade of existing infrastructure to support the deployment of renewable technologies, aligning with China's broader green transformation objectives.

Financial support mechanisms outlined in the 2024 catalogue include the encouragement of green bonds, concessional financing, and other investment instruments to fund projects that meet the catalogue's criteria. This financial backing is crucial for scaling up hydrogen, and renewable energy projects, ensuring their viability and sustainability. The catalogue also emphasises the importance of international cooperation and the alignment of domestic policies with global green standards, facilitating the exchange of knowledge and technology to advance China's green and low-carbon initiatives. Such financial instruments not only provide the necessary capital for large-scale projects but also incentivise private sector participation, thereby broadening the investment base and accelerating the deployment of critical green technologies.

Provincial and municipal governments have also established varying support mechanisms for hydrogen infrastructure:

- Dalian Municipality has implemented a subsidy framework providing up to 20 million yuan for hydrogen infrastructure projects. The funding structure specifically targets transportation and distribution facilities, with requirements for minimum project scale and technology verification.
- Sichuan Province's hydrogen development programme includes the establishment of industrial facilities in the Meishan zone of Tianfu New Area. The programme encompasses manufacturing capacity for hydrogen equipment and integration with existing industrial infrastructure.
- Weifang's hydrogen infrastructure support system incorporates direct funding mechanisms and tax provisions for qualifying projects. The municipality has established technical criteria and operational requirements for projects seeking financial support.

These regional initiatives operate within China's broader hydrogen infrastructure framework while maintaining autonomy in implementation approaches. The variation in regional support mechanisms reflects differences in industrial capacity, existing infrastructure, and economic priorities across provinces.

Barriers

Competition for renewable hydrogen is intensifying as other sectors increase demand. China is the world's largest hydrogen producer, but over 60% of this production relies on coal gasification, contributing significantly to emissions. Transitioning to green hydrogen—produced via renewable energy—faces challenges from multiple sectors:

- Industrial use: Heavy industries like steel and cement production are increasingly adopting hydrogen as a decarbonisation strategy. For example, China's Baowu Steel Group has initiated hydrogen-based steelmaking projects, aiming to reduce reliance on coal in blast furnaces. These projects alone are expected to consume over 1 million tonnes of hydrogen annually by 2030.
- Transportation: Hydrogen-powered fuel cells are gaining traction in heavy-duty transportation, including trucks, buses, and ships. Policies promoting hydrogen vehicle adoption, such as

subsidies for fuel cell buses in Guangdong Province, are driving demand. The Ministry of Transport projects that by 2030, 50,000 hydrogen fuel cell vehicles will be operational nationwide.

- Energy storage: Hydrogen is emerging as a key solution for storing excess renewable energy. Electrolysing surplus electricity into hydrogen stabilises the grid but diverts renewable electricity away from e-fuel production. China's ongoing energy storage projects are expected to utilise up to 15% of renewable hydrogen production capacity by 2035.

Electrolysis, the primary method for green hydrogen production, requires extensive renewable electricity. Scaling green hydrogen for e-fuels will require prioritising specific sectors, incentivising dedicated renewable energy projects, and expanding capacity to meet growing demands without resource conflicts.

Industrial applications of green hydrogen in China include the steel, chemical, transportation, and energy sectors:

- Steel industry: The Ordos Green Hydrogen Plant intends to supply hydrogen for direct reduced iron (DRI) production, a lower-carbon alternative to conventional steelmaking.
- Chemical industry: Projects like Baofeng Energy utilise green hydrogen in methanol synthesis, reducing fossil fuel dependency.
- Transportation: Hydrogen-powered buses and trucks have been deployed in pilot projects, showcasing green hydrogen's potential in reducing emissions in mobility.
- Energy storage: Hydrogen is increasingly considered for grid-scale storage, offering a solution to balance renewable energy supply fluctuations.

9.4.3.6 E-fuels

Market for e-fuels

China's efforts to decarbonise its economy and integrate renewable energy are expected to have a substantial impact on the demand for e-fuels across various transport sectors. While the country is advancing in electrification, specific segments such as heavy-duty vehicles and aviation face technical and economic challenges that may make e-fuels a feasible complementary solution for greenhouse gas (GHG) emissions reduction. China's substantial renewable energy capacity and industrial scale offer promising opportunities for domestic e-fuel production, but inter-sector competition, logistical challenges, and economic factors will shape the future demand landscape.

Inter-sector competition for e-fuels is expected to intensify as production capacity expands. The aviation sector, which has fewer viable decarbonisation alternatives, is likely to prioritise e-fuels to meet domestic and international climate targets. In contrast, the road transport sector, particularly light-duty vehicles, may rely more heavily on electrification, reducing its dependence on e-fuels. Nonetheless, the heavy-duty segment may present opportunities for e-fuel adoption where electrification is economically or technically unfeasible.

The aviation sector is therefore likely to become a prominent consumer of e-fuels in China due to the sector's limited alternatives for decarbonisation. Estimates suggest that China's total jet fuel consumption could reach 60.5 million tonnes by 2030, with SAF demand potentially growing to 3 million tonnes annually if blending targets are realised[383,384]. By 2050, projections indicate jet fuel demand may rise to approximately 132 million tonnes, requiring nearly 86 million tonnes of SAF to achieve a 65% blending target. The Chinese government has initiated SAF-related efforts, including technical guidelines and proposed blending mandates of 2–5% by 2030[384]. Additionally, the Civil Aviation

---

[383] **Dialogue Earth**. (n.d.). *China pilots sustainable aviation fuel*. Retrieved January 10, 2025, from https://dialogue.earth/en/digest/china-pilots-sustainable-aviation-fuel/

[384] **Deloitte China**. (n.d.). *Sustainable aviation fuel (SAF) in China*. Retrieved January 10, 2025, from https://www2.deloitte.com/cn/zh/pages/energy-and-resources/articles/saf-in-china.html

Administration of China (CAAC) has established technical centres aimed at standardising SAF production and enhancing regulatory oversight[385].

Heavy-duty on-road transport represents a significant opportunity for e-fuel adoption in China due to infrastructure and operational challenges limiting full electrification. In 2023, heavy-duty trucks accounted for a substantial portion of China's transport emissions, and while battery-electric and hydrogen fuel cell vehicles have made inroads into this sector, their adoption is hindered by high operational costs, limited charging or refuelling infrastructure, and long-haul range requirements. Rural and remote regions, in particular, lack the extensive grid infrastructure needed for widespread electrification. In these areas, drop-in e-fuels provide a near-term decarbonisation solution compatible with existing internal combustion engine (ICE) fleets, reducing emissions without requiring major infrastructure overhauls.

The heavy-duty on-road vehicle sector illustrates an interplay between electrification and alternative fuels, including e-fuels. In 2023, sales of new energy heavy-duty trucks in China grew by 36.1% compared to the previous year, with battery-electric trucks comprising nearly 89% of this market[386]. Hydrogen fuel cell trucks also experienced growth, albeit at a smaller scale, reflecting some interest in hydrogen-based decarbonisation pathways. In 2023, heavy-duty trucks accounted for a substantial portion of China's transport emissions, and despite the increased adoption of battery-electric and hydrogen fuel cell vehicles, significant technical and infrastructural barriers persist, particularly in rural and remote regions where electrification infrastructure lags. In such areas, e-fuels offer a practical alternative to reduce emissions from internal combustion engine vehicles (ICEVs) without the immediate need for extensive charging networks.

E-fuels, as a drop-in solution compatible with existing ICE fleets, offer a near-term and scalable decarbonisation pathway. These fuels reduce emissions without requiring major modifications to engines or refuelling systems, making them particularly well-suited for areas with limited infrastructure. Regions like western China, rich in renewable energy resources but less equipped for grid electrification, are optimal candidates for e-fuel adoption.

However, while e-fuels provide a promising solution, their production still depends on access to water, as hydrogen is obtained through the electrolysis of water. Western China, which accounts for approximately 57% of the country's land area but only around 6% of its population[387], faces significant challenges in this regard due to its limited freshwater resources. Unlike coastal regions with access to seawater for desalination, western China must rely on its already scarce freshwater supplies, complicating the large-scale production of hydrogen required for e-fuels. However, wastewater—from municipal, industrial, and agricultural sources—offers a promising alternative. Wastewater is abundant and often requires treatment before disposal, making it a dual-purpose solution for both water management and energy production.

Technological advancements, such as electrochemical and biological methods, enable hydrogen production from wastewater. For example, modular systems like forward osmosis-water splitting (FOWS) can produce hydrogen directly from wastewater at high rates, while biological processes like dark fermentation convert organic matter in wastewater into hydrogen[388].

Despite this limitation, the region's abundant renewable energy potential—particularly solar and wind—offers opportunities to produce e-fuels sustainably. The strategic development of water-efficient technologies and renewable-powered electrolysis could mitigate these challenges, enabling e-fuel production to support decarbonisation efforts.

---

[385] **Reuters**. (2024, July 3). *China regulator launches country's first green jet aviation fuel centre*. Retrieved January 10, 2025, from https://www.reuters.com/business/energy/china-regulator-launches-countrys-first-green-jet-aviation-fuel-centre-2024-07-03/

[386] **The International Council on Clean Transportation (ICCT)**. (2023, August 24). *China's readiness to transition to zero-emission heavy-duty vehicles*. Retrieved January 10, 2025, from https://theicct.org/publication/r2z-zero-emission-hdv-china-2023-aug24/

[387] **China Briefing**. (n.d.). *China's population by province: Regional demographic trends*. Retrieved January 10, 2025, from https://www.china-briefing.com/news/chinas-population-by-province-regional-demographic-trends/

[388] Cassol, G.S., Shang, C., An, A.K. et al. Ultra-fast green hydrogen production from municipal wastewater by an integrated forward osmosis-alkaline water electrolysis system. Nat Commun 15, 2617 (2024). https://doi.org/10.1038/s41467-024-46964-8

The light-duty vehicle sector presents similar dynamics, where electrification is accelerating but ICEVs are expected to remain significant in the medium term. Projections suggest that ICEVs will still account for a considerable share of China's vehicle stock through 2040, particularly in regions with slower adoption of electric vehicle (EV) infrastructure. E-fuels, compatible with existing ICE technology, could provide a transitional decarbonisation pathway. However, the adoption of e-fuels in this sector will depend on their ability to compete with conventional fuels and electricity in terms of cost, convenience, and emissions reductions. Policymakers will need to address these factors to ensure an efficient and balanced transition.

China's rapid adoption of electric vehicles (EVs) is reshaping energy strategies across the transportation sector. In 2023, EVs accounted for nearly 40% of new vehicle sales in China, significantly outpacing global projections for 2030. This growth has been driven by decreasing costs for Chinese battery electric vehicles, aggressive government policies, including purchase subsidies, tax incentives, and significant investments in charging infrastructure. While this shift reduces reliance on conventional fuels in the light-duty segment, it also necessitates substantial investment in grid capacity and charging infrastructure to accommodate the growing EV fleet.

The persistence of ICEVs highlights the transitional role e-fuels may play in achieving decarbonisation goals. While EV adoption is accelerating in light-duty vehicles segment, ICEVs are expected to remain prominent in the heavy-duty vehicle sector for decades, particularly in regions where electrification infrastructure development is slower. E-fuels, which require fewer changes to existing vehicle technology and distribution networks, present a practical, albeit partial, solution for emissions reductions in these contexts.

E-fuels activity

By 2024, more than 20 e-fuel projects were underway across China, reflecting substantial investments in scaling production capacities. A sample of these are depicted in Figure 9-82 and Table 9-61 below.

Figure 9-82. Map of a sample of proposed and operational e-fuel projects

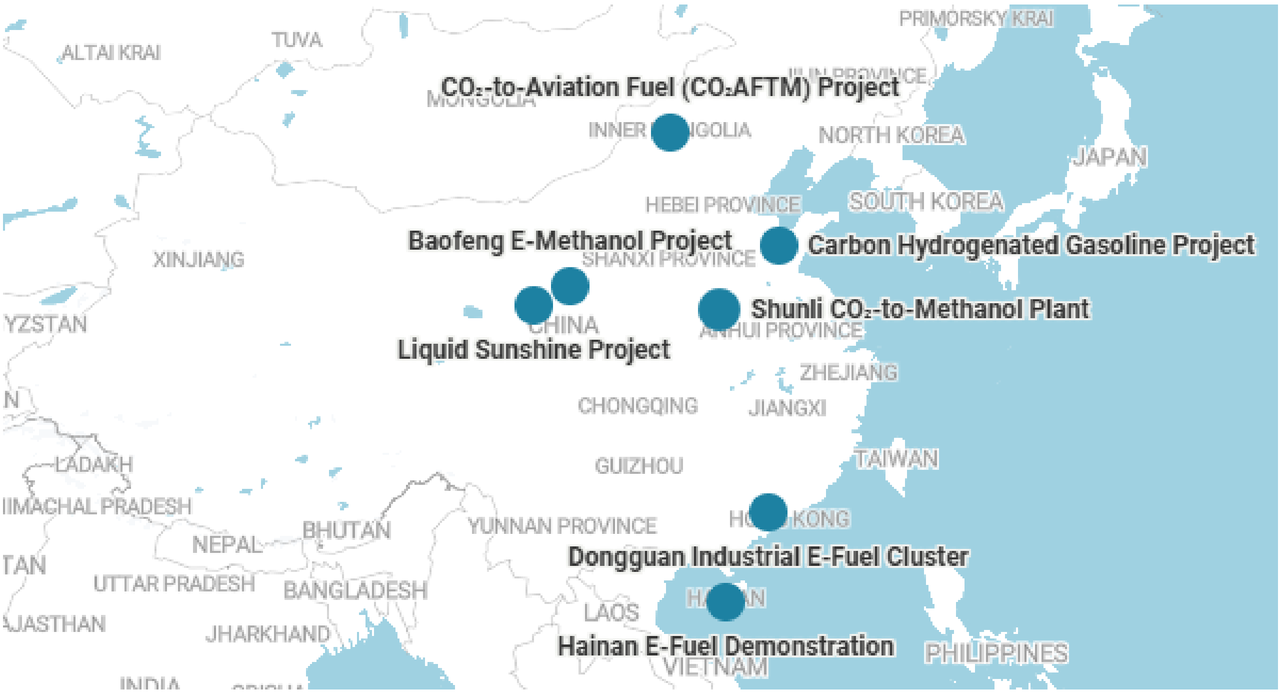


Table 9-61. Selection of e-fuels projects in China

E-fuel projects	State/Region	Description	Status	Capacity (t/year)
Shunli CO_2-to-Methanol Plant	Henan Province	Converts captured CO_2 and hydrogen into low-carbon methanol.	Operational	110,000
Baofeng E-Methanol Project	Ningxia Region	Produces e-methanol for industrial use and transport.	Operational	100,000
Hainan E-Fuel Demonstration	Hainan Province	Uses solar-powered electrolysis to produce e-diesel.	Planning	50,000
Dongguan Industrial E-Fuel Cluster	Guangdong Province	Integrated facility producing various e-fuels using renewable energy.	Planning	200,000

The Shunli CO_2-to-Methanol Plant in Henan Province highlights large-scale e-fuel production. Operational since 2024, this facility demonstrates the potential of converting captured CO_2 into methanol at an industrial scale, with an annual capacity of 110,000 tonnes.

The Baofeng E-Methanol Project in Ningxia serves as an example of renewable methanol production. With a capacity of 100,000 tonnes annually, it supports industrial and transportation needs, offering a renewable alternative to traditional fossil fuels. The project also illustrates the integration of renewable inputs in chemical production.

The Hainan E-Fuel Demonstration Facility exemplifies the integration of renewable energy into e-fuel production. Expected to commence operations soon, it aims to produce 50,000 tonnes of e-diesel annually through solar-powered electrolysis. This project highlights the viability of combining renewable energy with synthetic fuel manufacturing.

The Dongguan Industrial E-Fuel Cluster in Guangdong Province is China's most ambitious e-fuel initiative. Targeting a production capacity of 200,000 tonnes annually, the facility aims to produce a wide range of e-fuels by integrating diverse renewable energy sources.

Projects such as the "Liquid Sunshine" initiative in Lanzhou, Gansu Province, utilise renewable energy sources to produce methanol from carbon dioxide and hydrogen. Similarly, an e-fuel project in Zoucheng, Shandong Province, focuses on synthesising gasoline from carbon dioxide and hydrogen. These demonstration projects highlight the potential of synthetic fuels in reducing carbon emissions while maintaining a viable energy supply for sectors that are challenging to electrify, such as aviation, shipping, and heavy-duty transport.

E-Fuel hubs in China are also emerging as key components of its decarbonisation strategy, leveraging industrial clusters for integration with CCUS. Proposed hubs, such as those in Guangdong and Jiangsu provinces, aim to produce synthetic fuels like SAF and methanol using captured CO_2 and renewable hydrogen. These hubs benefit from proximity to both emission sources and renewable energy resources, reducing logistical complexity. Offshore renewable energy projects, such as wind farms in the South China Sea, provide the necessary electricity for hydrogen electrolysis, which, when combined with CO_2, enables sustainable e-fuel production. Additionally, pilot projects in regions like Inner Mongolia explore the feasibility of using surplus renewable energy for e-fuel synthesis. However, delays or inefficiencies in CO_2 and hydrogen transport infrastructure could disrupt the supply chain for these hubs. Optimising transport networks to prioritise e-fuel production will be crucial for scaling up these facilities.

The aviation sector is increasingly prioritising the development of as a critical strategy to reduce greenhouse gas emissions. Aviation accounts for approximately 2-3% of global CO_2 emissions, and its reliance on high-energy-density fossil fuels makes decarbonisation particularly challenging. Unlike other transportation sectors, such as road or rail, aviation has limited viable alternatives for reducing emissions, which underscores the importance of sustainable air fuel (SAF) as a near-term solution. This is due to the sector’s unique operational requirements, the long lifespan of aircraft, and the technical limitations of emerging technologies.

One of the primary challenges in decarbonising aviation is the need for fuels with high energy density. Traditional jet fuel, or kerosene, provides the energy required for long-haul flights, which represent the majority of aviation emissions. While alternative propulsion systems, such as battery-electric and hydrogen-powered aircraft, have been explored, they face significant limitations. Battery technology, for example, currently lacks the energy density needed to support long-distance flights without substantially increasing aircraft weight. Hydrogen, although promising, presents challenges related to storage and infrastructure due to its low energy density by volume. These limitations make SAF, which can be used as a "drop-in" fuel in existing aircraft and infrastructure, the most practical and scalable option for reducing emissions in the near term.

The long lifespan of commercial aircraft further complicates the transition to alternative energy sources. Aircraft typically remain in service for 20 to 30 years, meaning that even if new technologies like hydrogen or electric propulsion were developed today, it would take decades for the global fleet to transition fully. Retrofitting existing aircraft to run on alternative fuels is technically complex and costly. SAF, however, can be blended with conventional jet fuel and used in existing engines without modification, offering an immediate pathway to reducing emissions. This adaptability makes SAF an essential tool for decarbonising the current fleet while newer technologies are developed and scaled.

Given aviation’s substantial contribution to global emissions, China has prioritised SAF production from renewable feedstocks such as waste cooking oil. Junheng Industry Group Biotech operates facilities with an annual production capacity of 400,000 tonnes, of which 150,000 tonnes are dedicated to SAF in 2024. Similarly, Zhejiang Jiaao Enprotech is constructing a 500,000-tonne-per-year plant, with plans to double capacity in later phases. To support this industry, the CAAC launched its first SAF technical centre in Chengdu in July 2024. This centre focuses on setting policies, defining standards, and ensuring quality control to facilitate the integration of SAF in domestic and international aviation.

In the maritime and freight industries, e-fuels are being explored to meet international emissions reduction targets. A notable development is the partnership between COSCO Shipping Corporation and Australia's Fortescue, formalised through a memorandum of understanding in July 2024. This collaboration aims to develop technologies to lower emissions and establish a green fuel supply chain, including the potential use of vessels powered by green ammonia to transport iron ore and other mineral products between China and Australia.

In response to trade barriers, such as the European Union's anti-dumping tariffs on Chinese biodiesel, Chinese biofuel producers are diversifying their markets and products. Additionally, significant investments are being made in sustainable aviation fuel (SAF) production, with over US$1 billion allocated to developing SAF plants utilising waste cooking oil. This strategic shift reflects an adaptation to evolving global demand and regulatory landscapes.

China is also investing in technological research and industrial chain development for e-fuels. During the 2024 National People's Congress, Yin Tongyue, Chairman of Chery Holding Group, emphasised leveraging existing internal combustion engine technologies to advance green synthetic fuels. This approach aims to balance innovation with the practicality of adapting current infrastructure to accommodate new fuel types, facilitating a transition towards more sustainable energy sources in transportation.

Methanol Vehicle Pilot Program (2012–2018)

The Methanol Vehicle Pilot Program, led by the Ministry of Industry and Information Technology (MIIT), was conducted in 10 cities across five provinces from 2012 to 2018. The program involved over 1,000 vehicles, including passenger cars, buses, and heavy-duty trucks, operating on M100 methanol fuel. Over the course of the program, these vehicles accumulating approximately 200 million km of total mileage. While the program provided valuable data on methanol's potential as an alternative fuel, challenges such as infrastructure development and public acceptance remain areas for further improvement[389].

E-fuels market drivers and barriers

Policy and regulation

China has been actively developing and implementing policies to promote the use of e-fuels, including methanol, hydrogen, and other advanced fuels, as part of its broader strategy to achieve carbon neutrality by 2060. These policies are designed to reduce reliance on fossil fuels, enhance energy security, and mitigate environmental impacts. A selection of policies and regulations in China relevant to e-fuels are outlined in Table 9-62 below.

Table 9-62. Policies and regulations in China relevant to e-fuels

Policy/regulation	Location	Key points
Guidance on Methanol Vehicle Application[389]	Nationwide	Supports the development and deployment of methanol as a fuel and associated infrastructure
Establishment of SAF technical centre[390]	Chengdu	SAF Technical Centre established in July 2024 to develop standards, conduct research, and establish certification systems.
SAF Blending Mandate[391]	Nationwide, China	Proposed SAF blending mandate: 2% by 2025, increasing to 15% by 2030 (subject to policy refinement).
SAF Application Trials[392]	Nationwide, China	SAF trials in two phases: Phase 1 (2024) evaluated feasibility with pilot flights from key airports; Phase 2 (2025) to broaden application.

The CAAC has launched several initiatives to promote SAF. In July 2024, the CAAC inaugurated a SAF Technical Centre in Chengdu to develop standards, research SAF products, and establish certification systems. A phased SAF blending mandate has been proposed by the CAAC, targeting a 2% SAF blend by 2025 and a gradual increase to 15% by 2030, though these targets are still under discussion and subject to policy refinement.

In parallel, the NDRC, in cooperation with the CAAC, initiated SAF application trials in September 2024. These trials involved 12 pilot flights operated by major airlines, including Air China, China Eastern Airlines, and China Southern Airlines. Flights were conducted from key airports such as Beijing Daxing International Airport, Chengdu Shuangliu International Airport, Zhengzhou Xinzheng International Airport, and Ningbo Lishe International Airport. The initial phase of the programme, which ran from September to December 2024, evaluated SAF's operational feasibility, safety, and impact on aviation performance. A second phase planned for 2025 is expected to expand the scope of these trials and facilitate the gradual integration of SAF into regular airline operations.

In March 2019, eight ministries, including MIIT, the NDRC) and the Ministry of Ecology and Environment (MEE), jointly issued the Guidance on Methanol Vehicle Application. This policy encourages the nationwide development and deployment of methanol-fuelled vehicles. It supports the manufacturing of

[389] Methanol Institute (2019). *MIIT Policy Paper Press Release*. Available at: https://www.methanol.org/wp-content/uploads/2019/03/MIIT-Policy-Paper-Press-Release.pdf (Accessed: 14 January 2025).

[390] Civil Aviation Administration of China Scientific Research Institute (CAACSRI). (n.d.). *Launch of the SAF Centre*. Retrieved January 10, 2025, from https://www.caacsri.com/support/detail/909.html

[391] Modern Diplomacy. (2024, August 22). *China's new policy on sustainable aviation fuel (SAF): A step towards a greener future*. Retrieved January 10, 2025, from https://moderndiplomacy.eu/2024/08/22/chinas-new-policy-on-sustainable-aviation-fuel-saf-a-step-towards-greener-future/

[392] The State Council of the People's Republic of China. (2024, September 19). *China advances development of sustainable aviation fuel industry*. Retrieved January 10, 2025, from https://english.www.gov.cn/news/202409/19/content_WS66ec1223c6d0868f4e8eb175.html

methanol vehicles, the development of methanol production and fuelling infrastructure, and the establishment of relevant standards. The policy also promotes the use of methanol vehicles in regions with abundant methanol resources and experience, such as Shanxi, Shaanxi, Guizhou, and Gansu.

