Scotland's Net Zero Roadmap: Industrial Decarbonisation Technology Analysis Report

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Nomenclature

AC	Alternating current
AE	Alkaline electrolyser
AEM	Anion exchange membrane
ASU	Air Supply Unit
ATR	Autothermal Reformation
BEIS	Department for Business, Energy & Industrial Strategy
BioSNG	Bio Synthetic Natural Gas
CAPEX	Capital Expenditure
CCC	Climate Change Committee
CCGT	Combined Cycle Gas Turbine
CCS	Carbon capture and storage
CCSL	Carbon Clean Solutions
CCU	Carbon capture and utilisation
CCUS	Carbon capture, utilisation, and storage
CHG	Compact Hydrogen Generator
CHP	Combined heat and power
CAPEX	Capital Expenditure
DAC	Direct Air Capture
DBT	Dibenzyl toluene
DC	Direct current
DEA	Dimethanolamine
DFB	Dual fludised bed
DFB	Dry Low Emission
EUR	Euro
FEED	Front End Engineering Design

GBP	British pounds
GHR	Gas Heated Reformer
HHV	Higher Heating Value
HVAC	High voltage alternating current
HVDC	High voltage direct current
IGCC	Integrated gasification combined cycle
LCC	Line commutated converter
LCH	Low carbon hydrogen
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LCOHS	Levelised cost of hydrogen stored
LCV	Low calorific value
LHV	Lower heating value
LOHC	Liquified organic hydrogen carrier
MCH	Methyl Cyclohexane
MEA	Monothanolamine
MOF	Metal organic framework
NGCC	Natural gas combined cycle
OPEX	Operational Expenditure
PCC	Post combustion capture
PEM	Polymer electrolyte membrane
PDBT	Perhydro-dibenzyl toluene
POx	Partial oxidation
PSA	Pressure swing adsorption
PtG	Power-to-Gas
SGP	Shell Gas POx

SMR	Steam Methane Reformation
SNG	Synthetic natural gas
SNZR	Scotland’s Net Zero Roadmap
SOE/SOEC	Solid oxide electrolysis
R&D	Research and development
t	Tonnes
TOL	Toluene
TIC	Total Installed Cost
TRL	Technology readiness level
TSA	Temperature Swing Adsorption
TWR	Terrace Wall Reformer
USD	United States dollar
Water Gas Shift	WGS
WP	Work Package
VPSA	Vacuum Pressure Swing Adsorption
VSC-HVDC	Voltage source converter – high voltage direct current

About Scotland’s Net Zero Roadmap and Partners

Scotland’s Net Zero Roadmap (SNZR) is Innovate UK funded project number 75206. The aim of the project is to develop a roadmap that sets out how Scottish industry can move towards Net Zero by 2045, based on exploring a number of decarbonisation scenarios. The project focuses on a cluster of industrial activity on the East Coast of Scotland which covers many of the largest industrial sites across a range of sectors and 80% of Scotland’s industrial CO_2 emissions.

SNZR is led by NECCUS and other project partners are Costain Limited, Doosan Babcock Limited, Halliburton Manufacturing and Services Limited, Aker Solutions Limited, Wood Limited, Energy System Catapult Limited, Net Zero Technology Centre, Pale Blue Dot Energy Limited, Optimat Limited, The University of Edinburgh and The University of Strathclyde.

Executive Summary

Decarbonising industry in Scotland is a monumental undertaking that is essential to meeting net zero by 2045. Decarbonisation will require a combination of existing and developing technologies to make step change reductions in carbon dioxide emissions, whilst also removing carbon dioxide from the atmosphere. When selecting technologies for decarbonisation, understanding the vast landscape of developed and developing technologies is essential to ensure the most appropriate are selected and implemented at the right time. Today, very few of technology solutions offer a cost competitive alternative to current fossil fuels. However, the desire to address this is global, and a vast amount of research and development is well underway to reduce the cost of producing clean energy vectors and capturing and permanently storing carbon dioxide. Policy is also developing and will be required to help close this price gap, at least in the short term.

This report is provided by Net Zero Technology Centre as a deliverable to Scotland's Net Zero Roadmap Phase 2. The purpose of the report is to provide an understanding of the industrial decarbonisation technology landscape, to assist with selection and validation of technologies by the project. A techno-economic analysis has been performed on a range of technologies deemed relevant to the roadmap through stakeholder engagement in Phase 1 and through discussion with Phase 2 project partners. The key topics that have been analysed include hydrogen generation, carbon capture, utilisation and storage, fuel switching, and electrification.

There are numerous technologies available under development for producing low-carbon hydrogen, although few have been deployed and proven at large scales. Steam methane reformation with carbon capture and storage, and alkaline electrolysis are the most advanced, but emerging technologies such as enhanced autothermal reformation, partial oxidation, and proton exchange membrane electrolysis are gaining traction due to certain advantages. Low-carbon hydrogen can be used as an alternative fuel in many processes, providing some lower cost opportunities for retrofit rather than complete replacement of existing equipment. Hydrogen fuelled gas turbines will be essential to provide future dispatchable electricity generation, gas compression, and support combined heat and power decarbonisation. However, considerable further work is required to develop dry low emission hydrogen fuelled gas turbines.

Biomass presents a key opportunity to decarbonise industrial heating and is already commercially deployed. However, the biggest limitation on the use of biomass is likely to be availability of sustainable biomass. Electrification is feasible and well developed for several industrial processes, however, it has had limited commercial deployment at scale and is an expensive option compared to combusting natural gas. Reducing the cost of electricity and equipment required for integration (e.g., transformers and cabling) will have a significant impact on making this a more cost competitive option.

Carbon dioxide capture from low concentration point source emissions is commercially mature with amine-based solvents deployed at most post-combustion flue gas capture facilities worldwide. Several next generation chemical solvents offer exciting potential to reduce regeneration energy requirements and degradation. Direct air capture technology has progressed immensely over the last decade and may be an incredibly important technology to reach net zero, potentially providing a lower cost CO_2 capture option for emitters who struggle to decarbonise otherwise. However, the cost must reduce to be an affordable solution. Commercial deployment is expected mid-2020s with significant CAPEX reductions by 2030 and continuing to beyond 2050.

Carbon capture and utilisation offers the opportunity to create value adding products from waste CO_2 whilst avoiding the requirement for transport and sequestration. Most utilisation technologies have not yet been demonstrated at commercial scale and high costs represents a major barrier to widescale deployment. Depleted oil and gas reservoirs and deep saline reservoirs both offer potentially attractive targets for geological storage of CO_2. Uncertainty on capacity and injectivity is lower for depleted reservoirs, giving them a potential economic advantage. Injecting into depleted reservoirs below CO_2 bubble-point pressure presents challenges due to Joule-Thomson cooling effects. If this can be better understood, modelled, and components designed appropriately, costs can be reduced through various routes, including eliminating the requirement for CO_2 heating at the wellhead.

1 Introduction

1.1 Background and Motivation

Decarbonising industry across Scotland will require extensive collaboration across sectors to develop the end-to-end solutions required. This requires an integrated approach to ensure key stakeholders, infrastructure owners, emitters and future/ ongoing projects deliver a coherent, structured, integrated, and inclusive approach to achieving net zero in Scotland by 2045.

Underpinning nearly every decarbonisation option is a technology solution that is either available today or is under development. And for every technology solution, there are often many to choose from that are at various stages of Technology Readiness Level (TRL). Deciphering and understanding this global landscape of decarbonisation technologies is essential if Scotland's industries are to select the right technology for their needs, at the right time.

As part of Scotland's Net Zero Roadmap Phase 2, Net Zero Technology Centre builds upon the research and technology analysis performed in Phase 1 of the project, to perform a more detailed techno-economic analysis of possible decarbonisation technology solutions for industry across Scotland. The aim of doing so is to assist project partners in the selection of technologies to be included in engineering concept modelling. This is done by clearly presenting the most relevant technical and economic information for consideration.

In Phase 1, the following technology focus areas were identified through extensive industry and stakeholder engagement activities:

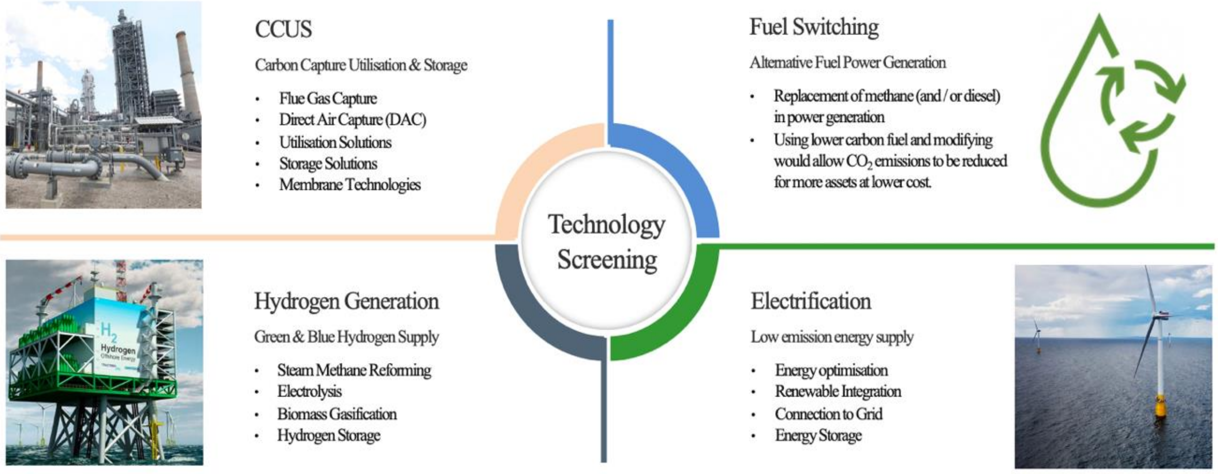


Figure 1 - Technology focus areas determined after stakeholder engagement in phase 1

Following this, a list of technologies across each of the categories was created to give a high-level overview of the technology types, advantages, challenges and TRL. This was compiled in a database style format for easy interrogation.

In Phase 2, through ongoing determination of the relevancy of each technology to the roadmap project, and with alignment to the scope of each Work Package 4 (WP4) partner, the database of technologies has been refined and more detail added to support WP4 partners with their technology selection. This includes analysis of further technologies in the key areas of interest.

This report serves as complimentary to the document **D3.2.1 - SNZR Industrial Decarbonisation Technology Analysis Database** which provides an alternative format on the technologies that have been studied.

1.2 Objectives

The objective of this report is to aid in the delivery of the Net Zero Technology Centre's role in Scotland's Net Zero Roadmap project – to support, challenge and validate findings related to technology selection and adoption. As mentioned, this can only be delivered if there is an understanding of technologies available for selection, today and in the future.

This report therefore provides this evidence base to increase understanding of the technology options, to aid in validation and selection of technologies proposed for deployment in the roadmap project. This report therefore gathers, analyses, and presents the pertinent techno-economic information available in public literature on key technologies across the 4 focus areas – hydrogen generation, CCUS, fuel switching and electrification.

Techno-economic information includes information relating to TRL, advantages and challenges, technology costs, scalability, deployment base, commercial readiness (including time to commercialisation), learning rates and cost reduction opportunities as far as possible.

1.3 Limitations

This report does not select the technologies for deployment in the project, but provides an evidence base to support and validate this selection. Information presented in this report has been predominantly gathered from publicly available sources and does not contain any confidential information. Best endeavours have been made to state any assumptions, whether they have been made by the author or obtained from a referenced source. Often some assumptions from a referenced source are not always clear.

Reported costs and details relating to technology advantages and commercial deployment timescales are often overly optimistic and based on best case scenarios – particularly when sourced directly from technology developer resources. It is therefore recommended to carefully study any assumptions before comparing reported technology benefits and costs.

Whilst the information contained in this report has been prepared and collated in good faith by the Net Zero Technology Centre, it makes no representation or warranty (express or implied) as to the accuracy or completeness of the information contained herein nor shall we be liable for any loss or damage resultant from reliance on same.

2 Hydrogen

2.1 Introduction

It is widely recognised that low carbon hydrogen will be essential to help the UK meet its legally binding commitment to achieve net zero by 2050, and Scotland's legally binding commitment to achieve net zero by 2045. BEIS highlights in their recent UK hydrogen strategy that 20-35 % of UK final energy demand could be delivered by hydrogen in 2050 [1]. The UK has a target of 5 GW low carbon hydrogen production by 2030, whilst the Scottish Government has also set a target of 5 GW low-carbon and clean hydrogen production by 2030 [2]. Both governments agree that both renewable and low-carbon hydrogen will play an increasing role in the energy transition to net zero.

It is also widely recognised that low carbon hydrogen's role will be alongside electrification and CCUS, with heavy industrial areas being expected to drive the earliest significant demand for hydrogen by 2030 through switching to hydrogen fuel from current fossil fuels. This will likely be driven by the sectors where electrification is not feasible or is too costly, for example, generation of high temperature heat. Further, hydrogen can be stored for long durations and provide flexible power generation and is an essential input to a range of chemical processes. Technologies required to support hydrogen fuel switching across Scotland's industry are analysed in Section 3.

Hydrogen can only be considered as a suitable decarbonisation technology if it can be produced with low CO_2 emissions, at sufficient volumes, and an acceptable price. Today's hydrogen production is nearly all derived from fossil fuels through Steam Methane Reforming (SMR), and without capturing any carbon emissions. A small amount of electrolytic hydrogen is produced for local transport projects and trials. Therefore, the focus of this section is on the analysis of technologies to produce and store renewable and low-carbon hydrogen today, and the emerging technologies that may be worth considering for future deployment scenarios.

2.2 Blue Hydrogen Production Technology

2.2.1 Introduction

Blue hydrogen is produced through the reforming of natural gas to hydrogen, whilst capturing most of the CO_2 emissions through CCUS. Grey hydrogen is the production of hydrogen from natural gas, without CCUS, and currently dominates the hydrogen production market globally. This process can be retrofitted with carbon capture. Blue hydrogen technologies can be classified as those with CO_2 capture rates greater than 60%, however, only those with capture rates of 90% or above are considered in this analysis for SNZR Phase 2.

There are several higher TRL technologies that are most used globally to produce syngas and hydrogen from natural gas. The focus in recent literature studies has mostly been around SMR and ATR (Autothermal Reforming) with CCS so there is more information available to report on, compared with Partial Oxidation (POx).

This section outlines the high, and lower TRL blue hydrogen technologies that have been analysed for consideration in the relevant scenarios of Scotland's Net Zero Roadmap Phase 2.

2.2.2 Overview of the Main Thermochemical Hydrogen Production Processes

Steam Methane Reforming is a standard process for syngas production that is most used globally through reacting methane with high temperature steam in the presence of a catalyst. The reaction is endothermic and requires heat to be supplied to the process for the reaction to take place, usually by burning additional natural gas in a reformer furnace. SMR is typically utilised for production of syngas with a H_2:CO ratio greater than 2. Several SMR plants globally have been retrofit with CCS to produce low carbon hydrogen.

Autothermal Reforming is also a standard process for syngas production combining POx with SMR in a single reaction chamber. ATR is utilised for production of syngas with H_2:CO ratio less than 2. There are plans to develop ATR systems with CCS across the UK, including as part of the H21 and HyNet projects in England. These projects plan to utilise an ‘enhanced ATR’ system, which is described later. No known ATR plants have been retrofitted with CCS.

Partial Oxidation is used in the ATR process but can also be used on its own to convert natural gas and other hydrocarbons to syngas. The produced H_2CO ratio is approximately 2 and is favourable for production of synthetic fuels. The system has been studied less in publicly available literature, so less information is reported in this section, but the technology should not be discounted on this basis as there are some significant benefits to this technology that are described later.

Process Overview

1. **Pre-feed and pre-reforming**

   SMR and ATR require pre-treatment and pre-reforming whereby natural gas is purified through desulphurisation to avoid poisoning of the catalysts downstream and is then pre-reformed with some steam to decompose long-chain hydrocarbons into methane and syngas [3]. This is not required for POx.

2. **Reforming**

   a. **SMR**

      Purified natural gas then proceeds to the reformer where the methane is reacted over a nickel-based catalyst with steam at a temperature between 800°C and 1000°C, and a pressure between 20 bar and 30 bar. Heat is supplied through the combustion of fuel gas in a reformer furnace. The chemical reaction:

      SMR $CH_4 + H_2O \rightarrow CO + 3H_2$ (endothermic)

   b. **POx**

      Un-treated natural gas is heated and delivered to the reformer where it is reacted with oxygen supplied by an air separation unit (ASU), without a catalyst. The cooling process generates high pressure steam which is used in the next process. The chemical reaction:

      POx of methane $CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2$ (exothermic)

   c. **ATR**

      Purified natural gas is delivered to the reformer where the non-catalytic exothermic reaction of oxygen with methane (POx) is combined with the catalytic endothermic reaction of SMR to create a heat balance so external heat input is not required.

Process temperature is between 900-1,150°C and requires oxygen from an ASUas input. The chemical reactions:

POx of methane $CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2$ (exothermic)

SMR $CH_4 + H_2O \rightarrow CO + 3H_2$ (endothermic)

3. **Water gas shift**

   The water gas shift (WGS) reaction reacts steam with CO to form more hydrogen and CO_2. The chemical reaction:

   Water gas shift $CO + H_2O \rightarrow CO_2 + H_2$ (exothermic)

4. **Hydrogen separation**

   A Pressure Swing Absorber (PSA) is typically used to separate the hydrogen from the syngas at high pressure and low temperature. See Section 4.2.3 for more details on this process. Around 85-90% of H_2 with a purity of >99.9% is recovered. PSA tail gas is then fed into the burners of SMR or ATR.

CO_2 Capture

For all processes, CO_2 from the oxidation of carbon atoms in the feedstock during reforming and shift is contained in the high-pressure product stream. For ATR and POx, this is the only direct source of CO_2 emissions, however for SMR, is only ~60%. These high pressure and high concentration CO_2 emissions can be captured more easily by applying pre-combustion capture methods. See Section 4.1.1.2.

SMR also produces CO_2 during combustion of the fuel gas (~40 %), which must be captured to achieve high CO_2 capture rates. Although there are multiple configurations possible of an SMR plant with CCS, only the case where flue gas is captured is considered here because capture rates of around 90% can be achieved (compared with ~60% maximum without flue gas capture) [4].

CO_2 capture from the combustion reaction exiting the furnace is released at atmospheric pressure and low concentrations, requiring high volume post combustion carbon capture equipment to remove impurities and compress the gas for storage.

2.2.3 Steam Methane Reforming

SMR is a proven and relatively simple technology. It is the most widely applied technology in the world for generating hydrogen with 50% of the world's hydrogen produced by this method [5].

A key advantage of SMR compared to ATR is that the process does not require a stream of pure oxygen to proceed. The SMR plants therefore have typically lower capital expenditure (CAPEX) than ATR plants because an air separation unit (ASU) to produce oxygen is not required. Conversely, SMR requires an additional supply of natural gas for combustion in the reformer furnace which introduces greater operating expenditure (OPEX).

The removal of the low-pressure CO_2 from the flue gas requires large post-combustion carbon capture equipment which incurs high CAPEX. The equipment also significantly increases the required plot area of the SMR plant.

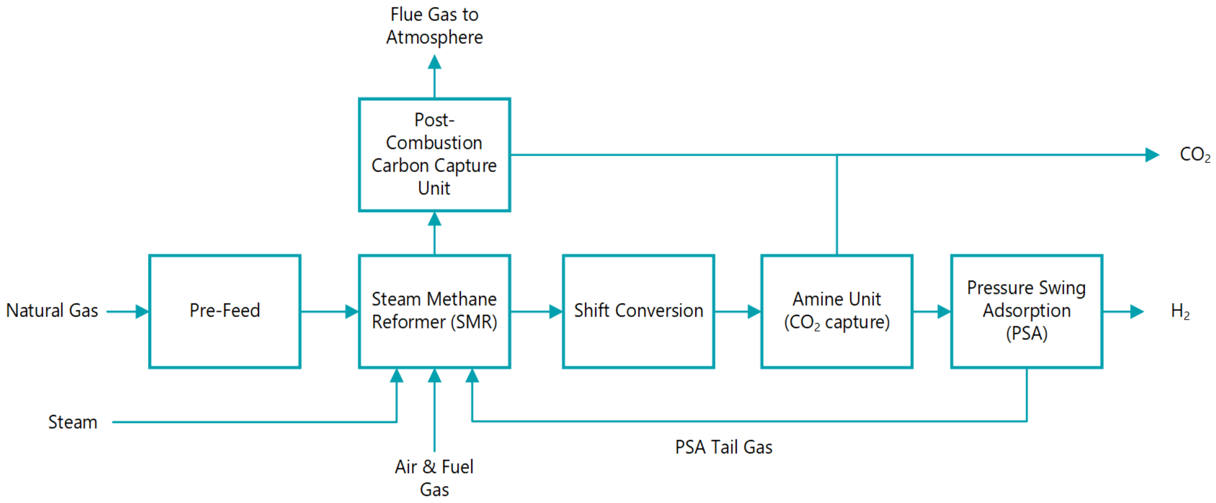


Figure 2 – SMR with carbon capture process diagram [6]

Scalability – Standard SMR has relatively limited scalability in a single train. A hydrogen production rate of ~200,000 Nm^3/h (~600 MW_{th}) is possible in a single train [7]. However, larger plants can be constructed using multiple trains that may have advantages in terms of operational flexibility. For example, a plant with multiple trains can shut down or restart a train to meet seasonal hydrogen demand, and a failure within a train does not result in operational downtime for the entire plant.

Table 1 - World's largest single train SMR plants in 2017 [4]

Owner	Plant Name	Location	Capacity [Nm^3/h]	SMR Licensor
Tuapse Refinery	U-34 *	Sao Francisco do Conde, Brasil	240000	Technip
Kuwait National Petroleum Co Ksc	CFP2*	Mina Abdulla, Kuwait	203500 (per train, 3 trains)	Haldor Topsøe
JSC Bashneft NOVOIL	HPU	Ufa, Russia	165000	Amec Foster Wheeler
TUPRAS	HPU*	Izmit, Turkey	160000	Technip
Abu Dhabi Oil Refining Company (Tarter)	Hydrogen 2 UNIT 1300	Ruwais, U.A.E	151000	Haldor Topsøe

*Under construction in 2017

Technology Development Status – Several SMR plants are in operation with carbon capture, producing around 0.5 Mt/yr H_2 between them [8]. Hence, this is the only technology that is currently being used solely to produce large scale hydrogen whilst capturing the carbon, so is the only low carbon technology that can be classed as **TRL 9**.

Costs – Standard SMR typically has the highest CAPEX due to the post combustion capture system requirement and the highest LCOH driven by the poorer carbon capture rate and conversion efficiency requiring a greater natural gas feedstock. Cost analysis from two different sources:

Table 2 – SMR with CCS cost analysis

Technology	Economic Analysis		Notes/ Reference
Standard SMR with Cansolv CCS	CAPEX (£MM)	207 – 237	Analysis from BEIS Low Carbon Hydrogen Supply Competition [9] at 100,000 Nm^3/h H_2 90% CO_2 capture rate
	OPEX (£MM/y)	25[1]	
	LCOH (£/kg-H2)	1.92 – 2.36	
Standard SMR with flue gas MEA capture	CAPEX (£MM)	265[3]	IEAGHG Technical Report [4] at 100,000 Nm^3/h H_2 90% CO_2 capture rate
	OPEX (£MM/y)	84(2,3)	
	LCOH (£/kg-H2)	1.60	

1- Not including feedstock
2- Including feedstock
3- EUR to GBP conversion 0.87

Analysis by BEIS [1] estimates that thanks to global technology learning, a CAPEX reduction of 1.26 % can be expected per year

2.2.4 Autothermal Reforming and Enhanced Autothermal Reforming

ATR technology is commonly used to produce syngas for Fischer-Tropsch processes in large-scale methanol production plants. This proves the technology is scalable and can produce large quantities of hydrogen in a single production train.

The ATR process heats the SMR reaction from the exothermic POx reaction which brings several advantages. OPEX is reduced since no fuel gas is required to heat a reaction furnace. Additionally, all CO_2 produced in the process is contained within the high pressure and high purity product stream and no CO_2 is released from combustion as flue gas. This results in a simpler carbon capture system and higher carbon capture rates. The reduced size and complexity of the carbon capture system also lower the overall CAPEX and plot area of the plant.

The POx reaction requires pure oxygen which must be produced by an ASU. The ASU has a high-power requirement which results in a significant increase in OPEX. The ASU also presents a large CAPEX investment with a poor economy of scale for hydrogen production outputs up to 90,000 Nm3/h [10]. Therefore, ATR is considered less economical for smaller plants with lower hydrogen production rates. Due to high temperature thermal processes, an ATR cannot readily be turned on and off, hence is most suitable as a baseload producer.

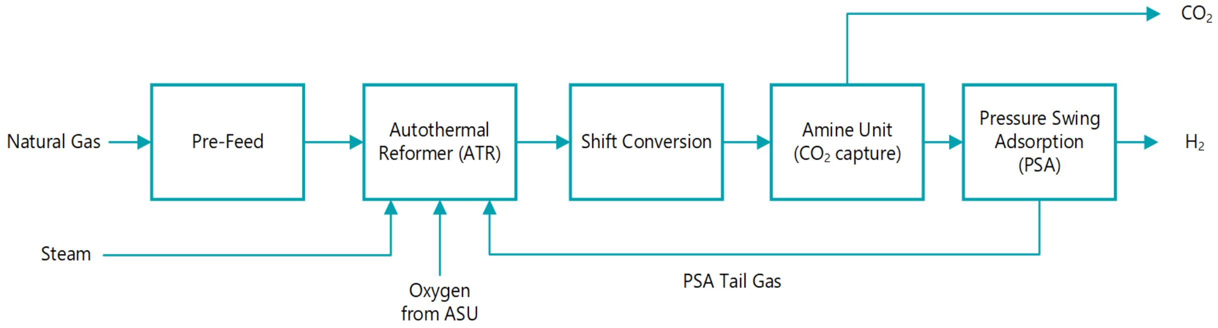


Figure 3 – ATR with CCS process diagram [6]

When being considered for new build blue hydrogen plants, an 'enhanced' ATR system is being specifically developed with increased heat integration resulting in higher efficiencies. This is done through the inclusion of a Gas Heated Reformer (GHR), which partially reforms methane prior to the ATR, and through reconfiguration of the standard processes to better integrate heat.

Johnson Matthey's Low Carbon Hydrogen (LCH) system couples an ATR with a GHR [10].The GHR recycles heat from the syngas stream exiting the ATR, to reform 30% of the total methane with steam to form syngas. This partially reformed gas is heated to 1500°C and partially oxidised with methane and oxygen, delivered from an ASU, before passing through a bed of steam reforming catalysts. Hot product gases from the ATR are cooled through the GHR, which recycles heat to perform the initial reforming. The Isothermal Temperature Shift reactor then converts more syngas to CO_2 and H_2, whilst recovering more heat to produce steam. The amine-based capture unit removes CO_2 and hydrogen is further purified with a PSA.

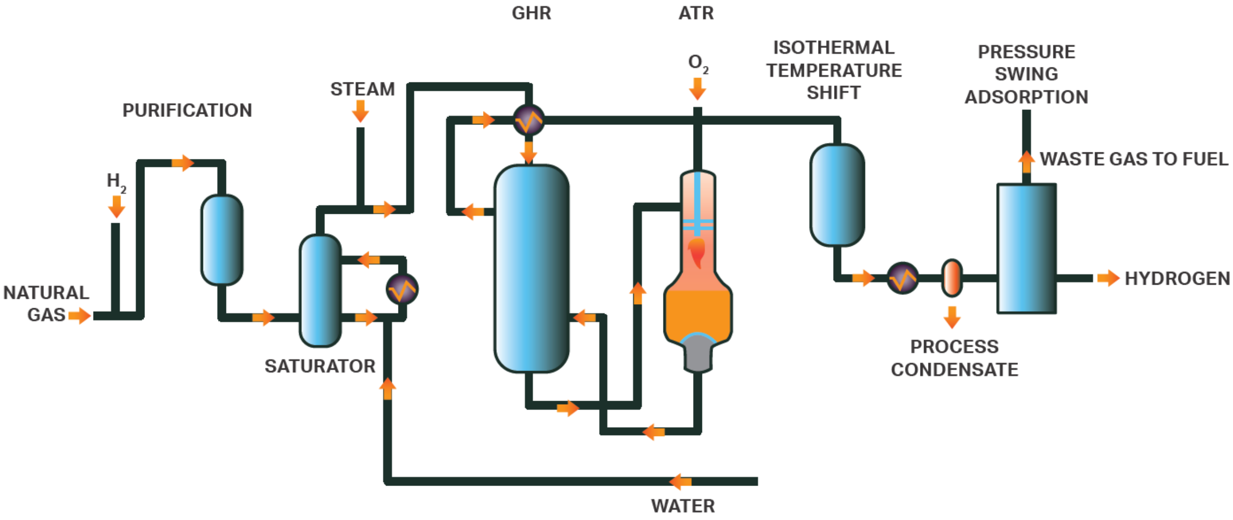


Figure 4 – Johnson Matthey's Low Carbon Hydrogen flowsheet [11]

All the CO_2 is included in the product stream so is easily removed, giving the LCH technology a high process capture rate of >95%. Capturing the CO_2 at high pressure reduces CAPEX and OPEX through avoiding compression before capture.

Scalability –ATR has proven scalability from the production of syngas in large-scale Fischer-Tropsch processes, however, not through the dedicated production of hydrogen. A hydrogen production rate of 500,000 Nm^3/h (~1,500MWth) is possible in a single train, which is significantly larger than the largest SMR based hydrogen plants. The improved single train scalability of the technology also gives advantages in terms of the reduced plot area and reduced CAPEX compared to a plant with the same hydrogen output and multiple trains. With increasing scale above 100,000 Nm^3/h, the LCOH decreases more rapidly than SMR. This is largely influenced by the high CAPEX of the ASU.

Technology Development Status – The Johnson Matthey's LCH (enhanced ATR) and standard ATR with CCS systems have not yet demonstrated at commercial scale, however many of the subcomponents are already proven and quick progress to TRL 9 expected prior to mid-decade as plants are built in the UK. This technology is currently at **TRL 7**.

Costs – Enhanced ATR typically has the highest CAPEX, attributable to the air and gas systems including the ASU, which offsets the reduced CAPEX requirement for a simplified carbon capture system. At a production rate of 100,000 Nm^3/h the LCOH is competitive, however, reduces further with higher hydrogen production rates and improved economies of scale. If the system can be integrated into a site with a supply of oxygen from an existing ASU, CAPEX and LCOH could be reduced dramatically.

Analysis by BEIS [1] estimates that thanks to global technology learning, a CAPEX reduction of 1.26 % can be expected per year, plus an additional 10% between 2020 and 2030 after the First-Of-A-Kind plant is established and benefits of learning-by-doing are realised. LCOH for enhanced ATR with CCS has been estimated between 1.73 – 2.66 £/kg-H_2 [9].

2.2.5 Partial Oxidation

Partial oxidation is a thermodynamically favourable method of producing syngas as the process is slightly exothermic and produces a H_2: CO ratio ~2 – which is preferrable for the synthesis of hydrocarbon fuels (methanol typically). Metal catalysts are often used but can suffer difficulties with operational control due to poor heat removal rates from catalysts. The process is typically used with low quality feedstock, such as heavy residue and solid feedstock (coal). The key step in the process is feedstock gasification, through which gasification agents used are oxygen or air, and often steam. Steam assists with mixing of feed and oxidant and moderates the temperature.

Shell Gas POx (SGP) is developed by Shell Catalysts & Technologies [12] and is based on a non-catalytic partial oxidation reaction process to produce hydrogen, coupled with ADIP ULTRA solvent technology for carbon capture. The main advantage of the SGP technology compared to ATR or SMR is reduced process complexity. Without the catalyst, there is no requirement to pre-treat the natural gas before entering the process which reduces the CAPEX required for purification equipment. The SGP technology is more flexible with feed gas quality and can handle feed contaminants.

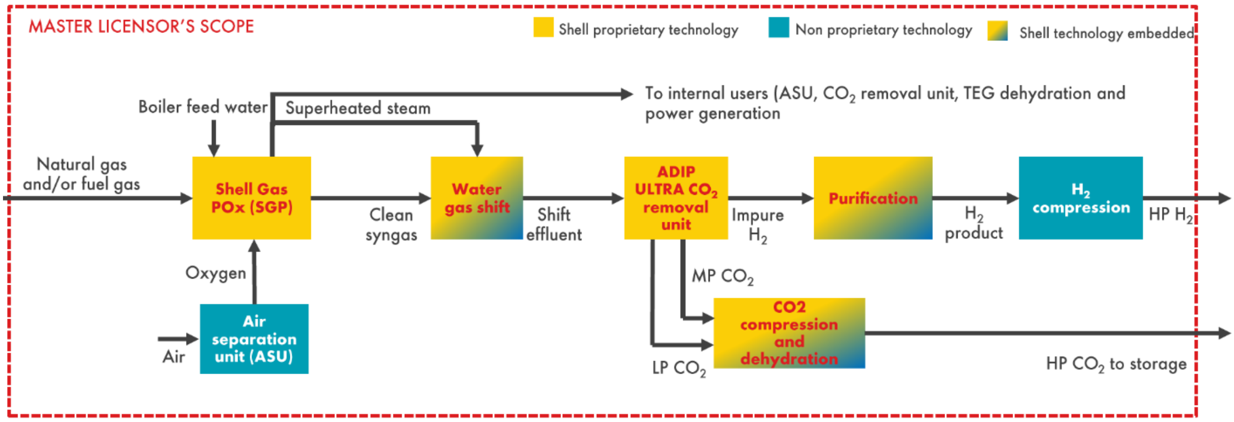


Figure 5 - Shell Gas POx flowsheet [14]

The energy balance of the SGP technology is also designed to maximise efficiency and provide OPEX savings. The SGP process does not require steam to operate like SMR or ATR processes. Steam is instead produced from the exothermic oxidation reaction heat and can be used in other parts of the process, reducing overall imported power.

However, the oxygen for this process is usually produced in an ASU, which considerably increases CAPEX of the plant and increases energy consumption. Energy consumption can be offset to an extent by the extraction of heat from the exothermic reaction.

Patrial oxidation can also be used with biomass sources to produce hydrogen. See details of Biomass Gasification in Section 2.3.7.

Scalability –Several large capacity plants are in operation or under construction. The largest of which is owned by Linde North America in LaPorte, USA and can produce approximately 7,200,000 Nm^3/h of syngas for the conversion to chemicals. The licensor for the gasifier of this system is GE and the gasifier licensor for three of the world's largest plants is Shell [13].

Technology Development Status – Commercially developed for syngas production but needs to be fully integrated and developed with CCUS, therefore currently **TRL 7**.

Costs – CAPEX and OPEX can be reduced through process simplification – mainly the elimination of purification equipment. This is particularly true for solid feedstock, however, for natural gas POx, the economic benefits are typically gained when no purpose-built oxygen plant (ASU) is required [13]. For a 500-t/d hydrogen production unit, Shell claim £22 MM/y lower OPEX, 35 % less power import and 10 – 25 % lower LCOH when compared to ATR with CCS [14].

2.2.6 Enhanced SMR

The standard **SMR** process can be enhanced by removing the requirement for post combustion CO_2 capture to improve capture rates and reduce CAPEX, and by recycling heat to minimise gas consumption. **Wood's Blue^{H2}** enhanced SMR technology includes a combination of a GHR (still under development) and Wood's proprietary terrace wall reformer (TWR). In the GHR, the endothermic partial reaction of methane to produce H_2 and CO is aided with recycled heat from the syngas exiting the TWR. The TWR in this system is a proprietary Wood technology and performs the final conversion of methane to H_2 and CO. After shift reaction, syngas is cooled further before amine CO_2 removal, where one stream is sent to the TWR as fuel gas and the second to the PSA. The PSA separates H_2 from the syngas and residual tail gas is also sent to the TWR.

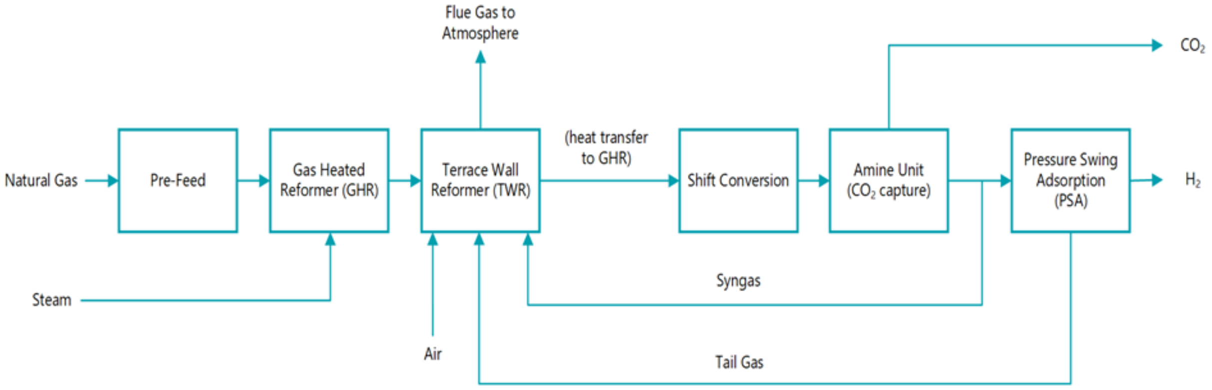


Figure 6 – Wood's Blue^{H2} flowsheet [6]

Figure 7 – Wood's Terrace Wall Reformer [6]

Once proven, Wood's Blue^{H2} technology could present several improvements over standard SMR. The main improvement being due to the elimination of post-combustion CO_2 capture as the furnace is fuelled by syngas. This means CAPEX and plot area of the plant can be significantly reduced. By recycling heat, the GHR can minimise fuel gas consumption – improving efficiency whilst decreasing net CO_2 production. Further, the TWR is a compact modular design that reduces footprint, with a favourable outlet temperature around 920°C, which can aid CO_2 capture performance.

Scalability – Enhanced SMR features the same core technology as standard SMR and therefore has similarly limited scalability. A hydrogen production rate of ~200,000 Nm^3/h (~600MWth) is considered possible in a single train. Larger plants can also be constructed by deploying several single-train modules with operational flexibility advantages.

Technology Development Status – All subcomponents of Wood's Blue^{H2} are proven, apart from the GHR which is expected to be piloted in 2021. Over 300 TWRs have been installed by Wood. The full system has not been integrated with the TWR, GHR, or with CCS, so current estimation is **TRL 5**, with potential to rapidly progress to TRL 7 if a demonstration plant can be established in near future.

Costs – Enhanced SMR has a potentially significant lower LCOH, CAPEX and OPEX than standard SMR. This is primarily driven by simplification of the carbon capture system, higher capture rates and a lower fuel gas requirement. Enhanced SMR is cost effective up to 100,000 Nm^3/h but cost effectiveness declines at greater scales compared to ATR solutions. Wood claims a very competitive £1.50 /kg-H_2 could be achievable with their technology, over a 25-year project life.

2.2.7 Sorption Enhanced Steam Reforming

Sorption enhanced steam reforming is a second-generation hydrogen production process that offers a simpler process layout compared to the conventional SMR. After purification of natural gas, methane is steam reformed within a fluidised bed reactor to form syngas. The CO content of the syngas is converted into CO_2 by the WGS reaction while also producing more hydrogen. CO_2 is then captured in the heated calciner with a calcium oxide (CaO) sorbent and removed from the product stream. The calcium looping CO_2 capture is the main innovation through which LCOH can be reduced. See Section 4.3.3.1 for more details on the Ca-looping process. Finally, the hydrogen stream is further purified by a PSA unit (if required).

Most advanced in this technology is the Gas Technology Institute with their patented Compact Hydrogen Generator (CHG). The technology is being developed under the HyPER project alongside Cranfield University and Doosan Babcock, funded through BEIS. Carbon capture rates of up to 96% are claimed possible with the CHG technology.

Technology Development Status –. The main challenge is the operation of high-pressure sorption enhanced reforming in a bubbling fluidised bed and reliable high-temperature solids handling [15]. The technology is currently at **TRL 4,** and funding has been secured to demonstrate a 1.5 MW_{th} pilot plant which aims to take the technology to TRL 6 in 2022.

Three principle CHG units are proposed: a 10 MW_{th} small industrial scale unit; a 50 MW_{th} small utility scale unit; and a 300 MW_{th} large utility scale unit, initially with a twin train concept (150 MW_{th} each). A 1,500 MW_{th} system has also been proposed by Cranfield University that comprises of 5 large utility scale CHG deployable modules.

Costs – An AACE Class IV cost estimate of the CHG technology also revealed cost savings compared with conventional SMR with CCS technology. The CAPEX of the plant is estimated to be reduced by 50%, largely due to the improved carbon system, and the levelised cost of hydrogen (LCOH) is estimated to be reduced by 20% [15].

2.2.8 Dry Reforming

Dry reforming is the reforming of methane with carbon dioxide into syngas, which can then be shifted to produce H_2, and CO_2 as described earlier. The technology can produce pure hydrogen but can also be classed as a CO_2 utilisation technology. The reaction of CO_2 and CH_4 is shown below:

$$CO_2 + CH_4 \rightarrow 2CO + 2H_2$$

Thermodynamics of dry reformation are less favourable than ATR or standard SMR as dry reformation is the most endothermic reforming reaction of methane because significant energy is required to react the fully oxidised CO_2 with methane. However, the proportional consumption of 1 mole CO_2 per mole of methane can reduce the overall carbon impact. H_2:CO ratio is limited to 1.

Improved process efficiency can be gained through utilising a waste stream of CO_2 as a full or partial replacement to steam. The main technological challenge is to overcome catalyst deactivation due to coking. Addition of water to the feed can minimise catalyst coke deposition and deactivation.

Linde and BASF have made significant progress in developing more effective and robust catalysts [16]. **Linde's DRYREF** syngas generation technology with BASF's SYNSPRIE catalyst can use CO_2 as feedstock to enable dry reforming of methane and minimize process steam requirement [17].

Importing CO_2 into the process reduces the steam to carbon ratio in the reformer and results in an increased thermodynamic equilibrium that minimizes the amount of CO_2 that needs to be removed, whilst reducing OPEX and CAPEX through reducing energy consumption and equipment sizes. The

SYNSPIRE catalyst prevents coke deposition under low S:C conditions and can be retrofit to existing steam reformers.

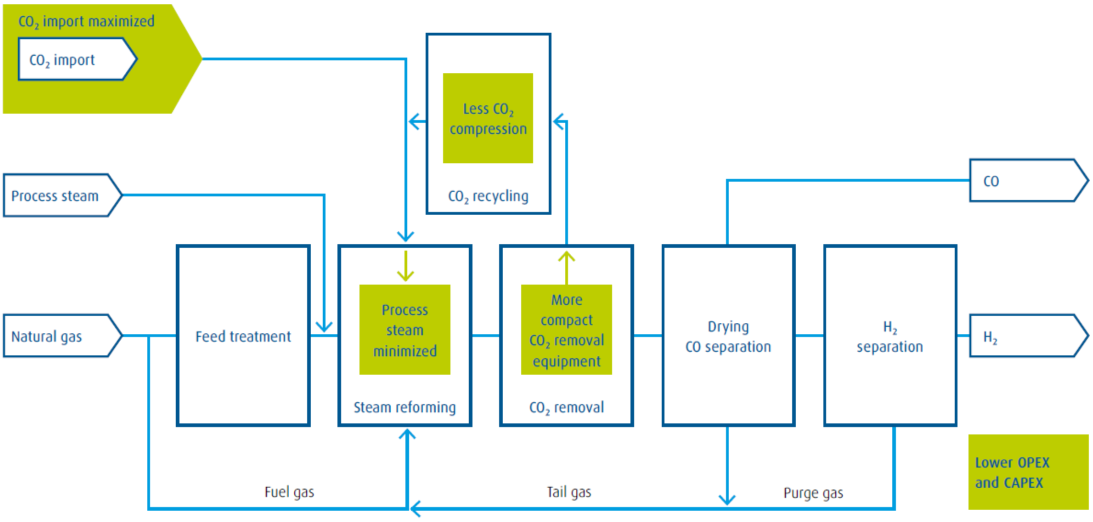


Figure 8 – Linde's dry reformation flowsheet [17]

Pilot testing of the system was completed in 2017, and commercial scale demonstration is claimed to have been achieved at Linde's industrial-scale HyCo plant in 2018. However, this appears to have been demonstrated for syngas production only.

Technology Development Status – Developed for steel industry, although application dedicated for hydrogen production with CCUS is limited [18]. Linde's demonstration plant reflects an estimated **TRL 6**. If technical challenges relating to coke deposition can be overcome through development of coke resilient catalysts that maintain high activity and stability, then industrial scales are likely to be achievable. A limiting factor on plant size may be the availability of large volumes of high purity CO_2 required for the 'dry' reformation process.

Costs – The process has potential to lower OPEX and CAPEX through reducing the steam to carbon ratio in the reformer, which minimizes the amount of CO_2 that needs to be removed – resulting in lower energy consumption and equipment sizes. Actual costs of the system have not been obtained; however, considering a dry reforming plant producing syngas which is then converted into methanol, CAPEX for such a plant is estimated to be slightly less than an equivalent steam reforming plant; resulting in a methanol cost approximately 10 – 15 % less [19]. The technology should be considered further in applications where enough CO_2 could be imported for negative prices from a neighbouring process or facility.

2.2.9 Natural Gas Pyrolysis

Natural gas and other hydrocarbons can be thermally decomposed through the process of pyrolysis, to produce solid carbon and hydrogen gas [20]. The process is endothermic and converts natural gas feedstock into carbon black and hydrogen [21]. Carbon black is a material produced by the incomplete combustion of hydrocarbons that can be used to form commercial products. The process may be favourable in locations where CO_2 transportation and storage routes are not readily available, and economics of the process may be improved through the development of new markets and applications for the solid carbon. The reaction:

$$CH_4 \rightarrow C + 2H_2$$

Methane pyrolysis can be divided into several categories:

- Thermal decomposition - reaction temperatures well over 1000°C
- Plasma decomposition - temperatures up to 2000°C generated by a plasma torch
- Catalytic decomposition - lower temperatures below 1000°C, aided by a catalyst
- Catalytic plasma decomposition – combination of plasma torch and a metal catalyst

Progress across the different methods varies significantly. Progress is being made by several companies including TNO, Monolith and BASF to improve performance of the catalyst, which rapidly deactivates [22].

The most advanced development is by Monolith, whose plasma pyrolysis method is potentially disruptive [23]. Their technique utilises plasma-based pyrolysis to heat the reaction using electrical power meaning no CO_2 is produced by combustion. The technology has the potential to be completely emissions free, including free of offsite emissions, if the electrical power is delivered to the process from renewable energy sources.

Figure 9 – Monolith's emissions free hydrogen plant [23]

Technology Development Status– Plasma decomposition is demonstrated by Monolith at **TRL 8**, but thermal and catalytic decomposition still at much lower TRL of 3-4 [21]. Monolith have demonstrated the technology on a commercial scale through their pilot plant at Olive Creek 1. Olive Creek 2 is planned to start production in 2024, and will produce 180,000 t/yr carbon black, and approximately 54,000 t/yr hydrogen (~ 70,000 Nm3/hr). Buyers of the solid carbon may impose economic, rather than technical limits on the scalability of the technology in many locations.

Costs – Detailed costs of this process are unknown at present. However, a techno-economic assessment by TNO, concluded that methane pyrolysis can be competitive with SMR, if the carbon co-product is saleable and a CO_2 tax of 50 euro per tonne is imposed [24]. The development of a market for the solid carbon produced will be crucial to the economics of this hydrogen production method.

2.2.10 Cost Comparison

There are huge regional variations in hydrogen production costs due to variations in the prices of fossil fuels, electricity, and carbon. Fuel costs are the largest components and account for between 45% and 75% of production costs [8]. Natural gas prices in Europe and the UK are higher than in Russia, the US, and the Middle East, hence, LCOH is higher in these regions.

Adding CCS to the SMR process, increases CAPEX by around 50%, increases fuel costs by 10%, and OPEX doubles due to transport and storage costs [8]. The influence of gas prices and CCS is highlighted in different regions in Figure 10.

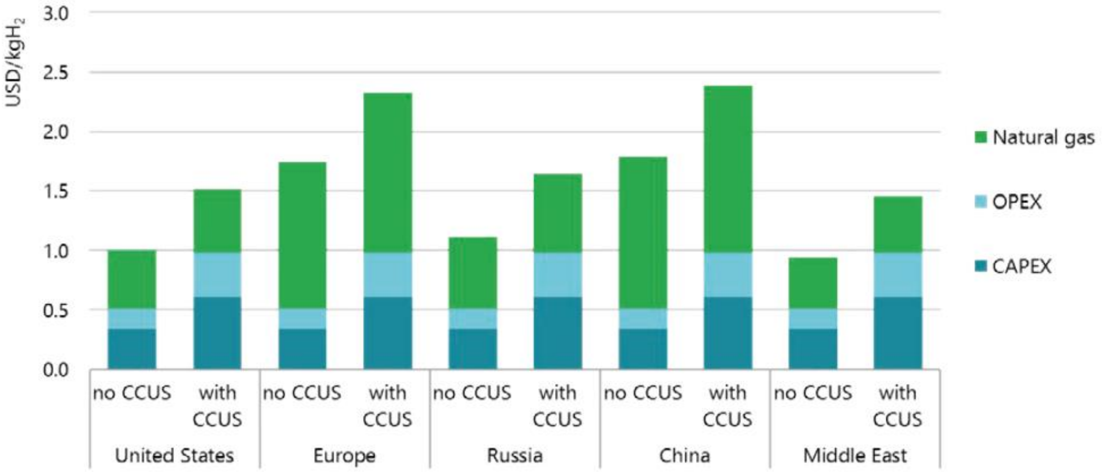


Figure 10- Hydrogen production costs based on natural gas prices around the world [25]

Note: All values are taken before Russia's invasion of Ukraine and the resulting increase in global energy prices.

Table 3 below provides an overview of technology costs from a range of literature sources – several of which are obtained from submissions under BEIS' Clean Hydrogen Supply Competition. It should be noted that with many variables and assumptions in CAPEX, OPEX and LCOH calculations, it is difficult to compare all technologies like-for-like without further standardisation of assumptions and economic basis. Further analysis beyond this table provides a standardised assessment from a single source.

Table 3 – Analysis from literature on CAPEX, OPEX and LCOE of blue hydrogen technologies

Technology	Economic Analysis		Notes/ Reference
Standard SMR with Cansolv CCS	CAPEX (£MM)	207 – 237	Analysis from BEIS Low Carbon Hydrogen Supply Competition [9] at 100,000 Nm^3/h H_2 90% CO_2 capture rate
	OPEX (£MM/y)	25[1]	
	LCOH (£/kgH2)	1.92 – 2.36	
Standard SMR with flue gas MEA capture	CAPEX (£MM)	265[3]	IEAGHG Technical Report [4] at 100,000 Nm^3/h H_2 90% CO_2 capture rate
	OPEX (£MM/y)	84(2,3)	
	LCOH (£/kgH2)	1.60	

Enhanced SMR (Wood’s Blue^{H2})	CAPEX (£MM)	122	Submission by Wood under BEIS Low Carbon Hydrogen Supply Competition at 100,000 Nm^3/h H$_2$ [26]
	OPEX (£MM/y)	22.4[1]	
	LCOH (£/kgH2)	1.50	
ATR + GHR (with CCS) Based on Johnson Matthey’s LCH system.	CAPEX (£MM)	203 – 253	Analysis from BEIS Low Carbon Hydrogen Supply Competition [9] at 100,000 Nm^3/h H$_2$ 97-98% CO$_2$ capture rate
	OPEX (£MM/y)	37 – 48[1]	
	LCOH (£/kgH2)	1.73 – 2.66	
Sorbent Enhanced Stream Reforming (Cranfield University CHG)	CAPEX (£MM)	105 – 114	Submission by Cranfield University under BEIS Low Carbon Hydrogen Supply Competition at 100,000 Nm^3/h H$_2$ [15]
	OPEX (£MM/y)	27 – 39[1]	
	LCOH (£/kgH2)	1.89 – 2.10	

1- Not including feedstock
2- Including feedstock
3- EUR to GBP conversion 0.87

Notes on Table 3:

- Further analysis is required to compare different references on the same economic basis. For example, Wood’s analysis under the BEIS Low Carbon Hydrogen Supply Competition uses a 25-year design life, compared to 20 years assumed by most other submissions.
- All costs are based on modelling – none of the technologies have been deployed at such scales whilst achieving high CO$_2$ capture rates stated.

BEIS have released analysis of the levelised costs of producing blue hydrogen through SMR, ATR and ATR with GHR technologies, with CCS, and at different scales [1]. LCOH estimates here have been calculated on a standardised basis. The report provides a comparison between 3 of the technologies and indicates the changing influence of LCOH components until 2050. Note that 1 MWh = 25.4 kg-H$_2$ (HHV) [27].

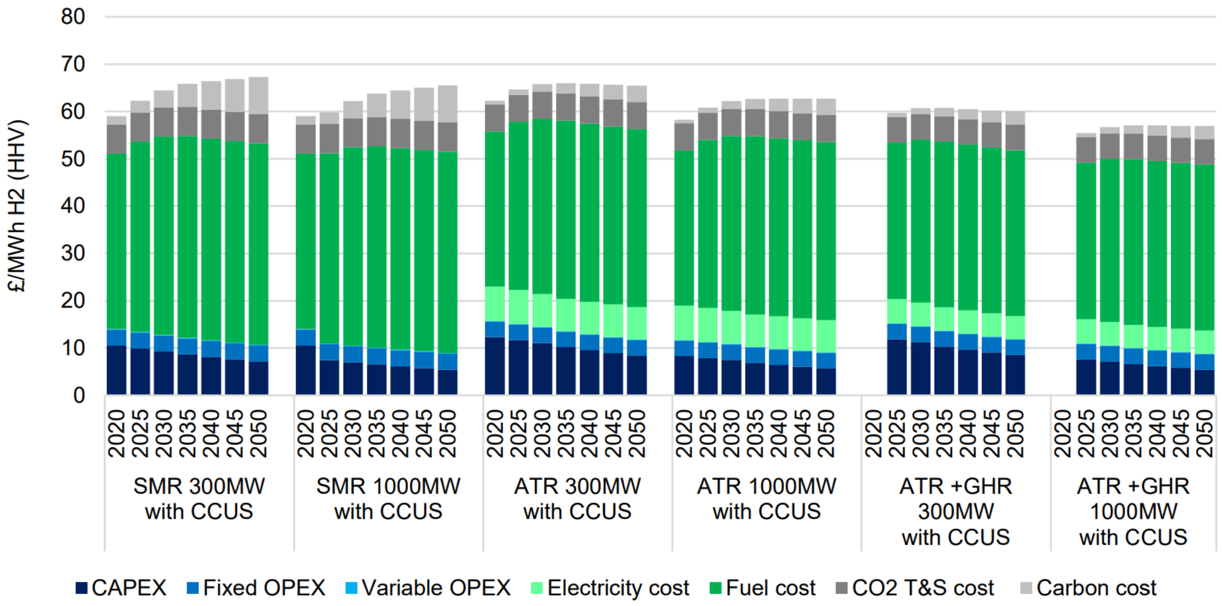


Figure 11 - LCOH estimates for CCUS-enabled methane reformation [1]

It is clear from this analysis that BEIS expects the 1000 MW ATR+GHR technology to deliver the lowest cost hydrogen, with a small increase in costs between now and 2050. For 300 MW ATR+GHR (with CCS), an LCOH of £2.44/kg-H_2 is estimated in 2020, with an increase to £2.56/kg-H_2 by 2050.

As mentioned, fuel costs are the largest cost component of all technologies and are expected to increase over time alongside carbon costs. The effect of the increasing carbon and fuel costs is most prominent with SMR technology, based on higher CO_2 emissions and higher consumption of natural gas compared to ATR technology.

Further analysis by Deloitte also highlights the strong effect of gas prices on blue hydrogen production cost and predict a similar LCOH of ~£2.50/kg in 2025. However, in contrast to BEIS analysis, Deloitte predicts a decrease in production costs to £2.0/kg by 2030, followed by an increase to £2.30/ kg by 2035.

2.2.11 Cost Reduction Opportunities

Despite the anticipated rising costs of fuel and carbon, CAPEX and OPEX can be reduced over time to help minimise the overall effect on LCOH:

- Cost reduction can be achieved through larger facilities bringing economies of scale (both in hydrogen production and CO_2 T&S), industrial CCS hubs where multiple facilities use the same CO_2 T&S infrastructure. This can also reduce risk and hence the cost of capital.
- Global technology learning and advancements, in terms of improving both process efficiency and the cost of CO_2 capture. Further detail on CO_2 capture technologies is detailed in Section 4.
- Integrating the design of the blue hydrogen production process presents opportunities to improve efficiencies and reduce costs, e.g., through minimising waste heat across the system.

Technological improvements in the process of producing hydrogen through SMR, ATR, POX, (or other) will reduce the LCOH. However, this process is generally well established for producing syngas, and future cost reductions in this area are likely to be small. Comparatively, the integration of these processes whilst capturing the carbon emissions is considerably more novel, hence, it is likely that most future blue hydrogen cost reductions will come from reducing the cost of CO_2 capture and improving overall system integration and process efficiency.

Cranfield University's Sorption Enhanced SMR estimates that a reduction in the cost of their CO_2 capture system, through calcium looping technology, can reduce system CAPEX by 50% (compared to BEIS counterfactual SMR with CCS) and LCOH by 20 %. Wood's Blue^{H2} system development has the potential to reduce LCOH through improving process efficiency by recycling high quality waste heat and by avoiding post combustion CO_2 capture and the requirement for an ASU.

In terms of what can be today to reduce the cost of blue hydrogen production, there are several aspects relating to site location and infrastructure that should be carefully considered:

- Hydrogen production located on brownfield sites close to existing industrial facilities will benefit from multiple cost-saving opportunities. Particularly beneficial if a site is already COMAH designated.
- Blue hydrogen production requires vast quantities of highly purified process water. Such facilities could be positioned within industrial clusters where an existing plant can provide the volume of water required at the desired quality. Otherwise, seawater access should be considered and the cost of installing the required infrastructure to supply and desalinate seawater.
- By co-locating hydrogen production with one or multiple industrial users, hydrogen can be consumed on-site which will reduce the need for additional hydrogen export infrastructure. By removing the requirement for a new hydrogen network or retrofitting natural gas pipelines, the capital costs can be lowered.
- For sites identified to support combined blue and green hydrogen production, major cost and footprint savings can be unlocked by using oxygen produced thorough water electrolysis as the oxygen feedstock for autothermal reforming. The high-power ASU required to extract pure oxygen from the air for traditional ATRs has a large associated CAPEX and OPEX which could be avoided.

2.3 Green Hydrogen Production Technology

2.3.1 Introduction

Electrolysis offers a promising option for large-scale hydrogen production from renewable sources. The principle of water electrolysis is defined as the process of using electricity to split water into hydrogen and oxygen. Currently, low-temperature electrolysis options include alkaline, proton exchange membrane (PEM) and the early-stage anion exchange membrane (AEM) electrolysis. The most notable high-temperature electrolysis technology is solid oxide electrolysis (SOE). AEM and SOE have high potential but are still at an advanced R&D stage and very few companies offer them at a commercial scale.

All water electrolysers can be broken down into three main components:

- **The cell** is the core of the electrolyser and is where the electrochemical process takes place. It consists of two electrodes, an anode, and a cathode, separated by a liquid electrolyte or a solid electrolyte membrane, porous layers to facilitate the transport of reactants and removal of products, and bipolar plates that offer mechanical support as well as distribute the flow.
- **The stack** includes multiple cells connected in series. It also contains spacers to insulate between electrodes, frames for mechanical support, seals, and end plates to avoid leakage.
- **The system**, also called the Balance of Plant (BoP), considers components required for preparation and treatment of reactants and products. The system includes water supply treatment, cooling, purification and compression of hydrogen and oxygen products. The overall system efficiency of a green hydrogen production facility is attributed to the individual efficiencies of the cell, stack BoP.

2.3.2 Alkaline Electrolyser

Alkaline electrolysers (AE) were the first electrolysis technology to be developed and deployed commercially. They are relatively easy to manufacture and offer the most reliable and robust electrolysis method, with proven operational lifetimes exceeding 30 years.

Alkaline electrolysers have the simplest stack and system design. Within the cell, electrode areas are manufactured up to 3 m^2. They operate using a highly concentrated potassium hydroxide (KOH) liquid electrolyte, diaphragms made of robust ZrO2 and nickel-coated stainless steel at the electrodes. Alkaline electrolysers operate by generating hydrogen at the cathode by removal of a hydroxide ion (OH), which transports through the liquid electrolyte to the anode, as shown below.

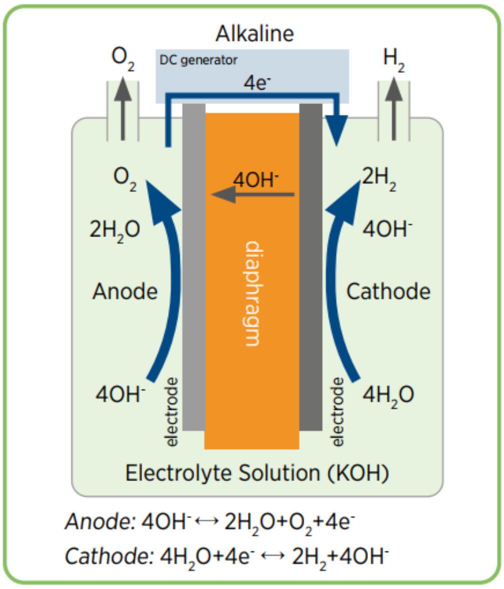
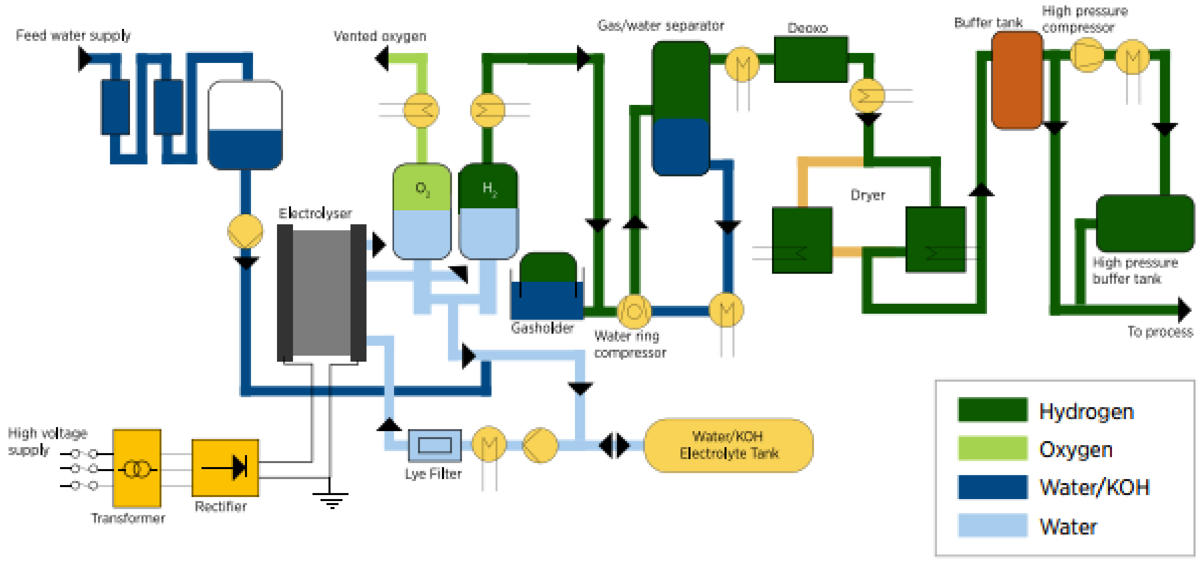


Figure 12 - Alkaline electrolysis [28]

Atmospheric AE, where the system operates and produces hydrogen at atmospheric conditions, is the most common form. There are also pressurised systems with a hydrogen output pressure of up to 200 bar. Many applications need pressurised hydrogen, and the higher output pressure saves costs and energy over using compressors. Pressurised AE is also better equipped to respond to changes in power input (e.g., from renewable energy). However, these benefits come at the price of slightly lower efficiency and more challenging design and maintenance.