Financial

China has been actively promoting green and low-carbon development through financial incentives and support mechanisms, particularly in the renewable energy sector. While e-fuels are not explicitly mentioned in literature, the broader framework of green finance and renewable energy support provides a foundation for understanding potential e-fuel development. This report examines the current financial incentives, support mechanisms, and key locations for e-fuel development in China, while highlighting gaps in publicised or existing support for this emerging sector.

China's financial sector has prioritised green finance to support low-carbon development. As of the third quarter of 2024, the outstanding balance of green loans exceeded 35 trillion yuan, and the stock of green bonds issued stood at nearly 2 trillion yuan, ranking among the top globally[393]. These funds are primarily directed toward renewable energy projects, such as wind and solar power generation, which could indirectly support e-fuel production. However, there is no explicit mention of e-fuels in the green finance support catalogue or statistical systems currently being developed.

The PBOC and the Ministry of Ecology and Environment have established a cooperative mechanism to promote green finance, including support for renewable energy projects. Key initiatives include:

- **Unified Green Finance Support Catalogue**: This catalogue aims to identify major directions for green finance support, but e-fuels are not explicitly included.
- **Pilot Projects and Regional Support**: Financial support models for regional environmental protection projects, such as wind and solar power generation, could be extended to e-fuel production facilities.

[393]**The State Council of the People's Republic of China**. (2025, January 9). *China unveils roadmap for boosting sustainable aviation fuel industry*. Retrieved January 10, 2025, from https://english.www.gov.cn/news/202501/09/content_WS677f09f6c6d0868f4e8ee9ee.html

9.5 TECHNO ECONOMIC ASSESSMENT RESULTS

9.5.1 Cost breakdown

A baseline scenario, as described in Table , has been modelled to investigate the contribution of main cost components to e-fuel production cost. This example is meant to be illustrative. The proportional contribution of the components will differ depending on multiple conditions, including but not limited to the size of the plant with CapEx contributing a larger proportion of the cost in smaller plants, the geographic location, feedstock costs, year of production.

Table 9-63. Baseline scenario for e-fuel production.

Parameter	Baseline	Unit
H_2 price	6.75	US$/kg
CO_2 price	90	US$/t
Production capacity	150	kt/year
Plant Lifetime	25	years

9.5.2 Sensitivity analysis

The range of values chosen for the current sensitivity analysis was informed by current and expected changes in the parameters studied. A summary of the baseline and variations is listed in Table 9-64.

Table 9-64. Bounds of adjusted parameters studied in the sensitivity analysis.

Parameter	Lower	Baseline	Upper	Unit
H_2 price	2	6.75	10	US$/kg
CO_2 price	20	90	650	US$/t
Production capacity	50	150	500	kt/year
CapEx variance	-50%	0%	+250%	%
Plant lifetime	20	25	30	years

With reductions in renewable electricity costs, reductions in electrolyser costs and advances in electrolyser efficiency, the price of hydrogen is expected to become as low as US$1/kg overtime [394] [395].However, the lower limit of hydrogen cost was limited to US$2/kg to account for likely additional costs associated with hydrogen transportation and storage. Furthermore, e-fuel production is unlikely to occur with hydrogen prices as high as US$10/kg, however, this was set as the upper limit to highlight the impact of increased hydrogen costs which cannot be mitigated by the improvement in any other parameter. The baseline value was set based on current hydrogen costs.

The lower, baseline, and upper values for CO_2 were set to represent possible costs of CO_2 sourced from high-, medium-, and low-concentration sources. Different configurations of CO_2 supply infrastructure could also be encompassed between the bounds with the lower limit representing a co-located high-concentration source and the upper representing a low-concentration source requiring transportation.

[394] Hydrogen Council. (2020). *Path to hydrogen competitiveness: A cost perspective*. Retrieved from https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

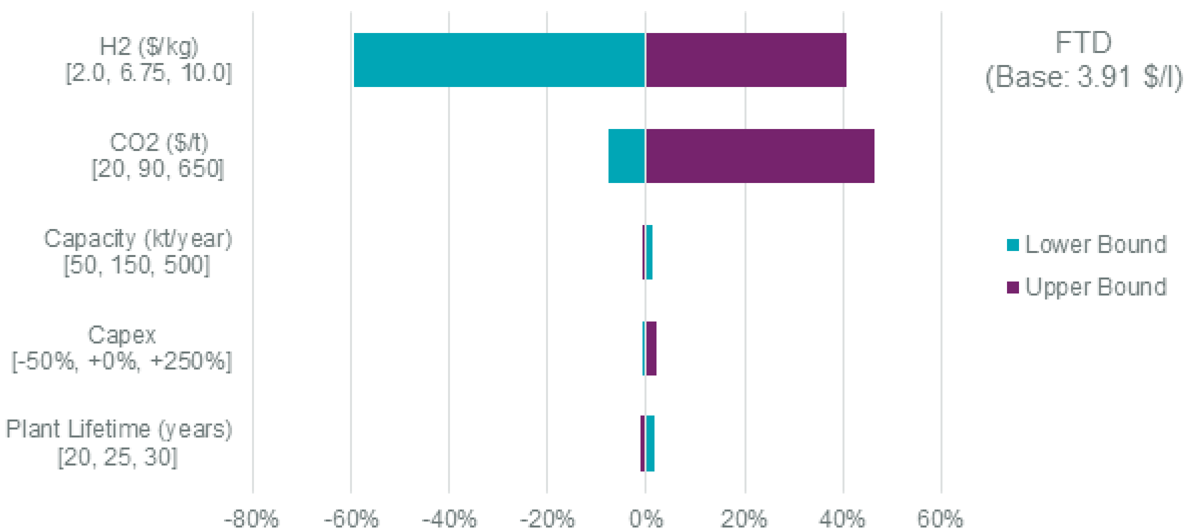
[395] IRENA (2024), International co-operation to accelerate green hydrogen deployment, International Renewable Energy Agency, Abu Dhabi.

The production capacity range represents small, medium, and large sized e-fuel plants. The justification for the bounds was given in an assessment of the expected e-fuel plant size conducted in an earlier section of the chapter. Previous studies conducted have shown via sensitivity analysis that factors such as e-fuel plant size have only marginal impacts (single-digit percentage points)[396].

As of yet, e-fuel plants are a nascent technology with limited real-world installations. Therefore, the lack of cost data renders capital cost estimates highly uncertain. Although costs are expected to reduce in the future as the technologies mature, scale up, and benefit from economies of scale, at this stage it is likely that the capital cost used in the literature, and a priori used here, are an underestimate. Therefore, the lower limit in Table is a reduction of capital cost by 50% representing the aforementioned cost reductions. The upper limit of 250% represents the possible uncertainty in the current estimates.

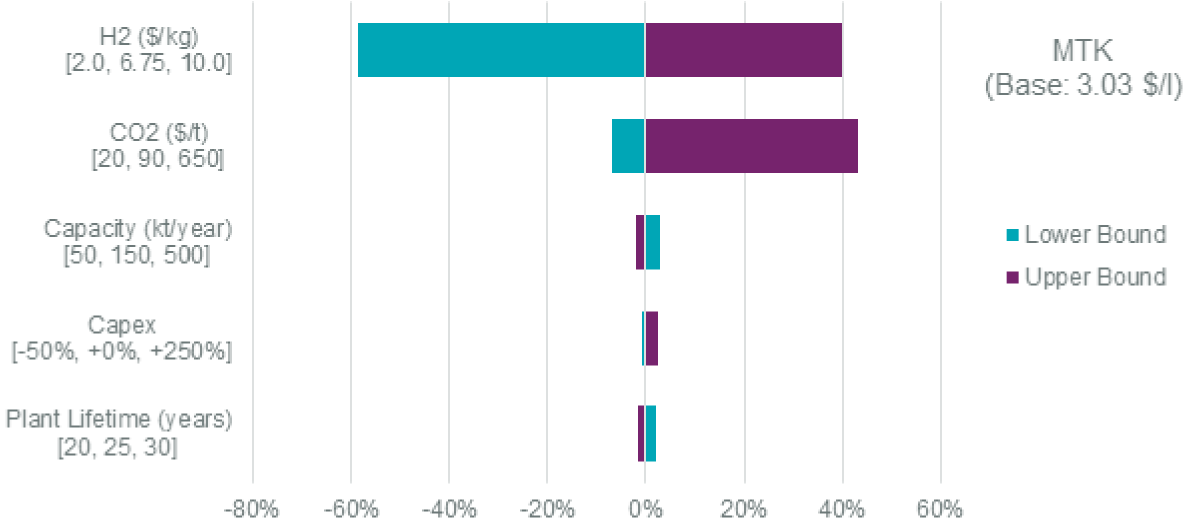
The findings of this analysis agree with previous studies had investigated e-fuel price sensitivity in the past. Zang et al. (2021) assessed the minimum fuel selling price of FT fuels under different market and policy scenarios, namely hydrogen price, CO_2 price, and CO_2 credit. They found that, similar to the analysis presented here, a 1% increase in hydrogen price caused a 0.8% increase in e-fuel cost. On the other hand, variation in CO_2 prices had a smaller effect on fuel price as an increase of CO_2 cost from 0 to 76 US$/t would increase fuel cost from 5.0 US$/gal (1.32 US$/kg) to 6.5 US$/gal (1.72 US$/kg)[397]

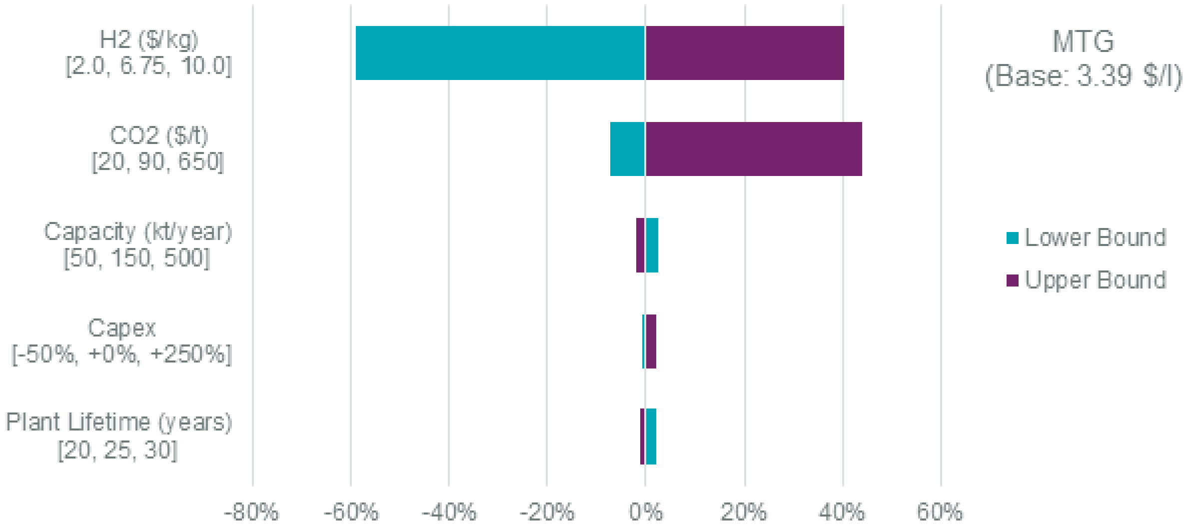
Figure 9-83. Sensitivity analysis for three fuel production pathways. FTD: Diesel via Fischer-Tropsch; MTK: Kerosene via methanol pathway; MTG: Gasoline via methanol pathway.



[396] Concawe & Aramco. (2024). *E-Fuels: A techno-economic assessment of European domestic production and imports towards 2050 – Update*. Retrieved from https://www.concawe.eu/publication/e-fuels-a-techno-economic-assessment-of-european-domestic-production-and-imports-towards-2050-update/

[397] Zang, G., Sun, P., Elgowainy, A. A., Bafana, A., & Wang, M. (2021). Performance and cost analysis of liquid fuel production from H_2 and CO_2 based on the Fischer-Tropsch process. *Journal of CO_2 Utilization, 46*, 101459. https://doi.org/10.1016/j.jcou.2021.101459





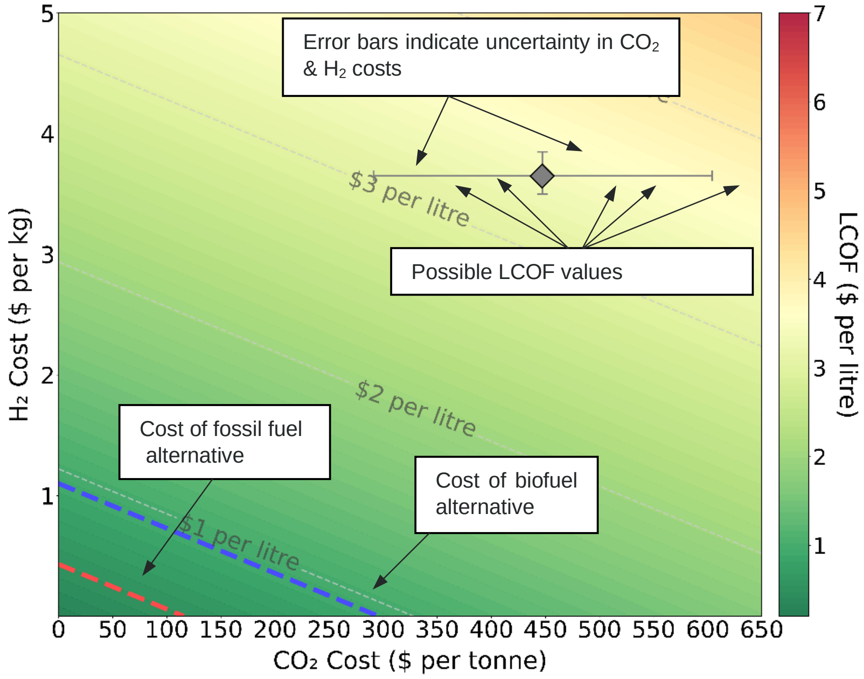
9.5.3 Scenario analysis

The findings will be visualised using multivariable graphs depicting the relationships between CO_2 cost, hydrogen cost, and e-fuel production cost.

For this analysis, it is assumed that e-fuel plant capacities will evolve over time: small-scale plants (50 kt/year) in the near term (2030), medium-scale plants in the medium term (2040), and large-scale plants in the long term (2050). CO_2 costs are presumed to depend on the source of CO_2, while hydrogen costs are influenced by the country of production and the year in question.

The resulting visualisations highlight the subsidies required for CO_2 and/or hydrogen to improve the economic competitiveness of e-fuels relative to alternative fuels. These findings provide insights into the role of subsidies in optimising the cost-effectiveness and market feasibility of e-fuels across diverse production pathways and temporal scales.

Figure 9-84. Illustrative example of a multivariable cost graph showing: the dependence of e-fuel cost (color bar) on CO_2 and hydrogen costs, the cost of laternative fuels, and the possible e-fuel production costs for a given scenario.



9.5.4 E-diesel

For the 2040 case, achieving parity with fossil diesel at US$0.44 per litre requires H_2 costs to remain at or below US$0.3/kg and CO_2 costs to be capped at an estimated US$40/t. These estimates represent the maximum thresholds for feedstock costs. Meeting these cost levels demands significant advancements in green hydrogen production efficiency and substantial reductions in carbon capture technology costs. However, it is important to note that achieving such low hydrogen costs may not be feasible in the absence of subsidies. Even under optimal conditions—such as co-location with renewable energy sources to eliminate transportation costs and access to exceptionally low electricity prices—achieving the required reductions in electrolyser technology costs and improvements in efficiency remains technologically ambitious. Additionally, while DAC (Direct Air Capture) costs would need substantial reductions to meet the US$40/t target, CO_2 costs at this level are currently available from high-concentration sources, which may provide a more immediate opportunity.

For HEFA diesel at US$0.99 per litre, parity is achievable with H_2 costs capped at US$1.26/kg and CO_2 at US$165/t, highlighting a more feasible pathway of comparison compared to fossil diesel. This scenario benefits from the higher price point of HEFA diesel, making e-diesel a competitive alternative to biofuels. These thresholds indicate that, with advancements in hydrogen production technologies and cost-effective carbon capture systems, the RWGS-FTD process could emerge as a viable alternative low-carbon fuel solution.

The economic viability of synthetic diesel via the RWGS-FTD pathway is driven by low-cost hydrogen, with CO_2 costs playing a secondary but significant role. Achieving H_2 prices between US$0.30–US$1.26/kg and CO_2 prices between US$40–US$165/t will depend on technological innovations and supportive policies. For H_2, improvements in electrolyser efficiency, reductions in renewable energy costs, and scaling hydrogen production infrastructure are crucial. For CO_2, policy incentives such as carbon credits and tax subsidies for CCU technologies will be essential in achieving the required cost reductions.

To achieve economic parity with fossil diesel, the required subsidies for hydrogen and carbon dioxide utilisation must be evaluated within a broader socio-economic and technological context. In Germany, for instance, achieving parity would necessitate hydrogen subsidies of approximately US$3.18/kg in

2030, increasing to US$2.46/kg by 2040 and further to US$1.80/kg by 2050, driven by advancements in electrolyser efficiency, renewable energy cost reductions, and scaling production infrastructure. These levels are critical to offset production costs and ensure green hydrogen is competitive with fossil fuels.

9.5.5 E-kerosene

For the 2040 case, achieving cost parity with conventional jet fuel in the MTK process necessitates strict control of feedstock prices and efficient conversion technologies. Benchmarking against jet fuel priced at US$0.44 per litre, the MTK pathway requires hydrogen costs to remain at or below US$0.37/kg. Similarly, CO_2 costs must be capped at approximately US$58/t to achieve economic viability. These requirements highlight the critical need for advancements in electrolyser efficiency and access to low-cost renewable energy resources to make the MTK pathway competitive with fossil-derived jet fuels.

Comparison with FAME demonstrates that achieving parity with HEFA SAF pricing involves relatively relaxed cost thresholds. FAME, priced at US$0.93 per litre, allows for hydrogen costs to remain below US$1.47/kg and CO_2 costs capped at US$214/t. These thresholds are significantly higher than those for conventional jet fuel parity, reflecting the lower economic pressures on hydrogen and CO_2 pricing for competitiveness with HEFA SAF. This comparison underscores the MTK pathway's unique challenges in matching fossil kerosene pricing while competing favourably with FAME.

The MTK process faces unique challenges in the aviation sector, where cost margins are narrow despite the critical need for decarbonisation. Regulatory frameworks like the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) and the increasing adoption of Sustainable Aviation Fuels (SAFs) provide a supportive backdrop for MTK development. Policy incentives such as subsidies for green hydrogen production and tax credits for CCU are essential to bridging the cost gap and fostering the commercialisation of MTK-derived jet fuel.

9.5.6 E-gasoline

For the 2040 case, achieving parity with fossil fuel gasoline at US$0.44 per litre requires hydrogen costs to remain at or below US$0.32/kg and carbon dioxide costs to be capped at US$48/t. These thresholds require slightly tighter cost controls than those required for HEFA diesel parity in the RWGS-FTD process.

To match the bioethanol price of US$0.93 per litre, hydrogen costs need to be capped at $1.27/kg, and carbon dioxide costs must not exceed US$178/t. These thresholds are slightly less restrictive than those for parity with conventional gasoline (US$0.32/kg for H_2 and US$178/t for CO_2), offering a marginally broader range for economic viability. This suggests that achieving cost competitiveness with ethanol may be a more attainable intermediate milestone for the MTG pathway, especially in regions where renewable hydrogen and advanced CCU systems are emerging.

Carbon dioxide costs must be tightly controlled to remain competitive within the gasoline market. The lower tolerance for CO_2 costs at US$65-108/t reflects the competitive pricing environment for gasoline. This places added pressure on CCU technologies to achieve cost reductions, building on many of the same principles discussed in the diesel analysis. While policy incentives and tax credits remain pivotal, the MTG pathway could also benefit from innovations specific to carbon recycling within methanol synthesis.

Figure 9-85. Levelised cost of fuel for e-diesel compared to fossil diesel and HEFA diesel.

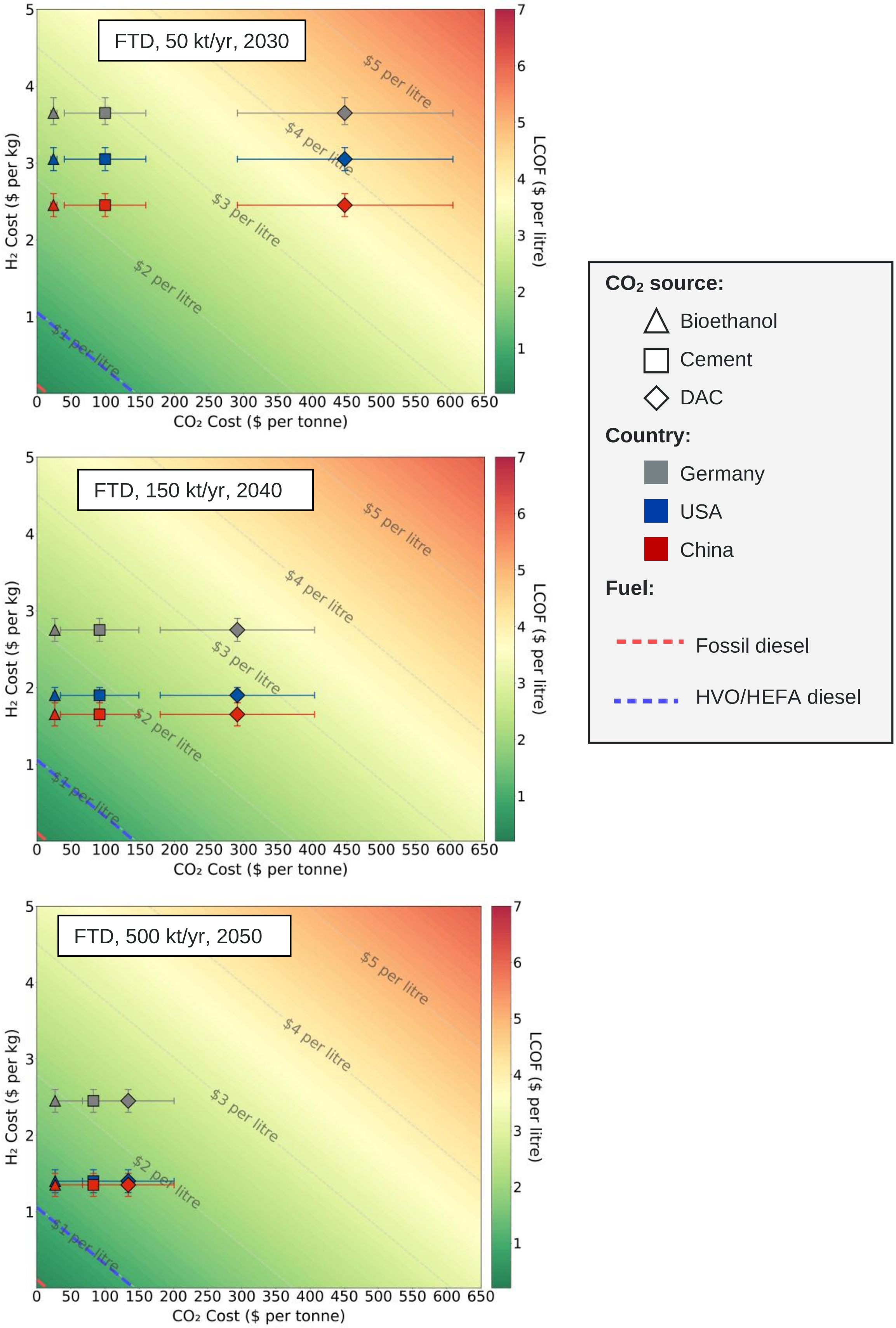


Figure 9-86. Levelised cost of fuel for e-kerosene compared to Jet fuel and HEFA kerosene.