In terms of benefits over other electrolysis technologies, alkaline delivers better system robustness due to its exchangeable electrolyte and produces high gas purity because of the lower gas diffusivity of its alkaline electrolyte and cheaper catalysts. Despite its benefits, KOH must be recirculated around the stack components and separated from the gases produced upon leaving the stack, which negatively affects the stack efficiency. Additionally, the liquid electrolyte also increases the likelihood for leakage and maintenance requirements, therefore newer approaches utilising a solid alkaline exchange membrane are being researched.

To prevent the intermixing of produced gases dissolved in the electrolyte, alkaline is restricted to a higher power-operating range and lower pressure levels. Additionally, alkaline electrolysers require balanced charges between the anode and cathode which pose a challenge to operate at differential pressures. As a result, their efficiency is typically lower in comparison to PEM technology.



Note: This configuration is for a generic system and might not be representative of all existing manufacturers.

Based on IRENA analysis.

Figure 13 – Typical system design and balance of plant for an alkaline electrolyser [28]

Table 4 – Alkaline electrolyser – techno-economics [28]

Design parameter	Value
Operating temperature (°C)	70 – 90
Operating pressure (bar)	1 – 30
Cell area (m^2)	1 – 3
Current density (A/cm^2)	0.2 – 0.8
Hydrogen purity (%)	> 99.5
System efficiency (kWh/kg_{H2})	50 – 78
System efficiency (%)	50 – 68
Plant size (MW)	10
Lifetime (hours)	60,000
System CAPEX ($£/kW_{el}$)	360 – 1,000 [8]

Technology Development Status – Alkaline electrolysis is at **TRL 9**, thanks to the technology having been proven in operational environments. Despite its high TRL, technological advancements in membrane and system designs can still help to overcome drawbacks associated with typical properties of alkaline systems such as low current densities (0.2 – 0.7A/m^2) and slow start-up times [29] [30]. Research enabling higher current densities was identified as the stand-out R&D challenge for alkaline electrolysers [30]. Advancements in the current density would improve the flexibility of load-following operation, allowing the electrolyser to change its power-level in response to a variable power input which is key when powered by renewable energy sources. Additional advances in membrane materials are also essential to all methods of electrolysis, which would improve the purity of hydrogen output, reduce costs, and improve operational lifetimes.

Scalability – The world's largest single-stack water electrolyser technology is AE. A 10MW unit was installed in March 2020 in Fukushima, Japan and can produce 1,200 Nm^3/h of hydrogen [31]. By combining multiple smaller stacks, some companies have been able to offer hydrogen production capacities up to 20MW without any negative effects on the system efficiency or electrolyser response capability [28]. Larger scales (100's MW) are achievable by combining more stacks, however, have not been achieved in practice.

Cost – The installed CAPEX is expected to reduce from £360 – £1000/kW$_{el}$ to £288 – £612/kW$_{el}$ in 2030 [8], with a further reduction to £144 – 500/kW$_{el}$ by 2050 [8]. Alkaline electrolysers have been deemed the most dominant and suitable electrolyser technology in 2020 given current production levels, however, PEM and SOE technologies will likely become more favourable beyond 2030 with production scale-up. The learning rate for alkaline electrolysers between 2020 to 2030 is estimated at 9%, lower than 13% and 18% for PEM and SOE, respectively [28].

2.3.3 Proton Exchange Membrane

PEM electrolysers, along with SOE and AE, separate the electrodes with an electron-insulating solid electrolyte. More specifically to PEM, the electrolyte is a solid polymer material, that is responsible for the transport of ions between electrodes and acts as a physical barrier separating hydrogen and oxygen gases. In a PEM electrolyser, water reacts at the anode forming oxygen and positive hydrogen ions, the protons then selectively travel through the PEM and react to produce hydrogen at the cathode, as shown in Figure 14. PEM electrolysers have been increasingly utilised in the production of hydrogen, with recent projects and advancements providing confidence in the technology's potential and readiness.

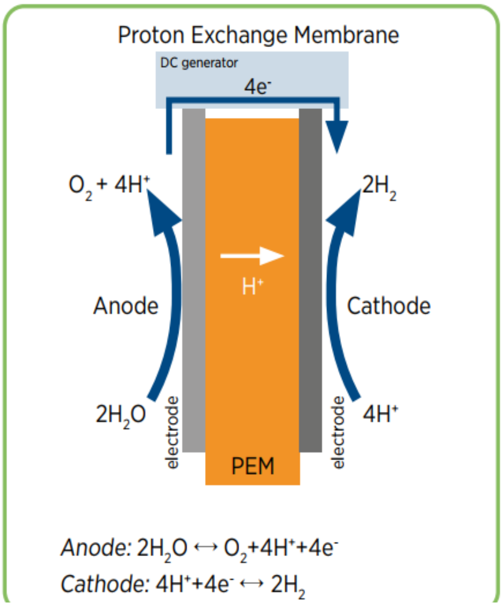
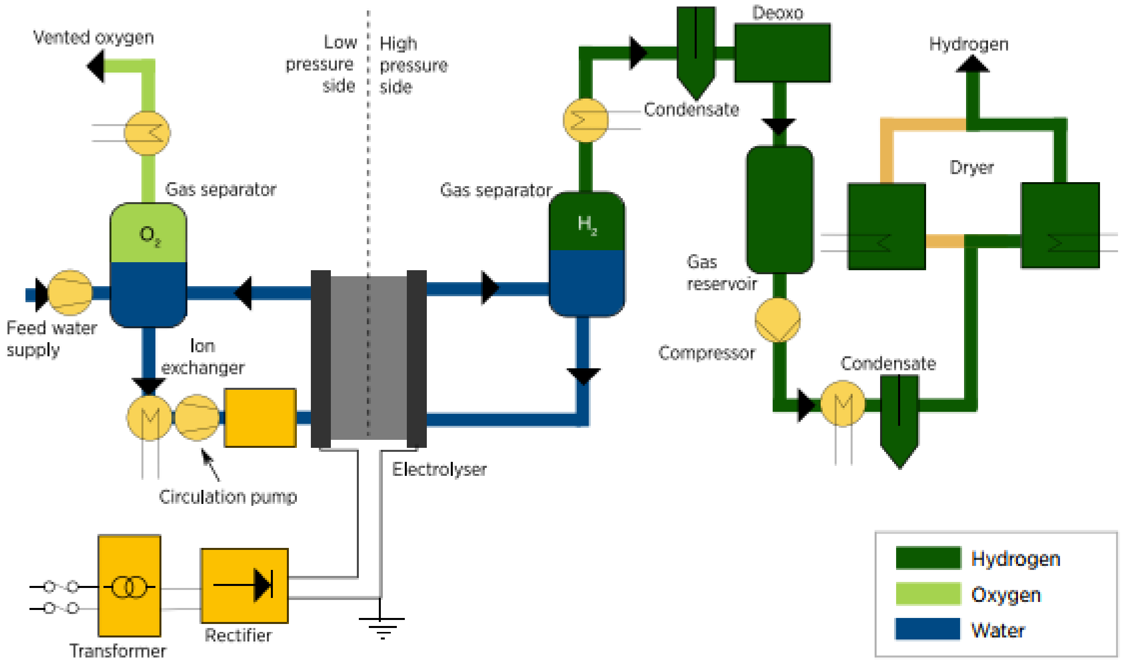


Figure 14 - Proton exchange membrane electrolysis [28]

PEM is characterised by its solid electrolyte (the membrane) and quick response times and is usually pressurised. While still less developed, the technology has made large steps and is reaching maturity. The costs are roughly 30% higher than AE but efficiency is on par. The stack lifetime is also expected to reach similar levels as AE (70,000-80,000 hours) and is close to achieving this with systems approaching 60,000 hours.

PEM electrolysers have one of the most compact and simplest system designs, yet they are sensitive to water impurities (iron, copper, chromium, and sodium) and can suffer from calcination. Electrode areas are quickly approaching 2,000 cm², yet this is still far from future concepts of large MW stack units using single stack concepts. The reliability and lifetime characteristics of large-scale, MW PEM stacks are yet to be validated.

PEM systems typically require pressure control, heat exchangers and circulation pumps, at the same time they have more design choices such as atmospheric, differential, and balanced pressure. The PEM membrane electrolyte allows for operation under differential pressure, typically 30 bar to 70 bar. This requires a thicker membrane to improve the mechanical stability and decreases gas permeation, which reduces efficiency. It could also require an additional catalyst to re-convert any hydrogen, which, due to higher pressures, would permeate more back to water [28].



Note: This configuration is for a generic system and might not be representative of all existing manufacturers.

Based on IRENA analysis.

Figure 15 - Typical system design and balance of plant for a PEM electrolyser [28]

Table 5 – Proton exchange membrane – techno-economics [28]

Design parameter	Value
Operating temperature (°C)	50 – 80
Operating pressure (bar)	< 70
Cell area (m^2)	0.15
Current density (A/cm^2)	1 – 2
Hydrogen purity (%)	99.99
System efficiency (kWh/kg_{H2})	50 – 83
System efficiency (%)	50 – 68

Plant size (MW)	5
Lifetime (hours)	50,000 – 80,000
System CAPEX (£/kW$_{el}$)	800 - 1300 [8]

Technology Development Status – PEM electrolysis has been commercially available for around 10 years; however, the technology is not yet at full industrial scale, therefore, **TRL 8** [32].

Some of the innovation areas being actively pursued in PEM technology include anode degradation, water purification, component integration and improvements in catalyst design, coating, and membrane materials, each with varying TRL's. Two stand-out challenges have been identified to advance PEM technology to its commercial potential, both with time-to-market of two years [6]:

- Research into developing anodes with a slower degradation will allow the system to withstand higher current densities and fluctuations further reducing response times.
- Developing stable catalyst supports will ensure better stability in fluctuating conditions, particularly important in renewable energy applications.

Bolstered by its superior characteristic for intermittent operation, this suggests that PEM is set to overtake alkaline as the most suitable technology by 2030 and beyond, supported by innovation, increased manufacturing capacity and operating experience.

Scalability – PEM systems currently are deployed on a small-scale, however there are projects in development which utilize advanced PEM technology for commercial green hydrogen production. The Refhyne project in Germany, once completed, will operate the world's largest PEM electrolyser at a capacity of 10 MW [12]. For the Gigastack project, ITM is designing a 5 MW PEM electrolyser which is to be utilised as part of a 20 MW stack, scaling up to 100 MW in total, with the total daily output from the PEM site being 2,100kg/day of hydrogen.

Cost- Currently, the installed CAPEX for PEM is £800 – £1,300/kWel. The installed CAPEX is estimated to reduce to £470–£1,100/kWel by 2030 and between £144 - 650/kWel by 2050 [25]. A learning rate of 13 % is widely recognised as a reasonable estimate.

2.3.4 Solid Oxide Electrolyser

Solid Oxide Electrolyser technology is mainly recognised for high operating temperatures (700-900°C), high efficiencies, and the use of steam instead of liquid water. The technology is not yet fully commercialised and lags AE and PEM in terms of scale and maturity.

SOE uses a solid ion conducting ceramic as the electrolyte giving robustness at high operating temperatures. Steam reacts with the negatively charged electrons at the cathode to generate hydrogen and negatively charged oxygen ions, which migrate across the ceramic electrolyte. On contact with the anode, the oxygen ions deposit electrons forming gas, and the electrons are routed along from the anode back to the power source. The silica oxide electrolyte can use materials such as yttria stabilised zirconia, an inexpensive ceramic.

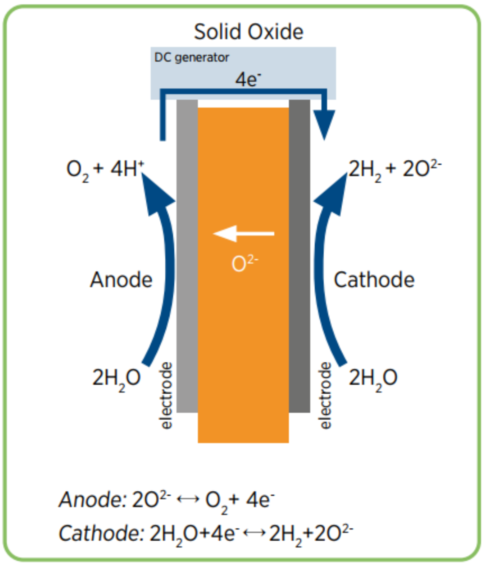
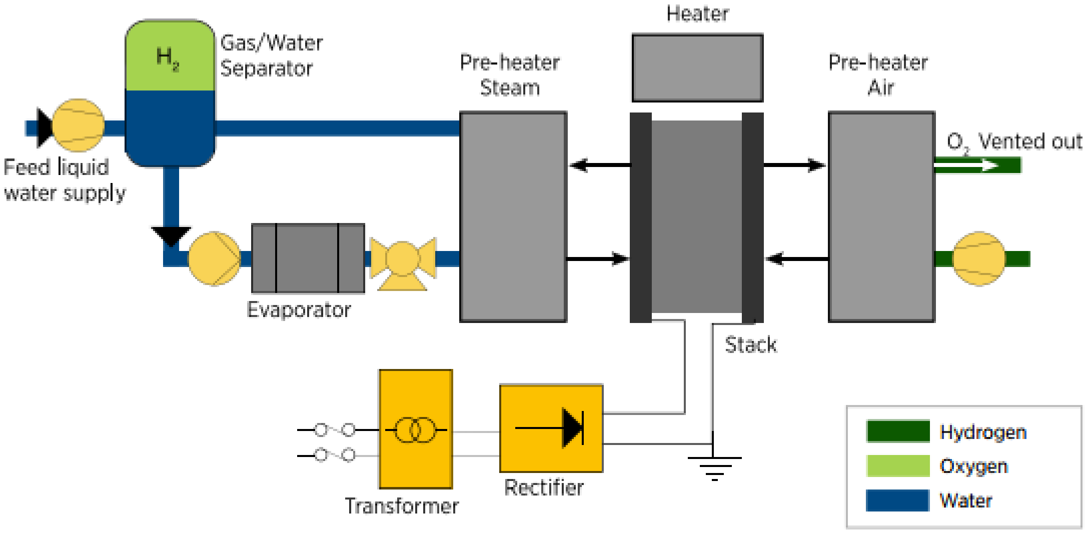


Figure 16 - Solid oxide electrolyser [28]

Thermo-chemical cycling, especially under shutdown/ramping periods, leads to faster degradation and shorter lifetimes, meaning that SOEs are less suited to intermittent power sources. Other issues related to stack degradation include challenges related to sealing at higher differential pressure, electrode contamination by silica used as sealants, and other additional contaminant sources from piping, interconnects, and sealing.

SOE can be coupled with heat-producing technologies for a higher system efficiency as the electrolysis of water is increasingly endothermic with increasing temperature. Therefore, energy demand is rapidly reduced due to the Joule heating of the cell, and then utilised in the water splitting reaction at high temperatures. When the cell runs endothermically, heat for water vaporisation can be supplied from other sources, such as waste-heat from industry or concentrated solar power plants. One important and fully renewable option is coupling SOEs with concentrated solar power, which could supply both electricity and the heat to the SOE electrolyser. A typical system configuration for SOE is shown below.



Note: This configuration is for a generic system and might not be representative of all existing manufacturers.

Based on IRENA analysis.

Figure 17 - Solid Oxid Electrolyser process overview [28]

Table 6 – Solid Oxide Electrolyser – techno-economics [28]

Design parameter	Value
Operating temperature (°C)	700 – 850
Operating pressure (bar)	1
Cell area (m^2)	0.02
Current density (A/cm^2)	0.3 – 1
Hydrogen purity (%)	99.9
System efficiency (kWh/kg_{H2})	45 – 55
System efficiency (%)	75 – 85
Plant size (MW)	1
Lifetime (hours)	< 20,000
System CAPEX ($£/kW_{el}$)	2,000– 4,000 [8]

Technology Development Status – SOE electrolysers are currently **TRL 5** having been successfully demonstrated at lab-scale. The biggest challenges are to exploit the high efficiencies yielded from SOEs and integrating with i) low carbon heat and ii) intermittent power sources. It is estimated that TRL 9 will be reached by 2030.

SOE's have so far only been demonstrated in the kW range, although there are a few projects in the pipeline in the MW range – the largest being Multhiphly at 2.6 MW (2024, Netherlands) [6].

Costs – Understanding SOE costs is more challenging as there are only a few companies responsible for their commercialisation. However, it is reported that CAPEX is greater than £2000/kW$_{el}$ in 2020 with costs expected to reduce to approximately between £580-£2000 kWel by 2030, and £360 - £720/kW$_{el}$ by 2050 [8].

2.3.5 Electrolyser Cost Comparison

The largest single cost component of green hydrogen is the cost of the renewable electricity needed to power the electrolyser unit. Production of green hydrogen is typically therefore more expensive than blue hydrogen, regardless of the cost of the electrolyser. A low cost of electricity is necessary to produce green hydrogen competitively.

Low electricity cost is not enough by itself for competitive green hydrogen production, reductions in the cost of electrolysis technology is also needed. Increasing module and stack size and manufacturing scale have significant impacts on cost; increasing a plant's production capacity from 1 MW to 20 MW could reduce costs by over a third. Each technology has its own stack design, which also varies between manufacturers. The optimal system design also depends on the application that drives system performance in aspects such as efficiency and flexibility.

Table 7 – Electrolyser cost comparison

Technology	Cost	2020	2030	2050	References
AE	**CAPEX (£/kW$_{el}$)**	360-1000	288-612	144-500	[8]
	LCOH £/kg-H2	4.90	2.60	1.59	[30]
PEM	**CAPEX (£/kW$_{el}$)**	800-1300	470-1100	144-650	[8]
	LCOH £/kg-H2	5.24	2.21	1.65	[30]
SOE	**CAPEX (£/kW$_{el}$)**	2000 - 4000	580-2000	360-720	[8]
	LCOH £/kg-H2	6.91	3.45	1.81	[30]

Note: LCOH has not been derived from the same CAPEX assumptions but has been calculated by [30] based on bottom fixed wind providing power to an onshore electrolyser system.

2.3.6 Electrolyser Cost Reduction Opportunities

Figure 18 demonstrates how a combination of various cost reductions and technology improvements could reduce the LCOH of green hydrogen to below that of blue. The three main technology-based factors influencing the LCOH of green hydrogen production, and therefore areas for cost reductions are:

- The cost of renewable electricity.
- The cost of electrolyser technology.
- The utilisation of electrolyser technology.

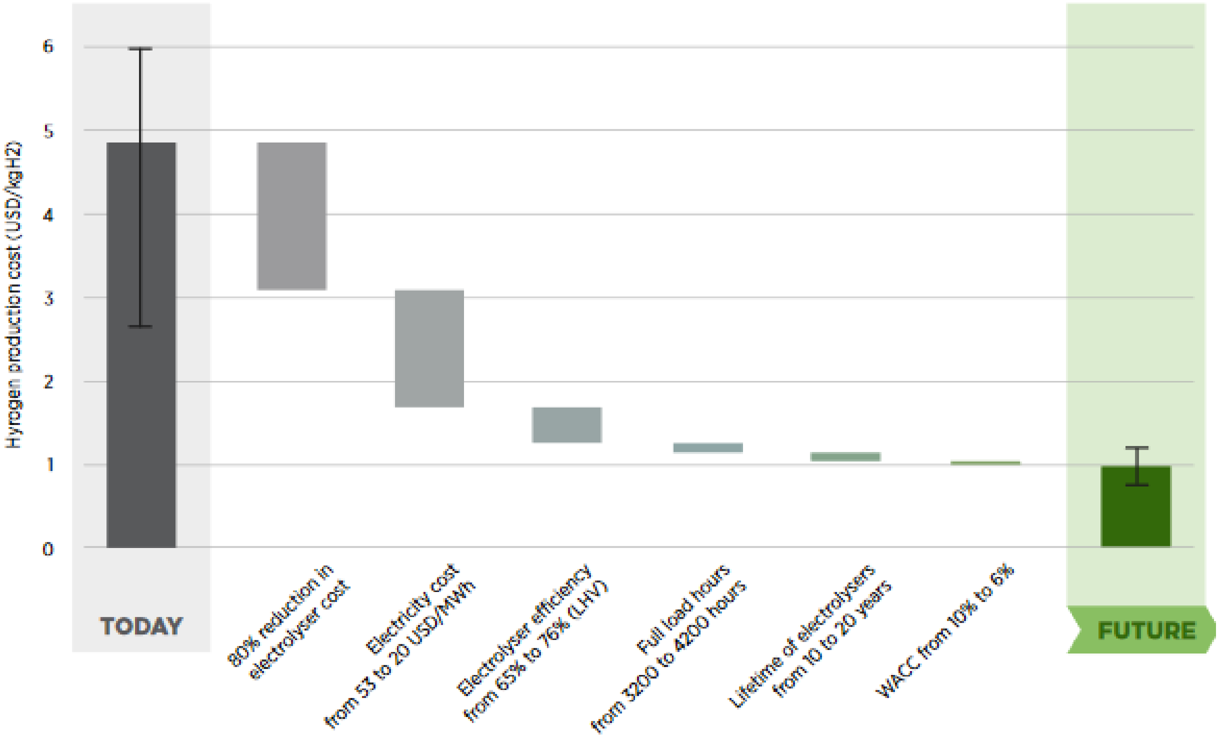


Figure 18 - Green hydrogen cost reduction methods [28]

Lowering the cost of electricity from renewables will contribute the biggest share of reduction in hydrogen production cost. In the offshore wind example, a 40% cost decline from approximately £50 to £28 per MWh could occur by 2030, accounting for costs lowering by around £0.9/kg-H_2. This is largely due to increases in offshore wind capacity factors with installation of larger turbines in regions with higher wind speeds. The five-year rolling average capacity factor for offshore UK wind power between 2015 – 2019 was 39% [33], whilst today's offshore new-build wind turbines average a capacity factor of 58 % [34]. Offshore Renewable Energy Catapult estimates that offshore wind wholesale electricity prices could drop below grid connected electricity by as early as 2024 [30].

With increasing technology maturity and production scale-up, the CAPEX requirements for both the electrolyser system and BoP are expected to decline significantly by 2030 and beyond into 2050. For alkaline, PEM and SOE electrolysers up to 2030, the learning rates are 9%, 13% and 18%, respectively.

At the electrolyser stack level, the two main opportunities for cost reduction are improvements to stack design and cell composition and increasing the module size [28]. Figure 19 to Figure 21 show the reduction in CAPEX for alkaline, PEM and SOE electrolyser systems up to 2050 with the cumulative deployment of all electrolyser technologies in the UK. The figures show the cost contribution of system costs (BoP, power electronics and gas conditioning) as well as individual elements specific to each type of electrolyser stack. Significant increases in unit scale deployment (e.g., 5MW to 10MW) and changes in market share between competing technologies are shown as jumps in the cost data.

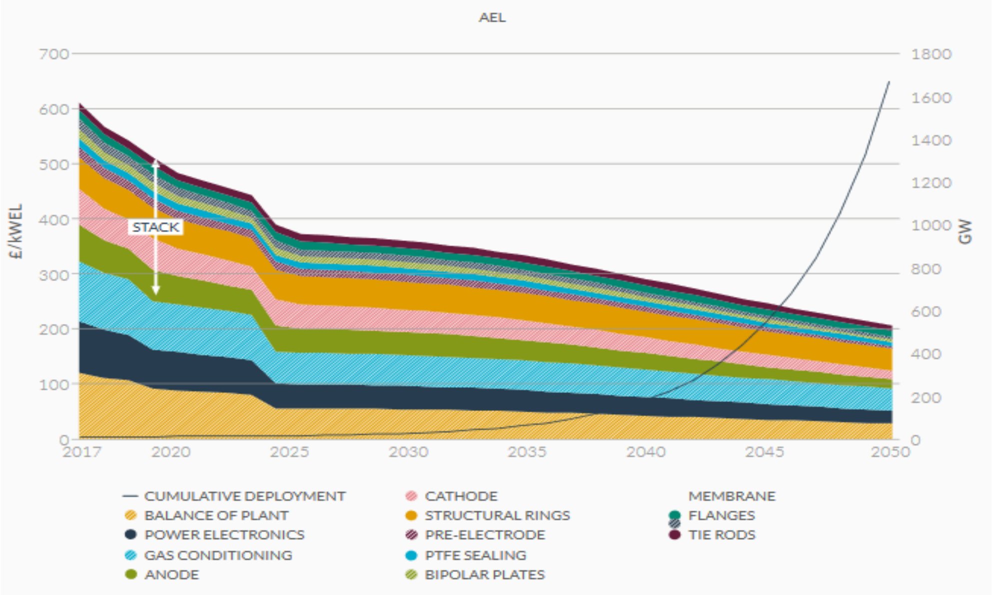


Figure 19 - CAPEX reduction breakdown for AE up to 2050 [30]

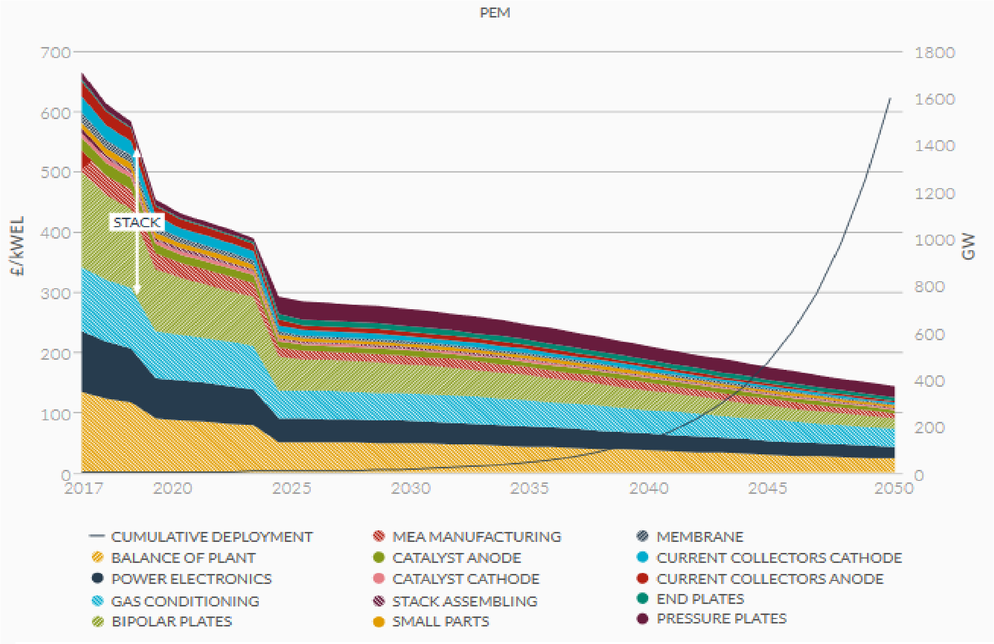


Figure 20 - CAPEX reduction breakdown for PEM electrolysers up to 2050 [30]

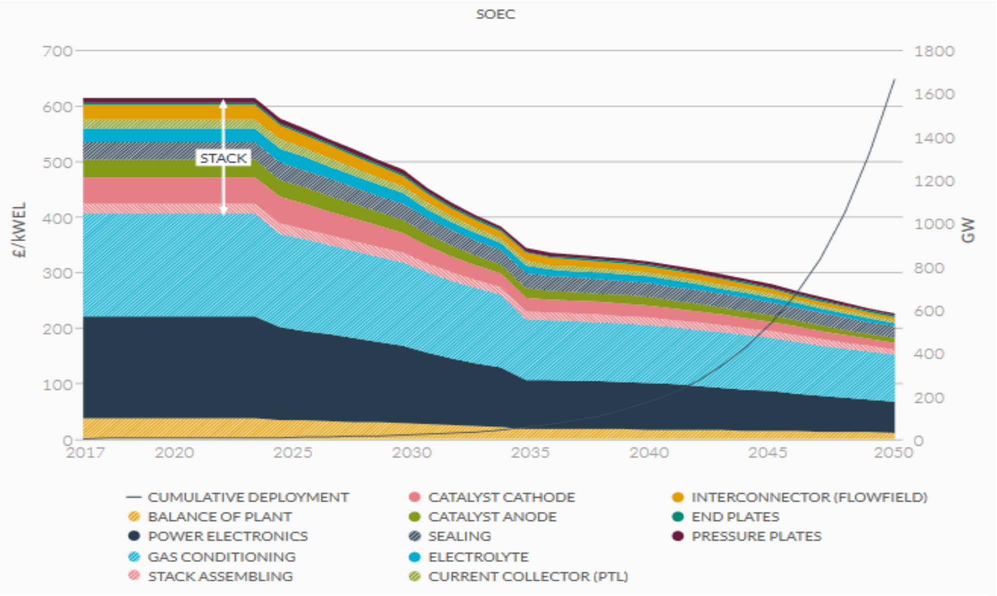


Figure 21 - CAPEX reduction breakdown for SOE up to 2050 [30]

Of the total potential LCOH reduction for all electrolyser technologies between 2020 and 2050, 75% is expected to be achieved by 2030. This major cost reduction is driven by rapid cost reductions of LCOE followed by a reduction in CAPEX with increasing unit scale, with the remaining cost reductions between 2030 - 2050 [30]. Alkaline electrolysers are currently the preferable technology for grid connected systems, given their maturity, scale and CAPEX [35]. By the mid-2030s, PEM electrolysers are expected to be cost-competitive with alkaline technologies. By 2030 they will likely be favourable due to benefits of compactness, suitability for renewable electrical input and future innovations to reduce the use of advanced electrode materials. This theory is supported by the trend of cumulative PEM installed capacity increasing at a greater rate than alkaline since 2011. SOE technologies are projected to have a higher cost than alkaline or PEM in 2030 but may become favourable by 2050 when co-located with industrial processes large quantities of high waste heat.

2.3.7 Biomass Gasification

Thermochemical production of hydrogen from biomass is more similar in process to reforming of natural gas in SMR, ATR and POx than other green hydrogen production method. However, when biomass is used in this process, biomass gasification can be classified as renewable hydrogen because of the renewable nature of biomass.

Gasification converts a carbonaceous solid fuel into a product gas (syngas), in the presence of a gasification agent. Adding steam as a gasification agent is common practice, not only due to the stochiometric effect, but for enhanced char gasification and temperature moderation [36]. Heat can be added externally (allothermal) or generated internally by the full combustion of some fuel. Reactor design and gasification agents vary, as does reactor type – fixed bed, fluidised bed, or entrained flow.

The technology is used globally with around 686 gasifiers in operation to produce liquid chemicals and fuels, gaseous fuels (SNG) and syngas for power generation – from a variety of different (mainly fossil) fuels [37]. However, the commercial deployment of biomass and waste gasification plants has been mostly limited to CHP applications. There are thousands of small to medium scale biomass and waste gasifiers around the world, with capacities 0.02-20 MW_{th} supplying CHP systems, district heating, power generation and incinerators. Tens of larger scale fixed and fluidised bed (10-140 MW_{th}) systems exist, using various biomass and waste sources to produce low calorific value (LCV) product gas to fuel cement kilns and co-fire with coal in power plants [37].

Further application of biomass gasification technology, and integration of syngas with more advanced processing has so far been impeded by competition from low-cost fossil fuels and policy uncertainty. For example, the development of advanced biofuels from biomass has been hampered at prototype stage due to unfavourable economics and lack of market support [37]. Several other projects have reached advanced development stages but have failed to complete development, all hindered by economics, but also a range of technical problems.

There are very limited literature resources available analysing biomass-gasification-based hydrogen production. The IEA have published the most advanced analysis of two different processes for generating hydrogen from biomass. The highest TRL technology will be focused on here [38].

Hydrogen Production Based on Dual Fluidised Bed Gasification Process

The most advanced biomass gasification system is the dual fluidised bed (DFB) system, developed by TU Wein in Austria. The system has been in operation for almost 20 years and has formed the basis of many commercial CHP plants.