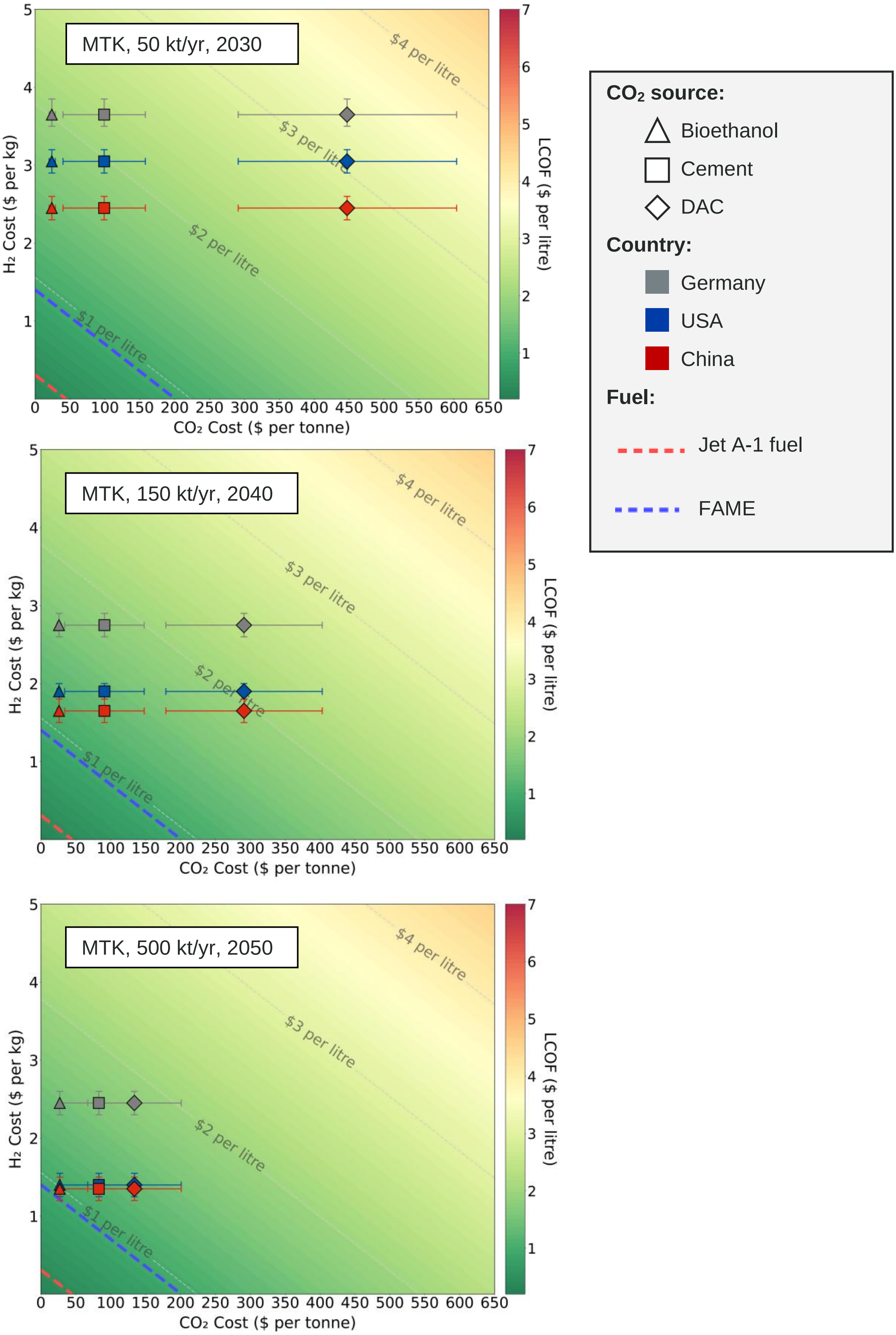
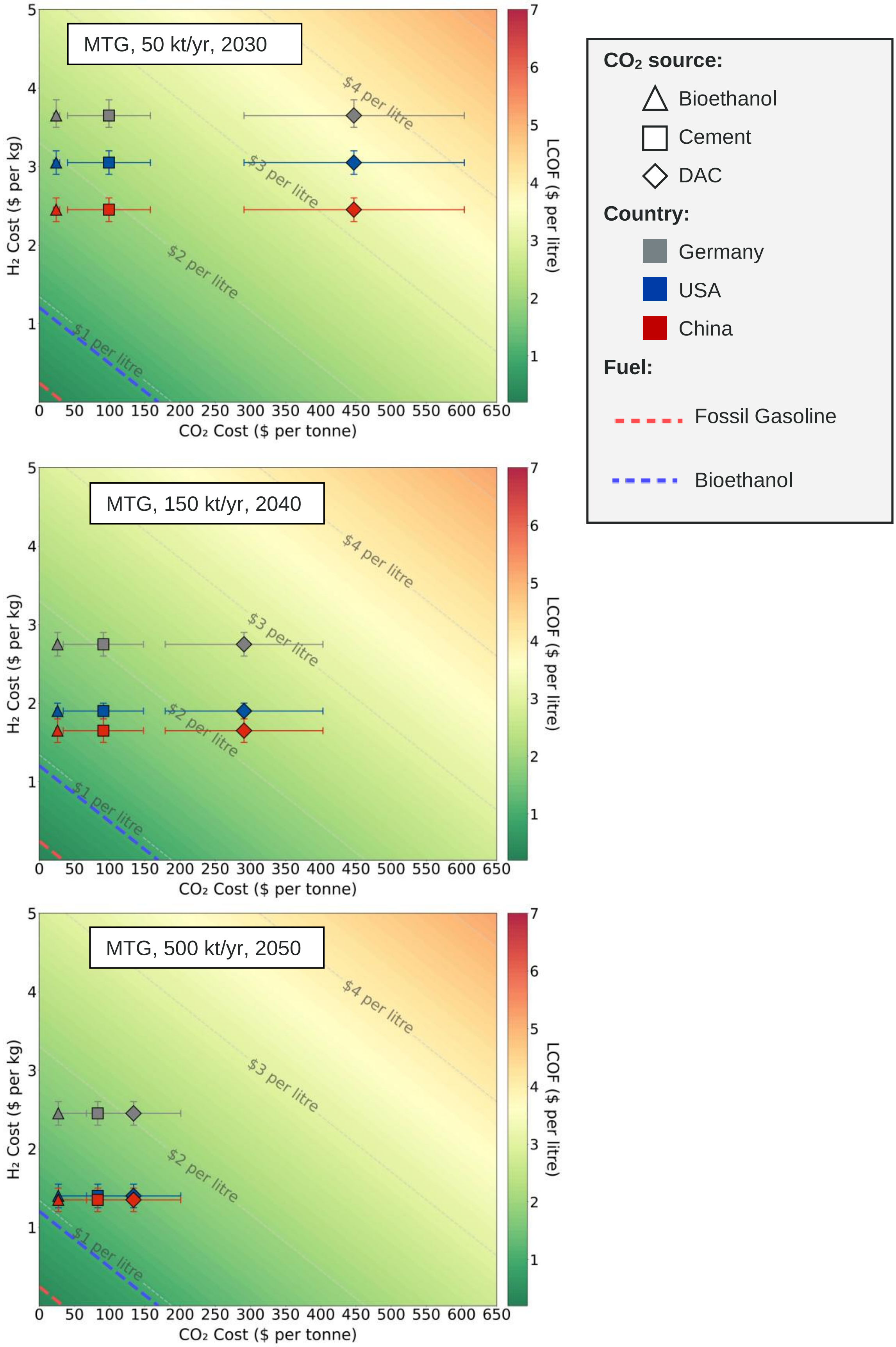


Figure 9-87. Levelised cost of fuel for e-gasoline compared to fossil gasoline and bioethanol.



9.6 ECONOMIC ASSUMPTIONS

The techno-economic assessment of e-fuel production requires a set of foundational economic assumptions pertaining to key input variables and operational parameters that influence the levelised cost of fuel. This section outlines the primary economic considerations made in this analysis, focusing on factors such as plant size, capital cost, price of hydrogen, price of CO_2, and price of electricity. This section systematically examines these assumptions, providing a transparent foundation for understanding the cost structure of e-fuel production and its sensitivity to key economic factors.

9.6.1 E-fuel plant production capacity

Oil refineries vary widely in size, with capacities ranging from less than 100,000 barrels per day (bbl/day) to over 1 million bbl/day. These sizes reflect a combination of factors, including market demand, regional crude oil availability, and economic considerations. The largest refineries, such as India's Jamnagar Refinery which processes 1.24 million bbl/day, are typically located in regions with high domestic or export demand for refined petroleum products. Their massive scale allows for significant economies of scale, reducing per-barrel processing costs and enabling competitive pricing in global markets. Smaller refineries, processing less than 100,000 bbl/day, are often located in regions with limited access to crude oil or where local demand for refined products does not justify larger operations. These facilities can be tailored to produce specific outputs, such as jet fuel or diesel, depending on regional needs.

The production facilities for e-fuels are expected to be much smaller than the scale of oil refineries above. This difference arises from factors related to feedstock availability, technology maturity, market demand, and the energy intensity of the processes. Based on a survey of existing e-fuel plants shown in Table 9-65 below, e-fuel plants might produce in the range of 1,000–10,000 bbl/day (50–500 kt/year), with pilot projects often operating at even smaller capacities. Scaling up e-fuel facilities is challenging because of the significant energy requirements for water electrolysis to produce green hydrogen and for the conversion of CO_2 and hydrogen into hydrocarbons. These processes are highly energy-intensive and scaling them economically depends on the availability of cheap, abundant renewable energy. Furthermore, the geographic dispersion of renewable energy resources (like solar and wind farms) limits the scalability of centralized e-fuel production facilities. This leads to smaller, decentralized production units. A study by Concawe (2024) recommended integrating e-fuel plants into existing refineries in the short to medium term to reduce the capital cost associated with hydrocracking and fractionation (upgrade) of the e-fuels, however they concluded that large centralised e-fuel plant had little advantage over small, distributed plants[398].

Apart from the availability of renewable electricity, e-fuel plants would require an assured supply of CO_2. A review of current global CO_2 sources in shows that there are more than 161 CO_2 source that emit more than 20MtCO_2/year, both single point sources and hotspots of multiple sources within a 30 km radius combined. Such quantities of CO_2 emissions would be sufficient for e-fuel plants with production capacities close to 500k bbl/day (25 million tonne per year) of fuel, equivalent to a medium sized oil refinery. Therefore, the limiting factor in scaling e-fuel plant production would not be CO_2 availability, at least not in the near term (2030). However, as economies continue to decarbonise large sources of CO_2 emissions might become more limited and there might be an increased reliance on DAC, thus a greater demand for renewable electricity.

As technology matures and the push for decarbonization intensifies, larger-scale e-fuel facilities may emerge, especially if policy support and technological advancements reduce costs. However, achieving scales comparable to traditional oil refineries will likely remain challenging due to the fundamentally different nature of their inputs and processes.

A high-level sizing exercise was conducted assuming e-kerosene production using MTK pathway as a proxy for e-fuel refineries and hydrogen feedstock supplied through an electrolyser of 70% efficiency. E-fuel refineries of 525 million bbl/day, similar to medium- to large-sized oil refineries, would require approximately 633 TWh of electricity per year (assuming electrolyser efficiency of 70%). This amount of electricity is so large that Germany, USA, or China would need to increase their total electricity generation capacity for this single plant by 128%, 15%, and 7% respectively, compared to 2023 levels. If the source of electricity is assumed to be renewable then the same countries would need to increase

[398] Concawe & Aramco. (2024). *E-Fuels: A techno-economic assessment of European domestic production and imports towards 2050 – Update*. Retrieved from https://www.concawe.eu/publication/e-fuels-a-techno-economic-assessment-of-european-domestic-production-and-imports-towards-2050-update/

their renewable energy generation by 249%, 63%, and 26%, respectively, for a single plant. The purpose of this back of the envelope calculation is to highlight the unlikelihood of e-fuel plants scaling to the same production capacity of conventional oil refineries.

Table 9-65. Electricity generation required to produce hydrogen for e-fuel plants of different sizes.

E-fuel plant capacity [bbl/day]	1,050	3,150	10,500	525,000
E-fuel plant capacity [kt/year]	50	150	500	25,000
E-fuel Plant capacity [MW]	68	205	683	34,125
CO_2 capacity [kt/year]	161	482	1,605	80,250
H_2 **capacity [kt/year]**	23	69	230	11,500
Electricity for H_2 **production [TWh/year]**	1.29	3.88	12.9	647
% share of total generation in 2023				
Germany	0.3%	0.8%	2.6%	128%
USA	0.0%	0.1%	0.3%	15%
China	0.0%	0.0%	0.1%	7%
% share of RE generation in 2023				
Germany	0.5%	1.5%	5%	249%
USA	0.1%	0.1%	1.3%	63%
China	0.1%	0.2%	0.5%	26%

Therefore, based on existing and announced e-fuel plants and based on the electricity generation outlined above e-fuel refineries are likely to be in the 1,000 to 10,000 bbl/day range to avoid competition for renewable electricity with other uses. Even at 10,500 bbl/day, Germany would need to increase renewable electricity generation by 5% above 2023 levels: challenging, but not impossible.

9.6.2 E-fuel plant Capital Cost

To address the uncertainties in the capital cost of e-fuel plants a sensitivity analysis was performed, explicitly considering the impact of variations in capital cost on the overall assessment. This analysis underscores the importance of acknowledging the limitations of the cost model while providing insights into the robustness of the conclusions drawn from the study.

9.6.3 Cost of hydrogen

Undoubtedly the costliest ingredient of e-fuels, hydrogen plays a crucial role in determining the overall cost of e-fuel production. As previously mentioned, e-fuel a defined in this study as synthetic fuel which uses hydrogen produced through renewable electricity, commonly referred to as green hydrogen.

Green hydrogen is produced using renewable energy to split water into hydrogen and oxygen without emitting carbon dioxide. The most common method is electrolysis, which uses electricity to split water. Alkaline electrolysis is a mature and widely used technology, while proton exchange membrane (PEM) electrolysis and solid oxide electrolysis are also prominent approaches, each utilizing different electrolytes and operating conditions. Emerging methods include photocatalysis, biological processes, thermochemical water splitting, and plasma-based processes among others. However, electrolysis remains the most commercially viable method for large-scale production.

The subject of green hydrogen production has been extensively studied in recent years and is not the focus of this study. Instead, this analysis assumes green hydrogen is available for e-fuels production at a range of prices, reflecting different supply chain configurations. These prices could represent hydrogen produced by a co-located electrolyser with minimal transport requirements but with dedicated storage, or hydrogen imported over long distances via pipelines, where transport costs form a significant portion of the total cost. Similarly, the range may include hydrogen shipped from abroad, where low production costs at the origin are offset by logistics expenses. These scenarios represent different points on the hydrogen price spectrum. Regardless of the hydrogen source, the critical factor is its effect on the cost of e-fuel production and its competitiveness with alternative fuels. By accounting for this range of hydrogen prices, this study provides insights into how varying hydrogen supply scenarios influence e-fuel economics.

A few ranges of hydrogen prices were chosen depending on the country considered in the analysis and the timeline, as shown in Table 9-66. These ranges reflect regional variations in hydrogen production costs, infrastructure development, and market conditions. For instance, countries with abundant renewable energy resources and well-established hydrogen supply chains may exhibit lower hydrogen prices, particularly in the longer term, as production scales up and efficiencies improve. Conversely, countries with limited access to renewable energy or those reliant on imported hydrogen may face higher prices due to transportation and storage costs.

The timeline also plays a critical role, as early-stage hydrogen markets typically feature higher costs due to immature infrastructure and limited economies of scale. Over time, technological advancements, policy incentives, and increased competition are expected to drive down costs. By incorporating a range of hydrogen prices across countries and timelines, the analysis captures the variability and uncertainty associated with global hydrogen supply, enabling a more comprehensive assessment of its impact on e-fuel production costs.

Table 9-66. Estimates of hydrogen costs for Germany, USA and China for 2030, 2040 and 2050[399].

Range of H_2 cost [US$/kg]	2030	2040	2050
Germany	3.5 - 3.8	2.6 - 2.9	2.3 - 2.6
USA	2.9 - 3.2	1.8 – 2.0	1.2 - 1.5
China	2.3 - 2.6	1.5 - 1.8	1.2 - 1.5

9.6.4 Cost of Carbon Dioxide

The importance of CO_2 supply and its characteristics were addressed in Section 9.1.5 of the Technical Annex. From an e-fuel production perspective, apart from cost, purity from catalyst damaging contaminants and supply assurance are key factors when assessing CO_2 sources. Drawing on the conclusions of the e-fuel supply chain study in the main body, the CO_2 sources that were chosen for further assessment are high concentration biogenic, industrial sources of emissions, and direct air capture (DAC).

The cost of CO_2 varies significantly based on its source and the effort required to purify and compress it for e-fuel synthesis. The most affordable CO_2, costing around US$ 20–30 per ton, comes from facilities that produce concentrated CO_2 streams. Biogenic sources of high CO_2 concentration such as bioethanol plants are likely to be targeted for e-fuel production in the near term (2030). This is because of the low cost of CO_2 capture due to high CO_2 concentration, in the case of ethanol fermentation CO_2 capture is inherent to the process, and because of their relatively small scale thus limiting their suitability to small scale e-fuel plants.

Capturing CO_2 from power, steel, and cement plants, requires adding carbon capture units, is more expensive, ranging from approximately US$ 50–100 per tonne depending on the technology and location. While carbon capture technologies at these facilities are relatively mature, they are yet to be deployed at the scale needed for the Power-to-X sector. Large scale industrial emitters such as cement plants and to lesser extent steel production are expected to persist in the mid to long term, depending on the region. Cement manufacturing is one of the largest industrial sources of CO_2 emissions. The process involves the heating of limestone (calcium carbonate) to produce lime, which inherently releases CO_2 as a by-product. Although efforts are underway to reduce emissions through carbon capture, alternative binders, and process optimization, cement production is expected to remain a significant CO_2 emitter for the foreseeable future.

[399] PwC. (n.d.). *Green hydrogen cost*. Retrieved from https://www.pwc.com/gx/en/industries/energy-utilities-resources/future-energy/green-hydrogen-cost.html

The steel industry also remains a major CO_2 emitter, primarily due to the use of carbon-intensive processes like blast furnaces, which rely on coke to reduce iron ore. While alternative methods, such as hydrogen-based direct reduction, are under development, scaling these solutions to replace traditional blast furnaces will take time. As a result, steel production is likely to remain a significant source of CO_2 in the medium term (up to 2040 and beyond in the case of China).

Direct air capture provides a potentially non-fossil based alternative source of CO_2, but at a greater cost. Currently planned DAC plants will have a capacity of 1 $MtCO_2$/year, enough for an e-fuel plant producing 500 kt of e-fuel per year. If commercially successful, DAC plants might be able to scale up to 1 $GtCO_2$/year, which is more than enough for even the largest e-fuel plants. Unlike CO_2 capture from other source, the cost of DAC is expected to decrease drastically in the future as the technology matures and competition increases. Current DAC costs are high, ranging from US$300–600 per ton, due largely to the low atmospheric CO_2 concentration of around 420 ppm. However, advancements and scaling are expected to lower costs to US$ 50–150 per tonne in the future[400] [401] [402]

As with the supply and cost of hydrogen, CO_2 is assumed to be available at a range of prices determined by the CO_2 source and timeline. The cost for carbon transport or storage are not included assuming that carbon is captured close to the e-fuel production site and the rate of capture exactly matches the demand. This is a simplifying assumption that deserves further scrutiny in future assessments. Ideally, e-fuel plants would be co-located with CO_2 capture sites. However, should CO_2 transport be required, it is expected to add 10 to 20 US$/$tCO_2$. Moreover, based on data available from a recent report[403], heat integration may reduce the cost of DAC by 6 – 27 US$/$tCO_2$, depending on the e-fuel production process and electricity cost.

Table 9-67. Estimates of CO_2 capture cost[404].

Range of CO_2 cost [US$/$tCO_2$][405]	2020	2030	2040	2050
Cement	47 - 168	40 - 158	34 - 148	27 - 138
Steel	74 - 103	67 - 98	60 - 93	54 - 87
Ethanol Plant	16 - 30	20 - 29	23 - 28	27 - 27
DAC	403 - 805	291 - 604	179 - 403	67 - 201

9.6.5 Cost of Electricity

In this analysis, electricity consumption is only considered for the provision of utilities to the e-fuel plant, not for the production hydrogen or CO_2 capture. As detailed previously, a range of prices were assumed for hydrogen and CO_2 feedstock, which would encompass within them the initial capital costs and electricity costs associated with the feedstock production.

Using Levelised Cost of Electricity (LCOE) projections for predicting future e-fuel production costs offers greater reliability and consistency compared to electricity capture prices. LCOE provides an average cost of renewable energy generation over a project's lifetime, aligning well with the long-term nature of e-fuel production planning. Future electricity prices are uncertain and depend on different factors such as the future demand for electricity, the share of variable renewable power sources, potential phase out of nuclear power, the integration with other energy sectors.

[400] Fasihi, M., Efimova, O., & Breyer, C. (2019). Techno-economic assessment of CO_2 direct air capture plants. *Journal of Cleaner Production, 224*, 957-980.

[401] Sanz-Pérez, E. S., Murdock, C. R., Didas, S. A., & Jones, C. W. (2016). Direct capture of CO_2 from ambient air. *Chemical Reviews, 116*(19), 11840–11876.

[402] Keith, D. W., Holmes, G., St. Angelo, D., & Heidel, K. (2018). A process for capturing CO_2 from the atmosphere. *Joule, 2*(8), 1573–1594.

[403] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, Concawe, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[404] International Renewable Energy Agency (IRENA). (2021). *Capturing carbon: A key to net zero*. Retrieved from https://www.irena.org/-/media/Irena/Files/Technical-papers/IRENA_Capturing_Carbon_2021.pdf

[405] Data has been adjusted using CEPCI index. Data for 2030 and 2040 deduced using linear interpretation between 2020 and 2050.

Unlike the highly variable and market-driven capture prices, which are difficult to predict due to their dependency on real-time supply and demand dynamics, LCOE incorporates broader trends such as technological advancements, economies of scale, and declining renewable energy costs. By focusing on LCOE, projections avoid the speculative complexities of energy markets while offering a robust foundation for modelling and decision-making. As LCOE price do not factor in intermittency of renewable energies and would require additional battery storage or intermittent hydrogen production, we excluded them for this analysis.

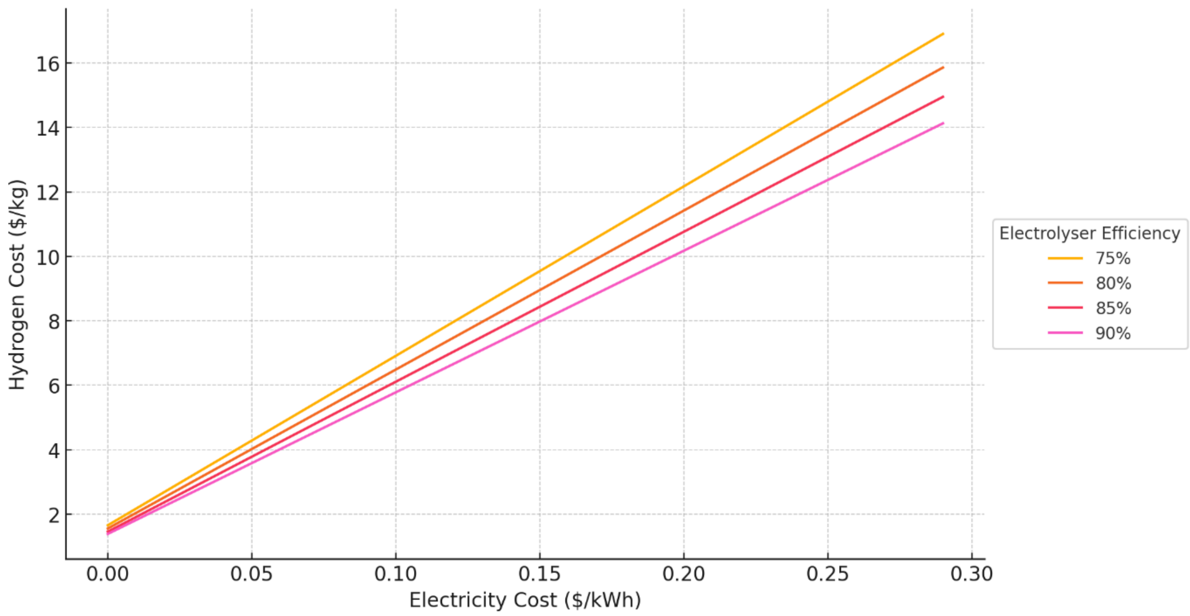
Table 9-68. Estimates of renewable electricity price ranges based on solar, onshore wind, and offshore wind[406].

Electricity cost [US$/MWh]	2030	2040[407]	2050
Germany	35 - 45	30 - 43	25 - 40
USA	30 - 40	25 - 33	20 - 30
China	25 - 45	20 - 40	15 - 40

9.6.6 Hydrogen cost projections

The following analysis scrutinises the assumption about hydrogen cost projections as presented in previous sections upon which the country TEA analysis was based. The aim of this section is to show the unlikelihood of reaching green hydrogen prices below US$2/kg in 2050 based on alkaline electrolyser technology. This is not to say that such low hydrogen prices are impossible, but they are improbable using existing technologies and may require other low-cost sources of hydrogen.

Figure 9-88. Projected Hydrogen Production Costs in 2050 - Impact of Electricity Price and Electrolyser Efficiency1.



[406] International Energy Agency. (2021). *Net zero by 2050: A roadmap for the global energy sector*. Retrieved from https://www.iea.org/reports/net-zero-by-2050

[407] Data for 2040 is a linear interpolation of 2030 and 2050.

This analysis presents a 2050 projection for hydrogen production taking into account reductions in electrolyser capital costs, based on an estimated demand of **245 kt H_2 per year (~1.8 GW)**. It examines the interplay between **electricity cost (US$/kWh)** and **hydrogen production cost (US$/kg)** at varying electrolyser efficiencies (ranging from 75% to 90%). The findings underscore a fundamental constraint: even under highly optimistic conditions—where electricity prices are exceptionally low and electrolysers operate near theoretical efficiency—the cost of hydrogen remains above a critical economic threshold.

For instance, at an electricity price of **US$0.05/kWh**—a figure already at the lower bound of renewable electricity price forecasts—the projected hydrogen costs are as follows:

- **US$4.28/kg** at **75% efficiency**
- **US$4.02/kg** at **80% efficiency**
- **US$3.79/kg** at **85% efficiency**
- **US$3.58/kg** at **90% efficiency**

Even if electricity prices decline further to **$0.03/kWh**, hydrogen production costs remain elevated:

- **US$3.23/kg** at **75% efficiency**
- **US$3.03/kg** at **80% efficiency**
- **US$2.86/kg** at **85% efficiency**
- **US$2.71/kg** at **90% efficiency**

At an extreme scenario of US**$0.01/kWh**—a price point well below realistic projections for 2050 renewable electricity price—the cost of hydrogen still does not reach the sub-US$1.50/kg threshold often cited as necessary for widespread competitiveness with fossil fuels:

- **US$2.17/kg** at **75% efficiency**
- **US$2.05/kg** at **80% efficiency**
- **US$1.93/kg** at **85% efficiency**
- **US$1.83/kg** at **90% efficiency**

These projections illustrate that while electricity costs are a major determinant of hydrogen pricing, they do not drive costs downward indefinitely. Even with near-zero electricity prices and near-unattainable electrolyser efficiencies, hydrogen production costs remain constrained above US$1.80–US$2.00/kg. Given that large-scale adoption of hydrogen as a cost-competitive energy carrier is widely believed to require prices below US$1.50/kg, this poses a significant economic challenge.

These findings suggest that reducing electricity costs alone is insufficient to achieve cost-competitive hydrogen production. Even with substantial improvements in electrolyser efficiency, the cost structure remains fundamentally constrained by factors beyond electricity prices, with CapEx emerging as a critical limiting factor.

For hydrogen production costs to reach a commercially viable level, CapEx would need to decline exponentially, far beyond the gradual reductions typically driven by economies of scale. While increased deployment and mass manufacturing could yield some cost reductions, historical trends suggest that scale effects alone are unlikely to drive the magnitude of cost declines required. Instead, achieving truly low-cost hydrogen would likely require:

- **A step-change reduction in electrolyser manufacturing costs**, potentially through novel materials, alternative manufacturing techniques, or automation.
- **Radical improvements in system design** to lower balance-of-plant costs, installation complexity, and integration overheads.
- **Disruptive innovations** in electrolyser technology, such as next-generation membranes, catalysts, or solid-state designs, that fundamentally alter the cost structure.
- **Aggressive policy interventions and incentives** that de-risk investment, accelerate deployment, and catalyse rapid industry maturation.

Even under optimistic projections, the hydrogen industry **cannot rely solely on economies of scale** to achieve cost parity with fossil fuels. Instead, it will require **a paradigm shift in cost reduction mechanisms**, with exponential CapEx declines enabled by both **technological breakthroughs and systemic market transformation**. Without such a disruptive shift, hydrogen production costs are likely to remain above key commercial thresholds, limiting its potential for widespread adoption.

9.6.7 TEA Limitations

Overall, in the TEA, assumptions are made to simplify processes and also to compensate for data deficiencies. Capital costs of novel technologies are hard to predict, since experience curve effects are often unknown. Moreover, many of the studies upon which capital cost estimates have been based, have used ratio factors adapted from best practice estimates from the chemical industry, which are used in the case study to estimate indirect costs such as maintenance and installation costs as a fraction of fixed capital investment. This bears the risk to overestimate indirect costs, since capital costs of novel technologies are significantly higher compared to standard equipment used in state-of-the-art chemical processes. More research is required to estimate realistic cost factors for novel fuel production processes.

The determination of total costs of e-fuel production is also based on many assumptions, for instance, the hydrogen and CO_2 prices. The production cost of green hydrogen is reliant on the availability of renewable electricity, which is often intermittent. The interplay between variable renewable energy (VRE) and e-fuel production costs is critical, with opportunities for optimisation primarily centred on capacity factor (CF) improvements. Previous studies suggest that VRE-rich regions (e.g., Ireland or Spain) with higher CFs can leverage cost advantages by directly aligning e-fuel production with renewable electricity availability[408]. CF optimisation minimises dependency on auxiliary energy sources, such as hydrogen storage, and reduces overall production costs by maintaining a steadier operation of electrolysers and associated systems.

A recent study elaborates that techno-economic modelling for e-fuels should account for the fluctuating nature of electricity prices driven by VRE integration[409]. Sensitivity analysis indicates that electricity prices dominate production costs in Power-to-Liquid (PtL) pathways, underscoring the value of dynamic load-following operation strategies. These allow plants to scale production in response to electricity availability, effectively utilizing low-cost electricity windows.

Dynamic loading and feedstock supply intermittency was not modelled in this study. Instead, this study provides indicative costs of e-fuel production for any combination of hydrogen and CO_2 prices, regardless of the hydrogen production process.

9.6.8 Modelling assumptions

- **Plant Operational Characteristics**
    - Plant Economic Life: Assumed to be 25 years.
    - Construction Period: Set at 4 years to align with typical project timelines for fluid processing facilities.
    - Annual Operating Hours: Estimated at 8,000 hours, representing near-continuous operation.
    - Utilisation Rate: Assumed to be 92%, accounting for planned downtime and maintenance.

---

[408] Grahn, M., Taljegard, M., & Brynolf, S. (2022). Review of electrofuel feasibility—Cost and environmental impact. *Progress in Energy, 4*(3), 032010. https://doi.org/10.1088/2516-1083/ac6f6e

[409] Shi, K., Guan, B., Zhuang, Z., Chen, J., Chen, Y., Ma, Z., Zhu, C., Hu, X., Zhao, S., Dang, H., Guo, J., Chen, L., Shu, K., Li, Y., Guo, Z., Yi, C., Hu, J., & Huang, Z. (2024). Perspectives and outlook of E-fuels: Production, cost effectiveness, and applications. *Energy & Fuels, 38*(9). https://doi.org/10.1021/acs.energyfuels.4c00234

- **Equipment Cost Adjustment and Scaling**

  - ***Cost Standardisation***:
    - Equipment costs sourced from the literature were adjusted to a 2025 base year using the Chemical Engineering Plant Cost Index (CEPCI). This adjustment ensures consistency by accounting for inflation and economic variations between the source year and the base year.
    - Adjustment Formula**:**

$$Adjusted\ Cost = Base\ Cost \times \frac{CEPCI_{base\ year}}{CEPCI_{Source\ Year}}$$

Production Costs

- **Total capital investment (TCI):**
  - The Total Capital Investment (TCI) for each scenario was calculated from the purchased equipment cost using the factorial estimation method, as outlined by Peters et al. for fluid processing plants[410].

Table 9-69. Cost factors for economic analysis.

Cost Component	Factor (as a fraction of delivered equipment cost)
Direct Costs	
Purchased Equipment (PC)	1.00
Purchased Equipment Installation	0.47
Instrumentation & Controls (Installed)	0.36
Piping (Installed)	0.68
Electrical Systems (Installed)	0.11
Buildings (Including Services)	0.18
Yard Improvements	0.10
Service Facilities (Installed)	0.70
Total Direct Costs (TDC)	3.60
Indirect Costs	
Engineering and Supervision	0.33
Construction Expenses	0.41
Legal Expenses	0.04
Contractor's Fee	0.22
Contingency	0.44
Total Indirect Costs (TIC)	1.44
Fixed Capital Investment (FCI)	TDC + TIC = 5.04
Working Capital (WC)	0.89
Total Capital Investment (TCI)	FCI + WC = 5.93

[410] Peters, M.S., Timmerhaus, K.D. and West, R.E. (2003) *Plant Design and Economics for Chemical Engineers*. 5th edn. New York: McGraw-Hill.

- **Fixed Costs of Production (FCP)**:
    - Represent costs independent of plant productivity, including salaries, maintenance, insurance, and property taxes.
    - **Formula**:

$$Fixed\ Cost\ of\ Production = 0.04\ \times\ TCI.$$

- **Variable Costs of Production (VCP)**:
    - Dependent on the production rate and process conditions. These costs encompass raw materials, utilities, and operational expenses, derived from mass and energy balances.

- **Economic Parameters:**
    - Interest Rate: 8%.
    - Gearing: 0.7
    - Targeted repayment period: 20 years

Levelised Cost of Fuel (LCoF):

The LCOF is a metric that expresses the cost per unit of fuel produced over the lifetime of a project. It accounts for all major expenditures—including capital, variable operating, and fixed operating costs—and relates them to the total fuel production. The LCOF formula is given by:

- **Formula**:

$$LCOF = \frac{Total\ Lifetime\ Cost}{Total\ lifetime\ fuel\ production}$$

- **Components**:
    - **Total Lifetime Costs**: Includes capital, fixed, and variable costs.
    - **Fuel Production Rate**: Derived from mass balance and process efficiency.

Since costs and production occur at different times throughout the project lifecycle, it is necessary to discount future cash flows to their present values. In this study, discounting is performed using the project's Weighted Average Cost of Capital (WACC). In the case of operating costs, it is assumed an increase in line with WACC over time is seen. This counteracts discounting, meaning operating costs remain effectively constant in real terms. Costs are estimated in USD ($).

9.6.8.1 Discounting approach

The Weighted Average Cost of Capital (WACC) serves as the discount rate for all relevant cash flows. It accounts for the project's capital structure, cost of debt, and cost of equity, incorporating tax effects.

$$WACC = (Inflation\ Adjusted\ Cost\ of\ Equity \times Equity\ Percentage) + (Cost\ of\ Debt\ \times Gearing\ \times (1 - Corporate\ Tax\ Rate))$$

- **Inflation Adjusted Cost of Equity** is the required return for equity investors.
- **Equity Percentage** represents the proportion of financing from equity.
- **Cost of Debt** is the effective borrowing rate.
- **Gearing** (Debt Ratio) reflects the proportion of debt financing.
- **Corporate Tax Rate** accounts for tax advantages of debt.

Table 9-70. Parameter Values Used in WACC Calculation.

Parameter	Value	Description
Inflation Adjusted Cost of Equity	29.57%	Real cost of equity financing.
Equity Percentage	30%	Share of total project financing funded by equity.
Cost of Debt	4.12%	Effective cost of borrowing.
Gearing (Debt Ratio)	70%	Share of financing from debt.
Corporate Tax Rate	30%	Corporate tax applied to earnings.
Resulting WACC	**10.89%**	Used for discounting cash flows.

This WACC is applied to the capital cost and fuel production calculations.

Table 9-71. E-fuel costs compared to alternatives[411]. Units are in $/litre.

Fuel type	Energy carrier	Scenario	Year		
			2030	2040	2050
Biofuel	**HVO/HEFA (2nd gen)**	min	0.60	0.55	0.55
		base	0.99	0.99	0.99
		max	1.21	1.15	1.15
	FAME (2nd gen)	min	0.66	0.66	0.66
		base	0.93	0.93	0.93
		max	0.99	0.99	0.99
	Ethanol (2nd gen)	min	0.71	0.66	0.66
		base	0.99	0.93	0.93
		max	1.37	1.04	0.99
Fossil	**Gasoline**	min	0.33	0.33	0.33
		base	0.44	0.44	0.44
		max	0.55	0.55	0.55
	Diesel	min	0.33	0.33	0.33
		base	0.44	0.44	0.44
		max	0.55	0.55	0.55
	Jet fuel	min	0.33	0.33	0.33
		base	0.44	0.44	0.44
		max	0.55	0.55	0.55
E-fuel	**E-diesel**	min	1.84	1.31	1.14
		base	2.54	1.76	1.36
		max	4.41	3.12	2.22
	E-kerosene	min	1.54	1.07	0.91
		base	2.06	1.40	1.07
		max	3.43	2.41	1.72
	E-gasoline	min	1.69	1.19	1.02
		base	2.32	1.57	1.20
		max	3.89	2.73	1.94

[411] Oil and Gas Climate Initiative. Net Zero 2050: Energy Demand Dynamics Across the Transportation Sector. 2024. Accessed December 20, 2024. https://www.ogci.com.

Table 9-72. Electricity generated in 2023 in Germany, USA, and China[412].

	Total electricity [GWh]	RE electricity [GWh]
Germany	505,000	260,000
USA	4,250,000	1,023,000
China	9,460,000	2,480,000

Table 9-73. Overview of e-fuel upgrade and potential compliance to specifications in the reviewed literature.

Reference	Process	Fuel output	Upgrade included	ASTM compliant?
Concawe (2024)	FTD	Diesel	Hydrocracking	Requires modification to meet EN/ASTM standards
	FTK	Kerosene	Hydrocracking	Assumed ASTM compliant for 50/50 blending
	MtG	Gasoline	Hydrogeneration	Assumed EN compliant
	MtK	Kerosene	Not specified	Not specified
Project SkyPower (2024)	FTK	Kerosene	Hydrocracking	Assumed ASTM compliant for 50/50 blending
	MtK	Kerosene	Hydrocracking	Assumed ASTM compliant for 50/50 blending
WEF (2020)	FTK	Kerosene	Not specified	Assumed ASTM compliant for 50/50 blending
Bube et al. (2024)	FTK	Kerosene	Hydrocracking + Hydrogeneration	Assumed ASTM compliant for 50/50 blending
	MtK	Kerosene	Hydrocracking + Hydrogeneration	Not specified
ERM (2024)	FTD, FTK, MtG, MtK	Kerosene, diesel, gasoline	Not specified	All assumed compliant
Ruokonen et al. (2021)	MtK, MtG	Kerosene, gasoline	Hydrogeneration	Requires modification to meet ASTM/EN standards
Grahn et al. (2022)	FTD, FTK, MtG, MtK	Kerosene, diesel, gasoline	Not specified	Not specified
Ash et al. (2020)	FTD	Diesel	Not specified	Not specified
Becattini et al. (2021)	FTK	Kerosene	Not specified	Assumed ASTM compliant for 50/50 blending
Zhou et al. (2022)	FTK	Kerosene	Not specified	Not specified

[412] Our World in Data. (2024). *Electricity generation in 2023*. Retrieved from https://ourworldindata.org/renewable-electricity-2023

Reference	Process	Fuel output	Upgrade included	ASTM compliant?
Albrecht et al. (2017)	FTK	Kerosene	Hydrocracking	Not specified
Becker et al. (2012)	FTG	Gasoline	Isomerisation, and catalytic reforming	Not specified
	FTD	Diesel	Hydrocracking	Not specified
Zang et al. (2021)	FT	Kerosene, diesel, gasoline	Hydrocracking	Not specified

Table 9-74. Fuel costs based on a review of the literature.

Reference	Basis of estimate	Feedstock input	Process	Battery limits	Production capacity [MW]	Fuel output	Production Cost [US$/litre] [413]
Grahn et al. (2022)	Estimates of CapEx and OpEx from literature	Purchased electricity and CO_2. Produced H_2	FTD, FTK, MtG, MtK	Electrolysis + fuel synthesis	50	e-fuels	3.2 – 3.5
Ash et al 2020	Estimates of CapEx and OpEx from literature	Purchased electricity and CO_2. Produced H_2	FTD	Electrolysis + fuel synthesis	N/A	diesel	3.4
Becattini et al. (2021)	Estimates of per unit costs from literature	Purchased electricity. CO_2 and H_2 produced	FTK	Electrolysis + DAC + fuel synthesis	N/A	kerosene	4.2 – 7.5
ERM (2024)	Estimates of per unit costs from literature	Purchased electricity. CO_2 capture. Produced H_2.	FTD, FTK, MtG, MtK	Electrolysis + CO_2 capture + fuel synthesis	70-110	e-fuels	1.7 – 2.1
Zhou et al. (2022)	Estimates of per unit costs from literature	Purchased electricity and CO_2. Produced H_2.	FTK	Electrolysis + fuel synthesis	200	kerosene	1.9 – 2.6
F.G. Albrecht et al. (2017)	Estimates of per unit costs from literature	Purchased electricity and CO_2. Produced H_2.	FTK	Electrolysis + fuel synthesis	34	kerosene	5.0

[413] CEPCI index was used to convert to 2024 USD value. Currency conversion from Euro to USD is based on the average closing price for that year.

Reference	Basis of estimate	Feedstock input	Process	Battery limits	Production capacity [MW]	Fuel output	Production Cost [US$/litre] [413]
Becker et al (2012)	Estimates of per unit costs from literature	Purchased electricity and CO_2. Produced H_2.	FT	Co-electrolysis + fuel synthesis	30	Kerosene + diesel	1.8 - 2.6
Zang et al (2021)	Aspen Plus simulation + estimates of per unit costs from literature	Purchased electricity, CO_2, and H_2.	FT	Fuel synthesis	180	E-fuels	0.7 – 2.6
Ruokonen et al (2021)	Aspen Plus simulation + estimates of per unit costs from literature	Purchased electricity, CO_2, and H_2	MT+MOGD	Fuel synthesis excluding methanol synthesis	13	e-fuels	4.5
Project SkyPower (2024)	Bottom up CapEx + OpEx costing	Dedicated RE plant. Purchased CO_2 Produced H_2	FTK	RE plant + electrolyser + fuel synthesis	35 - 270	kerosene	5.4 – 8.6
WEF Clean Skies for Tomorrow (2020)	Estimates of per unit costs from literature	Purchased electricity, CO_2, and H_2	FTK	N/A	N/A	kerosene	2.8
Concawe (2024)	Bottom up CapEx + OpEx costing	Electricity, CO_2, and H_2 production.	FTD, FTK, MtG, MtK	RE plant + electrolyser + CO_2 capture + storage + fuel synthesis + fuel transport	1,700	e-fuels	1.8 – 5.0

* Conversion to MW assumed a lower heating value of 43 MJ/kg, 7 barrels/tonne of oil, or 8000 hours of operation per annum, where necessary. Also, currency conversion from Euro to US$ is based on the average closing price for that year.

9.7 LIFE CYCLE ASSESSMENT

9.7.1 LCA Methodology

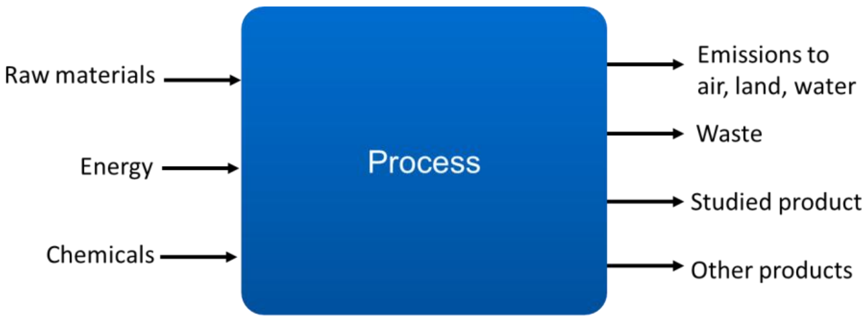
9.7.2 Introduction to LCA

Life cycle assessment (LCA) is a method of systematically assessing the environmental burdens associated with a product, process, or activity over the whole of its life cycle. The international standard for life cycle assessment, ISO 14040, states that:

"LCA addresses the environmental aspects and potential environmental impacts (e.g., use of resources and the environmental consequences of releases) throughout a product's life cycle from raw material acquisition through production, use, end-of-life treatment, recycling, and final disposal (i.e., cradle-to-grave)" (ISO, 2006).

LCA calculates the potential environmental impact of a product by quantifying the 'flows' entering and leaving a product system. Inbound flows include raw materials and energy flows, while outbound flows include emissions, wastes and by-products. This is shown in the figure below.

Figure 9-89: Flows into and out of the product system under study



Each of these flows is multiplied by a characterisation factor for the selected environmental indicator (in this instance climate change impact) to determine the kg CO_2e released across the product's lifetime.

There are different choices to be made when completing an LCA, including defining the system boundary, cut-off criteria, the impact categories covered and methodological approach.

The system boundary of a product system determines the unit processes to be included in the LCA study and which data as inputs and/or outputs to/from the system can be omitted. These are typically described in terms of 'cradle' to 'grave', split as described below:

- *Cradle to gate (upstream processes and core processes):* Inputs include all upstream sourcing and pre-processing of raw materials and transportation to the manufacturing facility as well as consumables needed for manufacture of the studied product e.g., energy, natural gas, water, etc.. Outputs include waste and emissions that arise from the manufacturing process.
- *Gate to grave (downstream process):* Includes all impacts associated with the distribution, storage, use and disposal at end-of-life.

However, similar system boundaries can be described using the terminology of 'well-to-wake', which is typically used when considering LCAs of fuels. The term 'well-to-wake' or 'well-to-wheel' (WtW) refers to the entire life cycle of a fuel, starting with the process of fuel production and ending with the delivery and use of a fuel (combustion). As with 'cradle-to-grave', WtW assessments consist of two parts: well-to tank (WtT) and tank-to-wake (TtW). WtT covers the impacts associated with production of the energy and transportation up to the vessel or vehicle's 'tank'. TtW covers the use of the fuel by the vehicle or onboard the vessel including combustion.

The ISO14040 standard provides the best practice framework and principles for completing LCA, however, it does not specify methodological decisions to be taken in any given study. Additional standards and methodologies can be used to inform or comply with agreed methodological approaches, depending on sector and application of the LCA. Examples include RED, FuelEU, IMO, and REFuelEU. Each method and LCA study will vary in data, scope and emission factor used.

As noted earlier in this report, this study has undertaken a literature review of multiple sources to source its data for analysis. It should be noted that results and data from these sources are collated from LCAs which follow differing guidelines and care has been taken to utilise inventory-level data (i.e. mass or energy of flows) as opposed to impact level data (kg CO_2e) to better ensure consisting modelling.

9.7.3 Methodological Approach

This study follows ISO 14040's approach to LCA methodology but does not seek compliance and should therefore not be interpreted as a full LCA. One key distinction is that, while an ISO 14040 compliant LCA would explore multiple environmental indicators such as ozone depletion and acidification alongside the carbon impacts, this study looks to identify the potential carbon impact only. This is in-line with the intended goal of the study and the agreed scope of the project. The results presented in terms of carbon dioxide equivalents[414] (CO_2eq.) per e-fuel production pathway.

9.7.3.1 Approach

9.7.3.1.1 Scope

Three e-fuel production pathways have been considered in this LCA assessment. Broadly, each of these pathways can be split into three steps: carbon sourcing, hydrogen sourcing and fuel processing. Within the carbon sourcing step, the following CO_2 sources have been considered: direct air capture, industrial CCU and biogenic CO_2. For the hydrogen step, only green hydrogen, produced through electrolysis using renewable electricity, has been covered. For the fuel processing, this includes all pre-processes (such as methanol synthesis, syngas production) and the subsequent upgrade to the final fuel (e-gasoline, e-kerosene and e-diesel).

Distribution, storage and use of the e-fuels after production, and any additives required to make the fuels 'drop-in ready', are considered out of scope and have not been included in the analysis. The decision to utilise this system boundary matches the goal of this study; to understand where e-fuels offer the greatest opportunity for decarbonisation. The implicit assumption is that the distribution, storage and combustion of the e-fuels does not, or does not significantly differ across the geographic, temporal or carbon source scenarios studies. It should be stressed that this statement can only be defended for the use-phase once the carbon modelling approach is established.