In the DFB technology, gasification with steam occurs without oxygen and separate to the combustion reaction which provides the required heat for endothermic gasification. The reactor fluidised bed is bubbled with steam, which acts as the gasification agent. Char is transported with bed material to the combustion reactor which is burned to produce heat. Circulation of bed material transports heat from the combustion to gasification reactor. A near nitrogen-free wood gas is produced.

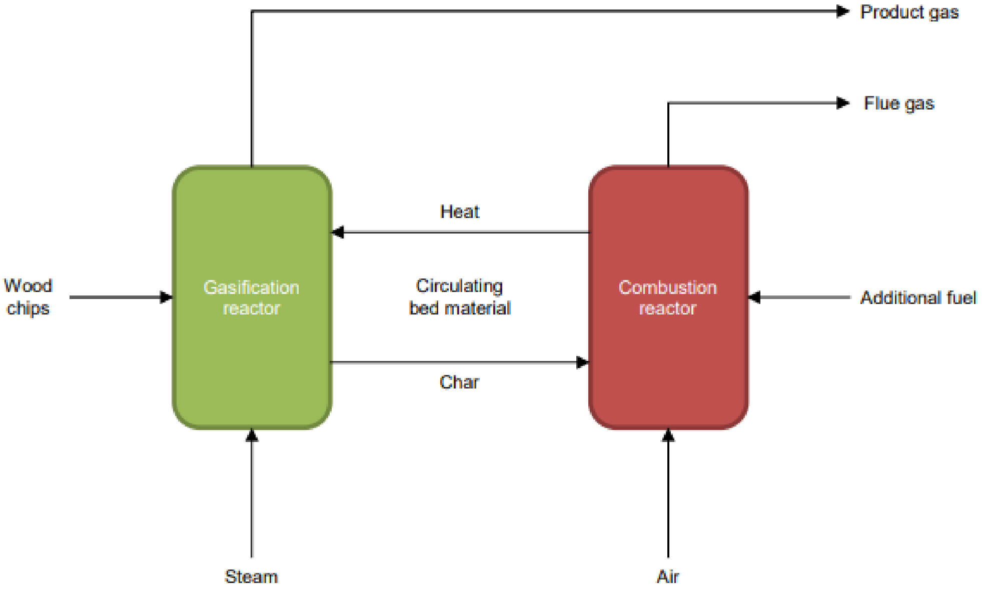


Figure 22 – Simplified process flow of DFB process [38]

At industrial scale, olivine is used as bed material and has two primary roles – carrying heat as described whilst acting as a catalyst in the gasification reactor. Using olivine, commercial plants with woody biomass feedstock achieve volumetric H_2 content of approximately 40%. H_2:CO ranges between 1.5-2:1 which is ideal for synthesis reactions such as methanol or Fischer-Tropsch synthesis. This DFB process can be integrated with further processes to produce pure hydrogen and has been analysed as a process chain by the IEA. Biomass to hydrogen efficiency is 68.9% [38].

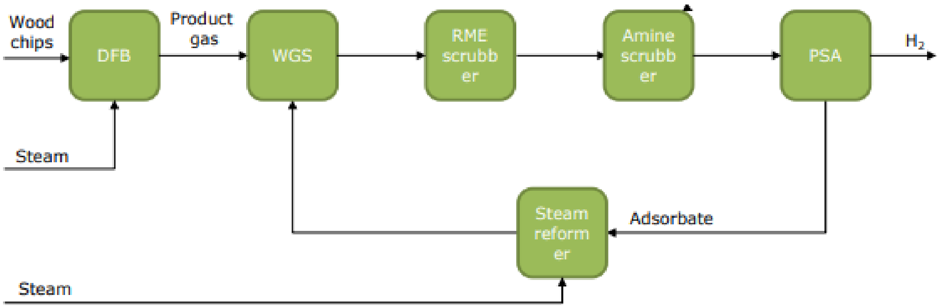


Figure 23 – Simplified flow diagram of DFB based hydrogen production [38]

After cooling and filtration, product gas H_2 content is increased in a WGS unit. Tar is then separated in an RME scrubber, and the steam condensed. An amine scrubber separates CO_2 which could then be utilised (not considered here). The gas stream is compressed to 10 bar and the PSA unit separates remaining gas components, resulting in a high purity H_2 output. Adsorbate is recycled into the WGS unit and used to fire the steam reformer.

Advantages – The carbon neutrality of biomass is the greatest advantage of this technology and the potential for negative emissions. Hydrogen can be produced in a near carbon neutral way without having to transport and store (or utilise) the waste CO_2 stream. If the CO_2 waste stream can be permanently stored, then then carbon negative hydrogen can be produced. Having said this, carbon intensity of all other elements in the system must be analysed, particularly any additional sources of energy required in the process. Inclusion of a PSA unit results in very high hydrogen content as per a methane reforming process (>99%).

Challenges – As with other biomass fuelled technologies, further development and commercial deployment of this technology will be hindered without subsidies. One of the greatest technical challenges lies the clean-up of contaminants in the RME Scrubber. When biomass is gasified, product gas contains fine particles of wettable dust (ash, unburned residues, and soot), tar and water vapour. As the tar condenses, it creates an adhesive coating on cool surfaces. Mixed with dust, this is very difficult to remove. This is less of a concern when syngas is combusted in a CHP system but is of greater importance for further processing into high purity hydrogen. Although individual process elements are relatively well developed, significant work is required to develop the full process chain and test at scale.

More generally relating to use of biomass, is the challenge around the availability of sustainable biomass material, without displacement of land and nutrients currently used for growing food, feed, and fibres. Globally, the estimated sustainable bioenergy potential is about half of the technical potential. Bioenergy provides approximately 9 % of global primary energy demand, and although it is well recognised that the technical and sustainable potential energy demands from biomass could increase, this needs to be done in parallel with the increase in supply to avoid disrupting other finely balanced industries who rely on the same biomaterials [39].

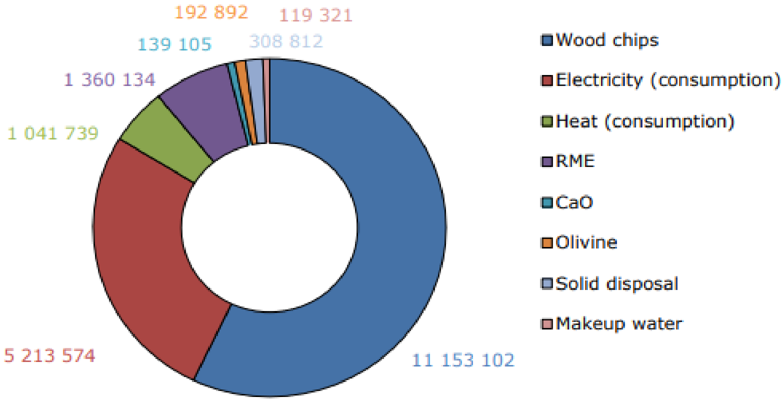


Figure 24 - Distribution of annual costs for a 50 MW DFB plant (EUR) [38]

Costs – A techno-economic assessment by the IEA estimates a hydrogen cost of £2.30/kg, based on a 50 MW H_2 output system with CAPEX of £55M, and an annual OPEX of £20M [38]. Similar to hydrogen production through natural gas reforming, it is evident that biomass feedstock (wood chips) is by far the greatest contributor to costs, so hydrogen cost and OPEX will vary hugely based on the price of biomass.

Technology Development Status – Because a system does not currently exist for producing high purity hydrogen from biomass, the TRL of process components must be analysed, alongside consideration of their integration. Of the components detailed in Figure 23, all can be considered TRL 9, apart from the RME Scrubber – TRL-8. The DFB process has been operated commercially and [38] claim in 2018 a TRL of 8 based on a limited number of operating hours. This 15 MW system is still in operation, so can likely considered TRL 9 today. Although the supporting processes have been simulated in an operational environment and proven at laboratory scale, the full process chain has not yet been tested near the final desired scale. Hence, overall system estimated **TRL – 5**.

2.3.8 Membrane-free Electrolysers

A promising alternative to other hydrogen production technologies is to bypass the requirement of a membrane or diaphragm positioned between the O_2 and H_2 evolving electrodes. Membrane-free electrolysers, when compared with conventional electrolysers containing solid membranes, are less complex, cheaper to assemble, and manufacturers claim they are more robust with an increased lifetime and durability [40].

Membrane-less electrolysers can be classed as ‘passive’, where buoyancy can separate the gas, or ‘active’, where electrolyte flow separates the gas. The geometry of an active membrane-free electrolyser can be based on the configuration of the electrodes, shown below in Figure 25 and Figure 26.

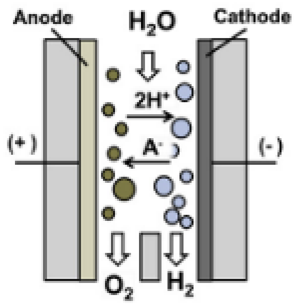


Figure 26 - Type I flow-by electrodes [41]

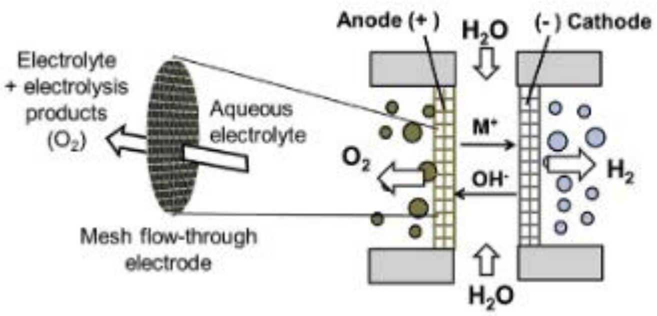


Figure 25 - Type II flow-through electrodes [41]

In both configurations, the electrodes are separated in parallel with the flowing liquid electrolyte in the space between them. In the type I configuration the H_2 and O_2 products are separated downstream as the aqueous electrolyte passes the anode and cathode. In the type II configuration, the anode and cathode are of a mesh type so that the flowing aqueous electrolyte passes through the electrodes from a pressurised outer chamber. The H_2 and O_2 separation occurs due to the divergence of the flowing electrolyte between the parallel electrodes.

Active membrane-free electrolysers have been shown to allow greater operating currents when compared with conventional H_2 production technologies leading to greater hydrogen purity, production density, and energy efficiency. Work by Gillespie et al presents the use of a type II flow through electrode configuration. With the use of pure nickel electrodes, current densities of 101.19 mA/cm^2 were achieved at an operating voltage of 1.8V DC, whilst current densities of 326.33 mA/cm^2 were achieved at an operating voltage of 2V DC [42].

Advantages – Several potential advantages include the reduced capital costs due to the lack of a membrane. The requirement for only three primary components (anode, cathode, and device body) drastically reduces device complexity. These features remove the issue of membrane degradation as typically incurred with conventional forms of hydrogen production, leading to a more durable device and a longer operational design life [41].

Another potential advantage with membrane-free electrolysers is their ability to operate with various liquid electrolytes that meet sufficient conductivity levels. Membrane-less electrolysers have been demonstrated with pH-neutral electrolytes as well as acidic and alkaline [43]. This feature is of strong interest within the hydrogen production industry as the safety concerns associated with pH-neutral solutions are lesser than with caustic electrolytes.

Challenges – There are several disadvantages associated with membrane-free electrolysers, one of which is the lower operating voltage efficiency at high operating current densities. This is due to the distance the ions must travel which is typically a lot further than, for example, the thickness of a Nafion membrane in a PEM electrolyser. The longer distance required for transport of the ions, the larger the total ohmic resistance of the solution which subsequently incurs higher solution IR losses [41].

A serious safety concern with membrane-free electrolysers occurs when there is an electrical arc formed between the two electrodes, resulting in sparks if the gap between the electrodes is small and a large voltage is applied across the electrodes. These conditions can be avoided with the inclusion of extra components within the system. Instruments such as sensors, interlocks and fail-safe designs as well as following the correct process safety principles should be utilised to prevent this from happening.

Costs – A techno-economic analysis was carried out by Manzotti et al, which found that predicted LCOHs from type II flow-through membrane-free electrolysers well outperforms conventional electrolysers and is competitive with SMR [44].

Typically, with other forms of electrolyser devices, the costliest components are stack components such as bipolar plates and current collectors, which are not required in the makeup of a membrane-free electrolyser [45]. With fewer working components and less opportunity for materials to degrade over time, device complexity and operational lifetime of membrane-free electrolysers has the potential to be higher than other forms of electrolyser devices. Although in future the capital costs of membrane-less electrolysers may be less, it is worth noting that these costs may be offset by higher costs of balance of system components such as pumps and compressors [41].

Scalability – CPH2 situated in Doncaster is looking to bring its patented hydrogen production technology into the global green hydrogen production market. Their innovative idea stems from using the membrane-free electrolysis technology and coupling with cryogenic separation to reduce stack complexity and costs whilst maintaining efficiencies as seen with other forms of electrolysers. The stated operational life of CPH2's technology is 25 years – much longer than a typical electrolyser's operational life. The design parameters for CPH2's current containerised membrane-free electrolyser (MFE220) can be found in Table 8.

Table 8 - CPH2's MFE220 Design Specification

Design Parameter	Value
Stack efficiency	**73-78 %**
Hydrogen Production	**Up to 451 kg/day**
Oxygen Production	**Up to 3609 kg/day**
Gas purity	**Up to 99.99 %**
Power input	**1000 kW**
Water consumption	**Up to 4060 L/day**
System dimensions	**40 ft container**

CPH2 are currently in the development stages a higher capacity membrane-free electrolyser (MFE440) with a total input power of 2 MW, capable of producing 900 kg-H_2/day. They place a focus on making their technology work as ‘plug and play’ where the user will only be required to provide the suitable foundations for the containerised unit with a supply of both water and electricity. CPH2 plan to build on their current capacity levels with the aim of implementing GW worth of production annually.

Technology Development Status – Membrane-free electrolysers have been well-studied over the years and will likely become a strong competitor with other forms of electrolysers. However, the actual system has not yet been proven through successful operations or full-scale test and demonstration, therefore, **TRL 7**. TRL 9 is expected soon with several planned commercial deployments around the world.

2.4 Low-Carbon Hydrogen Deployment Barriers

Although many of the main blue hydrogen producing technologies are at high TRL, there are currently barriers to the widespread deployment of hydrogen production, storage, transportation, and usage technologies across the value chain. Commercial Readiness Indicators can aid in understanding the barriers to the widespread commercial scaleup.

Analysis below covers the highest TRL hydrogen technologies to give an indication of the main levers that are required to accelerate widescale deployment of low carbon hydrogen technology. Unless progress is made, other technologies that reach TRL 8-9 in the near future will be subject to similar commercial scale-up constraints

Regulatory Environment – A strong consistent regulatory framework defines commercial deployment models for low-carbon hydrogen. Regulations and standards vary between regions and limit the development of a clean hydrogen industry. Without clear regulatory frameworks, commercial projects cannot fully understand their costs and potential revenue, limiting their ability to reach a financial investment decision (FID). Both CCUS and heat policy are therefore barriers to hydrogen deployment.

Policies are required to drive demand by creating an economic value for hydrogen use in new applications. Many technologies are ready to progress beyond commercial trial, but policy support is required to close the price gap. BEIS are in the process of developing a hydrogen business model in 2022, with contracts for low carbon hydrogen production to be issued in 2023.

Gas safety regulations, which define the specification of gas which can be transported in the gas network, limits hydrogen to 0.1% mol. Technical projects are ongoing to prove the safe transportation of hydrogen, but this evidence must be embodied in the regulatory framework. Cross border trade will benefit from common international standards for the safe of transport and storage of large volumes of hydrogen and for tracing the environmental impacts of different hydrogen supplies [8].

Market Opportunities -Although predicted to accelerate at an incredible pace, the current market opportunities for blue or green hydrogen are small, and the future market opportunities not well enough understood to instil widespread investor confidence. At present, significant concessional policy support is required to drive the scale-up of blue hydrogen production required to deliver a net zero energy system. For example, Acorn Hydrogen and CCS projects, HyNet, and H21 are all heavily funded by UK and Scottish governments.

Scaling technology development will help drive market opportunities enabling economies of scale to be realised and 'learning by doing' can help close the profitability gap. Hydrogen clusters and hubs will help drive these synergies between production, transportation and use by connecting industrial users with low-cost hydrogen supplies.

Lack of dedicated infrastructure to support a hydrogen economy needs to be addressed to drive market opportunities. There are only approximately 5,000 km of hydrogen transmission pipelines around the world, compared to more than 3 million km of natural gas pipelines [47]. Establishing international trading routes will further this growth.

Technical Performance – Technical performance data is lacking for multiple commercial projects operating in a range of environments. Most, if not all the blue hydrogen produced today is through CCS retrofit rather than new build facilities which are expected to dominate blue hydrogen production in future. Most performance data is extrapolated from similar applications, rather than multiple commercial data sets.

Essential, and related to these challenges, is the need to drive down the cost of producing hydrogen – to make it a viable alternative to fossil fuels. See Sections 2.2.11 & 2.3.6 for further analysis. R&D funding is required, alongside risk mitigation policies and larger demonstration projects to reduce the cost of capital.

2.5 Hydrogen Storage

As the energy transition accelerates and renewable, intermittent energy sources progressively dominate, it is widely known that more effective methods to store energy to balance supply and demand are required. Hydrogen has crucial role to play and can provide a solution to cost effectively storing energy for long periods of time.

Storing hydrogen is challenging due to being the lightest molecule with very low density. Therefore, for its storage to be economically viable, its density must be increased. There are several methods to do this, all of which require energy input or hydrogen-binding materials. This section analyses the main technologies relevant to the SNZR project.

2.5.1 High Pressure Gaseous Hydrogen

Compressed gaseous hydrogen is currently the mainstream option for large-scale storage. Maximum storage pressures typically range from 100 bar aboveground to 200 bar underground due to its material properties and associated operating costs. Large scale above ground storage of compressed hydrogen has higher investment costs associated with it meaning this method is usually less preferred.

Large scale storage of hydrogen within metal containers is not a common storage method however is common practice for natural gas therefore similar vessels could be applied for the storage of hydrogen. For the storage of large volumes of natural gas, 3 main metallic vessels are currently used: gas holders with pressure just above atmospheric, spherical pressure vessels with maximum storage pressures up to 20 bar and pipe storage that has a maximum storage pressure of ~100bar. Due to higher-pressure storage capability, pipe storage offers the most useful hydrogen storage solution from these options [48].

Retrofitting oil and gas pipelines has already been demonstrated offshore, where the pipeline material and dimensions meet the requirements for safe operation. However, not all pipelines will meet these requirements but could be made compatible for storage with technology such as polymer liners [49]. Today, the current hydrogen network consists of 8” and 12” pipelines made of carbon steel (API 5L or ASTM-specified grades) with design pressures between 40 to 60 bar [50]. The benefits of new hydrogen pipelines include low operational costs and long lifetimes up to 80 years.

Using the pressures and pipe diameter of existing pipe storage of natural gas, approximately 12 t-H_2 could be stored per km of pipeline. A design study [51] estimates that for a 500 t-H_2 underground pipe storage facility with 20” OD, a CAPEX of £377/kg-H_2 stored, and a levelised cost of hydrogen stored (LCOHS) of £1.58/kg-H_2.

High pressure gaseous hydrogen storage is well developed and understood and considered **TRL 9**.

2.5.2 Cryogenic Liquid

Pure hydrogen can be stored and transported as a liquid with higher energy density than hydrogen gas by cooling gaseous hydrogen to its cryogenic state below -253°C (20°C above absolute zero). Hydrogen liquefication is a well-established process, with the largest plant operating at a capacity of 36 tonnes per day of cryogenic hydrogen, and the most modern single unit producing up to 10 t per day [52] [53] [52] [53].

Feasibility is lower than the transport of liquefied natural gas due to the energy-intensive process and requires a combination of stages taking advantage of the Joule-Thomson effect through cooling, compression, and expansion. If the process were designed such that the hydrogen itself would provide this energy, 25 – 35% of the initial quantity of hydrogen would be consumed.

Once liquified hydrogen requires storage in a specialised cryogenic storage vessel called Dewars which are designed to minimise the boil-off rate. Liquified hydrogen is highly flammable and explosive. Dewars provide low surface to volume ratios and are double walled with a vacuum applied between walls to minimise potential heat transfer. Future advancements in larger-scale hydrogen liquefication have potential to reduce the cost of liquification, currently at around £0.8 per kg H_2 [33].

Cryogenic storage of hydrogen is at **TRL 9** with NASA operating the largest storage vessels at 230 t however typical vessels are often more in the region of 6t.

Figure 27 - Liquid hydrogen bulk storage [215] [216]

2.5.3 Geological

Since the 1970s, salt caverns have been used for hydrogen storage in the UK [36]. They allow hydrogen to be stored between 100 and 275 bar, with capacities ranging from 200,000 – 800,000 m^3 [28] [54]. Salt caverns however are not considered further detail within this report due to the lack of availability in Scotland.

A geological storage option which is available in Scotland is depleted oil and gas reservoirs. These are typically larger than salt caverns, with plentiful capacity to store hydrogen around the UK. It is estimated that the seasonal energy storage required in the UK is roughly 25% of the total energy from natural gas for domestic heating [55]. Increased knowledge due to operational experience and geophysical surveys are an advantage of storing gas in depleted fields. Depleted fields however are more permeable than salt caverns and contain contaminants that could compromise the purity of hydrogen stored thus increasing the estimated cost of storage to £1.50 /kg-H_2 (compared with £0.18/ kg-H_2 for salt caverns) [56].

Another underground geological storage option is aquifers, although currently less mature with mixed evidence for their suitability for hydrogen storage. There has been no trial hydrogen storage within aquifers at a commercial scale, and its feasibility is yet to be validated [25].

Geological storage of hydrogen is currently at **TRL 5**. For the TRL to advance, further understanding is required on how hydrogen reacts chemically with the rocks and contaminants in depleted fields along with potential migration and how the hydrogen can be recovered later.

2.5.4 Ammonia

Ammonia has been produced in very large quantities and used as a fertiliser for over 75 years, so has a well-established supply chain including infrastructure, safety regulations and handling practices. More than 90% of the world's ammonia today is produced by the Haber-Bosch process making it the most common and well-established method for ammonia production [57]. Ammonia production is energy intensive and is often coupled with SMR to provide the high temperature and pressure required for the process [58]. If ammonia fuel is the end-product, it could become a major contributor to a carbon-free economy.

A typical storage facility for large-scale ammonia can range from 15,000 to 60,000 tonnes, with individual vessels storing up to 40,000m^3 [59]. Ammonia can be stored in a liquid state at 25°C and 10 bar in low-pressure storage tanks that are manufactured for LPG.

In addition to the cost of hydrogen production, conversion to ammonia and reconversion back to hydrogen costs approximately £0.54/kg-H_2 and 0.26/kg-H_2, respectively [60].

Cracking ammonia to hydrogen, requires energy (heat at above 900°C) and is significantly less efficient than the dehydrogenation of other LOHCs (63% hydrogen recovery, compared to >95% for PDBT or MCH).

Ammonia is highly toxic and corrosive making storage difficult and can also cause severe skin burns and eye damage, is toxic if inhaled, is very toxic to aquatic life and is a flammable gas. Ammonia is more likely to be utilised as a transport method of hydrogen rather than a long-term storage solution.

Ammonia, transport, and storage has a **TRL of 9** as it is widely used across the globe and has an established supply chain.

2.5.5 Methanol

Methanol is another hydrogen-carrier that can be used directly in chemical or transport sectors. Alternatively, it can be re-converted back to hydrogen using a fuel reformer. Methanol is synthesised by steam reforming of hydrogen and carbon dioxide (see Section 4.4.5). Hydrogen is obtained from methanol via mixing with water and superheating. Based on high temperature steam reforming, this has a **TRL of 9**. Low temperature steam reforming processes are currently being developed which would reduce the energy demand but currently has a **TRL of 3**.

Storage, transport, and handling of methanol is well established due to its widespread use as a solvent in products such as paints, varnishes, and anti-freeze. Liquid methanol can be stored at atmospheric conditions in large low-pressure storage tanks, with negligible losses during storage and transport with a storage density (12.1% by mass). Methanol is very flammable, toxic and an irritant. In offshore oil and gas bulk transfer of methanol is becoming increasingly common; Methanex's Millennium Explorer is one example of a carrier which has a total capacity of 120,000 m^3 [40]. The cost of conversion and reconversion of methanol is approximately £0.57/kg-H_2 and £0.34/kg-H_2, respectively [60]. CO_2 released during dehydrogenation also needs to be captured and recycled back into the synthesis plant and adds approximately £0.4/kg-H_2 to the process [57].

2.5.6 Liquid Organic Hydrogen Carriers

Liquid Organic Hydrogen Carriers (LOHCs) present a novel solution for efficient and safe storage and transport of hydrogen. LOHC's are liquids or low-melting solids that can be reversibly hydrogenated and dehydrogenated in the presence of a catalyst. Hydrogen is chemically bonded to an organic molecule through the exothermic process of hydrogenation. This reaction occurs between 100°C–250°C and 1–50 bar. The loaded LOHC is transported to its destination where it is dehydrogenated to release high-purity hydrogen. This process is endothermic so takes place at higher temperatures between 150 – 400°C and low pressures [61].The unloaded LOHC is returned to the original facility.

LOHC's have similar physical properties to oil products so unlike ammonia, is liquid at ambient temperature and can be transported without the need for refrigeration or pressurised vessels. Hence, LOHCs are already compatible with existing pipeline or vessel infrastructure. LOHC's also have a long lifespan and retain their capability to store hydrogen without losses. Additionally, hydrogen released from dehydrogenation is high purity.

As with ammonia and methanol, there are costs associated with the conversion and reconversion processes. As well as hydrogenation and dehydrogenation, there is initial capital investment required for the LOHC chemicals and further transport costs as unloaded LOHC's need to be returned to their original location. The conversion processes are energy-intensive and require the equivalent energy of 35–40 % if hydrogen was used as an energy source [25]. Several LOHC molecules are under consideration with the two most advanced being Methyl Cyclohexane Toluene (MCH-TOL) and Perhydro-dibenzyl toluene – Dibenzyl toluene (PBDT-DBT).

2.5.6.1 Methyl Cyclohexane Toluene (MCH-TOL)

Methyl Cyclohexane (MCH) is a hydrogenated LOHC with Toluene (TOL) being the dehydrogenated LOHC (or base solvent). Toluene is mass produced and available at low prices (~£0.5/kg) and MCH has a hydrogen storage capacity of 6.1% by mass. MCH-TOL is at **TRL 8**.

Advantages of MCH-TOL is that both materials can be stored at ambient temperature and pressure, therefore reducing the energy requirements associated with compression, heating, and cooling. They can be stored in vessels designed for hydrocarbons, meaning that existing equipment can be repurposed. Heat can be recovered from the exothermic hydrogenation process to improve overall efficiency. One disadvantage is that toluene degrades over time therefore will require replenishing and disposing of safely as to not cause environmental damage. Another is that Toluene and MCH are irritants, toxic in high concentrations and flammable, so safe handling requires to be considered.

Conversion cost is estimated at £0.51/kg-H_2, and reconversion at £0.26/kg-H_2.

2.5.6.2 Perhydro-Dibenzyl Toluene – Dibenzyl Toluene (PBDT-DBT)

Perhydro-dibenzyl toluene (PDBT), the hydrogenated form of Dibenzyl toluene (DBT), is already being utilised as an LOHC with a **TRL 9**. DBT is a commercial heat-transfer oil that has been produced at scale since the1960s. DBT is slightly more expensive than toluene (~£4/kg) however, it has advantages over other LOHCs regarding transport, safety, and environmental considerations. PDBT has a slightly higher hydrogen storage capacity than MCH (6.2% by mass).

DBT and PDBT can be stored at ambient temperature and pressure, which reduces the energy requirements associated with compression and heating or cooling. The physical characteristics of DBT and PDBT mean that they can be stored and transported in vessels used for hydrocarbons, so CAPEX and carbon footprint can be reduced by repurposing existing equipment. DBT and PDBT are non-flammable and non-toxic, so no major precautions are required for material handling, although DBT is hazardous to the environment.

An example of this technology in use is StoragePLANT (hydrogenation unit)/ ReleasePLANT (dehydrogenation unit), offered by Hydrogenious LOHC Technologies in Germany. A demonstration project is ongoing in Germany, with hydrogenation capacity of < 400 Nm^3/hr of hydrogen.

Conversion cost is estimated at £0.38/kg-H_2, and reconversion at £0.11/kg-H_2, which represents the lowest conversion/ reconversion costs of the 4 liquid storage transport mediums, however, a higher cost of purchasing DBT means that the overall cost of PBDT-DBT is similar to MCH-TOL.

2.5.7 Metal Organic Frameworks

Hydrogen can be stored as a solid when it is chemically bonded to metal hydrides (Metal Organic Frameworks (MOFs)). As the bonds formed are much stronger than when hydrogen is adsorbed to another compound, hydrogen can be stored at a significantly higher density at atmospheric conditions [65]. There are numerous types of metal hydrides that hydrogen can bond with including elemental metal hydrides, intermetallic hydrides, complex metal hydrides, borohydrides and amides. Sodium borohydride ($NaBH_4$) is presently the most promising metal hydride out of those mentioned, as the others are deemed unacceptable due to poor thermodynamics, kinetics or difficult reaction conditions. However, the process of extracting hydrogen from $NaBH_4$ is not reversible and NaBH4 must be regenerated.

Hydrogen is bound to the metal hydride for its storage. Though, it can also be released from metal hydrides through heating or reacting with water, although this process is highly energy intensive. The released hydrogen must also undergo further processing to increase its purity which requires further energy input.

Currently, the use of MOF's is still being actively researched and there are substantial developments required before MOF's can be implemented in industrial applications. Commercially available systems led by Saes Group are limited in process capacity up to 140 Nm^3/h [66]. As such, the additional costs to convert, store, transport and re-convert MOFs are yet to be determined. Both uses of MOFs as a solid storage option and de-blending from the grid remain at a low **TRL 4–5** [67].

H2GO

H2GO have developed a Plug-and-Play (PnP) battery storage system using industrial sized electrolysers, hydrogen storage vessels and fuel cells. The hydrogen reactor used within the PnP storage module is pending a patent and works by storing hydrogen in solid-state and can dispatch hydrogen on demand. The following figures relate to the hydrogen reactor [63]:

- 1 kg-H_2 stored
- 16kWh of electrical energy per reactor
- Operates between 1-10 bar and below 100°C
- Equivalent to a 400-900 bar cylinder at the same volume but at 1 % of the pressure

H2GO's PnP stationary storage module has been designed within a shipping container unit to be used in temporary or permanent cases worldwide. The PnP storage modules work on the principle of being fed by surplus renewable electricity produced by, for example, wind turbines and converts this into hydrogen. This hydrogen can be stored for long periods with no losses incurred. Power can also be released on demand for high power applications.

H2GO are planning a pilot, consisting of a 1.5 MWh PnP module storing a total of 90 kg hydrogen. This has been funded from the Net Zero Innovation Portfolio Low Carbon Hydrogen Supply 2 Competition held by BEIS. This pilot project follows years of testing on the hydrogen reactor, with only the PnP storage module in development in recent years. The hydrogen reactor is estimated at **TRL 8**, with the PnP storage module estimated at **TRL 7**.

3 Fuel Switching and Electrification

3.1 Introduction

Consumption of fossil fuels currently dominates the fuel demand across industry in Scotland with most sites relying on this fuel to be supplied by the natural gas grid. Based on the need for deep decarbonisation and net zero targets in Scotland by 2045, cleaner alternative sources of energy need to be assessed as replacement to fossil fuels across industry. The most prominent alternative sources of energy are renewable electricity, clean hydrogen, and biomass & waste. For industries whereby fuel switching is not a suitable solution, carbon capture, utilisation and storage can be considered; technologies to support CCS are assessed in Section 4 .