Burdens associated with infrastructure, such as the infrastructure impacts associated with the production facilities, have been included. This approach differs to the scope recommended in the Renewable Energy Directive (RED) but has been adopted in this study so as to ensure that the impact of all relevant flows are considered.

9.7.3.2 Literature Review

Data collection first involved a process mapping to identify the steps associated with each of the e-fuel pathways. These were systematically mapped to enable a thorough understanding of e-fuel production for the three e-fuels included in the study. The output of the process mapping is shown in the figures below. These were built largely on the block flow diagrams included in the Section 2.

---

[414] This quantifies the potential amount of greenhouse gas (GHG) equivalents that are released into the environment, taking into account the total GHG emitted into the atmosphere that are liable to cause global warming. Note that 'eq.' refers to 'equivalent'.

Figure 9-90: Simplified process flow diagram of the MTG fuel pathway

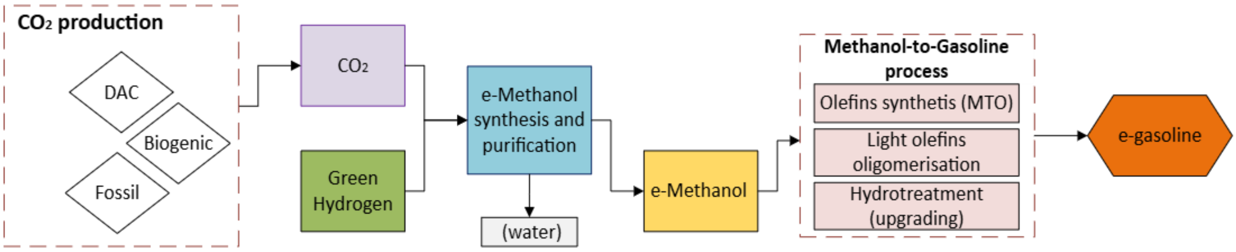


Figure 9-91: Simplified process flow diagram of the MTK fuel pathway

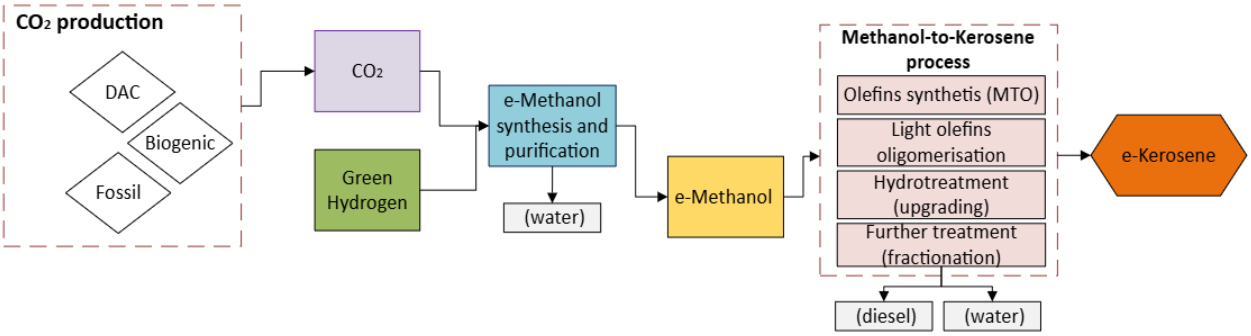
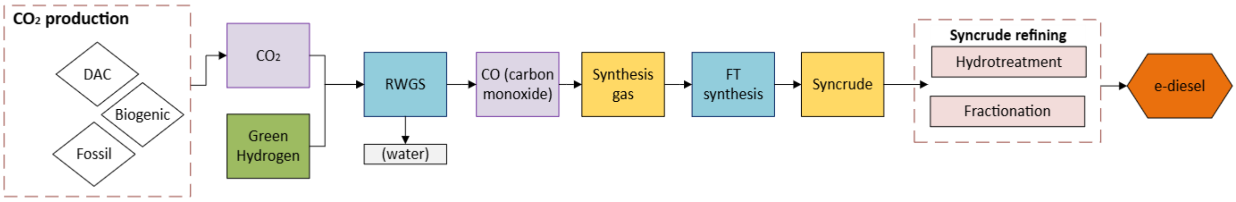


Figure 9-92: Simplified process flow diagram of the FTD fuel pathway



9.7.3.3 *Modelling*

Where ecoinvent datasets have been used for the sourcing of specific emission factors, this has been done using ecoinvent v3.11 under the Environmental Footprint (EF) 3.1 LCIA methodology for the GWP indicator. The ecoinvent database is a widely used and reputable among LCA practitioners' source of environmental impact data for a range of sectors and processes[415].

9.7.3.4 *Functional Unit*

The functional unit is a key element of LCA as it provides the reference to which the input and output data are normalised (in a mathematical sense) and must be clearly defined. The functional unit is determined by the function of the system being studied and must be consistent with the goal and scope of the study.

The functional unit for this study is defined as 1 MJ of fuel. This is consistent with the functional unit used within the technoeconomic analysis of the e-fuels and accounts for the primary function of the fuels, which is to provide energy through combustion.

To be consistent with the technoeconomic analysis, the lower heating value was used for modelling the fuel energy density of each fuel.

[415] Ecoinvent, 2024, Ecoinvent v3.11 database, available at: https://ecoinvent.org/database/

Table 9-75: Energy densities used for each fuel (based on the lower heating value)

Fuel	Energy Density (MJ/kg)
MTG	43.4[416]
MTK	43[3]
FTD	42.6[3]

9.7.3.5 Allocation Procedures

Allocation procedures were completed according to ISO 14044. In terms of background data, this study used the ecoinvent database, which defaults to economic allocation for most processes. However, in some cases a mass-based allocation is used where there is a direct physical relationship. The impact associated with the biogenic CO_2 sourcing was allocated based on an energy basis, allocated with 0% for the default. This was based on the exemplar scenario used (upgrading of biogas to biomethane), in which the energy bases allocation was assumed as 100% for the biomethane. A sensitivity was considered for this allocation based on switching to economic allocation, though since economic allocation would only allocate 5% of the GWP burden to the CO_2, it was therefore considered negligible.

Biogenic carbon sourced from upgrading of biogas to biomethane was selected as an exemplar scenario for focus in this study. This was selected as in this scenario is likely to be one of the lowest GWP sources of biogenic CO_2 as the CO_2 is separated within the process by which biomethane is separated. Therefore, since the aim of the biogas purification is to collect the bio-methane, the CO_2 can be treated as a waste and therefore is not allocated any of the impacts associated with the purification. This means that only the impacts associated with the subsequent collection and compression of the CO_2 for transport need to be considered; as the off gas which is collected has very few contaminants no further purification is needed.

The "Polluter Pays" principle has been used in this study. This is also known as the "recycled content" or "cut-off" approach. This is where only the burdens of processing waste generated by the system to an end-of-waste state (as defined in the ISO standards) are assigned to the system under study. Once the end-of-waste state is achieved, any further processing and associated impacts which are incurred by this material in the next system, are allocated to that system.

Therefore, in this study, the "cut-off" method has been applied to the carbon sourcing, through which the impact associated with the materials 'first life' are considered burden free on entrance to its 'second life'. I.e. within this study, the impact of carbon capture is only considered from the point that the carbon is available for capture, and therefore the impact associated with the production and combustion of the fuel sources which generate CO_2 for capture for the biogenic and industrial CCU sources are considered out of scope.

9.7.3.6 Carbon modelling approach

Three scenarios are considered for each of the e-fuels' CO_2 sources. Two of the scenarios, DAC and biogenic CO_2, remove carbon from the atmosphere before converting it into a fuel. The third scenario, industrial emissions, prevents a release of carbon to the atmosphere. Carbon removals and prevented releases present important LCA methodological considerations.

9.7.3.6.1 Carbon removals

Carbon removals are typically modelled using one of two methods: a -1/+1 or a 0/0 approach. Each refers to how the carbon within a system is drawn from the atmosphere is characterised.

[416] The Engineering Toolbox, Fuels – Higher and Lower Calorific Values, taken from https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html

-1/+1 approach

Under the -1/+1 approach, CO_2 withdrawn from the atmosphere and incorporated as carbon into a product is characterised as -1kg CO_2e / kg CO_2. When this CO_2 is released back to atmosphere (such as through combustion), it is characterised as 1kg CO_2e / kg CO_2. For a fuel, where 100% of the carbon will be returned to atmosphere upon combustion, the net impact is 0.

A study's system boundary choice has important implications for this modelling approach. Under a cradle-to-gate system boundary, fuels utilising carbon removals (such as from DAC or bio sources), will receive a negative characterisation factor, implying that e-fuel production removes carbon from the atmosphere. This inference can only be justified if the e-fuel user is allocated a positive characterisation factor when the fuel is combusted.

0/0 approach

Under the 0/0 approach, it is assumed that all carbon drawn down from the atmosphere will eventually be returned back to the atmosphere. Therefore, carbon removals are characterised with a 0, since they will not result in a net reduction in CO_2. When these sources are eventually released, they are also characterised with a 0, in order to balance the equation. Note that under a cradle-to-grave system boundary both the 0/0 and -1/+1 systems result in a net impact of 0.

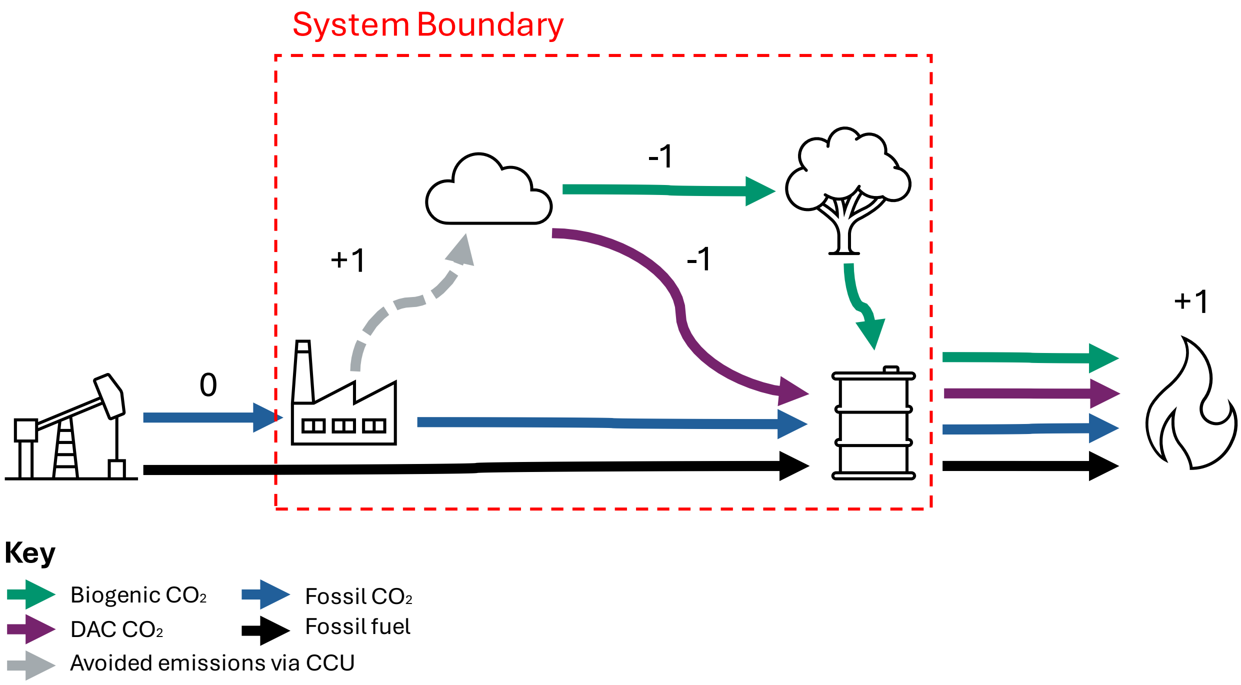
The difference in approach is most important when considering cradle-to-gate system boundaries. Under the 0/0 approach, the fuel producer does not receive a negative characterisation factor and the implication is that fuel production does not reduce atmospheric carbon emissions. This choice can only be justified if the eventual user of the fuel does indeed burn the fuel and characterises it as having a global warming potential (GWP) of 0.

It is this study's consideration that the purpose of a fuel is to be burnt, and that it will be released back to atmosphere. Both approaches consider that this function results in no net reduction in atmospheric carbon. Therefore, this study has opted to use a 0/0 approach as, under the study's cradle-to-gate scope, this approach will present results that do not suggest a net reduction is taking place.

9.7.3.6.2 Prevented releases

The industrial emissions carbon source does not represent a carbon removal. However, it does capture CO_2 that would otherwise have reached atmosphere. This is illustrated by the grey dashed arrow, which represents the CO_2 that would otherwise have been released to atmosphere.

Figure 9-93: Carbon allocation modelling



The consideration here is a consequential one, rather than attributional. The consequence of opting for the industrial CCU source is that industrial emissions do not reach atmosphere, the counterfactual for the biogenic and DAC sources is that these emissions do continue to reach atmosphere.

This can be modelled through system expansion to include the industrial emissions within the study's system boundary. For the industrial CCU system, industry does not release carbon to the atmosphere, but for the biogenic CO_2 and DAC systems, industry does release carbon to the atmosphere as usual. below states the GWP for each CO_2 source pathway under the 0/0 methodology selected above, and splits the results attributable to the fuel production and to the wider industrial system. A conventional fossil fuel's carbon modelling approach is also shown for context.

It can be seen that across the three CO_2 sources considered, the only CO_2 that is characterised is the CO_2 resulting from industrial emissions. For the bio and DAC systems, this CO_2 is released during production (the cradle to gate stage) as industrial emissions continue unabated. For the industrial CCU system, this CO_2 is released when the fuel is combusted (gate to grave stage).

Table 9-76: Carbon modelling approach for different CO_2 sources under 0/0 and system expansion approach.

CO_2 source	Stage	Cradle to gate stage (production)	Gate To grave stage (fuel use)	Total cradle to grave across expanded systems
Biogenic	e-fuel production and use	0	0	1
	Industrial activity producing CO_2	1	0	
DAC	e-fuel production and use	0	0	1
	Industrial activity producing CO_2	1	0	
	e-fuel production and use	0	1	1

CO_2 source	Stage	Cradle to gate stage (production)	Gate To grave stage (fuel use)	Total cradle to grave across expanded systems
Industrial CCU	Industrial activity producing CO_2	0	0	
Conventional fossil	Fossil fuel production and use	0	1	2
	Industrial activity producing CO_2	1	0	

All three e-fuel systems result in a net impact of 1, meaning that the differential between them is 0. Since the focus of this study is cradle-to-gate impact of the e-fuels, not a multi-functional system, and the results will most likely be used in attributional studies, not consequential, and crucially, industrial emissions do not affect the net result of the three systems, the decision has been taken to simplify the modelling considerations and exclude the industrial emissions from the system boundary.

It is important to stress however, that this decision can only be justified if the industrial CCU system does prevent emissions from occurring. This is why in addition to the quantitative analysis qualitative consideration will also be given to whether this is a fair assumption for the latter temporal scenarios.

9.7.4 LCI Data

9.7.4.1 Hydrogen

This study defines e-fuels as a synthetic fuel that has hydrogen inputs produced using renewable electricity only, commonly referred to as green hydrogen. Green hydrogen is produced using renewable energy to split water into hydrogen and oxygen.

There are several different methods for producing green hydrogen. The most common method is alkaline electrolysis[417], which a more mature and widely used technology. Newer methods such as proton exchange membrane (PEM) electrolysis and solid oxide electrolysis (SOE) are also common approaches, each utilizing different electrolytes and operating conditions. There are also other emerging technologies, such as biological processes and thermochemical water splitting, however, electrolysis remains the most commercially viable method for large-scale production of green hydrogen.

Green hydrogen produced through alkaline electrolysis was chosen for focus within this study as it remains the cheapest and most reliable option for larger-scale green hydrogen production. Additionally, with growing interest in green hydrogen, alkaline electrolysis is often most favourable as it works well with electricity from renewable sources such as wind which typically have higher levels of variability in their availability[418]. An efficiency of 70% has been assumed for the alkaline electrolysis. This is in-line with current peer reviewed literature suggesting a range of 60-80% efficiency[419,420]. Technological change has been assumed to be negligible for alkaline electrolysis as it is already established.

The table below states the estimated requirement for the H_2 feedstock for each e-fuel production route (as kg H2 required per kg of final e-fuel produced). These values have been sourced from multiple

417 Erbach., G. and Svensson, S., 2023, EU Rules for Renewable Hydrogen, retrieved from: https://www.europarl.europa.eu/RegData/etudes/BRIE/2023/747085/EPRS_BRI(2023)747085_EN.pdf

418 Energy Transition Outlook. (2022). Hydrogen Forecast to 2050. Hovik: DNV. Retrieved November 28, 2024, from https://www.dnv.com/focus-areas/hydrogen/forecast-to-2050/

419 El-Shafie, M. (2023). Hydrogen Production by water electrolysis technologies: A review. Results in Engineering, 101426. doi:10.1016/j.rineng.2023.101426

420 Sebbahi, S., Assila, A., Belghiti, A., Laasri, S., Kaya S., Hlil, E., Rachidi, S. and Hajjaji, A. (2024). *A Comprehensive review of recent advances in alkaline water electrolysis for hydrogen production.* International Journal of Hydrogen Energy, 82, 583-599, https://doi.org/10.1016/j.ijhydene.2024.07.428

literature sources[421,422,423,424,425,426,427,428,429] and are used to calculate the upstream emissions associated to the production of H_2 for use within each of the e-fuels production pathways.

Table 9-77: LCI data input of H_2 per kg of final e-fuel produced

E-fuel production pathway	Hydrogen (kg / kg fuel)
MTG	0.49
MTK	0.46
FTD	0.49

Table 9-78 provides the values and ranges for other energy and water requirement found in the literature review carried out for the study. Where only one value is provided, this is due to limitations in robust sources found.

Table 9-78: LCI data for the upstream production of 1kg of green hydrogen via alkaline electrolysis presented as minimum and maximum ranges based on literature sources

Utility Type	Minimum	Maximum	Unit
Electricity used for electrolysis[430,431]	47	66	kWh/kg H_2
Electricity used for water purification	0.1[432]		MJ/kg H_2
Water use	9[433]		kg/kg H_2
Infrastructure[434]	5.35e-10		p/kg H_2

[421] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[422] What is the energy balance of electrofuels produced through power-to-fuel integration with biogas facilities?, 2022, Gray et. al, Renewable and Sustainable Energy Reviews, Accessed at: https://www.sciencedirect.com/science/article/pii/S1364032121011539

[423] Renewable methanol production from green hydrogen and captured CO2: A techno-economic assessment, 2023, *Journal of CO2 Utilisation*, Sollai et. al, Accessed at: https://www.sciencedirect.com/science/article/pii/S2212982022004644

[424] Quantitative Design of a New e-Methanol Production Process, 2022, *Energies*, Rufer, A., Accessed at 29-07-24: https://www.mdpi.com/1996-1073/15/24/9309

[425] Methanol-to-Gasoline Process, 2023, Knop, V., *AWOE*, Accessed at: https://www.awoe.net/Synthetic-Gasoline-MTG-Process.html

[426] Life Cycle Assessment of synthetic hydrocarbons for use as jet fuel: “Power-to-Liquid” and “Sun-to-Liquid” processes, Treyer Karin, Sacchi Romain, Bauer Christian, February 2022

[427] Economic and environmental assessment of directly converting CO2 into a gasoline fuel, 2022, *Energy Conversion and Management*, Fernandez-Torres et. al. Accessed at: https://www.sciencedirect.com/science/article/pii/S0196890421012917

[428] A look into the role of e-fuels in the transport system in Europe (2030–2050) (literature review) , 2019, *Concawe*, Yugo et. al, Accessed at: https://www.concawe.eu/wp-content/uploads/E-fuels-article.pdf

[429] Process analysis and comparative assessment of advanced thermochemical pathways for e-kerosene production, 2023, *Energy*, Atsonios et. al, Accessed at: https://pure.strath.ac.uk/ws/portalfiles/portal/164159101/Atsonios_etal_Energy_2023_Process_analysis_and_comparative_assessment_of_advanced_thermochemical_pathways_for_e_kerosene.pdf

[430] El-Shafie, M. (2023). Hydrogen Production by water electrolysis technologies: A review. Results in Engineering, 101426. doi:10.1016/j.rineng.2023.101426

[431] Müller LJ, Kätelhön A, Bachmann M, Zimmermann A, Sternberg A and Bardow A (2020) A Guideline for Life Cycle Assessment of Carbon Capture and Utilization. Front. Energy Res. 8:15.doi: 10.3389/fenrg.2020.00015

[432] Element Energy. (2021). Low Carbon Hydrogen Well-to-Tank Pathways Study - Full Report. Zemo Partnership. Retrieved from https://www.zemo.org.uk/assets/reports/Zemo%20Low%20Carbon%20Hydrogen%20WTT%20Pathways%20-%20full%20report.pdf

[433] Hydrogen Council, 2021, Hydrogen decarbonization pathways, retrieved from: https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf

[434] Ecoinvent, 2024, Ecoinvent v3.11 database, available at: https://ecoinvent.org/database/

To calculate the minimum and maximum emissions of the upstream hydrogen production, the LCI consumption data were first multiplied by the corresponding emission factors (including electricity grid mix) to generate the kg CO_2eq./ kg green hydrogen. Thus, the input of green hydrogen into all three e-fuel production pathways was considered to include the electricity used for the alkaline electrolysis itself, the electricity used for the purification of water and the input of water needed, assumed to be fresh water. For the water use, an emission factor from ecoinvent was utilised reflecting the global market group for the production of 1kg tap water.

Additionally, infrastructure impacts associated with the production facilities have also been included. These impacts have been modelled based on an ecoinvent dataset for a chemical factory and have been considered on a per kg of output basis. This assumes a lifespan of 25 years for the hydrogen production with 8.99 tonnes of hydrogen produced per hour[435].

The green hydrogen production facility is assumed to be co-located at the fuel production site, thus no transport of the hydrogen is considered. However, the impact of transporting hydrogen has been considered within sensitivity analysis.

Green hydrogen's GWP is dependent on multiple factors, such as technology type, production location, transportation distance and mode, electricity source, hydrogen storage etc. Within this study, we focus on the likely impact of set scenarios for the location and electricity type with additional analysis on transport distance and type of transport.

9.7.4.2 *CO_2*

The second input required across all e-fuel production pathways is CO_2. The importance of CO_2 supply and its characteristics were addressed in Task 4 of this study. Drawing on the conclusions of Task 4, the CO_2 sources that were chosen for further assessment are high concentration biogenic, industrial sources of emissions, and direct air capture (DAC), which are defined as:

- Direct air capture (DAC): the process of extracting CO_2 directly from the atmosphere for storage or utilisation[436].
- Biogenic sourced carbon: the capture of CO_2 from a biogenic source.
- Industrial CCU: the capture of CO_2 from a fossil fuel based source.

As stated, within this study, CO_2 is modelled as burden free up till it is available for capture. Therefore, only the GWP impacts associated with the capture, processing and transport of the CO_2 are included, with the prior production and combustion of the biogenic and industrial CCU sources considered out of scope.

For the biogenic and industrial CCU CO_2 in particular, there are significant variation in the range of sources for the CO_2 available and subsequently the range in potential GWP can be substantial. Therefore, this study elected to focus on modelling exemplar scenarios so as to assess the lower range of GWP. This is aimed to provide insight into the scenarios which would help OGCI in its decision making to mitigate the carbon impact of its e-fuel production.

The LCI data collected for each CO_2 source are described in the sub-sections below. For all CO_2 sources, transportation impacts have been modelled assuming pipeline transport. A range of distances were set as 20 to 100 km, assuming in country sourcing.

9.7.4.3 *DAC*

DAC is currently only available on a small scale but is projected to grow in scale and availability. The technology is typically more energy intensive than biogenic and industrial CCU. This is due to DAC capturing the carbon from the atmosphere which has a much lower concentration of CO_2 than the combustion exhaust gases that biogenic and industrial CCU are from more concentrated point sources.

There are two technological approaches currently utilised: solid and liquid DAC. Solid DAC uses solid adsorbents operating under a vacuum and a medium temperature, whilst liquid DAC uses aqueous

[435] Ecoinvent, 2024, Ecoinvent v3.11 database, available at: https://ecoinvent.org/database/

[436] IEA, 2024, Direct Air Capture, retrieved from: https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage/direct-air-capture

basic solutions which release the CO_2 through a series of units operating at high temperature. Typically, DAC utilises both heat and electricity[437].