In 2018, Element Energy and Jacobs delivered a comprehensive review of the industrial fuel switching options for industrial processes across the UK [68] [69]. The report categorised 5 'process types' across industry and provided an assessment of hydrogen, electrification, and biomass technologies to replace these existing fossil fuel combustion processes. The report provides a wealth of information around technology development status, commercialisation plans and costs of different technologies in these areas which will be used by the Scotland's Net Zero Roadmap project team.

Instead of repeating work done in the 2018 report, this section of the report focuses on the context of industries present in Scotland, whilst also assessing the technology options into which there has been less research. The scope of analysis in this section has been developed by Net Zero Technology Centre after discussion with SNZR project WP4 partners Doosan Babcock and includes:

- Retrofitting existing fossil fuelled heating processes with hydrogen (rather than full replacement).
- Hydrogen fuelled gas turbines – retrofit and replacement.
- Gas turbines for hydrogen compression.
- Biomass retrofit of Combined Cycle Gas Turbines (CCGTs) in Combined Heat and Power (CHP) systems.
- Bio-Synthetic Natural Gas (BioSNG) production (for consideration as an alternative fuel).
- Electrical infrastructure to support electrification of existing fossil fuelled processes.

3.2 Hydrogen Fuelled Industrial Processes

In many cases, fuel switching a fossil fuelled industrial process to a low carbon alternative is technically achievable and provides an extremely effective means of process decarbonisation if the alternative fuel is produced in the appropriate, low carbon manner. Hydrogen is one such alternative fuel that can deliver deep decarbonisation and can be used in many cases as a replacement to natural gas with minimal capital cost impact on equipment – compared to electrification or retrofitting carbon capture.

This section delivers a techno-economic analysis of the main hydrogen fuelled opportunities across industrial processes, highlighting the technologies that should be considered for decarbonisation today, and those emerging technologies that will likely play a significant role in future.

Retrofitting an existing process or technology is very often a much less expensive option than replacement, so the retrofit of natural gas fuelled processes will be the focus:

- Hydrogen boilers/ indirect heating
- Hydrogen furnaces/ direct heating
- Hydrogen fuelled gas turbines

Firstly, the benefits and challenges of hydrogen as an alternative fuel in industrial processes will be explored – relevant to nearly all hydrogen fuelled industrial applications.

3.2.1 Hydrogen as an Alternative Fuel

Unlike CO_2 capture, using hydrogen as a primary fuel source for combustion has several advantages as a means of decarbonisation:

- Minimal cost impact on combustion equipment (burner replacement often required).
- Zero plot space requirement at the combustion process.
- Capability of mitigating very high levels of CO_2, regardless of scale.
- Suited to dispersed sources without CO_2 transport & storage infrastructure.
- Higher pressures and temperatures can be achieved than electrification.

However, there are still some significant challenges relating to using H_2 as a fuel source, largely relating to differences in combustion properties:

H_2 flame adiabatic temperatures are approximately 200 K more than a methane flame, which impacts materials, emissions, and efficiency.

H_2 has much wider flammability limits, which impacts health and safety because H_2 can be ignited much more easily.

Of particular concern in burners is the relative increase in hydrogen flame speed, meaning that the very reactive H_2 flames are more prone to flashback from the combustion chamber into the mixing zone.

A reduced concentration of radiant species in a H_2 flame results in a lower flame emissivity and reduction in radiative heat transfer.

Although more H_2 is required by volume for the same energy output, approximately 20% less air is required to produce a flame comparable to natural gas, reducing mass flow and heat transfer.

3.2.2 Impact on Hydrogen on Industrial Equipment

There are several key considerations relating to the conversion of hydrogen in all industrial processes which are not designed for burning 100 % hydrogen. This is explored in detail by Element Energy in their 2018 report for BEIS [70],and is summarised here:

NOx Emissions will increase when natural gas is blended or replaced with hydrogen, due to the increased flame temperature. Lean combustion and dilution can both be used to reduced adiabatic flame temperature and NOx emissions. Oxyfuel combustion of hydrogen may be required in some cases to suitably reduce NOx emissions (e.g., glass melting), with significant impact on CAPEX and OPEX [71].

Flame Positioning – A 100 % hydrogen flame is shorter and positioned closer to the burner tip due to higher flame speeds and faster ignition. This can be managed with high proportions of water or steam added to the fuel.

Heat Transfer – Lower heat transfer caused by a lower emissivity and mass flow can be mitigated by adjusting water feed (indirect heating) or recirculating flue gas (direct firing). Further research and demonstration are required to address concerns over product quality produced through processes reliant on radiative heat transfer (e.g., glass furnaces).

Leakage – Due to the particle size of hydrogen, and very low viscosity, higher standards of welds, joints and flanges are required to prevent leaks. Fortunately, high diffusivity of hydrogen means that effective ventilation can quickly dilute leaks in air to below its flammability limit.

Material Embrittlement – Accelerated at elevated temperatures and pressures, hydrogen can be absorbed by some materials, resulting in loss of ductility or embrittlement. Common materials are recommended by engineering standards for hydrogen systems, including carbon steels, austenitic stainless steels, and polyethylene piping.

Flue Gas Composition – For direct fired equipment where combustion gases come into direct contact with product, changes in combustion gas composition can have a significant impact. In glass furnaces or lime kilns, changes in flue gas moisture content needs to be further investigated.

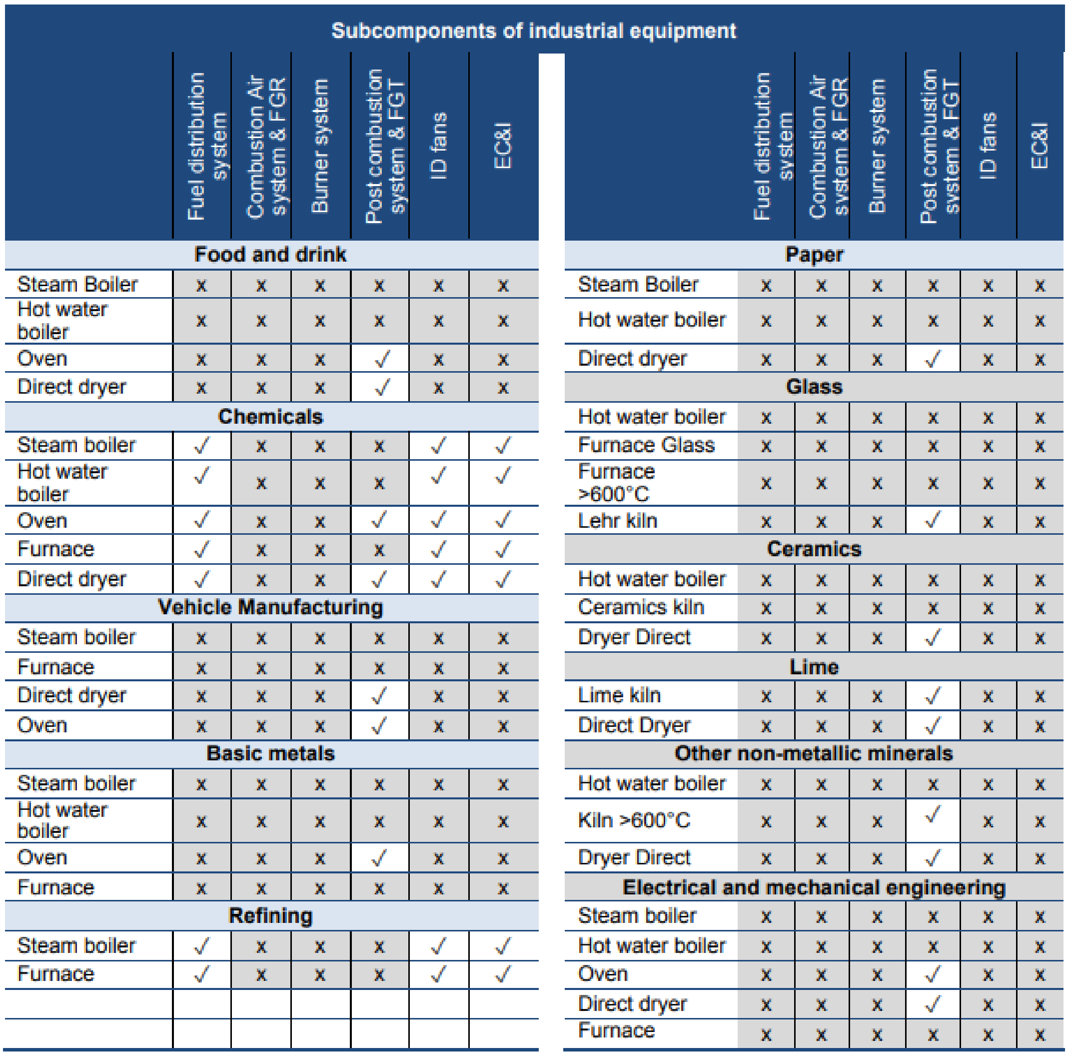
3.2.3 Conversion of Industrial Heating Equipment to Hydrogen

When considering the conversion of heating equipment to a hydrogen fuel, the whole system must be considered, including the following:

- Fuel distribution system
- Combustion air system, including flue gas recirculation
- Burner system
- Post combustion and flue gas treatment
- Induced draft fans
- Electrical control and instrumentation

Element Energy indicated that for most existing industrial heating equipment, nearly all the above components would need to be replaced when converting to hydrogen [68], including for every case, the combustion air and burner systems. Technically, there are no know limitations to conversion of such sub-components, however, these have not been proven at scale and effects on product quality in certain processes requires further research. As such, TRL for most hydrogen heating retrofit solutions can be classified at **TRL 7**.

Table 9 – Subcomponents of industrial equipment likely to need replacement [68]



Subcomponents of industrial equipment						
	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Food and drink						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	√	x	x
Direct dryer	x	x	x	√	x	x
Chemicals						
Steam boiler	√	x	x	x	√	√
Hot water boiler	√	x	x	x	√	√
Oven	√	x	x	√	√	√
Furnace	√	x	x	x	√	√
Direct dryer	√	x	x	√	√	√
Vehicle Manufacturing						
Steam boiler	x	x	x	x	x	x
Furnace	x	x	x	x	x	x
Direct dryer	x	x	x	√	x	x
Oven	x	x	x	√	x	x
Basic metals						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	√	x	x
Furnace	x	x	x	x	x	x
Refining						
Steam boiler	√	x	x	x	√	√
Furnace	√	x	x	x	√	√

Subcomponents of industrial equipment						
	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Paper						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Direct dryer	x	x	x	√	x	x
Glass						
Hot water boiler	x	x	x	x	x	x
Furnace Glass	x	x	x	x	x	x
Furnace >600°C	x	x	x	x	x	x
Lehr kiln	x	x	x	√	x	x
Ceramics						
Hot water boiler	x	x	x	x	x	x
Ceramics kiln	x	x	x	x	x	x
Dryer Direct	x	x	x	√	x	x
Lime						
Lime kiln	x	x	x	√	x	x
Direct Dryer	x	x	x	√	x	x
Other non-metallic minerals						
Hot water boiler	x	x	x	x	x	x
Kiln >600°C	x	x	x	√	x	x
Dryer Direct	x	x	x	√	x	x
Electrical and mechanical engineering						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	√	x	x
Direct dryer	x	x	x	√	x	x
Furnace	x	x	x	x	x	x

Note: x represents those that need replacement.

3.2.4 Hydrogen Fuelled Industrial Heating Technology

3.2.4.1 Hydrogen Boilers and Indirect Heaters

Indirect heating involves heating gases or liquids through a furnace tube, without direct contact between combustion gases and the product being heated. This type of heating is largely applicable to refining and petrochemicals, where temperatures of 240-600°C are required. Hydrogen boilers can be used to generate high pressure steam (up to 240°C), or low-pressure steam (80-240°C).

Hydrogen boilers can be used in the same applications as current gas-fired boilers. Research by TNO has concluded that in most cases only a burner retrofit is required to convert industrial gas boilers to burn a hydrogen percentage greater than 30 % [72]. Progressive control system replacement is also necessary [10]. Hydrogen burners are already available in heating applications as they are used in some industrial niches where hydrogen is available as a by-product.

Technology Development Status – TNO indicate a TRL 9 for hydrogen boilers based on proven technology in some niche applications [72]. Element Energy indicate a more conservative **TRL estimate of 7-8**, based on the lack of commercial application at large scale [70]. This estimate appears to be more reasonable. The CCC estimates first commercial deployment in 2025 [69], whilst Element Energy predict as soon as 2024 for achieving commercial readiness based on smaller scale implementation at a simple site.

Scalability – TNO assume that boilers of any size can be converted to hydrogen through burner retrofit – therefore, could range from <1MWth to >300 MWth.

Costs – Total Installed Costs for a new hydrogen fuelled boiler are estimated to be around 15-20 % higher than a counterfactual natural gas boiler [70]. Retrofit costs are estimated to be around 15-20 % of CAPEX for the required replacement parts. As with natural gas, the biggest contribution to process costs will be the fuel price. As part of the HyNet assessment, retrofit costs of two 7 MW boilers is estimated at £355,000 (£50/kWth), which includes new burners, flue gas recirculation controls, ancillaries, pipework, and pressure let-down stations.

3.2.4.2 Hydrogen Furnace and Direct Firing

Direct firing involves heating a solid material whereby combustion gases come into direct contact with the material. Many such processes require high temperatures from 240-2,000°C. Some industries use direct heating for drying and separation, typically with temperatures below 200°C. Some examples particularly relevant to Scotland include:

- Rolling in the Steel Finishing sector
- Kiln firing in Cement production
- Melting in the Glass industry

As mentioned, the physical ability to retrofit a direct heating application to burn hydrogen is as per hydrogen boilers/ indirect heating applications, however, there are some specific concerns relating to product quality that have yet to be addressed.

Glass Melting and Cement Manufacturing – The ability to use hydrogen for melting glass and firing a cement kiln is largely unknown due to the lack of process data even at lab-scale [71]. High moisture content in exhaust gases is of concern and needs to be studied and high levels of NOx emissions managed. Further, the poorer radiative properties of a hydrogen flame are of concern but could potentially be improved by co-firing hydrogen with biogas, or the injection of other additives that increase flame luminosity; In cement manufacturing, using clinker dust could be considered [73]. The TRL of using hydrogen is in glass melting regarded as 4, however, could progress quickly with concentrated research in this area. As part of the HyNet project, a demonstration is being designed to validate if a hydrogen furnace retrofit solution at NSG's Greengate works could provide adequate heat transfer from the flame to the melt, sufficiently control NOx emissions, and not damage furnace refractory.

Technology Development Status – Excluding the specific cases for hydrogen use in glass melting and kiln firing, the estimated **TRL** is **5**, although this is expected to increase quickly to 9 as commercial demonstration projects get underway. One limiting factor to the large-scale demonstration of such projects is the current lack of supply of hydrogen in the UK [74]. The CCC estimates first commercial deployment in 2026 [69]. Glass Futures predicts 2025 -2030 [74].

Scalability – Once a technically suitable solution is developed for all relevant applications, there are no known limits to scalability of the technology and scalability will be like that of natural gas fired equipment.

Costs – Similarly to hydrogen boilers, total installed costs for a new hydrogen direct heater are estimated to be around 15-20 % higher than a counterfactual natural gas boiler [68]. Modifications to Greengate Works Glass Furnace (HyNet) are estimated to be £2.3 M for a 50 MW_{th} Glass Furnace (£46/kW_{th}), including partial burner replacement, ancillaries, pipework, and pressure let-down [75]. Fuel costs will be considerably higher than the natural gas fired case, but a hydrogen fuelled option could overall be competitive with natural gas (including CO_2 cost) by 2035 [74].

3.2.5 Hydrogen Gas Turbines

3.2.5.1 Overview

Gas turbines are used in a vast variety of applications, from CHP schemes to onshore electricity generation, grid stabilization, offshore power generation and gas compression. When considering the retrofit capabilities of existing gas turbines, although some manufacturers claim a small number of certain turbines can already be fuelled by 100% hydrogen, **conversion capabilities will need to be analysed on a turbine-by-turbine and site-by-site basis.**

New gas turbines are being developed that are designed to burn blends of hydrogen and methane, up to 100% hydrogen, as means of future-proofing the technology once a hydrogen supply is available. However, with typically very long lifetimes of equipment and high CAPEX, the option of conversion rather than replacement may be preferred in many cases.

When converting gas turbines to hydrogen, challenges are similar to those experienced when fuel switching industrial heaters. Most challenging of all is the retrofit of a combustion system that was precisely designed for methane combustion; Higher flame temperatures, higher laminar flame speeds and lower autoignition delay means that maintaining the integrity of the combustion system and controlling NOx emissions is a formidable challenge. Controlling the NOx emissions to a suitable level (<25 ppm) with increasing amounts of hydrogen in the fuel blend is the ultimate research and development target of most technology providers.

In **Dry Low Emission (DLE) or premixed** combustion technology, fuel and air are mixed prior to combustion to accurately control flame temperature and NOx emissions. The main difficulties in DLE combustion systems with hydrogen are the risk of fuel ignition in the mixing passages, the flame burning closer to the ignition points and burning too close to liner walls. The capability of a DLE combustion system to combust hydrogen depends on the specific system and engine operating conditions [76] [77] [78].

Non DLE or **diffusion** combustion technologies typically have a greater ability to handle a wide range of fuel compositions, and up to 100% hydrogen is possible on certain systems. The technology uses diffusion or partially pre-mixed flames. Diffusion flames usually have higher flame temperatures and require dilution to control NOx emissions. Dilution is achieved by injection of steam, water, or nitrogen [76] [77] [78].

As well as the combustion system, impacts on the auxiliary package and power plant must be considered in full. Modifications may also be needed to handle larger volumes of hydrogen fuel, to address hydrogen leakage and material compatibility, address safety standards of electrical equipment, upgrade gas detection systems and exhaust gas systems.

Technology Development Status – Certain hydrogen gas turbines are available to buy from a range of manufacturers as described below, however, the deployment of these at scale has been limited so far due to lack of demand. Also, these 100% hydrogen systems are typically limited to combustion systems which require dilution and so have a more limited range of application than pre-mixed (DLE) systems; These systems can be considered TRL 7.

For the preferred dry pre-mixed systems, **TRL is lower at 5**, but based on developers plans, can be expected to reach TRL 7 not before 2023, and only for a limited number of gas turbines.

Further, the development of a retrofit solution for existing gas turbines can also be considered at TRL 5 for dry combustion systems. However, several ongoing projects aim to progress this to TRL 7 by 2024/5, including developments by Net Zero Technology Centre, Siemens, and Ethos Energy.

Costs – Accurate retrofit costs of a hydrogen gas turbine are unknown at present, however, HyNet has estimated an installed cost for new 160 MW_{th} hydrogen gas turbine CHP system to be £252 M [75].

Suitability – Gas turbines are used in many different applications with more than 39 CCGT and 350 CHP sites across the UK. Gas turbines are also used to power centrifugal compressors at high pressure natural gas compression stations, drawing natural gas from the pipeline. Crucially, CCGTs are used to not only generate power for the electricity network, but also provide grid stabilisation support that cannot be provided by renewable sources, including reactive/ active power absorption and generation.

Gas turbines are typically high CAPEX assets with a long lifetime, so retrofitting an existing gas turbine for hydrogen service could prove to be a financially attractive option over replacement.

3.2.5.2 Ongoing Developments

Siemens

By 2030, Siemens intends to develop gas turbines capable of operating on 100% hydrogen fuel with DLE technology. Today, Siemens WLE aeroderivative gas turbines can run on 100% hydrogen. Most gas turbines can operate with up to 15 % hydrogen but depends on the package and local certification requirements. Certain industrial gas turbines with 3rd gen DLE systems have hydrogen capabilities of up to 50-60 % [76]. Siemens stress that hydrogen capabilities need to be analysed on a case-by-case basis**.** Siemens aim to demonstrate the hydrogen capability of many of their turbines with DLE by 2023.

The HYFLEXPOWER project, funded through Horizon 2020 aims to demonstrate burning of up to 100% hydrogen of a $12MW_e$ CHP facility, owned by Engie Solutions in France. Pilot demonstration is expected in 2023.

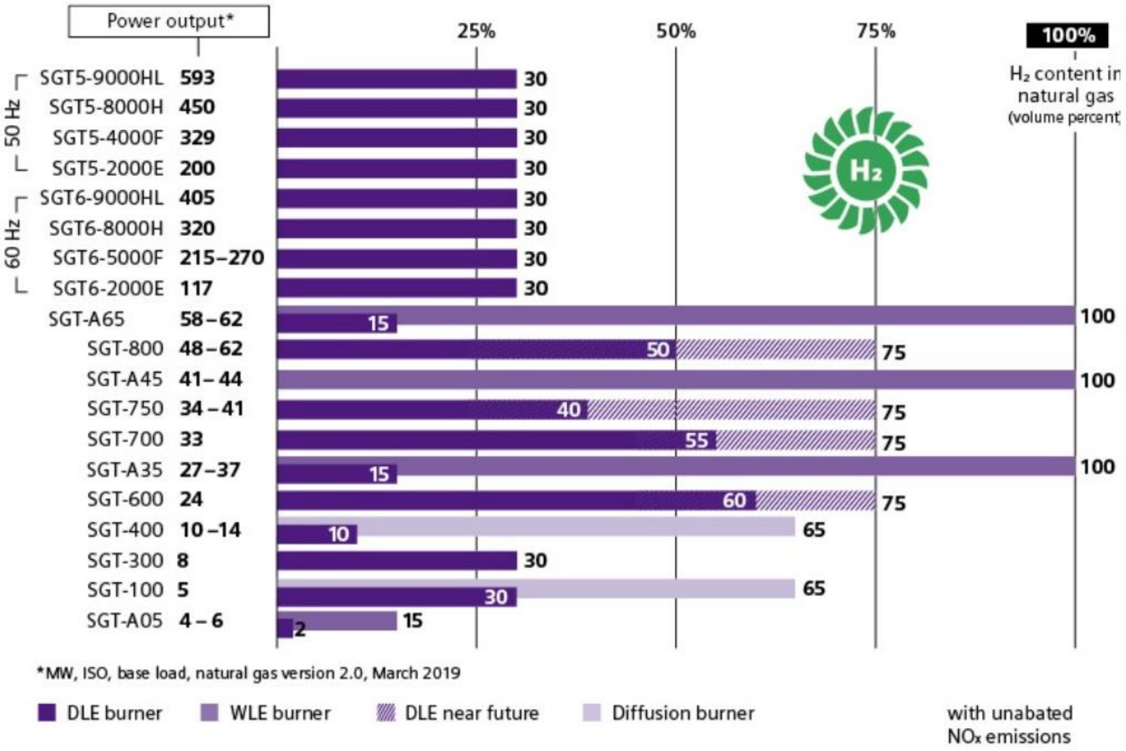


Figure 28 – Siemens' gas turbine fleet hydrogen capabilities [76]

Baker Hughes

Baker Hughes' gas turbine fleet has a range of capabilities when fuelled with hydrogen. Their GE10 turbine already has capabilities of up to 100 % hydrogen with steam injection for NOx control. Their NovaLT range of turbines (5.7 – 16.9 MW) can burn up to 100 % hydrogen and switch between natural gas and hydrogen as required. Like Siemens, the next stage of development is to develop DLE combustion technology for these turbines and confirm suitable control of NOx emissions (without dilutant injection) [79].

GE

GE have been operating gas turbines with hydrogen fuels blends in more than 75 gas turbines across the world, in applications such as steel mills, refineries and petrochemical plants. 25 of these gas turbines have operated on fuels with at least 50 % hydrogen. Most of this experience has been with syngas fuel. The GT13E2 with AEV combustor has a demonstrated capability of operating on up to 60 % hydrogen blends without dilution control and with NOx emissions less than 15 ppm [78]. Below shows the hydrogen capabilities of their gas turbines, today, and in the future.

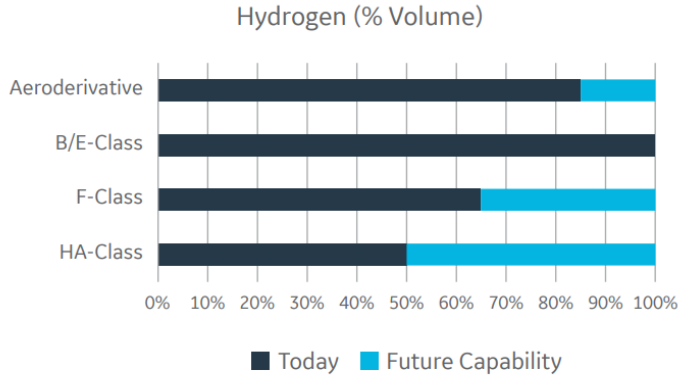


Figure 29 - GE's gas turbine hydrogen capability [219]

Net Zero Technology Centre

Net Zero Technology Centre has secured £2.3 m funding from Scottish government to develop a low carbon fuelled gas turbine retrofit solution, match-funded by industry to £4.6 m total. This is primarily focused on developing solutions to retrofit offshore gas turbines to decarbonise oil and gas operations in the North Sea. The first phase study will assess the retrofit capabilities of several gas turbines installed on offshore assets in the North Sea. Several different low carbon fuel blends will be considered, including blends of hydrogen and ammonia. The second phase project will trial an onshore gas turbine with this fuel blend. The aim is to develop a retrofit solution by 2024. The technology development will likely be in collaboration with Siemens as the main technology developer.

Several other technology developers are at similar stages of research and development and have several gas turbines that can operate on different blends of hydrogen and natural gas. Such developers include ANSALDO ENERGIA, MAN Energy Solutions, MITSUBISHI HITACHI POWER SYSTEMS and Solar Turbines.

3.2.6 Pipeline Capacity Hydrogen Compression

Due to the comparatively high throughput, centrifugal compressors are the preferred choice for high flowrate pipeline applications and are used cross Scotland and the world for this purpose. These are typically either powered by a natural gas fuelled turbine, or an electrically driven motor. CO_2 emissions from the former are high, whilst will vary for the latter option depending on the carbon intensity of the electricity available. Therefore, retrofitting natural gas fuelled compressors with an electrically driven alternative could have a significant impact on system CO_2 emissions.

With regards to future pipeline flow mediums, it is highly likely that many major compression stations will need to be upgraded to be suitable to compress and transport up 100 % hydrogen [80]. If the compressor is electrically driven, then only part of the system that encounters hydrogen may need to be changed, providing that the rotational speed of the motor is acceptable for hydrogen service. For natural gas fuelled compressor systems, challenges with switching the gas turbine to hydrogen fuel and the development status is described above. Both the gas turbine and the compressor will likely need to be replaced.

For 100 % hydrogen compression, reciprocating compressors currently offer the most efficient solution. Approximately 750,000 Nm^3/h can be achieved with parallel arrangement of compressors [81]. It is less likely that reciprocating compressors will need to be completely replaced, although this needs to be analysed on a case-by-case basis [82].

Hydrogen compression with centrifugal compressors is more complicated, and although have been used in petrochemical applications for many years, their efficiency is lower than that of reciprocating compressors. Hydrogen presents several unique challenges – mainly due to the low molecular density and impact on materials. For blends of hydrogen and natural gas of up to 10 %, minor modifications of existing equipment are expected, however, with blends up to 40 % hydrogen, the existing compressor housing can be maintained, but impellers, gears and feedback stages must be adjusted or replaced. For blends greater than 40 % hydrogen, the compressor must be replaced [83].

Due to the low molecular weight, to achieve a required compression ratio of ~1.3:1 per impeller (as per natural gas), impeller tip speed must be increased by a factor of 3 to ~700 m/s. This requires new impeller development that can withstand the high centrifugal forces, made from hydrogen resistant materials [83].

An infrastructure report on the European Hydrogen Backbone project assumes that compression stations across Europe will be powered by electricity and operated at lower pressures of 67-80 bar for a 48" pipeline [80]. If this is the case, capacity of and proximity to nearby HV electricity network must be considered, as well as backup power supply options.

Technology Development Status – Compressors for hydrogen service do exist, and can be classed as TRL 9, however, compressors with a suitable efficiency designed for high volume pipeline flows are less well developed**.** Siemens Energy highlight that the necessary developments have been initiated, so that the technology should be available in the coming years [83].

The Department of Energy, sponsored a project, delivered by Concepts NREC in 2015, to analyse, design and fabricate a pipeline capacity hydrogen compressor, capable of 240,000 kg/day (108,000 Nm^3/h) flowrate and 81 bar outlet pressure. The project developed a compressor impeller that could sustain high tip speeds at a pressure ratio of 1.26:1, with hydrogen compatible materials. All other components in the system were off-the-shelf, manufactured components. The project achieved **TRL 5.** Although all components were designed and built or purchased, laboratory testing of the system was not completed due to lack of funding [77].

Based on [77], there does not appear to any insurmountable challenges with progressing a higher efficiency 100% hydrogen centrifugal compressor for pipeline transport – the technology will likely be developed in due course as the demand grows. For example, Baker Hughes and Air Products have agreed a collaboration (June 2021), to develop hydrogen compression technology for the NEOM carbon-free hydrogen project with plans to start production in 2025 [84]. Like to industrial fuel switching technologies, a current limitation to development is the lack of demand for such a technology, plus the lack of supply of hydrogen for testing a hydrogen system.

Costs – Specific technology costs of compression systems from recently published sources have been challenging to source, and suppliers have not been contacted. However, Concepts NREC indicated an electrically driven compressor package (240,000 kg/day and 81 bar outlet pressure) would cost approximately £4 M [77]. Further, a report on the European Hydrogen Backbone indicated that a hydrogen service compressor system (electrically driven) would cost between 1.9 – 5.7 £M/MW$_e$ – an estimated price premium of between 140 – 180 % over a similar natural gas compressor [80].

3.3 Bioenergy CHP Retrofit

3.3.1 Introduction

Combined Heat and Power systems concurrently produce electrical power and useful thermal energy. The term CHP covers a vast range of possible prime movers and fuel sources, including gas turbines, steam boilers and reciprocating engines. Most relevant to this project is the CHP system which incorporates a CCGT fuelled by natural gas. Across the UK in 2020, half of all CHP schemes included a CCGT, and natural gas represented 72 % of the fuel consumed, whilst refineries accounted for the largest share of capacity at 36 %. Renewable fuels accounted for 15 % [85].

Due to the low CO_2 partial pressure in exhaust gases resulting in high CAPEX and OPEX, along with other factors such as availability of transport and storage, the cost of decarbonising a CCGT with post combustion CO_2 capture may be prohibitive. It is therefore necessary to explore other options for decarbonisation. One such route is to explore if syngas from biomass can be used directly in a gas turbine (or with minimal processing), or if further products that can be created from syngas can be used. See Section 2.3.7 on biomass gasification technology where the production of syngas and hydrogen from biomass has been explored.

There are several options for further conversion after creating syngas from biomass. Most research to date has been focused on transportation fuels [86]. Fischer-Tropsch synthesis can be used to convert CO and H into liquid hydrocarbons. Hydrogen and methanol production have already been explored in different sections of this report. A further option that is relevant to CCGTs and other processes currently burning natural gas, is BioSNG.

3.3.2 Syngas Fired CCGT Retrofit

If syngas produced from the gasification of biomass could be utilised directly in a CCGT based CHP, the system could achieve near carbon neutrality without the need for installation of expensive post-combustion carbon capture equipment. However, as with burning blends of hydrogen and natural gas, there are significant compatibility issues with switching from natural gas to a high hydrogen content fuel. Particularly due to the complex nature of a gas turbine-based system, comprehensive analysis of the gas turbine system is required on a case-by-case basis.

Conversely to 100 % hydrogen, syngas typically has a much lower caloric value than natural gas (although varies depending on ratios of H_2:CO), which leads to low flame temperature and decreased reaction rates. Further, due to the lower energy density, a higher mass flow is required to achieve the desired temperatures. This results in an increased power output, but with decreasing energy content, the turbine’s surge margin can be reached, meaning that compressor cannot add enough energy to overcome backpressure [87]. In addition, challenges arise due to material compatibility with hydrogen when considered a retrofit solution. As a result, natural gas turbines cannot be easily retrofitted to operate on low calorific gas [88].