Table 9-79 provides the LCI ranges sourced within the literature review used within the study. These values are used to calculate the upstream emissions associated to the production of DAC sourced CO_2 for use within the e-fuels production pathways. The ranges for electricity provided also include the utility requirements for compression.

Additional requirements such as water consumption, sorbent use and calcium carbonate consumption were not included as these all expected to contribute less than 1% of the total GWP associated with the DAC CO_2[438,439,440].

As with the H^2 production, infrastructure impacts associated with the production facilities have been included based on an ecoinvent dataset for a chemical factory. This assumes a lifespan of 50 years for the hydrogen production with 50,000 tonnes produced per hour[441].

Table 9-79: LCI data for the upstream production of 1kg of CO_2 via DAC presented as minimum and maximum ranges based on literature sources

Description	Minimum	Maximum	Unit
Electricity[442]	0.37	0.76	kWh/kg CO_2
Heat[37]	3.40	8.80	MJ/kg CO_2
Transport	25	100	km/kg CO_2
Infrastructure[443]	4.0E-10		p/kg CO_2

9.7.4.4 Biogenic

Biogenic CO_2 is the carbon dioxide resulting from the decomposition, digestion or combustion of biomass or biomass-derived products. Biogenic sources are typically available on a smaller scale than industrial CCU. Many sources ascribe biogenic CO_2 with zero GWP impact, however, this does not consider the impacts associated with the capture, purification and compression of the CO_2. There are a range of sources available for biogenic CO_2, with some of the most common including paper and pulp, sugar, energy-to-waste, and biomass with the highest biogenic portion of CO_2.

The biogas industry where biogas, a mixture of CO_2 and biomethane, is produced through the anaerobic digestion of biomass is a key potential source of biogenic CO_2. Biogenic CO_2 can be captured through three routes[444]. The first is from the process where biogas is upgraded to biomethane, by separating the biogenic CO_2 from the methane. Biogenic carbon can also be captured from the flue gas produced if biogas is combusted in gas engines to produce heat and power. Lastly, biogenic carbon can be captured during the production of biohydrogen from biogas. In all of these cases, the carbon dioxide that is captured at a high purity from a process in which it would otherwise be considered a waste and emitted to the atmosphere.

[437] IEA, 2024, Direct Air Capture, retrieved from: https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage/direct-air-capture

[438] De Jonge, M., et al., 2019, Life Cycle Carbon Efficiency of Direct Air Capture Systems with Strong Hydroxide Sorbents, retrieved from: https://www.sciencedirect.com/science/article/pii/S1750583618301464?via%3Dihub

[439] Wang, J., et al, 2023, Energetic and Life Cycle Assessment of Direct Air Capture: A Review, retrieved from: https://www.sciencedirect.com/science/article/pii/S2352550922003384?via%3Dihub

[440] National Energy Technology Laboratory, 2021, Life Cycle Greenhouse Gas Analysis of Direct Air Capture Systems, retrieved from: https://netl.doe.gov/sites/default/files/netl-file/21DAC_Skone.pdf

[441] Ecoinvent, 2024, Ecoinvent v3.11 database, available at: https://ecoinvent.org/database/

[442] Wang, J., et al, 2023, Energetic and Life Cycle Assessment of Direct Air Capture: A Review, retrieved from: https://www.sciencedirect.com/science/article/pii/S2352550922003384?via%3Dihub

[443] Ecoinvent, 2024, Ecoinvent v3.11 database, available at: https://ecoinvent.org/database/

[444] European Biogas Association, 2020, Biogenic CO from the Biogas Industry, retrieved from: https://www.europeanbiogas.eu/wp-content/uploads/2022/10/Biogenic-CO2-from-the-biogas-industry_Sept2022-1.pdf

Biogenic carbon sourced from upgrading of biogas to biomethane was selected as an exemplar scenario for focus in this study. This was selected as in this scenario is likely to be one of the lowest GWP sources of biogenic CO_2 as the CO_2 is separated within the process by which biomethane is separated. Therefore, since the aim of the biogas purification is to collect the bio-methane, the CO_2 can be treated as a waste and therefore is not allocated any of the impacts associated with the purification. This means that only the impacts associated with the subsequent collection and compression of the CO_2 for transport need to be considered; as the off gas which is collected has very few contaminants no further purification is needed.

Table 9-80 presents the LCI ranges used for modelling the impact associated with compression [445,446,447,448].

Table 9-80: LCI data for the upstream production of 1kg of CO_2 via biogenic carbon sources presented as minimum and maximum ranges based on literature sources

Description	Minimum	Maximum	Unit
Electricity used for compression	47	66	MJ/kg CO_2
Transport	25	100	km/kg CO_2

9.7.4.5 *Industrial CCU*

Industrial CCU CO_2 is captured from larger sources such as from power plants, natural gas processing facilities and some industrial processes. There are three methods for industrial carbon capture. The most common is post-combustion, in which the fossil fuels are burnt, and the CO_2 is removed captured from the flue gases and compressed. CO_2 can also be captured pre-combustion through partially oxidising the fossil fuel to form a synthetic gas, from which the H_2 and CO_2 can be captured. The last technique is through oxy-fuel combustion, in which the fossil fuel is burnt in oxygen instead of air. The resulting flue gas consists of mainly CO_2 and water vapour. Cooling is used to condense the water vapour, leaving almost pure CO_2 that can be transported and stored[449].

As post-combustion industrial CO_2 capture is the primary method used currently, this is the scenario used for this study. More specifically, the assumed scenario is CO_2 is capture from a power station flue gas via an amine CO_2 capture system.

Table 9-81 presents the LCI ranges used for modelling the impact associated with the impacts associated with sourcing industrial CO_2[450,45,451,452,453,454].

445 Prussi, M., et al., 2020 JEC Well-to-Tank report v5, retrieved from: JRC Publications Repository - JEC Well-to-Tank report v5

446 Kahler, F., et al., 2021, Turning off the tap for fossil carbon – Future prospects for a global chemical and derived material sector based on renewable carbon, retrieved from: https://renewable-carbon.eu/publications/product/turning-off-the-tap-for-fossil-carbon-future-prospects-for-a-global-chemical-and-derived-material-sector-based-on-renewable-carbon/

447 Von der Assen, N., et al., 2016, Selecting CO2 sources for CO2 utilization by environmental-merit-order curves, Environmental science & technology, Vol. 50 (3), 1093-1101. doi: 10.1021/acs.est.5b03474

448 Deutz, S. and Bardow, A., 2021, Life-cycle assessment of an industrial direct air capture process based on temperature–vacuum swing adsorption. Nature Energy, Vol. 6 (2), 203-213. doi: 10.1038/ s41560-020-00771-9

449 Resources for the Future, 2020, Carbon Capture and Storage, retrieved from: https://www.rff.org/publications/explainers/carbon-capture-and-storage-101/#:~:text=They%20fall%20into%20three%20categories,exhaust%20of%20a%20combustion%20process.

450 Prussi, M., et al., 2020 JEC Well-to-Tank report v5, retrieved from: JRC Publications Repository - JEC Well-to-Tank report v5

451 Kahler, F., et al., 2021, Turning off the tap for fossil carbon – Future prospects for a global chemical and derived material sector based on renewable carbon, retrieved from: https://renewable-carbon.eu/publications/product/turning-off-the-tap-for-fossil-carbon-future-prospects-for-a-global-chemical-and-derived-material-sector-based-on-renewable-carbon/

452 Von der Assen, N., et al., 2016, Selecting CO2 sources for CO2 utilization by environmental-merit-order curves, Environmental science & technology, Vol. 50 (3), 1093-1101. doi: 10.1021/acs.est.5b03474

453 Deutz, S. and Bardow, A., 2021, Life-cycle assessment of an industrial direct air capture process based on temperature–vacuum swing adsorption. Nature Energy, Vol. 6 (2), 203-213. doi: 10.1038/ s41560-020-00771-9

454 Ecoinvent, 2024, Ecoinvent v3.11 database, available at: https://ecoinvent.org/database/

Carbon capture absorption has been modelled with heat and electricity requirements. As with all technologies, the utility requirements vary depending on the system used. For the heat requirement, the literature review collated ranges. These sources reported a heat demand at ~3.7-4.7 MJ per kg of CO_2 for existing technology based on measured data, lowering to around 2.2 MJ per kg for estimated data on future technology developments[455,456,457]. These values align with advice provided by a Ricardo expert who advised a typical heat demand of 3.3 MJ per kg of CO_2 is standard for the industry.

Electricity requirements for the absorption were suggested to be over 1 MJ / kg CO_2 by some sources[458,459]. These values are significantly higher than expected by our Ricardo expert, therefore the figure from the JEC report[460] was used only as it was deemed most reputable, and in line with expectations for current technology. The range in electricity values for carbon capture is likely due to variation in the age of the sources and even for studies published recently, the age of technology being assessed.

Electricity requirements for compression have also been included. Additionally, monoethanolamide requirements have been added as an input, as it is the primary solvent in early-stage implementation of post-combustion CO_2 capture due to commercial availability, relatively low cost, fast absorption rate[461]. The quantity of monoethanolamide is modelled based on an ecoinvent process for liquid CO_2.

Infrastructure impacts associated with the production facilities have been included based on an ecoinvent dataset for a chemical factory. This assumes a lifespan of 50 years for the hydrogen production with 50,000 tonnes produced per hour[462].

Table 9-81: LCI data for the upstream production of 1kg of CO_2 via industrial CCU presented as minimum and maximum ranges based on literature sources

Description	Minimum	Maximum	Unit
Electricity used for absorption	0.18		MJ/kg CO_2
Electricity used for compression	0.4	1.8	MJ/kg CO_2
Heat	2.20	4.19	MJ/kg CO_2
Monoethanolamide	0.013		kg/kg CO_2
Transport	25	100	km//kg CO_2
Infrastructure	4.00E-10		p/kg CO_2

9.7.4.6 Fuel Production

The data for fuel production is largely based on the data presented in the techno-economic assessment. The following sub-sections breakdown the LCI used to model the MTG, MTK and FTD fuel production processes.

[455] Kahler, F., et al., 2021, Turning off the tap for fossil carbon – Future prospects for a global chemical and derived material sector based on renewable carbon, retrieved from: https://renewable-carbon.eu/publications/product/turning-off-the-tap-for-fossil-carbon-future-prospects-for-a-global-chemical-and-derived-material-sector-based-on-renewable-carbon/

[456] Von der Assen, N., et al., 2016, Selecting CO2 sources for CO2 utilization by environmental-merit-order curves, Environmental science & technology, Vol. 50 (3), 1093-1101. doi: 10.1021/acs.est.5b03474

[457] Deutz, S. and Bardow, A., 2021, Life-cycle assessment of an industrial direct air capture process based on temperature–vacuum swing adsorption. Nature Energy, Vol. 6 (2), 203-213. doi: 10.1038/ s41560-020-00771-9

[458] Von der Assen, N., et al., 2016, Selecting CO2 sources for CO2 utilization by environmental-merit-order curves, Environmental science & technology, Vol. 50 (3), 1093-1101. doi: 10.1021/acs.est.5b03474

[459] Deutz, S. and Bardow, A., 2021, Life-cycle assessment of an industrial direct air capture process based on temperature–vacuum swing adsorption. Nature Energy, Vol. 6 (2), 203-213. doi: 10.1038/ s41560-020-00771-9

[460] Prussi, M., et al., 2020 JEC Well-to-Tank report v5, retrieved from: JRC Publications Repository - JEC Well-to-Tank report v5

[461] Li, K., et al., 2016, Systematic study of aqueous monoethanolamine (MEA)-based CO2 capture process: Techno-economic assessment of the MEA process and its improvements, retrieved from: https://www.sciencedirect.com/science/article/pii/S0306261915016827

[462] Ecoinvent, 2024, Ecoinvent v3.11 database, available at: https://ecoinvent.org/database/

9.7.4.6.1 Methanol production

MTG and MTK both rely on e-methanol. E-methanol can be produced through two methods:

- Via a two-step route that uses synthetic gas which involves the reduction of the CO_2 feedstock to CO, followed by conversion of CO and hydrogen to methanol.
- Via a direct route that uses hydrogenation of CO_2 with H_2 over a heterogeneous catalyst to produce the methanol.

The ranges for H_2, CO_2 and electrical energy requirements used are shown in the table below[463,464,465,466]. The calculated energy efficiencies of methanol production range between ~80 to 90% depending on the process conditions and reported data on heat and power consumption and/or production. Typical methanol carbon conversion efficiencies from CO_2 range between 90 and 99% in literature[467,468].

The ranges below were used for e-methanol production for both the MTG and MTK pathways to represent the production of 1kg of e-methanol which was then scaled by the quantity of e-methanol required to upgrade to e-gasoline and e-kerosene respectively.

Table 9-82: LCI data for the upstream production of 1kg of e-methanol presented as minimum and maximum ranges based on literature sources

Description	Minimum	Maximum	Unit
H_2	0.188	0.208	kg/kg e-methanol
CO_2	1.37	1.45	kg/kg e-methanol
Electricity	0.74	1.07	MJ/kg e-methanol

9.7.4.6.2 MTG production

MTG production further processes e-methanol into a gasoline fuel that meets required standards. Hydrogenation is integrated as an additional reaction step to saturate aromatics and olefins with hydrogen and produce a fuel suitable for use in engines.

Table 9-83 shows the ranges for H_2, methanol and electrical energy requirements used to model e-gasoline production through MTG[469,470]. Data has been collected across various sources though it should be noted that limited information is available on the official MTG process as it is licensed by Exxonmobil.

[463] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[464] What is the energy balance of electrofuels produced through power-to-fuel integration with biogas facilities?, 2022, Gray et. al, Renewable and Sustainable Energy Reviews, Accessed at: https://www.sciencedirect.com/science/article/pii/S1364032121011539

[465] Renewable methanol production from green hydrogen and captured CO2: A techno-economic assessment, 2023, *Journal of CO2 Utilisation*, Sollai et. al, Accessed at: https://www.sciencedirect.com/science/article/pii/S2212982022004644

[466] Quantitative Design of a New e-Methanol Production Process, 2022, *Energies*, Rufer, A., Accessed at 29-07-24: https://www.mdpi.com/1996-1073/15/24/9309

[467] Technology factsheet – Methanol production from CO2, 2019, *Remko Detz*, Accessed at: https://energy.nl/wp-content/uploads/technology-factsheet-methanol-from-co2-7.pdf

[468] Techno-Economic Modelling of Carbon Dioxide Utilisation Pathways at Refineries for the Production of Methanol, 2022, *AIDIC*, d'Amore et. al, Accessed at: https://re.public.polimi.it/retrieve/102e86c0-fe75-443f-bb42-78af3e0d4b33/2022_AIDIC_dAmore-etal_016.pdf

[469] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, p. 176, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[470] Methanol-to-Gasoline Process, 2023, Knop, V., *AWOE*, Accessed at: https://www.awoe.net/Synthetic-Gasoline-MTG-Process.html

Table 9-83: LCI data for the upstream production of 1kg of e-gasoline presented as minimum and maximum ranges based on literature sources

Description	Minimum	Maximum	Unit
H_2	0.001		kg/kg e-gasoline
Methanol	2.28	2.67	kg/kg e-gasoline
Electricity	0.71		MJ/kg e-gasoline

9.7.4.6.3 MTK production

As with MTG, MTK production utilises e-methanol and converts it to e-kerosene using a similar process.

Table 9-84 shows the ranges for H_2, methanol and electrical energy requirements used to model e-kerosene production through MTK[471,472]. As the fuel specification for kerosene is different, requirements for additional hydrogen for the hydrogenation stage are different.

Table 9-84: LCI data for the upstream production of 1kg of e-kerosene presented as minimum and maximum ranges based on literature sources

Description	Minimum	Maximum	Unit
H_2	0.01		kg/kg e-kerosene
Methanol	2.32	2.40	kg/kg e-kerosene
Electricity	0.72		MJ/kg e-kerosene

9.7.4.6.4 FTD production

The Fischer-Tropsch (FT) synthesis process can be used to produce e-diesel. This involves the reduction of CO_2 to carbon monoxide (CO) through Reverse Water Gas Shift (RWGS), whereby CO_2 is reformed with H_2 to produce CO and water. The resulting synthesis gas is then converted to a syncrude via FT synthesis. This syncrude is then further refined by hydrotreatment and fractionation to produce fuels with appropriate specifications[473].

Table 9-85 shows the ranges for H_2, CO_2, heat and electrical energy requirements used to model e-diesel production through RWGS & FT[474,99,475]. As the reaction is exothermic, the energy demand requirements vary depending on how the heat requirements can be met. Within the minimum scenario below, it is assumed that the heat requirement is powered by electricity only, without the need for burning of fuels. The maximum scenario however assumes that the heat requirement is met through natural gas.

[471] E-Fuels: A technoeconomic assessment of European domestic production and imports towards 2050, 2022, *Concawe*, p. 177, Accessed at: https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf

[472] Life Cycle Assessment of synthetic hydrocarbons for use as jet fuel: “Power-to-Liquid” and “Sun-to-Liquid” processes, Treyer Karin, Sacchi Romain, Bauer Christian, February 2022

[473] Kerosene production from power-based syngas -A technical comparison of the Fischer-Tropsch and methanol pathway, 2024, Fuel Journal, Bube et. al, Accessed at: https://www.researchgate.net/publication/379543754_Kerosene_production_from_power-based_syngas_-A_technical_comparison_of_the_Fischer-Tropsch_and_methanol_pathway

[474] Life Cycle Assessment of synthetic hydrocarbons for use as jet fuel: “Power-to-Liquid” and “Sun-to-Liquid” processes, Treyer Karin, Sacchi Romain, Bauer Christian, February 2022

[475] What is the energy balance of electrofuels produced through power-to-fuel integration with biogas facilities?, 2022, *Renewable and Sustainable Energy Reviews,* Gray et. al, Accessed at: https://www.netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/ftsynthesis

Table 9-85: LCI data for the upstream production of 1kg of e-diesel presented as minimum and maximum ranges based on literature sources

Description	Minimum	Maximum	Unit
H_2	0.14	0.63	kg/kg e-diesel
CO_2	1.54	4.61	kg/kg e-diesel
Electricity	42.62	1.9	MJ/kg e-diesel
Heat	0.00	9.95	MJ/kg e-diesel

9.7.4.7 *Fossil fuel Equivalents*

The table below provides the range of GWP used within this study to represent the cradle-to-gate impact associated with the fossil fuel based equivalents[476]. The impact can vary depending on several factors, including region of production. These ranges were sourced from ecoinvent v3.11, which is the world's largest LCA database and the latest version at the time of calculation.

Table 9-86: GWP range for fossil fuel based equivalent fuels

E-fuel	Equivalent fossil fuel	Minimum	Maximum	Unit
MTG	Gasoline	0.02	0.03	kg CO_2e / MJ
MTK	Kerosene	0.01	0.02	kg CO_2e / MJ
FTD	Diesel	0.01	0.03	kg CO_2e / MJ

9.7.4.8 *Grid Mix*

As stated, three temporal scenarios were included; current, 2030 and 2050. In order to establish a minimum and maximum emission factor for each of these temporal scenarios, each was split into a grid mix (representing the maximum i.e. worst-case scenario) and 100% renewable grid mix (representing the minimum i.e. best-case scenario). The same renewable grid mix was utilised across all three temporal scenarios to reflect the minimum value as it was assumed that the best case of 100% renewable electricity sources would remain constant going into 2030 and 2050. The maximum grid mix was however adjusted for 2030 and 2050 to capture the changes in the split of electricity generation over time. It should be noted that since H_2 is modelled as green hydrogen, renewable electricity is modelled for the H_2 under all scenarios, while the electricity consumption for the carbon sourcing and fuel production processes are modelled as renewable or grid mix (current, 2030 or 2050).

For the renewable grid mix (minimum), electricity emission factors were sourced from ecoinvent database based on the renewable energy source that has the highest contribution to the total grid as per the current literature. This was wind for Germany[477] and US[478], and hydropower for China[479].

To generate the electricity emission factor for each renewable type by region, an average of the available datasets within ecoinvent was taken. For example, for wind for Germany, an average of four processes was used as ecoinvent contains multiple variations of datasets for the same renewable

[476] Ecoinvent, 2024, Ecoinvent v3.11 database, retrieved from: https://ecoinvent.org/database/

[477] Fraunhofer Institute for Solar Energy Systems (ISE). (2024). Public Net Electricity Generation 2023 in Germany: Renewables Cover the Majority of the Electricity Consumption for the First Time. Retrieved December 2, 2024, from https://www.ise.fraunhofer.de/en/press-media/press-releases/2024/public-electricity-generation-2023-renewable-energies-cover-the-majority-of-german-electricity-consumption-for-the-first-time.html

[478] EIA. (2023). Electricity Explained: Electricity in the United States. Retrieved from https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php

[479] IEA. (2022). China: Renewables. Retrieved from https://www.iea.org/countries/China/renewables

energy type. These four processes covered the production of 1kWh electricity from renewable wind sources covering <1->3MW onshore and offshore turbines. For the US, an average of three processes was used which included the production of onshore wind electricity only between from <1MW to >3MW turbines.

For China, the same approach was taken for the hydropower source where the average was calculated based on a range of hydro-powered technologies including alpine reservoir and river run-off. Here Ricardo also performed a further adjustment to the hydropower electricity emission factor to better align to a representative scenario of hydroelectric power electricity production in China. Thus, the pumped storage dataset was excluded from the average generated.

Additionally, in the absence of knowing the exact location of the final e-fuels production within China and US and a lack of an aggregated dataset available for the total countries, certain geographical assumptions were applied. These included:

- The Hebei region of China was selected for the hydropower processes based on it being the province in which the capital city of Beijing sits. This is assumed to reflect a more conservative electricity emission factor based on a highly industrialised region of China.
- The emission factors for the SERC Reliability Corporation (SERC) region of the US were used to reflect the wind electricity production for the US geographical scenario under study. These datasets are the most appropriate choice to reflect the southeastern states of the US which includes the Gulf Coast, a particular area of interest within the wider tasks of this project.

In order to reflect the maximum temporal scenario of current, grid electricity emission factors for China, Germany and US were used based on the most recent available grid mix for each country and based on grid mix projections for 2030 and 2050[480],[481,482,483]. Electricity emission factors from ecoinvent were used to model the grid electricity (maximum) for each geographical region.

Table 9-87: Electricity emission factors for each temporal and geographical scenario for carbon sourcing and fuel production electricity consumption

Temporal Scenario	Geographical Scenario	Electricity Emission Factor (kg CO_2e / kWh)
Renewable (minimum)	China	0.006
	Germany	0.022
	US	0.016
Current (maximum)	China	0.686
	Germany	0.481
	US	0.513
2030 (maximum)	China	0.528
	Germany	0.163
	US	0.379
2050 (maximum)	China	0.132
	Germany	0.103
	US	0.291

[480] DeStatis, 2023, Press release No. 090 of 9 March 2023, retrieved from: https://www.destatis.de/EN/Press/2023/03/PE23_090_43312.html

[481] Energy Information Administration (EIA), 2023, Annual Energy Outlook, available from https://www.eia.gov/outlooks/aeo/

[482] CNPC Economics & Technology Research Institute, 2018, China Energy Outlook, available from https://eneken.ieej.or.jp/data/8192.pdf

[483] IEA, 2019, The sustainable development scenario, retrieved from IEA: https://www.iea.org/

9.7.5 Results

9.7.5.1 Life cycle stages

When exploring the impact across the cradle-to-gate impact of the e-fuel production, it is important to explore the breakdown of each life cycle stage. The following figures display the cumulative GWP per each life cycle stage, by CO_2 source, for each e-fuel, using the China renewable electricity scenario only. The figures show the results under the minimum, average and maximum impact scenarios.