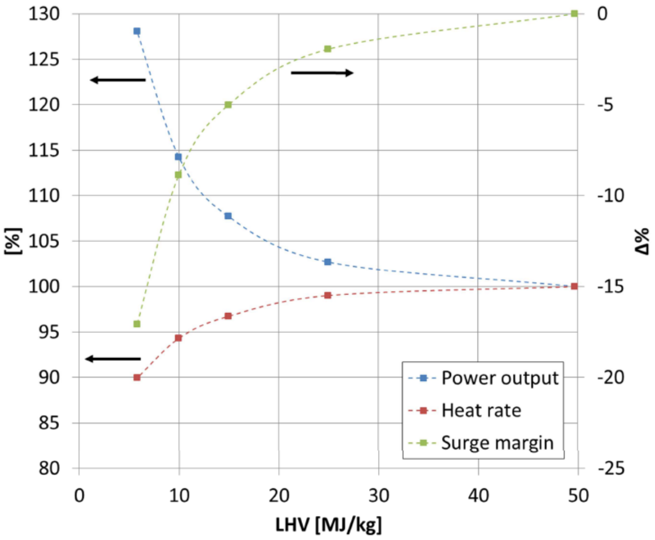


Figure 30 - Effect of LHV on power, heat rate and surge margin for a generic gas turbine [87]

There are no known literature studies, experimental work, or projects ongoing that are considering syngas as a retrofit solution for a natural gas fired gas turbine. It is therefore deduced that this route of decarbonisation is unlikely. Further to the retrofit challenges, addition of biomass gasification equipment would likely be a very significant capital investment; hence, efforts should be spent analysing other possible solutions such as alternative fuels or complete replacement of the engine with an Integrated Gasification Combined Cycle.

3.3.3 BioSNG

There are two main routes to the production of BioSNG (or biomethane): Thermal gasification and anaerobic digestion. Thermal gasification involves the methanation of syngas produced from woody and lignocellulose biomass. This syngas is produced through biomass gasification, which is described in more detail with a focus on hydrogen production in Section 2.3.7. Further, section 4.4.6 focuses on how waste CO_2 can be utilised to produce synthetic methane although is not classed as BioSNG if the CO_2 is derived

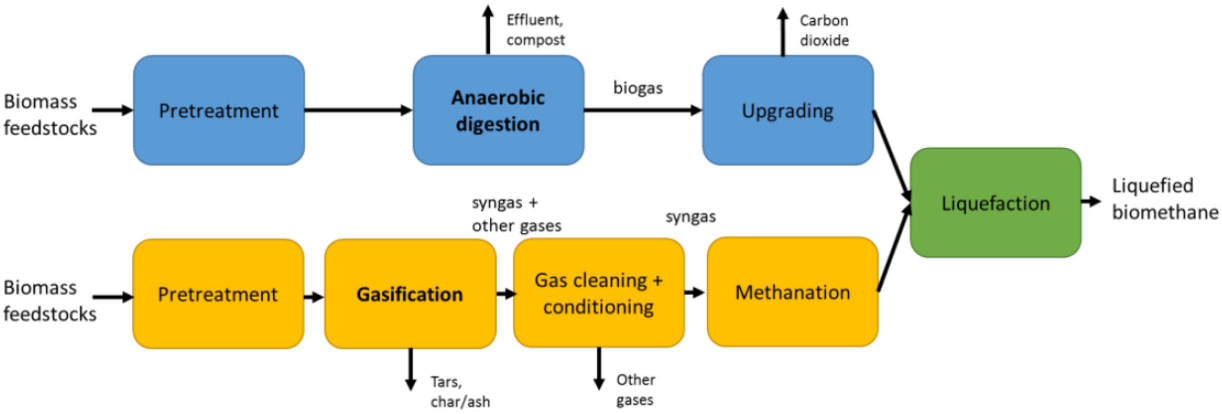


Figure 31 - Main conversion routes for BioSNG production [39]

from fossil fuels. Anaerobic digestion produces biogas (mixture of CH_4 and CO_2) through the biochemical digestion of organic matter. This can then be upgraded to produce pure CH_4. Anaerobic digestion has a much lower efficiency and needs larger reactors so is less suitable for large-scale plants [39]. These two main conversion routes are shown in Figure 31. Inclusion of liquefaction is optional and dependent on the desired form of methane.

The methanation technology required depends heavily on the gasification technology and the syngas composition. A nickel-based catalyst is typically used for thermochemical methanation, and the primary reaction:

$$CO + 3H_2 \rightarrow CH_4 + H_2O$$

A H_2:CO ratio of 3 is preferred, so a water-gas shift is usually used before methanation. Gas treatment is required to ensure very low sulphur compounds [86]. Any methane produced during gasification does not have to be converted, so a high methane content in the syngas stream improves the efficiency of the process.

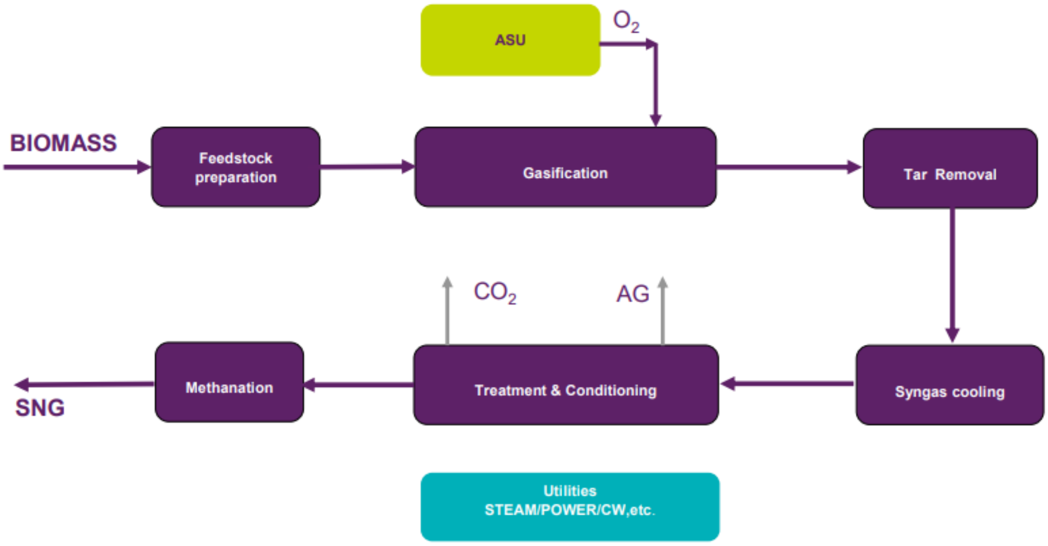


Figure 32 - Biomass gasification to BioSNG block flow diagram [217]

Advantages – The primary benefit of this technology is the widescale applicability of BioSNG in every current system that burns natural gas and its ability to effectively decarbonise these applications. BioSNG can be used, stored, and transported like methane and natural gas.

Challenges – The greatest challenge, as with biomass gasification for hydrogen production, is the availability of sustainable biomass material – without the displacement of land and nutrients currently used for growing food, feed, and fibres. Globally, the estimated sustainable bioenergy potential is about half of the technical potential. Bioenergy provides approximately 9 % of global primary energy demand, and although it is well recognised that the technical and sustainable potential energy demands from biomass could increase, this needs to be done in parallel with the increase in supply to avoid disrupting other finely balanced industries who rely on the same biomaterials [39].

Technology Development Status – The TRL of the biomass gasification process (to syngas) has been detailed in Section 2.3.7 and is at a maximum TRL of 9. Methanation is a relatively novel technology; the VESTA technology by Wood appears to be most advanced and is offered on a commercial basis. A demonstration plant has been in operation since 2014 in China, but it is unclear if this has been deployed commercially and if the syngas cleaning unit is suitable for biomass gasification applications. Therefore, a **TRL of 4-5** is estimated.

A 6 MW_{th} BioSNG demonstration plant is nearing completion in Swindon and commissioning took place in 2020. The fullsize RadGas technology development is intended to be powered by 60 MW_{th} biomass input (refuse waste and wood). Advanced Biofuel Solutions are currently commissioning the plant. Provided commissioning and start-up goes to plan, the system is expected to achieve TRL 8 soon.

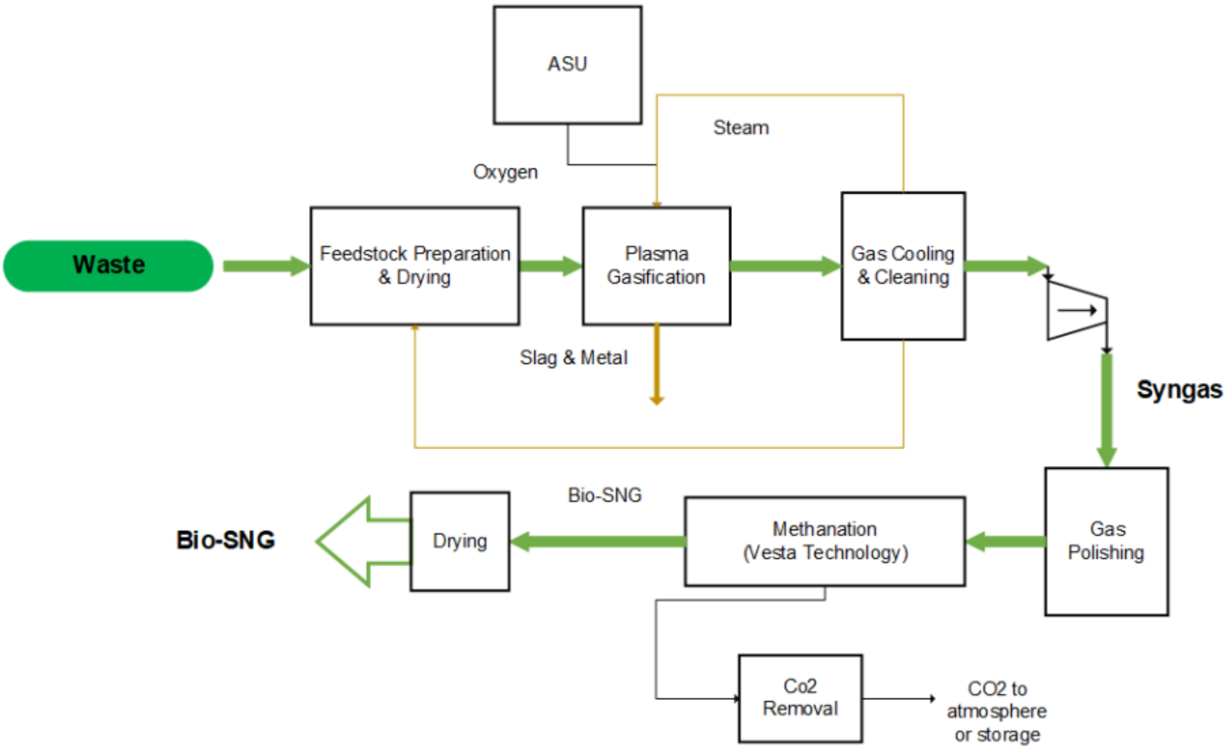


Figure 33 – Advanced Biofuel Solution's RadGas technology [37]

Costs – There are limited costs available in literature of BioSNG. Those that have been found are reported below.

Table 10 – Biomethane production cost values found in literature

Source	Production Cost (£/MWH)
Current Situation	
[89]	58 – 155 [1]
[90]	96- 128 [2]
[91]	81
2050 Predictions	

[92]	32
[91]	47

[1]: The cost range results from the influence of plant capacity and feedstock use.
[2]: The lower value is for a 150 MW gasification plant and the higher value for a 20 MW plant. Relatively high conversion efficiencies between 69 and 76% have been assumed.

Navigant [93] highlight how costs in 2050 could be 50 % less than they are today due to several factors:

- Commercial deployment resulting in improved operations, increased plant utilisation, and optimised processes.
- Lower costs due to economies of scale – largely due to reduced risk and improved performance driving deployment of larger-scale facilities.
- Improved energy conversion efficiency through improved syngas cleaning, more robust catalysts, and higher-pressure gasification.

3.4 Electrification of Industrial Processes

3.4.1 Introduction

The focus of electrification technology analysis in this section has been determined though discussions with SNZR project WP4 partner Doosan Babcock and driven by their scope of work. Therefore, the two technology types of most interest to the project are the technologies deployed at industrial site level as a replacement to fossil fuelled processes, and the infrastructure technologies enabling the interconnection of sites with the grid.

As introduced at the start of this section, electrification technologies suitable to replace many fossil-fuelled processes are well understood and at a high level of development, for example, electric boilers and heaters (TRL 9). Less well developed are plasma gas heaters, electric kilns, infra-red heaters, microwave heaters and HPHT heat pumps. The technology development status and costs of many electrification technologies are covered in detail by Element Energy [68], so this work is not repeated here. The most relevant information on these technologies has been detailed in **D3.2.1 - SNZR Industrial Decarbonisation Technology Analysis Database.** This section does however explore further the technology development status of electrification technologies not available today, for providing very high temperature heat (>1000°C).

When considering the integration of electrification technologies with the electricity network, it is also pertinent to assess the technologies that enable this; for example, large scale electrical infrastructure will be required to supply green hydrogen plants with renewable electricity. Electrical infrastructure-related technologies for consideration in this project include high voltage cabling and converter stations for both high voltage alternating current (HVAC), and voltage source converter – high voltage direct current (VSC-HVDC) systems. VSC refers to the converter technology which is widely used on newer projects due to its ability to independently control active and reactive power so will be considered here. This is in comparison to line commutated converter (LLC) technology which was widely used for early HVDC projects.

3.4.2 Developing Electrification Technology for Very High Temperature Heat

McKinsey [94] estimates that it is technologically possible today to electrify up to half of the industrial fuel consumption. Element Energy [68] estimates a smaller UK potential of 26 % electricity fuel switching technical potential in 2030. However, there is a consensus that the least developed technologies are those delivering very high temperature heat (> 1000°C).

One such technology that is under development is the large-scale electric ceramic tunnel kiln, requiring temperatures direct, high temperature heat up to 2000°C. This technology is estimated at TRL 6 (1 MW scale) but is not considered further due to the lack of requirement for this technology in Scotland.

3.4.2.1 Plasma Gas Technology

Most applicable to Scotland’s industry is the developing Plasma Gas Technology, which can be used as an alternative to a natural gas fired furnace in cement production. Thermal plasma torches are a potentially attractive fuel switching option for the cement industry, characterised by high temperature and enthalpy. The technology is considered TRL 9 in metal processing industries (deployed up to several MW) but has not yet been deployed at scale in the cement industry [73].

Plasma is a state of ionised gas, generated through applying an electric current through a gas to create an electric arc. Electric arcs are self-sustaining discharges between an anode and cathode. The arc is stabilised and restricted through cooling the outer layers, usually through gas-flow stabilisation.

Today, the maximum power of a plasma torch in industry is believed to be produced by ScanArc, delivering 8 MW, with efficiency 85-90%. This technology is marketed towards agriculture, metal recovery, incineration, forestry, heating furnace and construction industries.

It is worth noting that the highly CO_2 emitting chemical reaction in the Clinker cannot be abated by switching fuels, so it is likely that CO_2 capture will need to be deployed to achieve deepest decarbonisation of the process, at least for this process.

Technology Development Status - The CemZero project by cement manufacturer Cementa and Vattenfall has completed a feasibility study and showed that electrified cement production is technically possible but needs to be verified in larger scale tests. The biggest challenge to overcome is the lifetime extension of anode and cathode, which rapidly wears due to thermal stress. The report by [73] highlights an optimum fuel switching mix of 83.3% biomass and 16.7% thermal plasma in the calciner, with biomass and hydrogen used exclusively in the kiln. This smaller contribution by plasma heating is largely due to high disruption risk in the calciner. Further work is required to understand the most appropriate intervention point. It is unclear exactly when and if this technology will be fully developed for cement production.

Key areas for further work [73]:

- Power supply requirements
- Cement kiln specific prototype plasma torch design
- Composition and choice of plasma gases (waste CO_2 from clinker could be considered)
- Thermal stress tests of plasma torch electrodes
- Thermal efficiency assessment
- Cost benefit analysis of power fired heat vs combustion fuel
- Optimised location of plasma burners and relationship with calciner meal inlets and degree of calcination assessment
- Kiln riser velocities and aerodynamics

Costs – Cost estimates by [73] suggest that for 10% thermal plasma replacement (10 MW) would require a CAPEX of £4.6m to £8.4m (460-840 £/kW$_e$), with double operating costs due to higher costs of electricity. Element Energy [68] estimate a TIC in this range of 750 £/kW$_e$.

3.4.3 HVAC and VSC-HVDC Technology Overview

When transmitting power over long distances, the higher the voltage, the lower the transmission losses – hence the need for high voltage AC and DC for transmitting large quantities of power over long distances. 400 kV is the highest onshore transmission voltage in Scotland, and it is expected that large future offshore windfarms will be connected at this voltage where possible, or 275 kV otherwise. Modern wind turbines generate voltages up to 66 kV AC, so need to be stepped up for transmission between offshore and onshore substation. HVAC is currently deployed across all offshore windfarms in the UK, but VSC-HVDC will be deployed for the Dogger Bank projects [95]. VSC-HVDC links exist across the UK to connect long distances between different countries, including: the Western HVDC Link between Hunterston and North Wales, the AQUIND Interconnector between England and France, and the North Sea Link between Norway and the UK. Current windfarms across Scotland all utilise HVAC technology, but as distances and power flows from windfarm to shore increase in future, VSC-HVDC will likely be implemented in many future projects across Scotland.

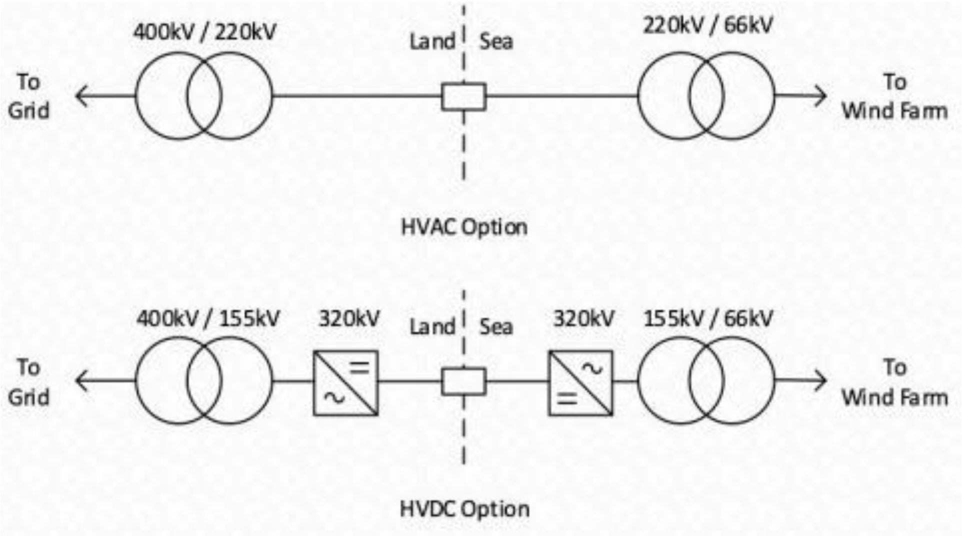


Figure 34 - Schematic of offshore transmission system based on HVAC and HVDC technologies [95]

Technology Comparison – DC transmission requires only 2 conductors per circuit, compared with 3 conductors for a 3-phase AC circuit, hence HVDC transmission cabling costs considerably less than HVAC (route cost). Further, VSC-HVDC can utilise the full capacity of the conductor, whereas HVAC cabling must be higher rated due to the peak voltage being approximately ~1.4 x higher than the average voltage. HVAC systems experience higher losses (6.7 % per 1000 km compared to 3.5 %), mainly due to corona discharge. HVAC lines can be more easily tapped into at different points without the need for expensive converter stations.

VSC-HVDC converter stations are expensive and not required for HVAC (terminal cost). There is therefore a breakeven distance at which HVDC becomes cheaper than HVAC as route cost of HVAC rises much more sharply with distance than with VSC-HVDC. As an estimate, analysis shows a breakeven distance of 87 km for a subsea cabled system connecting a 0.6 GW offshore windfarm to shore, and 71 km for a 1.4 GW offshore windfarm [96].

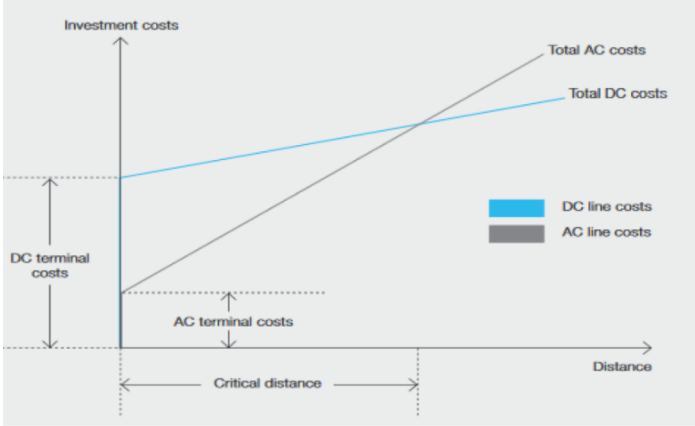


Figure 35 - Cost comparison for HVDC and HVAC power transmission [218]

3.4.4 Cost of Cabling and Infrastructure

Cost estimates from HVAC and VSC-HVDC projects are not easily found in publicly available sources due to the confidential nature of the information, and suppliers of equipment should be contacted for accurate costings. However, some information has been found in literature and is reported on in this section. Project capital costs are dominated by the cabling, infrastructure, and service/ installation costs.

3.4.4.1 Cabling

Table 11 – Costs of common HVAC and VSC-HVDC cabling [96]

HVAC Cables			VSD-HVDC Cables		
Voltage *(kV)*	**Size (mm^2)**	**Cables cost per set (k£/km)**	**Voltage *(kV)***	**Size (mm^2)**	**Cables cost per set (k£/km)**
±150	1000	670	**132**	630	685
	1200	730		800	795
	1400	785		1000	860
	1600	840	**220**	500	815
	2000	900		800	975
±300	1000	855		1000	1000
	1200	940	**400**	800	1400

	1400	1015		1200	1700
	1600	1090		1600	2000
	2000	1175		2000	2150

3.4.4.2 Infrastructure

A report by BVG Associates [97] provides a guide to costs of installing an offshore windfarm, from development and project management through to decommissioning. There is information in this report useful to help understand typical costs of onshore electrical infrastructure.

Onshore Substation – The report estimates a cost of £30 million (£30k/MW) for an onshore VSD-HVDC substation, relevant to a 1 GW windfarm, which transforms HVDC power from the export cable to three phase AC (400 kV or 275 kV). The area of land required is approximately 7.5 hectares. An additional £8 million is estimated for further buildings, access, and security to such a converter station. Construction of such an onshore substation is estimated at £25 million (£25k/MW).

Further, Navigant [98] provides a range of CAPEX of onshore substations across UK projects, depending on the developer of the substation – Offshore Transmission Owner (OFTO) or Transmission System Operator (TSO).

- OFTO onshore substation costs range between 32 – 67 k£/MVA, with a median of 54 k£/MVA
- TSO onshore substation costs range between 10 – 49 k£/MVA, with a median of 46 k£/MVA

This lower cost range and median for TSOs is likely driven by cost synergies at existing substations owned by the TSO which can be upgraded at lower cost than a new build.

3.4.5 Other Technology Developments

HVAC and VSC-HVDC technologies are fully commercialised (**TRL 9**), however, many technology developers are investing in research and development to make the equipment more efficient, reliable, compact, and lower cost. For example, Hitatchi-ABB’s HVDC Light system been developed thanks to improvements in component voltage and power ratings, improved semi-conductors and insulation materials. The technology is aimed at connecting smaller-scale renewable power generation plants to the AC grid. Regardless of capacity, HVDC converter technology is expensive, and is not compact.

Aberdeen based QL Tech is aiming to develop a DC to AC converter system (PowerLink), which is 10 times cheaper and 5 times smaller than existing systems. They aim to develop this by utilising the latest power electronic technology pioneered for electric cars, deployed in a novel configuration. This technology could have a big impact in the offshore sector – to enable powering of oil and gas operations from offshore renewables and reducing the cost of offshore floating wind converter stations. The technology could also be deployed onshore once developed, for example to supply the DC power from and AC supply required for electrolyser technologies. Although at low TRL currently, the developer aims to achieve TRL 5 within 12 months, and progression to TRL 7 within another 24 months.

4 Carbon Capture, Utilisation, and Storage

4.1 Introduction

Carbon capture, utilisation, and storage (CCUS) refers to a suite of technologies that can play an important and diverse role in meeting global energy and climate goals. CCUS' ability to mitigate CO_2 emissions at source and enable large-scale reductions of CO_2 already in the atmosphere makes it an essential part of the solution in achieving Scotland's (and global) net-zero targets.

Today, there are 22 CCUS facilities around the world with capacity to capture more than 40 MTe_{CO2} each year [99]. If not being used on-site, the captured CO_2 is compressed and transported by pipeline, ship, rail, or truck to be used in a range of applications or injected into deep geological formations.

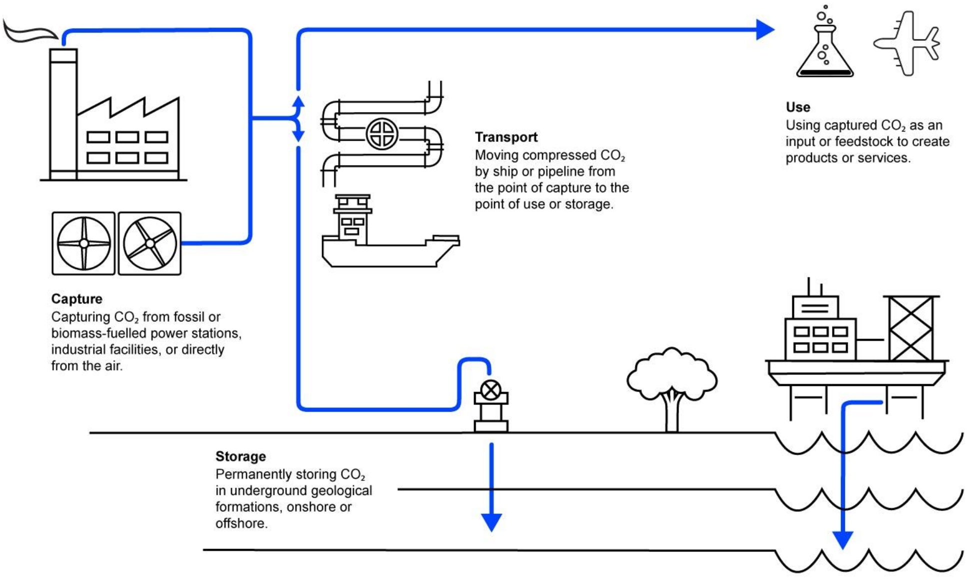


Figure 36 – Carbon capture, utilisation and storage pathway [99]

Scotland has the potential to be a leader in the global CCUS market, largely due to the plentiful CO_2 storage potential and opportunity to repurpose existing infrastructure. A techno-economic review of CCUS technologies has been undertaken to help the project understand and select the most suitable technology options for deployment in the roadmap project. The 3 subcategories of technologies that have been explored in this section include carbon capture, utilisation, and storage. Because the greatest focus of global R&D efforts is on technologies to capture CO_2 directly from point sources or from the atmosphere and the greatest range of options exists in this area, most effort has been spent exploring these technology options.

4.1.1 Point Source Carbon Capture

4.1.1.1 Post-Combustion CO_2 Capture

Post-combustion Capture separates CO_2 from the flue gas of conventional fossil-fueled power plants. In a typical natural gas power plant, the gas is combusted with air where it expands through a turbine to generate electricity. The flue gas consists mostly of nitrogen (N_2), and CO_2.

Post-combustion Carbon capture is the most common type of technology commercially applied in industry for CO_2 removal from power generation and heavy industries, most notably demonstrated in the Petra Nova (USA) and Boundary Dam (Canada) coal-fired power plants where 1.4 and 1.0 MTPA of CO_2 is captured respectively. Its main benefit is the ability to be retrofitted to existing processes.

Separating CO_2 from a flue gas stream is challenging for several reasons:

- CO_2 is present at **dilute concentration** and at **low pressure** (slightly above atmospheric); thus, a large volume of gas must be treated as summarised in Table 11 [100]:

Table 12 – Typical flue gas partial pressures for post-combustion capture [100]

Point Source	CO_2 Partial Pressure (kPa)	Gas Stream Pressure (kPa)
Natural Gas Combined Cycle (NGCC)	3.8 – 4.6	Atm.
Biomass / Waste-Fired Power Plant	10.1 – 12.2	Atm.

- Trace impurities (e.g., particulate matter, oxygen (O_2), sulfur dioxide (SO_2), nitrogen oxides (NOx)) in the flue gas can **degrade sorbents** and reduce the effectiveness of certain CO_2 capture processes.
- CO_2 is **captured at low pressure.** Compressing it from atmospheric to pipeline pressure incurs a substantial auxiliary power load on the overall power plant system.

4.1.1.2 Pre-Combustion CO_2 Capture

Pre-combustion Capture separates CO_2 from gasification and reforming processes in which a gaseous fuel, or synthesis gas (syngas), is formed, consisting mainly of hydrogen, carbon monoxide and CO_2. In an integrated gasification combined cycle (IGCC) power plant, a carbon-based fuel is reacted with steam and oxygen under pressure to form syngas, which is used to fuel a gas turbine generator to produce electricity. The recovered heat is used to produce steam that also drives a turbine generator designed to generate electricity. The carbon is captured from the syngas **before it is combusted**.

To **facilitate carbon capture and increase the hydrogen production**, the syngas is shifted in a water-gas-shift (WGS) reaction to produce additional hydrogen and convert the carbon monoxide into CO_2. Pre-combustion capture is typically more efficient than post-combustion capture due to the higher concentration of CO_2 after the WGS reaction and the high pressure of the syngas [100]:

Table 13 – Typical syngas partial pressures for pre-combustion capture [100]

Point Source	CO_2 Partial Pressure (kPa)	Gas Stream Pressure (kPa)
SMR Hydrogen Production	300 – 480	2000 – 3000
Natural Gas Reforming Syngas	300 – 1200	2000 – 3000

4.1.2 Oxy-Combustion CO_2 Capture

Oxy-combustion capture refers generally to capture of carbon dioxide using processes in which the combustion oxidant stream is **oxygen rather than air**, thus removing the large volume of nitrogen present in post-combustion technologies.

Oxy-combustion capture initially only referred to schemes in which a conventional boiler was sealed to air ingress and fed with oxygen and recycled flue gas instead of air with associated downstream purification processes. However, in recent years, gas turbine schemes have also been developed which can operate in an oxygen/ flue gas oxidant regime.

4.2 High TRL Carbon Capture Technology

4.2.1 Summary

This technology review section covers technologies that can be classified as TRL 9 and have had some (albeit varying) levels of commercial deployment. See a summary in Table 14 of the different technologies analysed, prior to further details in the relevant sections.

It is important to note that the costs of capture have not been compared on a standard basis and are from a range of sources, so cannot all be compared equally. See relevant sections below for further details on any assumptions and process conditions.

Table 14 – High TRL carbon capture technology summary

Technology	Technology Development Status	TRL	Costs
Amine Based Chemical Absorption	Amine based technology has been used for decades in the natural gas processing industry. It is deployed on a commercial scale, capturing CO_2 from several emitting industries.	9	£31-£54/Te_{CO2}[1]
Pressure Swing Adsorption	PSA units are extensively utilised in the hydrogen production and natural gas industries.	9	£35-£53/Te_{CO2}[1]
Vacuum Pressure Swing Adsorption	The VPSA process is commercially deployed in the Port Arthur CCS project capturing up to 1 MTPA of CO_2.	9	£35-£53/Te_{CO2}[1]
Physical Absorption	Physical solvent technology has been used for decades in the natural gas processing and gasification industries. It is deployed on a commercial scale, capturing CO_2 in mainly pre-combustion applications.	9	£47-£54/Te_{CO2}[1]
Gas Separation Membranes (Syngas)	Spiral wound and hollow fibre membranes are commercially deployed In the Petrobras Santos Basin capturing up to 1 MTPA of CO_2 for reinjection into oil and gas reservoirs.	9	£13-£64/Te_{CO2}[1]

[1]: See relevant sections below for cost references

4.2.2 Amine Based Chemical Absorption

In chemical absorption, acid gas components (CO_2 and H_2S) in the gas stream dissolve in a solvent within the absorber column and are held in aqueous solution by ionic balance with the dissociated solvent ions [101]. This contact occurs in traditional gas-liquid contactors, and CO_2 transfers from the gas phase into the liquid phase. The CO_2-loaded rich solution is pumped to a regenerator vessel where it is heated to liberate gaseous CO_2 and the lean solution is circulated back to the absorber.