Figure 9-94: **Minimum scenario**: Cradle-to-gate GWP impact for e-fuel production broken down by lifecycle stage, for each CO_2 source, assuming China renewable electricity only

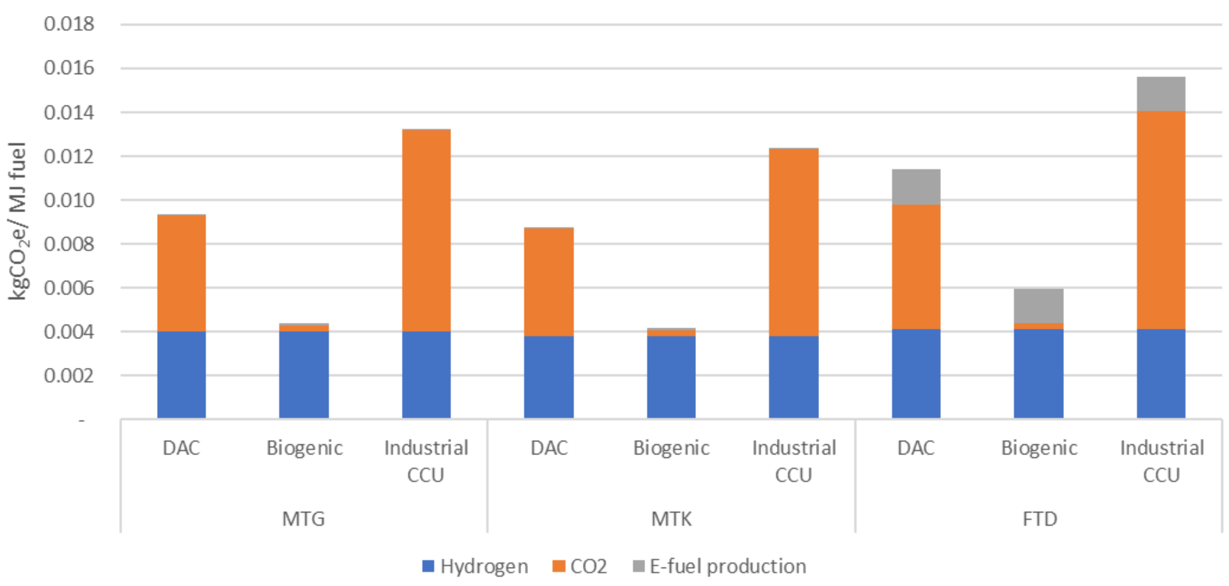


Figure 9-95: **Average scenario**: Cradle-to-gate GWP impact for e-fuel production broken down by lifecycle stage, for each CO_2 source, assuming China renewable electricity only

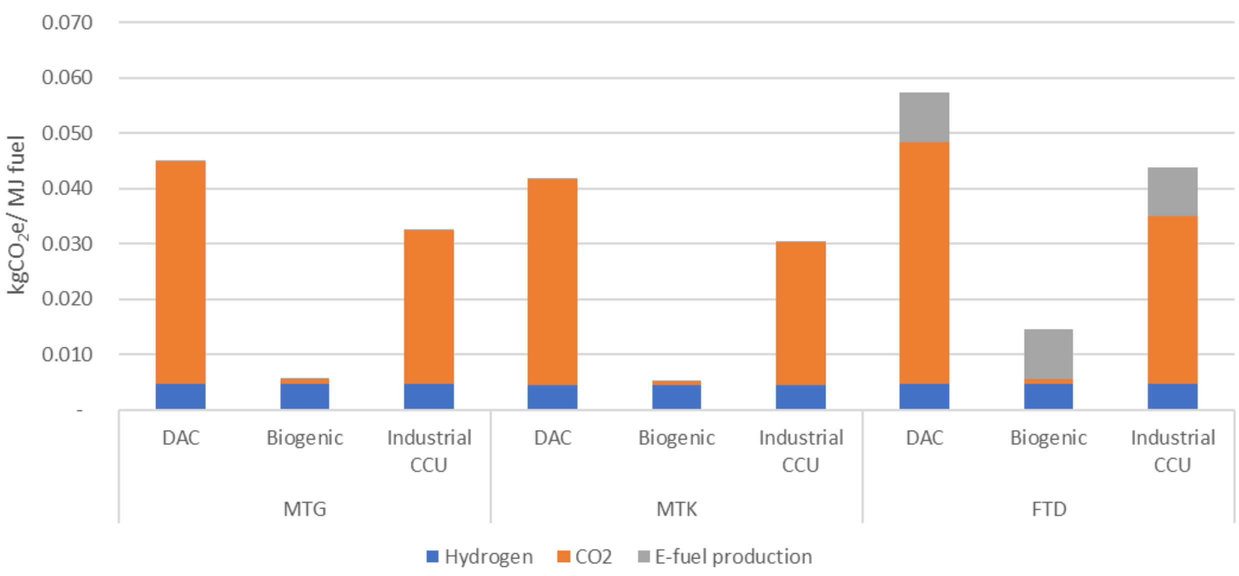
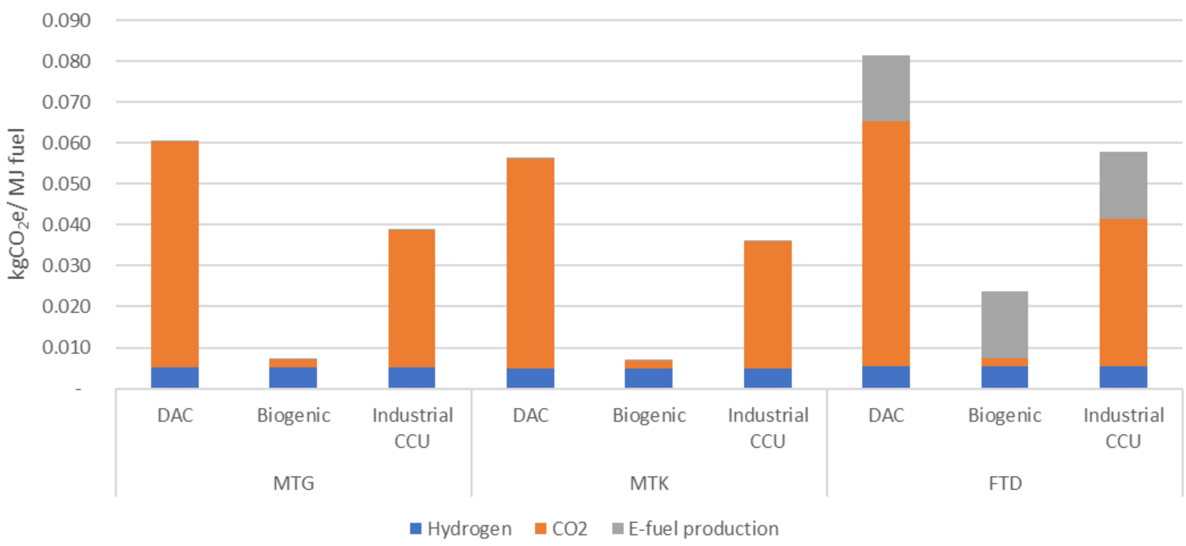


Figure 9-96: **Maximum scenario**: Cradle-to-gate GWP impact for e-fuel production broken down by lifecycle stage, for each CO_2 source, assuming China renewable electricity only



9.7.5.1.1 Renewable only sensitivity

The analysis above assumes that, excluding hydrogen production, grid electricity is utilised in e-fuel production. Even under the 2050 scenario, this assumption results in the e-fuels cradle-to-gate impact remaining at a level likely to be in line with fossil equivalents, although they will still remain lower on a cradle-to-grave basis (see Section 6.2.6).

This section explores how low the e-fuels' GWP could be if renewable energy is utilised for the entire production pathway, not just hydrogen. The figures below plot the GWP of the different e-fuels for each of the carbon sources, for each geography using 100% renewable electricity for the average scenario, i.e. hydrogen production, CO_2 capture and e-fuel production all use renewable electricity. The scenario for the different fuel and carbon source are indicated by the shape and colour of the data points as shown in the keys within the figures below. The fuels are split as follows; MTG is represented by a diamond shape, MTK by a triangle, and FTD by a circle. Carbon sourced through DAC is represented in grey, biogenic sourced carbon represented in green, and industrial CCU represented in orange.

Figure 9-97: **Average scenario**: Cradle-to-gate GWP impact for MTG production comparing geographic region and carbon source, assuming renewable electricity only

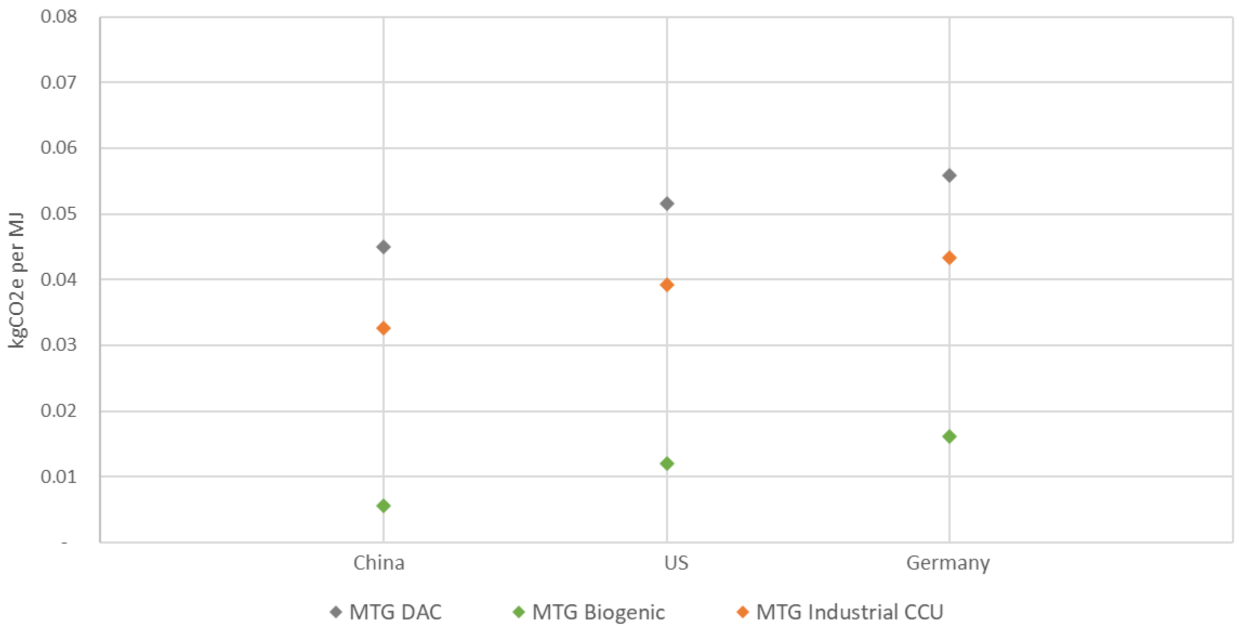


Figure 9-98: **Average scenario**: Cradle-to-gate GWP impact for MTK production comparing geographic region and carbon source, assuming renewable electricity only

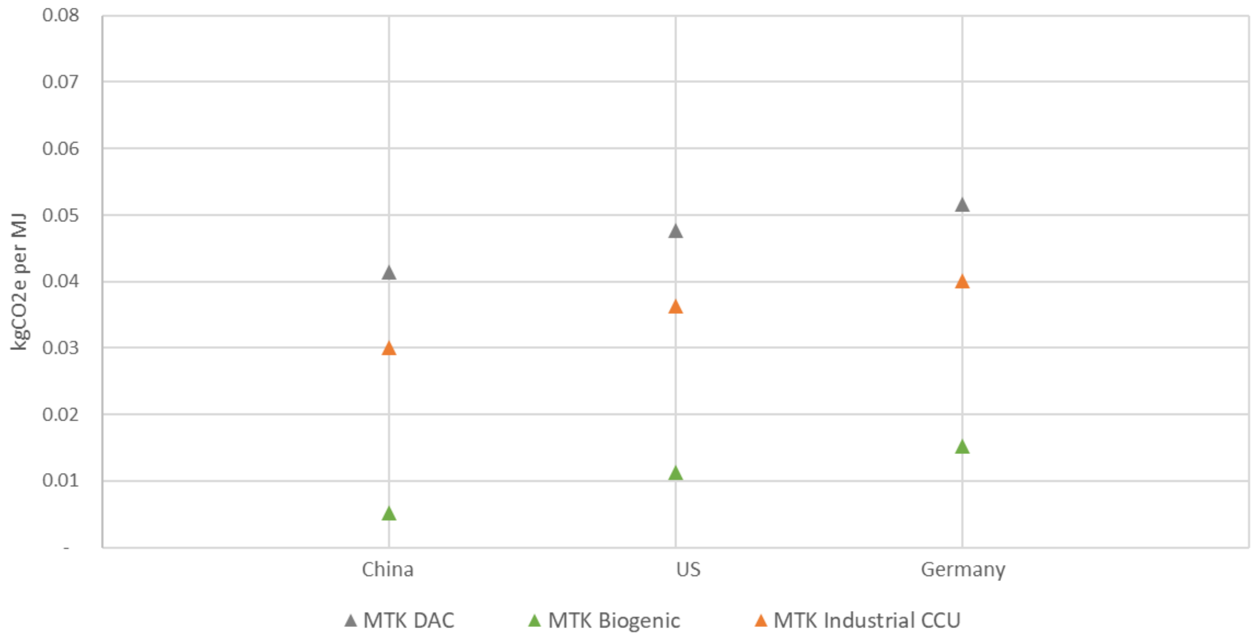
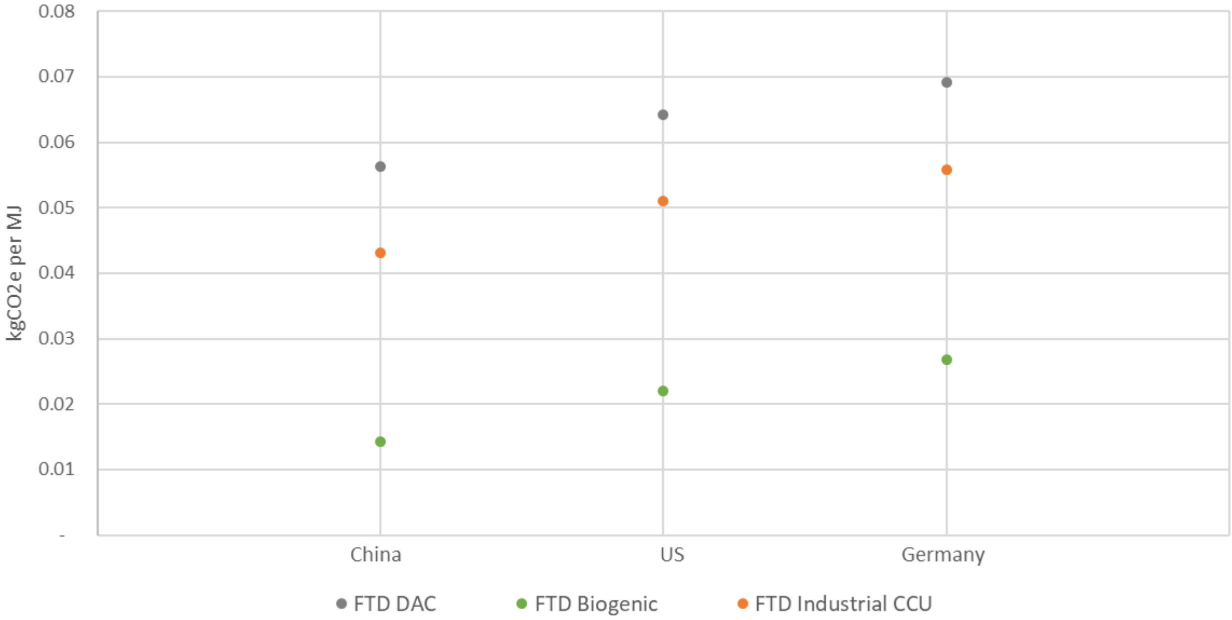


Figure 9-99: **Average scenario**: Cradle-to-gate GWP impact for FTD production comparing geographic region and carbon source, assuming renewable electricity only

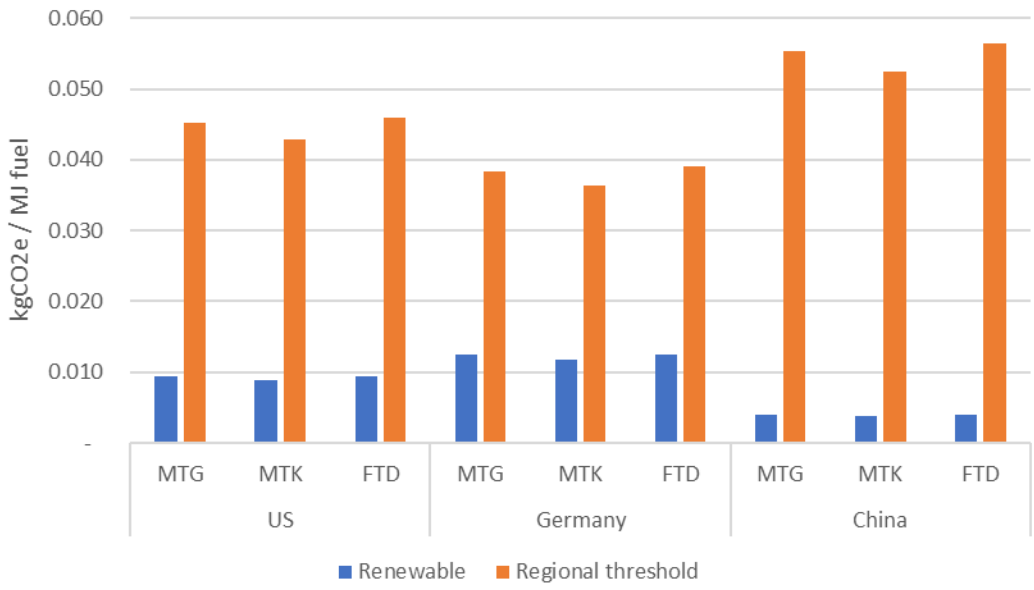


When using renewable electricity only, China is found to have the lowest impact across all scenarios, since hydropower has a lower GWP than the wind power modelled for US and Germany. It should be noted that under other methodologies, such as RED II, renewable electricity, that passes the additionality rule, is considered to have zero GWP impact. This is significant when reporting under the directive, as if you were following the RED methodology then the GWP result would be reduced even further, assuming it passes the additionality rule. Within this study, we have selected to include infrastructure impacts so as to ensure we capture the full impact of the life cycle stages.

Under the above scenario, DAC scenarios are seen to be the highest, due to having the highest modelled heat requirement. Additionally, the DAC FTD pathway is seen to have the highest GWP, due to requiring the greatest quantity of CO_2 per kg of fuel, and due to having the highest modelled heat requirement within the fuel production process.

9.7.5.1.2 Hydrogen hotspot

Figure 9-100: Likely GWP range per MJ fuel for hydrogen sourcing per country



9.7.5.2 Heat Source

Figure 9-101: Cradle-to-gate GWP impact for MTG production comparing utilising waste heat with natural gas consumption, all assuming China renewable electricity scenario only

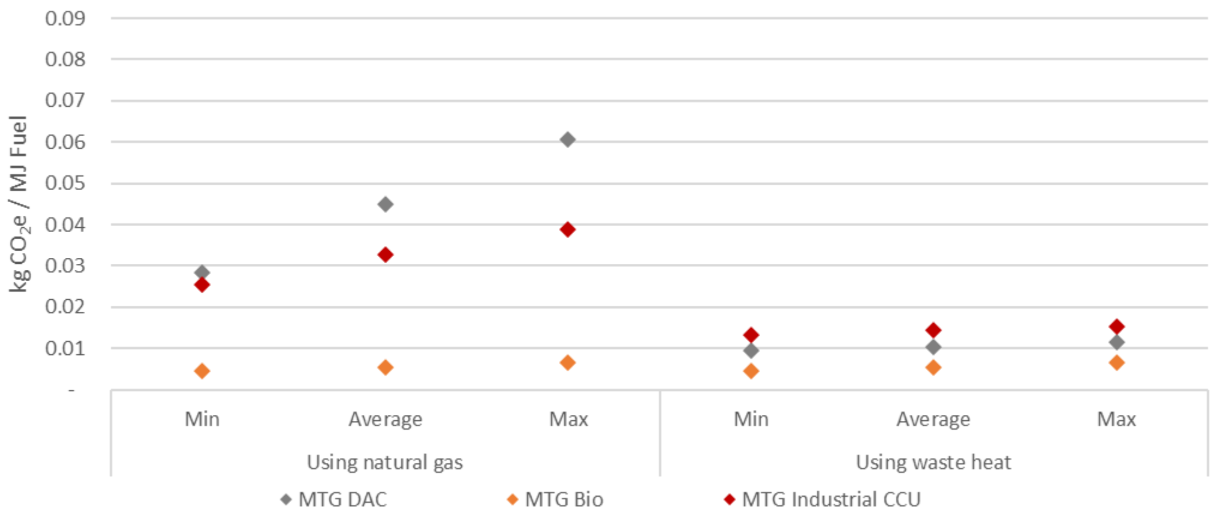


Figure 9-102: Cradle-to-gate GWP impact for MTK production comparing utilising waste heat with natural gas consumption, all assuming China renewable electricity scenario only

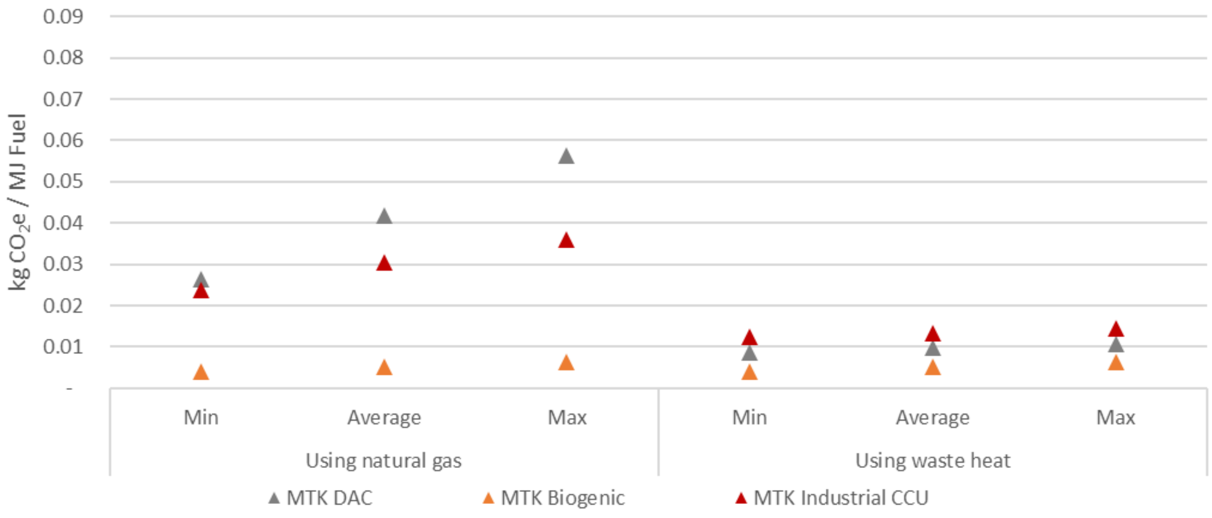
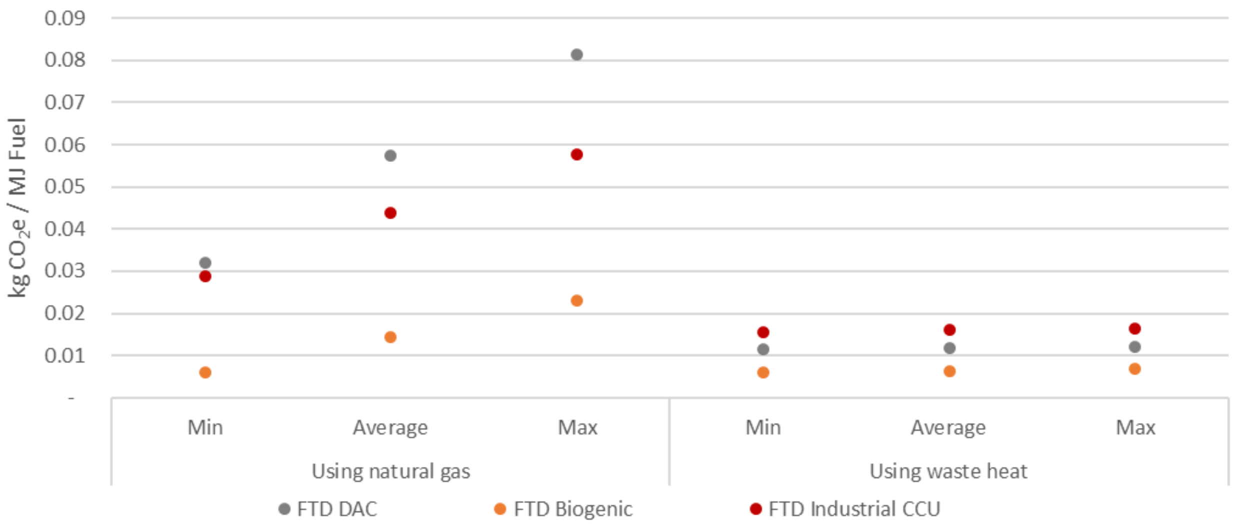
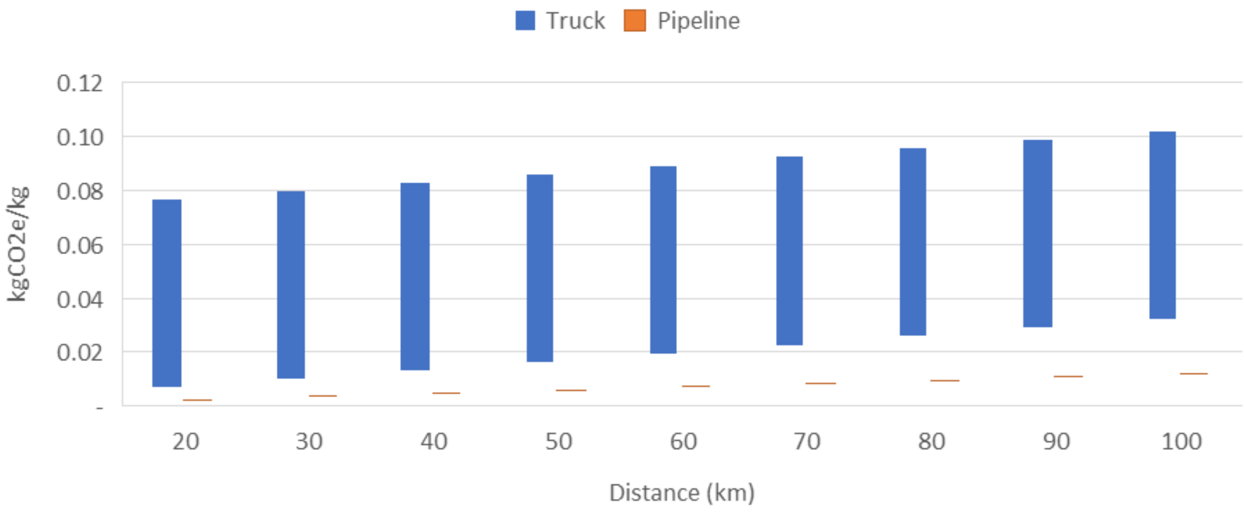


Figure 9-103: Cradle-to-gate GWP impact for FTD production comparing utilising waste heat with natural gas consumption, all assuming China renewable electricity scenario only



9.7.5.3 *Transportation*

Figure 9-104: GWP impact comparison of truck and pipeline transport per kg



9.7.5.4 *Electrolyser Efficiency*

Figure 9-105: **Minimum scenario**: Cradle-to-gate GWP impact for e-fuel production broken down by lifecycle stage, comparing assumed electrolyser efficiency, split by carbon source assuming China renewable electricity only

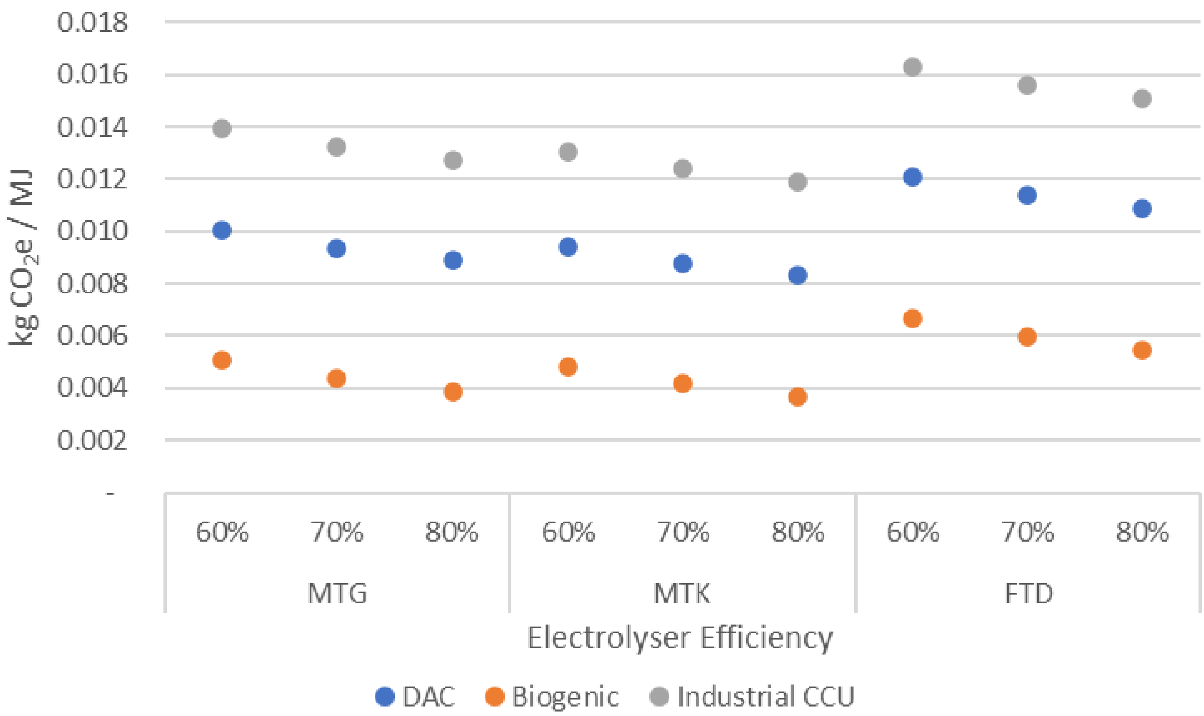


Figure 9-106: **Average scenario**: Cradle-to-gate GWP impact for e-fuel production broken down by lifecycle stage, comparing assumed electrolyser efficiency, split by carbon source assuming China renewable electricity only

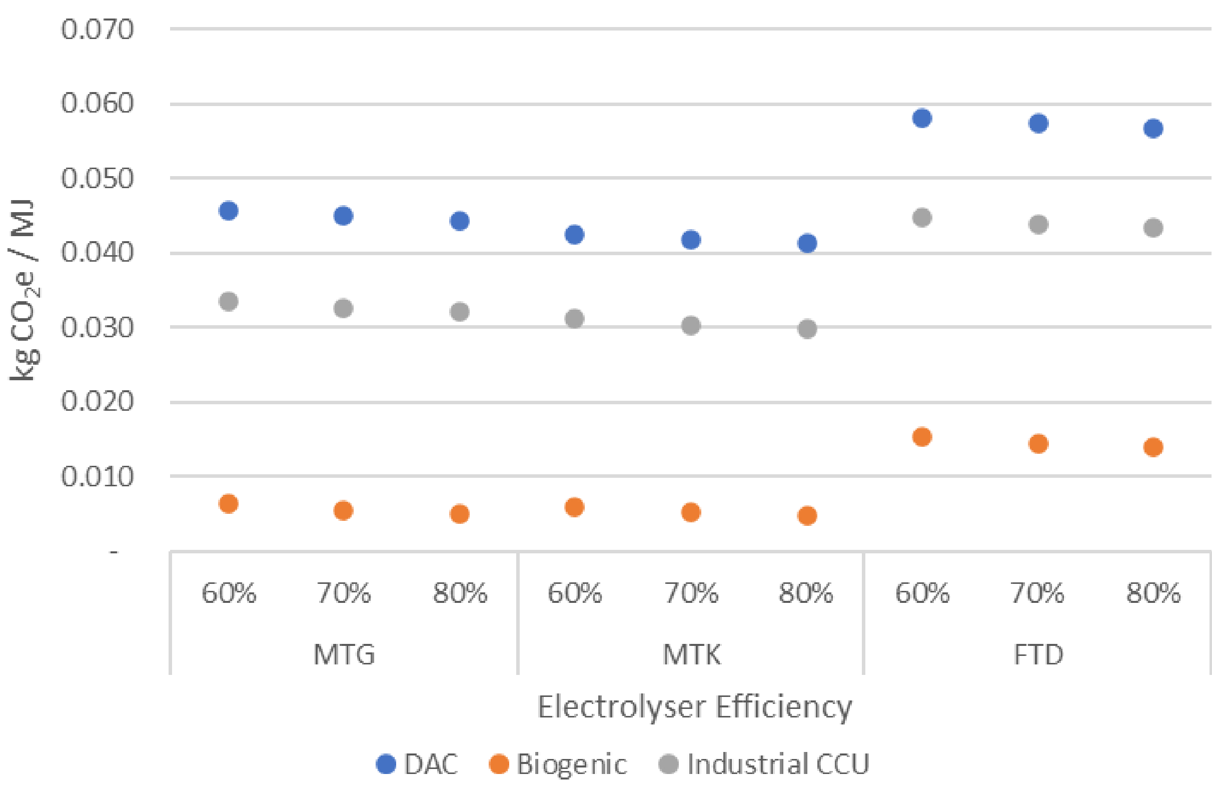
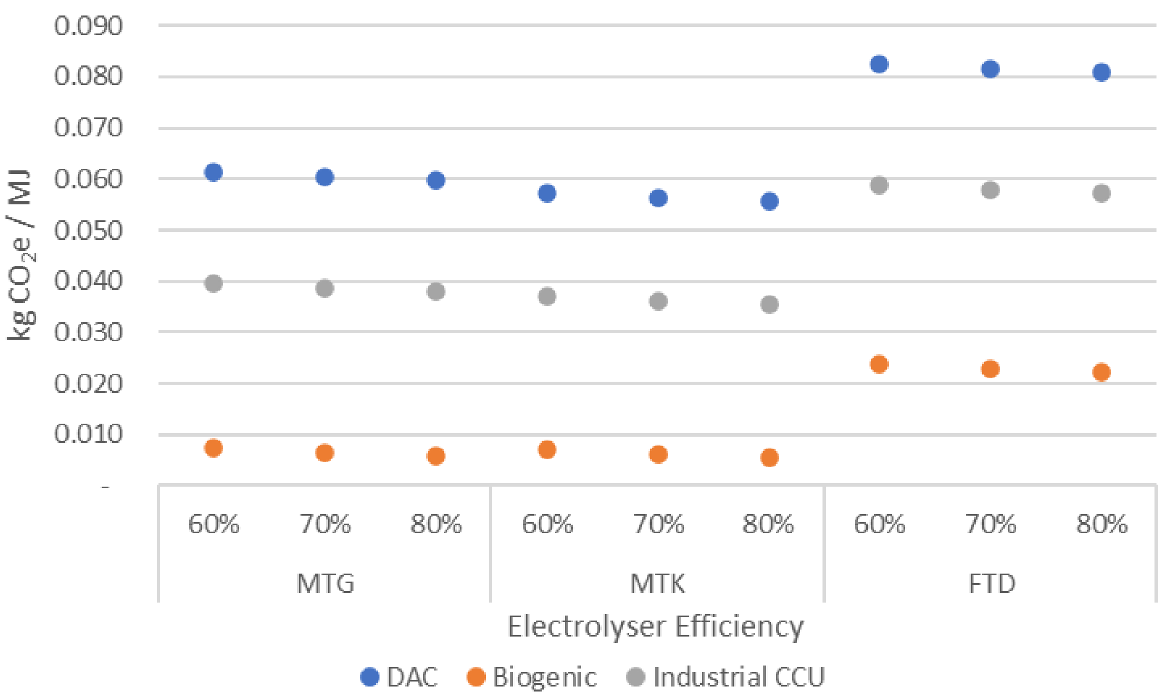


Figure 9-107: **Maximum scenario**: Cradle-to-gate GWP impact for e-fuel production broken down by lifecycle stage, comparing assumed electrolyser efficiency, split by carbon source assuming China renewable electricity only



As discussed, when considering and comparing the life cycle carbon impacts of fuels, it is important to consider how carbon modelling approach regarding prevented CO_2 releases. Within this study, we have selected a focus on the cradle-to-gate impact of e-fuel production without including the gate-to-grave impacts (associated with distribution, storage and use), as, excluding carbon allocation, the GWP impact of gate-to-grave impacts will be identical at a net level. Therefore, the cradle-to-gate system boundary of this study allows for greater focus on the key differences.

Under the system expansion approach used in this study for fossil fuels, the CO_2 which is released on combustion needs to be accounted for in calculation of the total cradle-to-grave impact, whereas for e-fuels, the CO_2 released on combustion does not need to be included in the GWP since the additional consideration of the carbon captured (in the case of DAC and biogenic CO_2) or avoided (in the case of fossil CO_2) will be re-released on combustion of the fuel. Assessing cost per GWP saved in e-fuels

The transition from fossil fuels to e-fuels is a critical component of decarbonising transport and industry. E-fuels, produced via Power-to-Liquid (PtL) pathways, utilise captured CO_2 and renewable electricity to generate synthetic hydrocarbons, potentially reducing lifecycle greenhouse gas (GHG) emissions.

A key parameter for assessing their economic and environmental viability is the cost per unit of GWP (Global Warming Potential) saved when substituting e-fuels for conventional fossil fuels. This metric, measured in US$ per $kgCO_2e$ saved, quantifies the economic efficiency of carbon abatement through e-fuel adoption.

This section outlines the methodology for calculating this cost, using cradle-to-gate life cycle emissions ($kgCO_2e/l$) and fuel cost (US$/l). A worked example follows, demonstrating its application using data from different production pathways (e.g., DAC, Biogenic, Industrial CCU) and regions (China, US, Germany).

9.7.6 Data and system boundaries

To conduct this analysis, cradle-to-gate GWP and cost data for based on the analysis in Section 5 and 6 was utilised:

1. **Fossil Fuels** (Baseline): Gasoline, Diesel, and Kerosene
2. **E-Fuels**: Produced via DAC, Biogenic, and Industrial CCU pathways.

Table 9-88. GWP of Fossil Fuels ($kgCO_2e$ per litre)

	GWP ($kgCO_2e/l$)		
	Lower	Upper	Avg
Gasoline	3.20	3.52	3.36
Kerosene	2.78	3.13	2.96
Diesel	3.58	4.30	3.94

Table 9-89. GWP of e-fuels by region and production pathway ($kgCO_2e$ per litre)

Region	CO_2 source	MTG			MTK			FTD		
		Cradle-to-gate GWP ($kgCO_2e/l$) using renewable electricity								
		Lower	Upper	Avg	Lower	Upper	Avg	Lower	Upper	Avg
China	DAC	0.32	1.92	1.12	0.35	2.09	1.22	0.36	2.86	1.61
	Biogenic	0.13	0.32	0.22	0.14	0.35	0.24	0.36	0.72	0.54
	Industrial CCU	0.32	1.28	0.80	0.35	1.39	0.87	0.72	2.15	1.43
US	DAC	0.64	2.24	1.44	0.35	2.09	1.22	0.72	3.22	1.97
	Biogenic	0.32	0.32	0.32	0.35	0.35	0.35	0.36	1.07	0.72
	Industrial CCU	0.64	1.60	1.12	0.70	1.39	1.04	0.72	2.51	1.61
Germany	DAC	0.64	2.24	1.44	0.70	2.44	1.57	0.72	3.22	1.97
	Biogenic	0.32	0.64	0.48	0.35	0.70	0.52	0.72	1.43	1.07
	Industrial CCU	0.64	1.60	1.12	0.70	1.74	1.22	1.07	2.51	1.79

Table 9-90. Cost of e-fuels by region and pathway (US$ per litre).

Region	CO_2 source	MTG			MTK			FTD		
		Cost of production (US$/l)								
		Lower	Upper		Lower	Upper		Lower	Upper	
China	DAC	1.07	1.71	1.39	0.96	1.51	1.24	1.22	1.97	1.59
	Biogenic	0.93	1.08	1.01	0.83	0.97	0.90	1.04	1.22	1.13
	Industrial CCU	0.93	1.49	1.21	0.83	1.32	1.08	1.04	1.70	1.37
US	DAC	1.07	1.71	1.39	0.96	1.51	1.24	1.22	1.97	1.59
	Biogenic	0.93	1.08	1.01	0.83	0.97	0.90	1.04	1.22	1.13
	Industrial CCU	0.93	1.49	1.21	0.83	1.32	1.08	1.04	1.70	1.37
Germany	DAC	1.64	2.27	1.96	1.45	2.01	1.73	1.86	2.61	2.23
	Biogenic	1.49	1.64	1.57	1.33	1.46	1.39	1.68	1.86	1.77
	Industrial CCU	1.49	2.05	1.77	1.33	1.81	1.57	1.68	2.34	2.01

9.7.7 Calculation of Cost per GWP Saved

9.7.7.1 GWP Savings

The GWP savings per litre by switching from fossil fuels to e-fuels is given by:

$$\Delta GWP = GWP_{fossil} - GWP_{e-fuel}$$

where GWP_{fossil} is the cradle-to-grave GWP of the conventional fossil fuel and GWP_{e-fuel} is the cradle-to-grave GWP of the synthetic e-fuel.

9.7.7.2 Incremental Costs

The additional cost per litre when switching from fossil fuels to e-fuels is:

$$\Delta Cost = Cost_{fossil} - Cost_{e-fuel}$$

where $Cost_{fossil}$ is the production cost of the conventional fossil fuel and $Cost_{e-fuel}$ is the production cost of the synthetic e-fuel.

9.7.7.3 Cost per GWP saved

$$Cost\ per\ GWP\ Saved = \frac{\Delta Cost}{\Delta GWP}$$

providing the cost effectiveness of emission reductions via e-fuels.

Figure 9-108. Cost per GWP saved based upon region, pathway and CO_2 source.

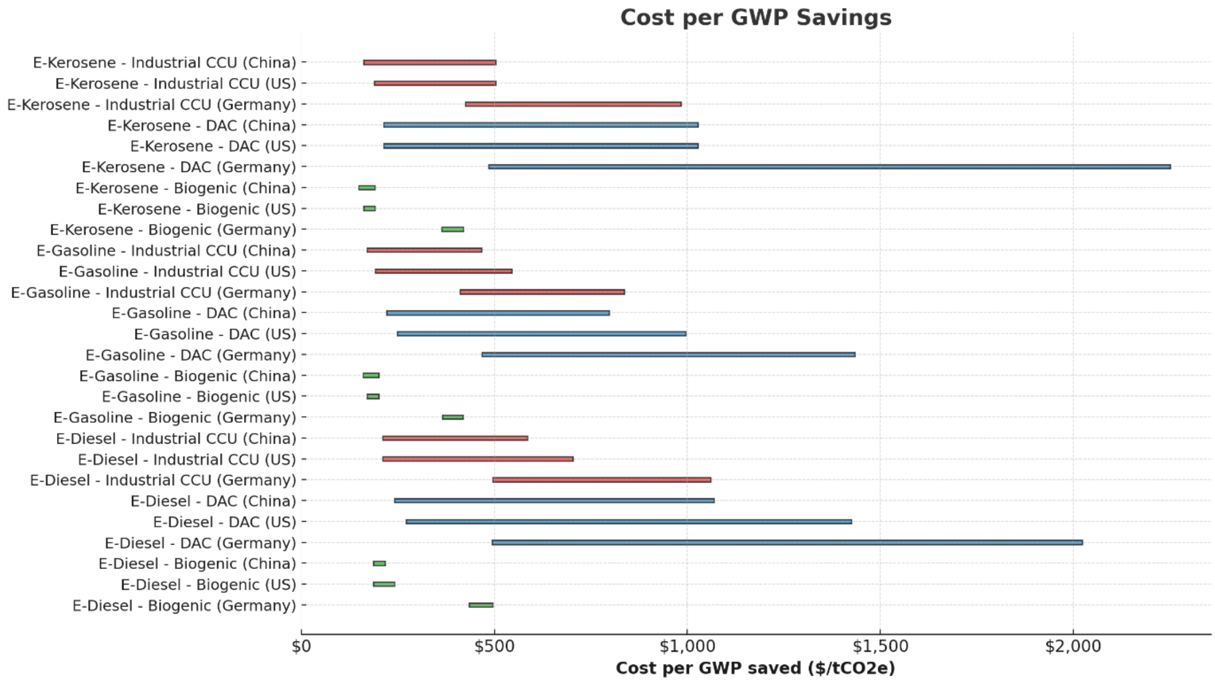


Table 9-91. Summary of CO_2 Abatement Costs Across Key Low-Carbon Technologies and Fuel Pathways. Figures are as quoted, i.e. uncorrected for differences in assumptions.

Study/Method	Region/Scope	CO_2 Source/Pathway / Technology	As reported abatement Cost ($/t$CO_2$e)	Notes
This Study	China, US, Germany – Transport Fuels	DAC, Biogenic, Industrial CCU	~400-2200	Derived from cradle-to-gate LCA for fossil fuels versus e-fuels; reflects differences in CO_2 source, production pathway, and regional factors.
Fraunhofer ISI (2023)[484]	Germany – Road Transport	DAC-based e-fuels	~1000-1100	Focuses on substituting petrol with e-fuels; renewable electricity assumptions are similar.
ICCT (2022)[485]	US & EU – Aviation (e-kerosene)	Mixed: Point-source & DAC CO_2	US: ~400 EU: ~600	Regional differences stem from varying energy and CO_2 capture costs; use of point-source CO_2 helps lower abatement costs.
Martin et al. (2023)[486]	Norway – Multi-sector Transport	DAC, Biogenic, Industrial CCU	~870–1760	Pathway variability; cost reductions expected via scaling and technological improvements.
IRENA & AEA (2022)[487]	Global (Projection for e-fuels)	Green H_2 + CO_2 (DAC/Point-source)	Now: ~720–1400; 2050: ~310–610	Projections show cost reductions by 2050 due to learning curves and technological improvements.
Battery Electric Vehicles (BEVs)[488]	Global	Electrification Efficiency Improvements	~50-150	Abatement via BEVs significantly cheaper due to higher drivetrain efficiency compared to e-fuels.

484 Fraunhofer ISI (2023): Fraunhofer Institute for Systems and Innovation Research. *Decarbonisation Pathways for Transportation: E-Fuels Assessment Report 2023*.
485 ICCT (2022): International Council on Clean Transportation. *Assessment of E-Fuel Cost-Effectiveness for Aviation in the US and EU, 2022*.
486 Martin, S., et al. (2023): *Cost and GHG Abatement Analysis for E-Fuel Production Pathways*, Advances in Applied Energy.
487 IRENA & AEA (2022): *Global Projections for E-Fuels: Cost Competitiveness and Policy Implications*.
488 IEA (2023): *Global EV Outlook 2023*. International Energy Agency.

Study/Method	Region/Scope	CO_2 Source/Pathway / Technology	As reported abatement Cost ($/t$CO_2$e)	Notes
Direct CCS on Power Stations[489]	Global	Post-combustion capture at fossil plants	~50-100	Mature technology with relatively low incremental cost per tonne CO_2 avoided.
Energy Efficiency Improvements[489]	Global	Operational measures (e.g., building retrofits)	~10-50	One of the most cost-effective options; benefits vary widely by sector and application.
Renewable Energy Deployment[489]	Global	Wind/Solar replacing fossil generation	~20-100	Highly dependent on local resource quality and grid conditions; generally lower abatement costs than e-fuels.
Biofuels – Yellow Grease HEFA Diesel[490]	US	Renewable Diesel via HEFA	~116-270	Conversion of yellow grease into diesel; cost depends on diesel price and feedstock availability.
Biofuels – Swine Manure HTL Diesel[490]	US	Renewable Diesel via Hydrothermal Liquefaction	~5-103	Low-cost abatement due to avoided emissions from conventional manure management.
Fischer-Tropsch (FT) Diesel from Biomass[491]	Global	FT Diesel via biomass gasification	<100	Cost-effective when fossil fuel prices exceed ~$2.30/gallon; includes efficient by-product utilisation.
Pyrolysis Bio-Oil[491]	Global	Bio-oil from biomass pyrolysis	<100	Becomes competitive when heavy fuel oil prices exceed ~$1.2/gallon.
Biofuels – Sugarcane, South Africa[492]	South Africa	Sugarcane-based biofuels	55–140	Lifecycle GHG emissions 45% lower than fossil fuels

[489] IPCC (2022): *Climate Change Mitigation Report*; IEA (2023): *World Energy Outlook*.
[490] NREL (2022): Snowden-Swan et al., *Techno-Economic Analysis of Renewable Diesel from Waste Oils & Animal Fats*.
[491] Zacher et al. (2021): *Cost and Carbon Abatement Potential of Bio-oil and FT Diesel Production Pathways*, Environmental Science & Technology.
[492] Tomascheket al. (2013): *Greenhouse Gas Emissions and Abatement Costs of Biofuel Production in South Africa*, Journal of Energy in Southern Africa.

T: +44 (0) 1235 75 3000
E: info@ricardo.com
W: www.ricardo.com