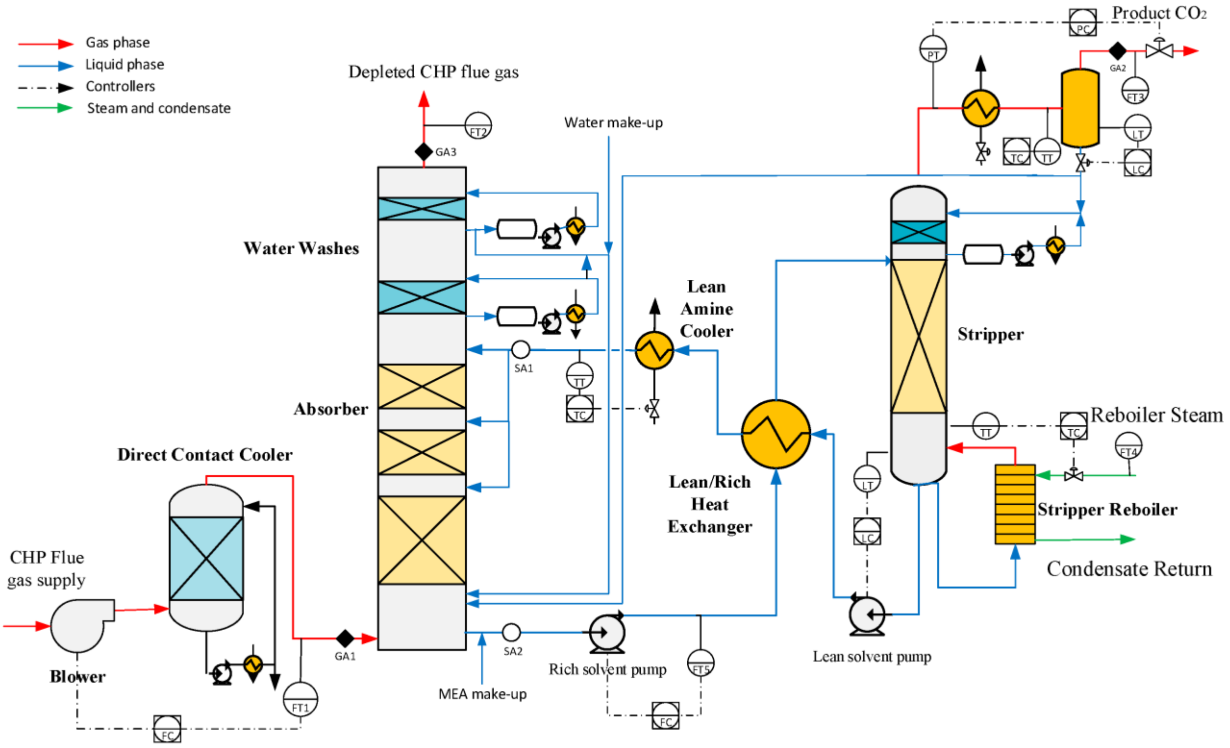


Figure 37 – Chemical absorption overview [102]

The main advantage of chemical absorption is that the formation of chemical bonds between the acid gas and the solvent largely prevent migration of the acid gas from the solvent back into the gas phase. This allows very low acid gas levels to be achieved in the treated gas. Absorption is used widely in the chemical, petrochemical, and other industries, and as a result, operational confidence in absorption process is high. Indeed, virtually all near-term and mid-term carbon capture processes under development are absorption based.

The disadvantage of chemical absorption is that breaking the bonds between the acid gas and solvent in the regenerator column is energy intensive, imposing a circa. 10% efficiency penalty on a power plant [103]. Moreover, the characteristics allowing formation of bonds with acid gas tend to make chemical solvents susceptible to degradation by contaminants in the flue gas.

At lower CO_2 partial pressure, chemical solvents have a higher absorption capacity, which makes them more attractive for use under low partial pressure gas conditions. At higher partial pressure, the relationship between solvent capacity and partial pressure follows Henry's Law (linear relation), so physical solvents are preferred.

Different amine-based solvents have been developed, including: monoethanolamine (MEA), 2-amino-2-methyl-1-propanol (AMP) and diethanolamine (DEA). The main licensors of amine-based solvents for carbon capture applications include:

- Shell (Cansolv Process)
- MHI (KM CDR Process)
- Fluor (Econamine FG+)
- Aker Carbon Capture (Just Catch)
- Siemens (Post-CAP)
- Dow (DOW Amines)

Technology Development Status – Amine-based carbon capture technology is used extensively in the natural gas processing industry and has been deployed on a commercial scale in post-combustion carbon capture applications. Therefore, this technology can be considered as **TRL 9**.

In post-combustion carbon capture applications, amine-based technology is currently installed at capacities up to 1.4 MTPA of CO_2 captured (Boundary Dam, USA). In the next decade, this is expected to increase significantly to 6.0 MTPA with the commissioning of the San Juan Generating Station Carbon Capture project in 2023 [104].

In the UK, a new BECCS pilot project is currently being carried out at the Drax power station using KS-1 solvent developed by MHI. This solvent is currently being utilised at the Petra Nova plant. The 12-month pilot will capture around 300 kg of CO_2 a day for the purpose of confirming its technology's suitability for use with biomass flue gases at Drax. The Drax BECCS project aims to operate at a commercial scale by 2027 [104].

Costs – Current costs for amine-based carbon capture are estimated between **£31-£54/Te$_{CO2}$** depending on the CO_2 content and partial pressure [100].

4.2.3 Adsorption

Sorbent-based CO_2 capture involves the chemical or physical adsorption of CO_2 using a solid sorbent. Solid sorbents generally are associated with a reduced regeneration energy penalty, operate at higher temperatures, and have a lower environmental impact compared to solvents.

Sorbent-based technologies under development are aimed at improving the cost and performance of CO_2 separation. R&D objectives include novel sorbents (e.g., alkali ceramic-based, carbon-based, and calcium oxide-based sorbents) that maintain a high CO_2 adsorption loading capacity, can withstand multiple regeneration cycles with minimal attrition, and perform efficiently at the high temperatures to avoid the need for syngas cooling and reheating [105].

Pressure Swing Adsorption

Pressure Swing Adsorption (PSA) is widely used in industry to separate carbon dioxide, carbon monoxide, methane, and water from syngas streams to produce high-purity hydrogen in refineries and petrochemical facilities.

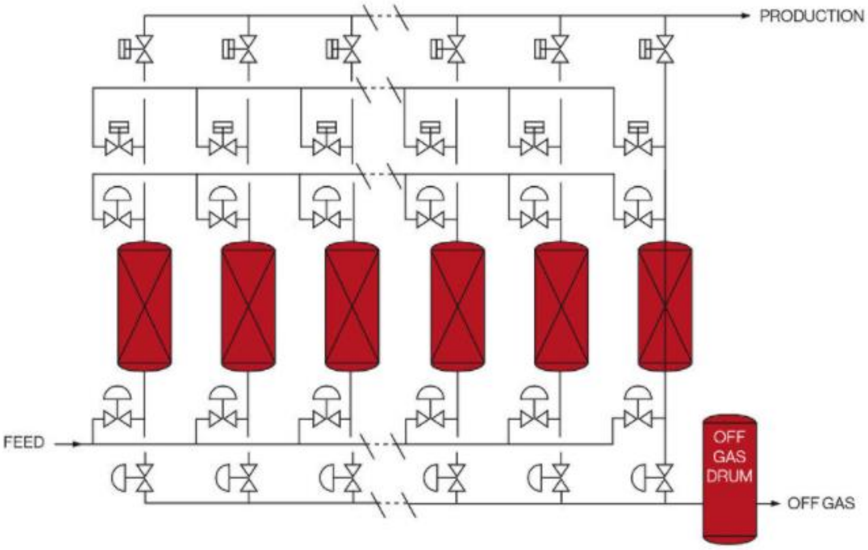


Figure 38 – Pressure swing adsorption schematic [107]

The key advantage of this technology includes the low energy consumption due to no additional heating requirement and relatively low maintenance costs.

Conversely, moisture needs to be removed prior to gas entering the PSA system due to the potential of water to block the adsorbent’s micropores, reducing system performance. Conventional pressure swing adsorption processes are not well-suited to atmospheric post-combustion CO_2 capture due to the energy required to compress the large volume of low-pressure gas.

Vacuum Pressure Swing Adsorption

Vacuum Pressure Swing Adsorption (VPSA) is a sub-ambient pressure variation of a PSA system – the CO_2 is adsorbed at one pressure and released as the bed is regenerated at a lower pressure. In a typical process, first the adsorption takes place, which is followed by applying a rinse, then evacuation and purge to desorb the adsorbed gas.

Mostly zeolites are used in the VPSA process, however, other improved adsorbents with a higher surface area are being developed. These include heavy metal organic frameworks, zeolite imidazolate frameworks, and carbon-based materials which are less adsorptive to water. The technology is best suited to flue gases with CO_2 concentrations greater than 10 % to minimise the necessary bed volumes [108]. The technology has some significant advantages over traditional PSA units:

- Due to its low-pressure operation, VPSA can be used to capture CO_2 from low pressure exhaust gas unlike PSA which would require compression of the flue gas stream.
- The VPSA process has lower life-cycle costs compared with PSA plants.
- VPSA plants have greater efficiencies, less maintenance costs, and far-lower energy expenses compared to PSA systems.
- VPSA plants extract maximum sieve and power efficiencies compared to PSA plants.

Technology Development Status – PSA/VPSA is widely used in industry to separate carbon dioxide, carbon monoxide, methane, and water from syngas streams to produce high-purity hydrogen in refineries and petrochemical facilities. Therefore, these technologies can be considered as **TRL 9**.

Due to PSA's significant utilisation in the natural gas processing industry, it can be concluded that the technology is highly scalable. Modern PSA systems used in the industry can vary from 2 adsorbent beds separating air, to 16 bed systems producing more than 100,000 Nm^3/hr of hydrogen [109]. For carbon capture applications, VPSA is commercially operating at the Port Arthur CCS project, capturing up to 1 MTPA of CO_2 [104].

Costs – Current costs for PSA/VPSA carbon capture are estimated between **£35-£53/Te_{CO2}** for pre-combustion CO_2 capture from SMR in the hydrogen production process [110].

4.2.4 Solvent Based Physical Absorption

Physical solvents work by absorbing the acid gas physically rather than chemically and they tend to be favourable over chemical solvents when the partial pressure of acid gases is very high (i.e., in pre-combustion applications) [110]. CO_2 can be separated from such solvents by reducing the pressure in the desorber, significantly reducing the energy requirements in the desorption process.

Physical solvent processes are generally only recommended for reducing acid gas concentrations from very high levels to moderate levels and are often chosen for gasification system designs. Physical solvents are also more prone to co-absorption of hydrocarbons, making them less suitable for natural gas treating, particularly for rich natural gases (not usually a problem for syngas applications).

The main physical absorption processes include the Selexol and Rectisol processes.

Selexol is composed of dimethyl ethers and polyethylene glycols (DEPG). The Selexol process is licensed by UOP and is highly selective, delivering separate H_2S and CO_2 rich streams while also removing mercaptans.

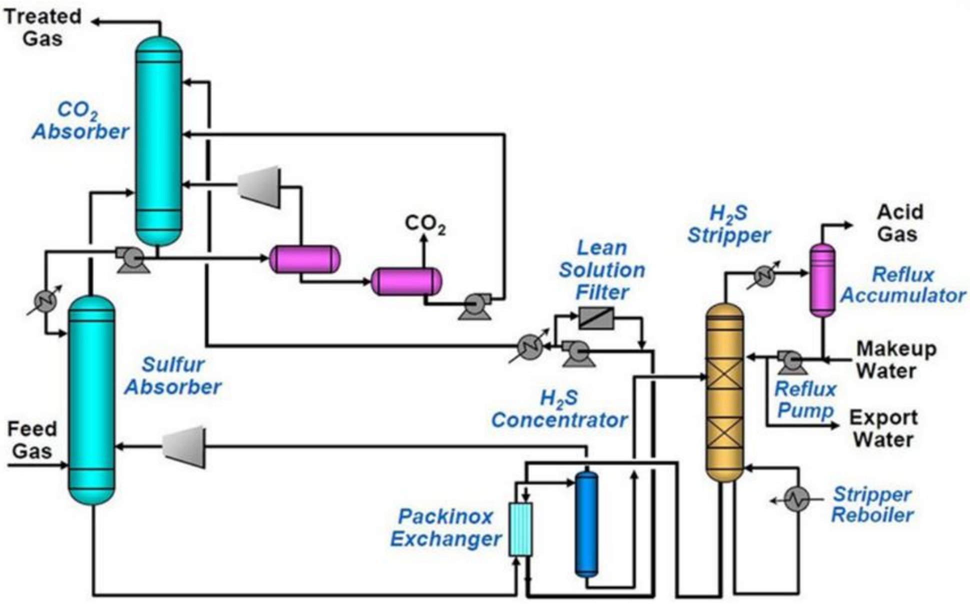


Figure 39 – Selexol process schematic [111]

Rectisol is licensed by both Linde and Lurgi. It uses a methanol-based solvent at sub-ambient temperatures. Its main advantage is that while it is selective and removes carbonyl sulphide, the main component of the solvent is cheap compared to Selexol. This technology is well established at a large scale in ammonia production plants and at gasification plants using coal, petroleum coke, and biomass feedstock.

Technology Development Status – Carbon capture technology using physical solvents is used extensively in the natural gas processing industry and has been deployed on a commercial scale in pre-combustion carbon capture applications, particularly in gasification systems. Therefore, this technology can be considered as **TRL-9**.

Currently, physical solvent processes are installed up to 4,000 TPD (1.46 MTPA) CO_2 captured in the syngas and natural gas processing industry.

Costs – Current costs for the Selexol process is estimated at between **£47/Te$_{CO2}$** (CO_2 capture from an IGCC plant) and **£54/Te$_{CO2}$** (CO_2 capture from a pulverised coal gasification plant) [112].

4.2.5 Gas Separation Membranes

Gas permeation membranes exploit the difference in physical and chemical interactions between gases and a membrane material, causing one component to pass through the membrane faster than another. Membrane separation has the advantages of steady state operation, absence of moving parts and modular construction and hence has been applied successfully for the separation of CO_2 from light hydrocarbons in the petroleum and natural gas industries. However, the major challenge for membranes comes from the potential fouling of the membrane surfaces from particulate matter and their unsuitability for typical post-combustion low pressure flue gas streams which require compression to increase CO_2 partial pressure.

Various types of membranes are currently available for pre-combustion capture such as the Separex membrane system licensed by UOP. A CO_2-rich feed gas mixture passes over the polymeric membrane at high pressure where it separates into two streams. Carbon dioxide, hydrogen sulphide and water vapour permeate readily through the membrane collecting on the low pressure permeate side. The high-pressure residual retains most of the methane, ethane, other hydrocarbons, and nitrogen. In a two-stage system, the first stage low-pressure permeate is compressed for further treatment at the second-stage membranes to recover hydrocarbons.

Hydrocarbon recovery can be as high as 99 % for a two-stage design, and 95 % for a single stage without compression. Feed rates vary from 3 MMSCFD to 700 MMSCFD, with CO_2 levels from 3 % to 70 % and feed pressures from 28 to 110 bar [113].

Membrane designs include metallic, polymeric, or ceramic materials capable of operating at elevated temperatures. The main R&D focus is to develop membranes that have high permeability and selectivity with low pressure drop and a higher tolerance to contaminants (e.g., sulfur).

Technology Development Status – Membranes for pre-combustion carbon capture are operating on a commercial scale. Therefore, this technology can be considered as **TRL-9**.

Currently, the largest use of pre-combustion membrane technology is in Petrobras' Santos Basin, where membranes are located on an FPSO to capture up to 1 MTPA of CO_2 (composition ranging from 8-15%) for reinjection into reservoirs [104].

Costs – Current costs for the membrane-based CO_2 capture is estimated at between **£13/Te$_{CO2}$** (35 % CO_2 in the feed gas) and **£64/Te$_{CO2}$** (10 % CO_2 in the feed gas) [114].

4.3 Disruptive Carbon Capture Technology

4.3.1 Summary

There is a concerted effort globally to reduce the costs of carbon capture, with numerous developments of disruptive next generation capture technologies that are emerging and potentially transformational. Next generation technologies are defined as those that have progressed through lab testing and are on route to pilot testing [100]. These technologies are targeting cost reductions through enhanced materials, processes, and equipment. A summary of those which have been analysed in this report are outlined in Table 14.

It is important to note that the costs of capture have not been compared on a standard basis and are from a range of sources, so cannot all be compared equally. See relevant sections below for further details on any assumptions and process conditions.

Table 15 – Disruptive carbon capture technology summary

Technology	Technology Development Status	TRL	Cost
APBS-CDRMax	Carbon Clean Solutions' CO_2 capture technology is currently operating at over 30 facilities worldwide at a maximum scale of 174 TPD (63 kTPA).	8	£30/Te_{CO2}
Water-Lean Solvents	Ion Clean Energy have conducted pilot-scale testing with multiple flue gases up to a scale of 12 MW_e.	6	£27-£31/Te_{CO2}
Biphasic Solvents	IFPEN/Axens have conducted pilot-scale testing with flue gas from coal-fired power plants up to a scale of 3.5 MW_e.	6	£33/Te_{CO2}
Calcium Looping	Two European projects are developing calcium looping capture technologies in steel (C4U) and cement production (CLEANKER) at pilot and pre-commercial scales.	7	£36-£43/Te_{CO2}
Chemical Looping	Chemical Looping is operational in around 35 pilot projects with capacity up to 3 MW_e for coal, gas, oil, and biomass combustion.	6	£36-£39/Te_{CO2}
Cryogenic Capture	As part of commercialising the CryoCell® technology, a demonstration plant was designed and built by Cool Energy Ltd in Western Australia. The field test program has demonstrated the technical viability of solid phase CO_2 separation and cost comparison studies indicate improved economic viability for high CO_2 gas field developments.	7	< £25/Te_{CO2}
Gas Separation Membranes (Post-Combustion)	MTR have completed a 1,400-hour field test of its membrane in a 20 TPD pilot plant at the National Carbon Capture Centre in Alabama, USA.	6	£19/Te_{CO2}

VelexoTherm (TSA)	The VelexoTherm process was successfully demonstrated at a 0.5 TPD scale during 2017.	7	£23/Te_{CO2}
MCFC	A pilot project has been completed at the James Barry coal and natural gas-fired power plant in Alabama to concentrate and capture 54TPD of CO_2.	7	£24/Te_{CO2}
DAC (Carbon Engineering)	Carbon Engineering's technology has been demonstrated on a sub-scale with a fully functional prototype.	7	£158/Te_{CO2}
DAC (Climeworks)	Climework's technology has been demonstrated at pilot-scale, capturing up to 900 Te_{CO2}/yr at the Hinwill plant in Switzerland.	6	£102/Te_{CO2}
Allan-Fevedt Cylce	A 50MW_{th} Allam-Fetvedt Cycle commercial demonstration facility is currently operating in La Porte, Texas.	8	£53/MWh
Oxyfuel Combustion	Total's Lacq large pilot plant in France consists of a 30 MWth oxy-firing of a natural gas fired boiler, storing CO_2 in a depleted natural gas reservoir.	7	£28-32/Te_{CO2}

4.3.2 Innovative Liquid Solvents

Significant research efforts have been made in developing chemical solvents that offer greater absorption capacity, a reduced process energy penalty and less degradation than current amines that are widely used for post-combustion capture.

4.3.2.1 APBS-CDRMax – Carbon Clean Solutions

Carbon Clean Solutions' CDRMax solvent is a formulation of amines and salts — known as Amine-Promoted Buffer Salts (APBS). The CDRMax process is similar to conventional absorption processes and allows CO_2 capture from power plants, kilns and chemical facilities with a reduced equipment footprint and lower costs.

CDRMax has a high solvent stability, low corrosivity, low regeneration energy requirements, and holds up well in oxygenated environments. As well as being utilised in the CDRMax process, the solvent has 'drop-in' replacement capability which means it can replace solvents in existing facilities to reduce thermal energy requirements by up to 20% [115].

Technology Development Status – Carbon Clean Solution's (CCSL) CO_2 capture technology is currently operating at over 30 facilities worldwide. The technology is operating commercially in an integrated carbon capture and utilisation (ICCU) environment at a maximum scale of 174 TPD (60 kTPA). In a pure post-combustion application, the technology has been demonstrated at a maximum scale of 240 TPD (88 kTPA). Therefore, the technology can be considered as **TRL-8**.

CCSL have been selected to deliver the Acorn CCS project FEED. The project involves the capturing of post-combustion CO_2 emissions from St Fergus gas terminal by the mid-2020s, with captured CO_2 stored offshore with annual volumes anticipated to grow to 5-10Mt/yr of CO_2 capture by 2030. Operating at this scale with CCSL's technology would certainly progress the technology to TRL-9.

Costs – CCSL claim that CAPEX can be reduced by 20% and OPEX by 40% when compared to conventional MEA-based absorption [115]. They also claim that the CDRMax produces CO_2 with a purity of 95–99.9% with a cost of capture of **£30/Te$_{CO2}$** when used within the CDRMax process [115].

4.3.2.2 Water-Lean Solvent – Ion Clean Energy

Ion Clean Energy's water lean-solvent capture technology is similar to commercially available aqueous amine-based systems, where the CO_2 is chemically absorbed onto the solvent and then released in the desorption process via the application of heat [116].

Ion's solvent consists of a blend of amine and organic diluents that possess low or no water content. These solvents induce a shift in chemical equilibrium and an increase in mass transfer rates for a fixed CO_2 partial pressure compared to traditional amines.

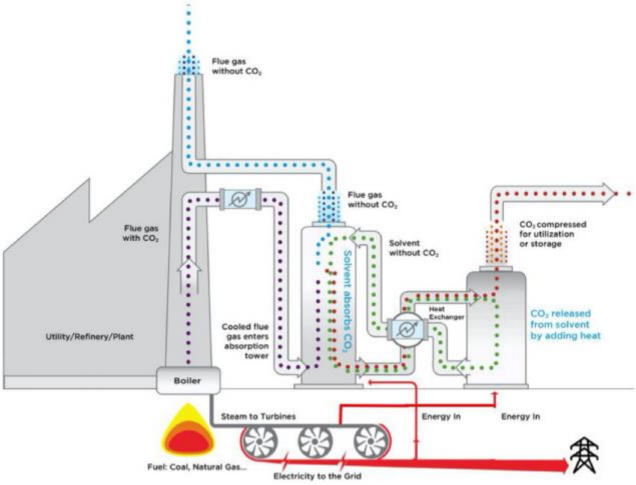


Figure 40 – Ion Clean Energy process schematic [100]

Technology Development Status – Ion Clean Energy have conducted pilot-scale testing with multiple flue gases up to a scale of 12 MW$_e$ [116]. Therefore, this technology can be considered as **TRL-6.**

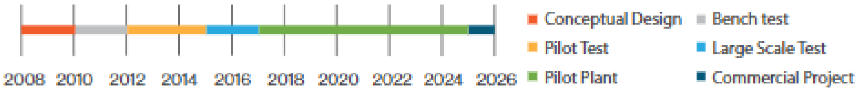


Figure 41 – Ion Clean Energy commercialisation timeline [116]

A feed study is currently underway for a 600 MW$_e$ CO_2 capture plant located at the Gerald Gentleman Station coal-fired plant in Nebraska which will progress the technology to TRL-7. Based on the commercial timeline obtained from the CCS institute, Figure 39, a commercial-scale plant using this technology is expected to be in operation by 2025 progressing the technology to TRL-8.

Costs – CO_2 capture costs have been measured in the range of **£27-£31/Te$_{CO2}$** utilising a coal-based flue gas [116]. Ion Clean Energy observed 25%-33% cost reduction compared to traditional amines because of the lower regeneration energy required for water-lean solvents.

4.3.2.3 Biphasic Solvents – IFPEN / Axens DMX Process

The term "biphasic solvent" refers to solvent processes where two liquid phases are formed once CO_2 is absorbed in the solvent. The heavy liquid phase contains the CO_2 and is separated out by gravity and sent for CO_2 regeneration [100]. The technology suppliers claim that the energy penalty applied to the overall plant decreases from -11.6 % to -9.1 % with DMX compared to MEA 30 % wt. [117].

Technology Development Status – IFPEN/Axens have conducted pilot-scale testing with flue gas from coal-fired power plants up to a scale of 3.5 MW$_e$ [116]. Therefore, this technology can be considered as **TRL-6.**

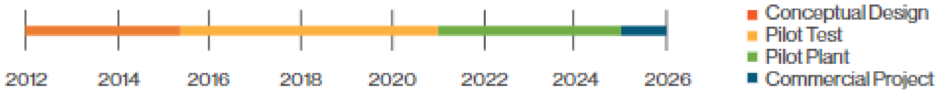


Figure 42 – DMX process commercialisation timeline [116]

The first large-scale commercial plant is planned at the Arcelor Mittal Site (cement plant) in Dunkirk [118]. Commencing in 2025, the DMX process will be utilised to capture up to 1 MTPA of CO_2, progressing the technology to TRL-8.

Costs – The technology developers have claimed CO_2 capture costs of **£33/Te$_{CO2}$,** compared to £42/Te$_{CO2}$ for a reference MEA solvent [117].

4.3.3 Solid Looping

4.3.3.1 Calcium Looping

The Calcium Looping (CaL) process utilises the reversible chemical reaction between lime (CaO) and CO_2 to capture CO_2 from a gaseous stream. CO_2 in the gas stream reacts with CaO in an exothermic carbonation reaction to form $CaCO_3$ at temperatures in the range of 600-700°C [110].

The product $CaCO_3$ from the carbonator is then sent to a separate vessel called a calciner where the calcination reaction takes place at a high temperature (around 900°C). This releases high purity CO_2 suitable for transport to a sequestration site.

The CaO produced is then sent back to the carbonator to complete the loop. Oxy combustion within the calciner is typically used as a source of heat for the calcination reaction. The CaO sorbent is derived from cheap, abundant, and environmentally benign limestone. Waste sorbent can be sold to the cement industry. The main shortcoming of Ca-looping technology is the decreased reactivity of CaO through multiple calcination-carbonation cycles.

This technology is potentially highly applicable to decarbonisation of cement manufacturing. If Calcium looping can be integrated with cement manufacture, the highly CO_2 emitting calciner could be replaced with a calcium looping plant which would capture CO_2 from flue gas and eliminate emissions during CaO production.

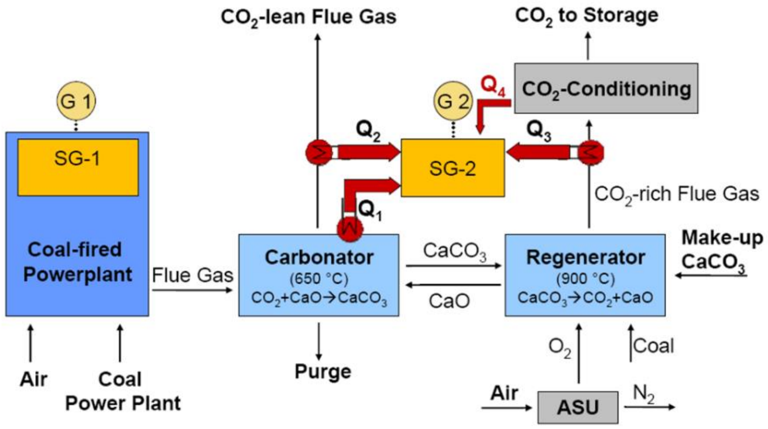


Figure 43 – Calcium Looping process schematic [119]

Technology Development Status – Two European projects are developing calcium looping capture technologies in steel (C4U) and cement production (CLEANKER) at pilot and pre-commercial scales [110]. Therefore, this technology can be considered as **TRL-7.**

The LEILAC2 project, which commenced in 2020, will build a demonstration plant that will capture round 0.1 MTPA of CO_2 from the Heidelberg Cement plant using Calix's advanced calcination reactor. The Calix reactor can potentially be heated using renewable electricity or fired with biofuels to provide low emissions heat, lowering overall plant emissions to near-zero.

Costs – Carbon capture costs have been estimated at **£36-£43/Te$_{CO2}$** based on a flue gas produced from a cement plant [120].

4.3.3.2 Chemical Looping Combustion

Chemical Looping Combustion (CLC) typically uses a dual fluidised bed system to circulate a metal oxide (oxygen carrier) between oxidation and reduction reactions. In the oxidiser, the carrier is oxidised, and, in the reducer, the metal oxide is reduced by the fuel, which is oxidised to CO_2 and H_2O. The reduced metal is then transferred to the air reactor (oxidiser) and re-oxidized before being reintroduced back to the fuel reactor completing the loop [110].

Using oxygen without nitrogen means that carbon capture is facilitated by chemical looping as the reducer exit gas contains almost all the CO_2 generated by the system which can be easily separated from water via condensation.

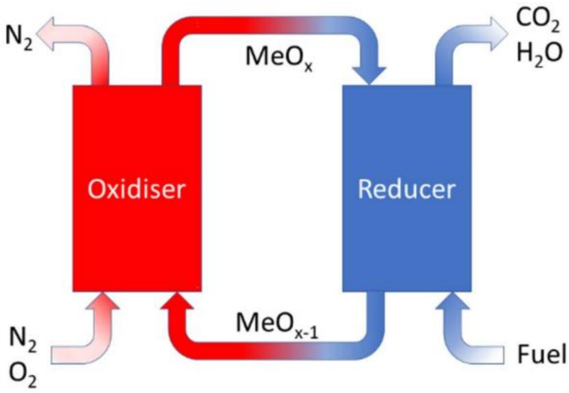


Figure 44 – Chemical Looping process schematic [100]

Current research and development efforts are focused on developing and refining oxygen carriers with sufficient oxygen carrying capacity and durability.

Technology Development Status – Chemical Looping Combustion is operational in around 35 pilot projects with capacity up to 3 Mwe for coal, gas, oil, and biomass combustion [110]. Therefore, this technology can be considered as **TRL-6**. Scale up will not be straight forward due to inherent differences between the operation of large- and small-scale fluidised beds [106].

Costs – Carbon capture costs have been estimated at **£36-£39/Te$_{CO2}$** based on operating within in IGCC plant [112].

4.3.4 Temperature Swing Adsorption – VelexoTherm

The Svante VelexoTherm™ Temperature Swing Adsorption (TSA) process uses proprietary solid sorbents to adsorb CO_2 from a flue gas stream. The adsorbents are arranged in a circular structure which is rotated (approximately 1 revolution per minute) to simultaneously expose different sectors of the structure to each step in the process. In step one, the adsorbent is exposed to the flue gas where CO_2 binds to the surface of the absorbent [116].

In step two, steam passes through the loaded absorbent structure, heating it and releasing the CO_2. The CO_2 is then easily separated from the steam (by condensing the steam to water) and is ready for compression. In the final step, the adsorbent is rotated into a cold air stream to cool it and prepare it for loading with CO_2 [121].

Svante Adsorbents have been engineered to catch and release CO_2 in less than 60 seconds, compared to hours for other technologies. The technology has been tailored specifically to the challenges of CO_2 separation from N_2 for carbon capture from post-combustion dilute flue gas using adsorbents.

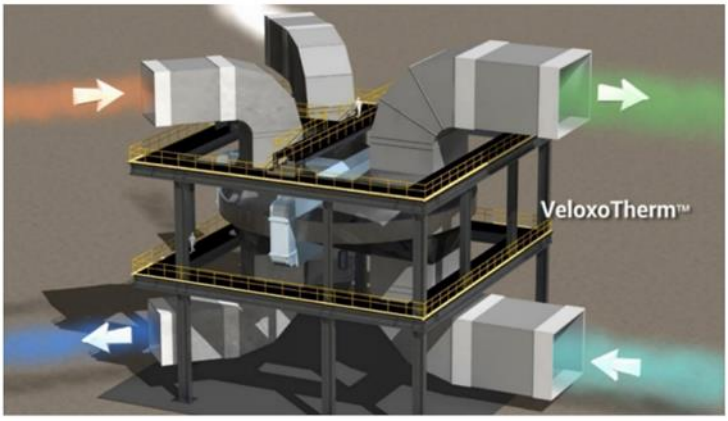


Figure 45 – VelexoTherm TSA unit [100]

Technology Development Status – The VelexoTherm process was successfully demonstrated at a 0.5 TPD scale during 2017 [116]. Therefore, this technology can be considered as **TRL-7.**

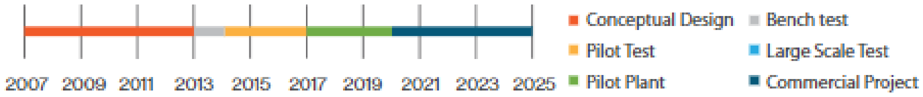


Figure 46 – VelxoTherm commercialisation timeline [116]

A demonstration plant is planned at a Lafarge Cement plant in Colorado, capturing up to 1.5 MTPA of CO_2 [121]. Once operational, this will progress the technology to TRL-8.

Costs – Carbon capture costs have been estimated at **£23/Te$_{CO2}$** from an unknown flue gas source with a 3 MTPA CO_2 capture capacity [116]. This cost will be confirmed once scale-up to this capacity is achieved.

4.3.5 Post-Combustion Gas Separation Membranes

Membranes perform a passive separation of CO_2 using a difference in pressures provided by blowers and pumps. Unlike amine-based capture processes which require large amounts of steam to strip CO_2 from loaded solvent, MTR's capture process is driven entirely by electricity. Membrane skids are compact and modular which enables capture systems to be fit into existing plants with little available space.

Membrane Technology Research's (MTR) Polaris™ modular membrane system is the first membrane developed specifically for CO_2 capture from combustion flue gas [122]. Polaris^{TM} consists of banks of pressure vessels that are combined to form a single 'mega-module' [100]. The system is 10 times more permeable to CO_2 than conventional gas-separation membranes and is applicable across several industries including: coal and natural gas-fired power plants, and cement plants. The membrane does not contain any chemical reaction or moving parts, making it simpler to operate and maintain.

MTR has two design variations: one for high CO_2 removal rates (90 %) and a second for partial capture rates (~60 %). Where a high capture rate is not required, the lowest cost-of-capture is often achieved with partial capture using a simple, "end of the tailpipe" solution.

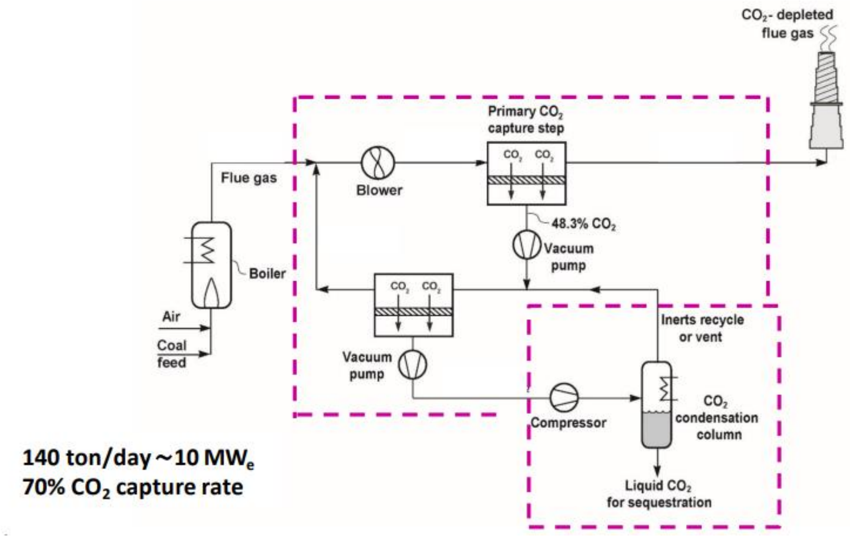


Figure 47 – MTR Polaris^{TM} process schematic [123]

Technology Development Status – In general, further R&D is focused on developing low-cost, durable membranes that have improved permeability and CO_2 selectivity, whilst being stable and tolerable of flue gas contaminations.

MTR have completed a 1,400-hour field test of its membrane in a 20 TPD CO_2 pilot plant at the National Carbon Capture Centre in Alabama, USA [116]. Therefore, this technology is considered **TRL-6**.

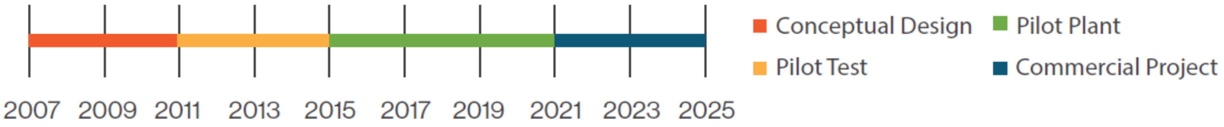


Figure 48 – MTR Polaris commercialisation timeline [116]

Funded by the Department of Energy, a project is ongoing between MTR Technology Centre Mongstad, Dresser Rand, Trimeric and Worley to design, build and operate a Polaris™ system to demonstrate a cost-effective membrane process for flue gas CO_2 capture from a coal fired power plant. The goal is to scale-up the advanced Polaris Gen-2 membrane and modules to a final form which is optimised for commercial use. This development will progress the technology to TRL 7 – for use with coal combustion flue gas.

Costs – MTR show the variation of CO_2 capture costs with feed pressure and process layout in Figure 49. Lowest cost operation can be achieved at partial capture rates (70-85%). For higher capture rates, a multi-stage cascade design is necessary which sharply increases costs. Approximately **£19/Te$_{CO2}$** is claimed to be achievable capturing 70-75 % of CO_2 from a coal fired flue gas.

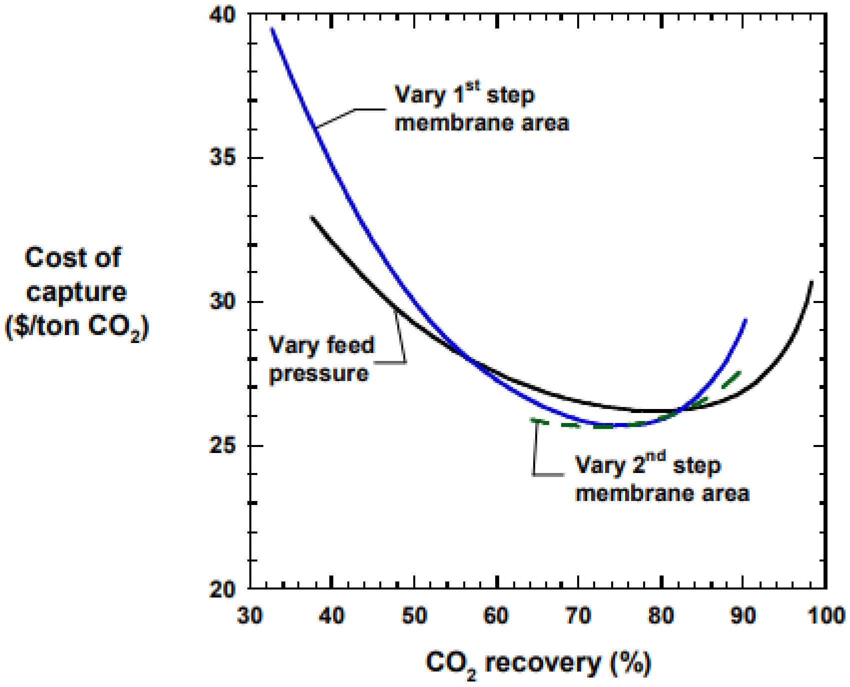


Figure 49 – Cost of MTR Polaris CO_2 capture with varying CO_2 recovery [122]

4.3.6 Cryogenic Capture

CO_2 can be separated from syngas or flue gas by using their different condensation and sublimation properties. The temperature involved in this process is typically around -60°C. The cooling can be provided by expansion of the process gas or by external refrigeration. There are several different methods that have been, however, key technology providers include CryoCell and SES.

The installation of cryogenic systems is highly limited by available cryogenic sources in order to make the process economic, meaning that location is limited to these sources as it depends on the location of an LNG station [124].

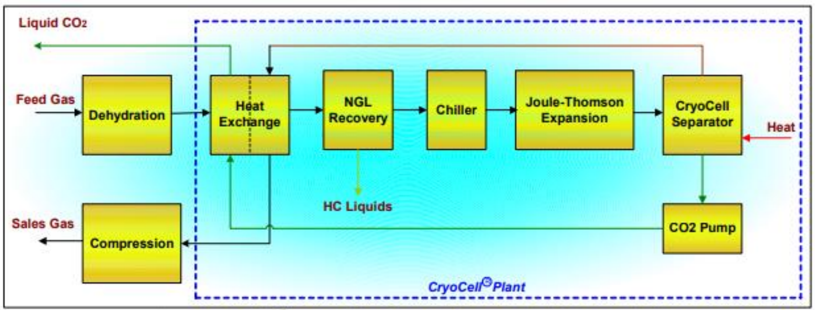


Figure 50 – CryoCell Cryogenic Separation schematic [125]

Technology Development Status – As part of commercialising the CryoCell® technology, a demonstration plant was designed and built by Cool Energy Ltd in Western Australia and tested in collaboration with industrial partners including Shell Global Solutions. The field test programme has demonstrated the technical viability of solid phase CO_2 separation and cost comparison studies indicate improved economic viability for high CO_2 gas field developments [125]. Therefore, this technology can be considered **TRL-7**.

The first commercial-scale demonstration of cryogenic CO_2 capture is planned by sustainable energy solutions, capturing up to 100 TPD of CO_2. This will progress the technology to **TRL-8.**

Costs – Sustainable Energy Solutions claim CO_2 capture costs less than **£25/Te$_{CO_2}$** for their cryogenic technology [126], however, assumptions behind this figure are unknown so cannot be reliably compared to other costs of CO_2 capture. The figure was determined for coal combustion flue gas, so capture cost would be significantly higher with a lower concentration flue gas stream.

4.3.7 Molten Carbonate Fuel Cell with Electrochemical Membrane

Fuel cells convert the chemical energy of gaseous fuels to electrical energy and heat. Molten carbonate fuel cells (MCFCs) are one type of fuel cell currently being developed. They are high temperature (550-650°C) fuel cells using a molten alkali metal (Li/Na/K) carbonate salt mixture as electrolyte.

Carbon dioxide in flue gas reacts with oxygen to form carbonate ions at the cathode of the cell. The carbonate ions then travel through the electrolyte to the anode where they combine with hydrogen to produce water and CO_2 and the fuel cell generates electricity. The CO_2 is then separated from the water ready for compression [127].

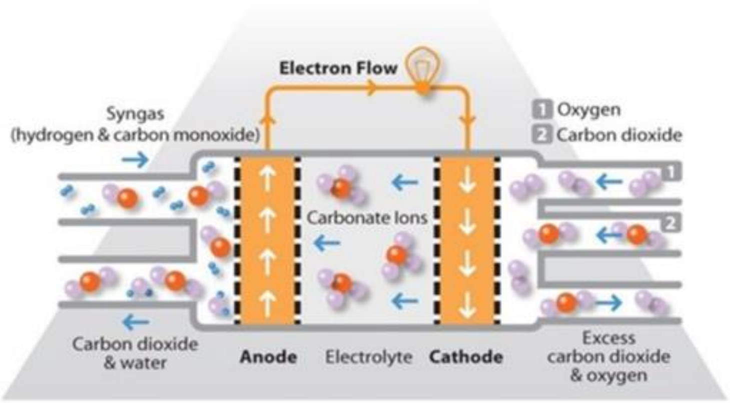


Figure 51 – MCFC schematic [128]

Technology Development Status – A pilot project has been completed to capture CO_2 from natural-gas and coal generating units at the James M. Barry Electric Generating Station. The project is in collaboration with ExxonMobil and up to 54 TPD CO_2 is captured [116]. Therefore, the technology can be considered as **TRL-7**.

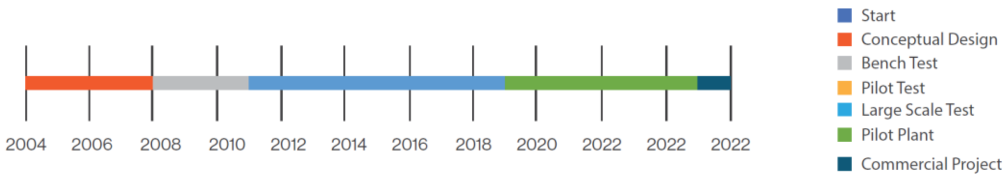


Figure 52 – MCFC commercialisation timeline [116]

Fuel cell stacks are constructed in a modular fashion which allows for uniformity but also suitable for homogenous large volume production. The geometry of the stacks allows easy installation even in crowded or compact areas.

Costs – Very low carbon capture costs of **£24/Te$_{CO2}$** have been reported by the developer for flue gas capture from a mixture of natural gas and coal fired generation units during pilot testing [116]. No other underlying assumptions are known.

4.3.8 Direct-Air Capture

Direct Air Capture (DAC) is the main competitor to exhaust gas-based point source emission capture technologies. DAC aims to capture CO_2 directly from the atmosphere using either liquid solvents or solid sorbents as the capture media. Key technology suppliers include Carbon Engineering, Climeworks, and Global Thermostat. DAC is expected to be scaled up to capture circa. 10MTe$_{CO2}$/yr by 2030 [129].

Net-negative global emissions are needed to reach the climate change mitigation targets. Furthermore, DAC offers an alternative to address carbon emissions from distributed sources and could be installed to manage fugitive emissions from the CCS network and leakage from geological formations. DAC technologies could in theory be situated anywhere provided there is access to an available energy source and sequestration sites.

However, there are significant challenges. Removing and concentrating CO_2 from air to a pure stream (> 90%) requires a much greater energy input and treated gas volume than CO_2 capture from concentrated point sources. This section analyses two of the DAC technology solutions that have developed furthest and have most publicly available information.

4.3.8.1 High Temperature Aqueous – Carbon Engineering

Carbon Engineering's DAC system uses an extremely large, dispersed wet-scrubbing air contactor integrated with two chemical looping processes using potassium hydroxide (KOH) or sodium hydroxide (NaOH) and calcium hydroxide ($Ca(OH)_2$) to capture CO_2 from the atmosphere [130].

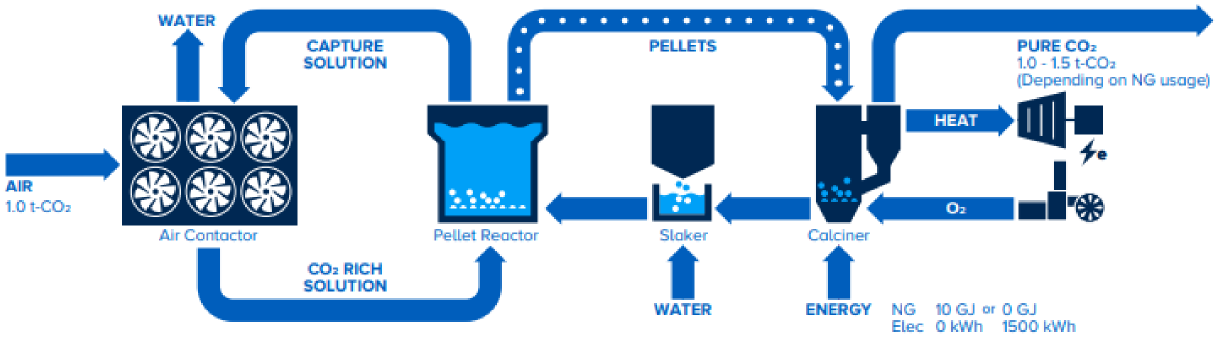


Figure 53 – Carbon Engineering DAC schematic [104]

The process starts with an air contactor – a large structure modelled off industrial cooling towers. A large fan pulls air into this structure, where it passes over thin plastic surfaces with potassium hydroxide solution flowing over them. This non-toxic solution chemically binds with the CO_2 molecules, removing them from the air and trapping them in the liquid solution as a carbonate salt.

The CO_2 contained in this carbonate solution is then put through a series of chemical processes to increase its concentration, purify, and compress it, so it can be delivered in gas form ready for use or storage. This involves separating the salt out from solution into small pellets in a structure called a pellet reactor (or causticizer).

These pellets are then heated to 900°C in the third step, a calciner, to release the CO_2 in pure gas form. This step also leaves behind processed pellets that are hydrated in a slaker and recycled. The process can operate with either renewable electricity or natural gas to provide the energy to the calciner. When natural gas is used, the CO_2 from combustion is captured and delivered along with the CO_2 captured from ambient air.

Technology Development Status – Carbon Engineering's technology has been demonstrated on a sub-scale with a fully functional prototype. Therefore, this technology can be considered as **TRL 7** [116]**.**

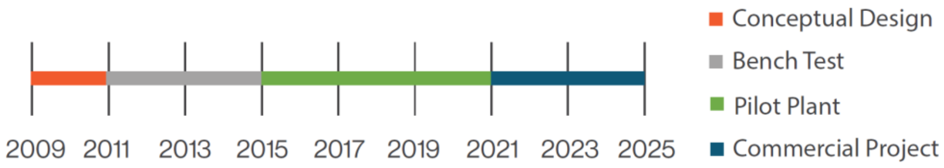


Figure 54 – Carbon Engineering DAC commercialisation timeline [116]

The largest commercial DAC plant to date is to begin construction in 2022 in the Permian Basin using Carbon Engineering's technology to capture up to 1 MTe_{CO2}/yr for purposes of enhanced oil recovery [131]. This will progress the technology to TRL 8.

Costs – Based on a 1 MTe_{CO2}/yr system, CAPEX of the first plant has been estimated at **£693/Te_{CO2}**. Powered by electricity (£42.50/MWh_{el}) with a 25-year lifetime, CO_2 capture costs are calculated at **£158/Te_{CO2}** and OPEX is estimated at 3.7 % CAPEX [132].

Based on a learning rate of 10 % and an assumed global scale-up of DAC technology, future CAPEX costs have been predicted. Lifetimes of DAC technologies are estimated to extend to 30-years beyond 2030:

Table 16 – Estimated future costs and global capacity of high-temp DAC, adapted from [131] and [133]

Parameter	2020	2030	2040	2050
Global DAC Capacity (MTe_{CO2}/a)	0.01 [133]	10 [133]	763 [131]	8,213 [131]
CAPEX (£/Te_{CO2}.a) [131]	693	179	104	79

4.3.8.2 Low Temperature Solid – Climeworks

Climeworks' DAC technology consists of modular CO_2 collectors, which selectively capture carbon dioxide in a two-step process. Firstly, air is drawn into the collector with a fan and CO_2 is adsorbed onto the surface of a highly selective filter material that sits inside the collectors [134].

Secondly, after the filter material is saturated with CO_2, the collector is closed. The temperature is then increased to between 80 and 100 °C which releases the CO_2 at a purity of over 99%. The gas is then cooled to 45 °C and collected. Climeworks' system typically uses 2,000 kWh heat and 250 kWh electricity per ton of CO_2 capture.

Technology Development Status – Climeworks' technology has been demonstrated at pilot-scale, capturing up to 900 Te_{CO2}/yr at the Hinwill plant in Switzerland [135]. In September 2021, Climeworks started operation of their 4,000 Te_{CO2}/yr capacity Orca project – although the performance of this plant at the time of writing is unknown. In 2022, Climeworks started development of a 36,000 Te_{CO2}/ yr commercial facility in Iceland called Mammoth which should be operational by summer 2024. Therefore, this technology can be considered as **TRL-7.**

Costs – Based on a 1 MTe_{CO2}/a system, CAPEX of the first plant has been estimated at **£620/Te_{CO2}**. When integrated with a free source of waste heat (1,750 kWh_{th}/Te), with a 20-year lifetime, CO_2 capture costs are calculated at **£102/Te_{CO2}**.OPEX is estimated at 4 % CAPEX [132].

Based on a learning rate of 10 % and an assumed global scale-up of DAC technology, future CAPEX costs have been predicted. Lifetimes of DAC technologies are estimated to extend to 30-years beyond 2030:

Table 17 – Estimated future costs and global capacity of low-temp DAC, adapted from [95]

Parameter	2020	2030	2040	2050
Global DAC Capacity (MTe_{CO2}/a)	0.01 [133]	10 [133]	763 [131]	8,213 [131]
CAPEX (£/Te_{CO2}.yr) [131]	620	161	93	71

4.3.8.3 SMART-DAC – CO2CirculAir

SMART-DAC is an innovative CCUS project led by CO2CirculAir as part of a consortium of partners including; Process Design Center (PDC), Optimus Plus Aberdeen, Heriot Watt University and Net Zero Technology Centre. The project has been funded through the BEIS GGR Innovation Programme and has completed Phase 1 with Phase 2 funding being released 2022.

CO2CirculAir's SMART-DAC technology aims to capture CO_2 directly from the air using a two-step process: absorption of CO_2 from air by membrane gas absorption (MGA) using a potassium hydroxide (KOH) solution absorbent with regeneration of the absorbent by membrane electrolysis/electrodialysis (ME/ED). Phase 1 has advanced the technology from TRL 4 to TRL 5 in the MGA aspect, and the regeneration process from TRL 4 to TRL 6.

The primary aim of the project is to redesign membrane gas absorption (MGA) modules for efficient CO_2 capture from air, with an aim of achieving 100 t-CO_2e/year capture capacity. To enable this, the pilot plant has been designed to capture 0.314 t-CO_2e/day, based on 350 operational days with a 10 % overdesign margin, equating to a total of 110 tC-O_2e/year capture capacity [136].

Shown in the figure below is the concept PFD schematic that has been used as the basis of design for the SMART-DAC pilot plant:

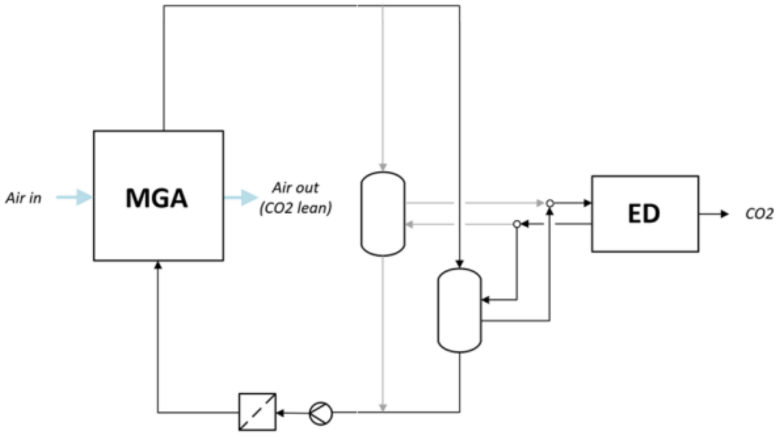


Figure 55 - SMART-DAC PFD Schematic [136]

A simplified version of the process is as follows: the MGA module uses a membrane to keep the gas and liquid phases separate while allowing mass transfer between the phases. The KOH absorbs CO2 from the air as it passes through the membrane, converting into potassium bicarbonate ($KHCO_3$) on contact with the CO_2. The $KHCO_3$ is converted back into KOH in the regeneration step to be reused as an absorbent and the CO2 is separated out.

For the contacting of air flow through the membranes, only wind circulation will be used as opposed to turbines used in current DAC systems. Power will only be required for the electrochemical regeneration process of the used absorption material. A tanker storage system will be used to manage operational down time and periods of low passage of air through the system to enable continuous and efficient operations.

The pilot plant is set to be demonstrated in Larne, Northern Ireland at the offices of B9, a test site partner for the operation and development of SMART-DAC.

4.3.8.4 Project D.R.I.V.E. - Mission Zero Technologies

Project D.R.I.V.E. (Direct Removal through Innovative Valorisation of Emissions) is a project funded BEIS that makes use of Mission Zero Technology’s innovative DAC (Direct Air Capture) technology.

The project is led by Mission Zero Technologies, with the consortium made of up Optimus Plus, an engineering consultancy company based in Aberdeen, and O.C.O. technology, a CCUS partner and future host for the pilot plant.

Figure 56 shows a representation of the DAC technology consisting of the main components; solution-based air-contactor, electrochemical separation module and the depressurisation process within a release chamber for producing the CO_2 gas at ambient temperature:

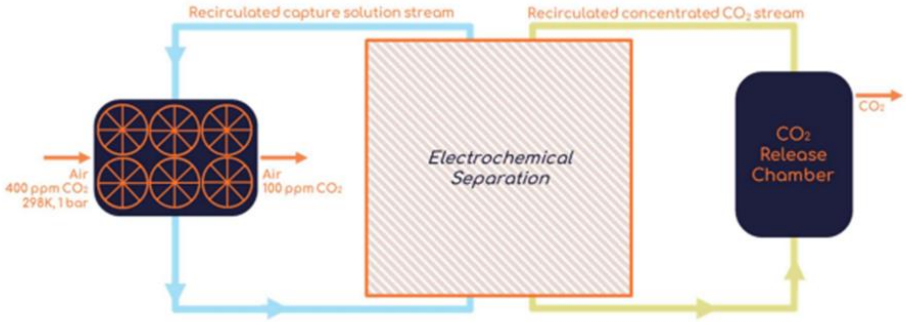


Figure 56 - Project D.R.I.V.E. DAC Technology [137]

The DAC pilot plant aims to use Mission Zero Technologies DAC technology to capture 120 t-CO_2/year at the site owned and operated by consortium partner O.C.O. technology. Phase 2 developments of the project are currently underway.

4.3.9 Allam-Fetvedt Cycle

The Allam-Fetvedt Cycle is an innovative natural gas (or syngas from gasification of coal) fired power generation technology. This technology can produce electricity with >97 % CO_2 capture at a levelised power price approximately 22 % higher than conventional natural gas combined cycle [100].

Oxy-fuel combustion produces CO_2 which is used as the working fluid to drive a turbine. This enables inherent CO_2 capture, compression, and dehydration as well as the elimination of NOx and Sox. The technology is not a retrofit solution and is only applicable to new power generation or compression applications.

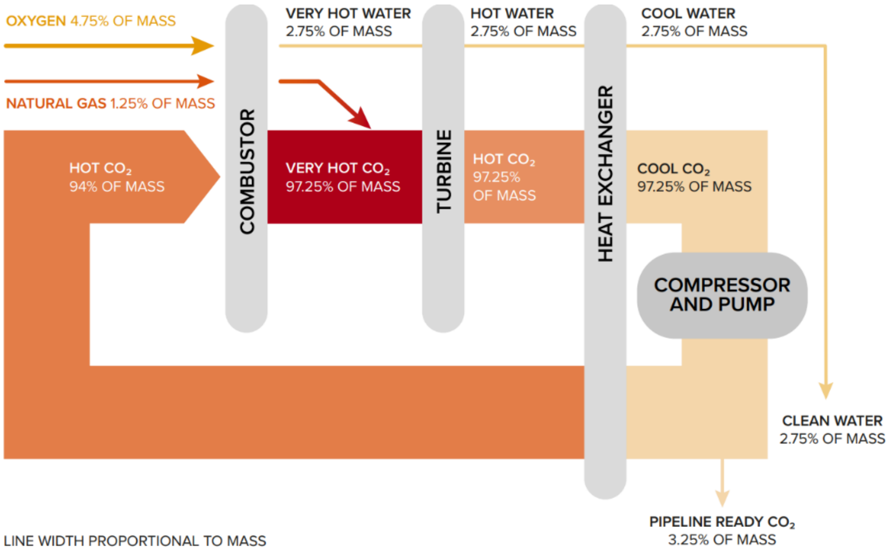


Figure 57 – Allam-Fetvedt Cycle schematic [100]

Technology Development Status – A 50M Wth Allam-Fetvedt Cycle commercial demonstration facility is currently operating in La Porte, Texas [116]. Therefore, this technology can be considered **TRL-7**.

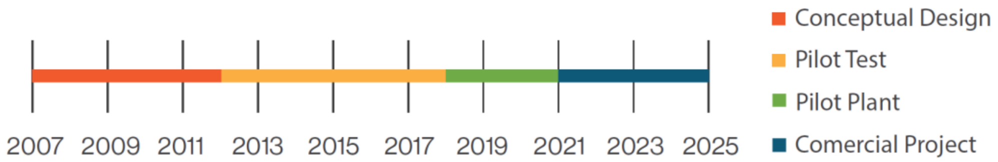


Figure 58 – Allam-Fetvedt Cycle commercialisation timeline [116]

Several natural gas commercial projects are currently in development as well as coal-based systems. A pre-FEED study for an Allam Cycle power production facility in the United Kingdom was announced by McDermott in June 2020.

Costs – Levelised cost of electricity is estimated at **£53/MWh** (in the US) with carbon capture rate greater than 97 %. This is in comparison to £43/MWh for a conventional gas-fired power plant (without CCS) and £60/MWh for a gas-fired power plant (with conventional CCS) [116].

4.3.10 Oxyfuel Combustion

The challenges of capturing CO_2 from dilute flue gas in post combustion capture can be mitigated if the combustion is carried out in the presence of oxygen instead of air. The burning of fossil fuel in an atmosphere of oxygen leads to excessively high temperatures – as high as 3500°C. The temperature is moderated to a level that the material of construction can withstand by recycling a fraction of the exhaust flue gases.

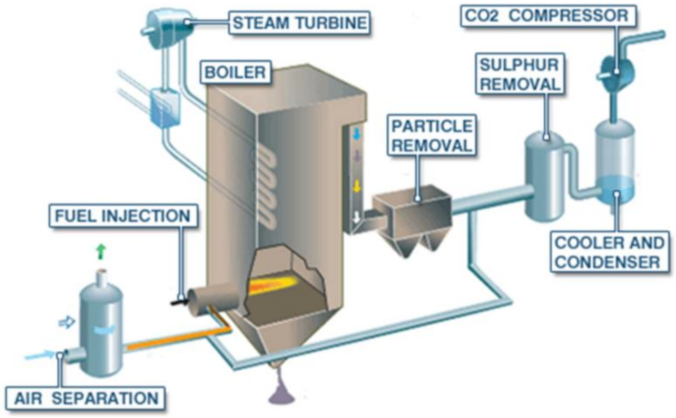


Figure 59 – Oxyfuel combustion process schematic [137]

Technology Development Status – Total's Lacq large pilot plant in France consists of a 30 MWth oxy-firing of a natural gas fired boiler, storing CO_2 in a depleted natural gas reservoir [106]. Therefore, this technology is considered **TRL-7**.

The scalability of this technology will be based on the scalability of the ASU (Cryogenic air separation units) which have high TRLs. Oxy-fuel boilers can be retrofitted to existing fossil-fuelled power stations.

Costs – Carbon capture costs are expected to be between **£28-32/Te$_{\mathbf{CO2}}$** from a cement plant [120].

4.4 Carbon Utilisation

4.4.1 Summary

CCU offers the opportunity to enhance the economic benefit of CO_2 capture and/or provide a use of CO_2 for emitters that lack the required infrastructure for transport and storage. Revenues from CCU applications could potentially offset some of the capital associated with a commercial-scale carbon capture project. For example, the deployment of a CCU application within a cluster could offer operational and commercial flexibility for optimal use of CO_2 [138].

A key stumbling block is that markets for CO_2 utilisation are already saturated with CO_2 produced from existing industrial processes. It is key that incentives are provided to increase the demand for alternative products using captured CO_2 which will act to drive the rate of CCU penetration into existing markets.

Moreover, most CCU technologies are yet to be demonstrated at a commercial scale. The high costs associated with these technologies represents a major barrier to wider deployment. Lowering costs depends largely on the significant R&D efforts both in the UK and worldwide. Table 17 outlines the technology development status of a variety of different CCU technologies.

Table 18 – Summary of reviewed carbon utilisation technologies

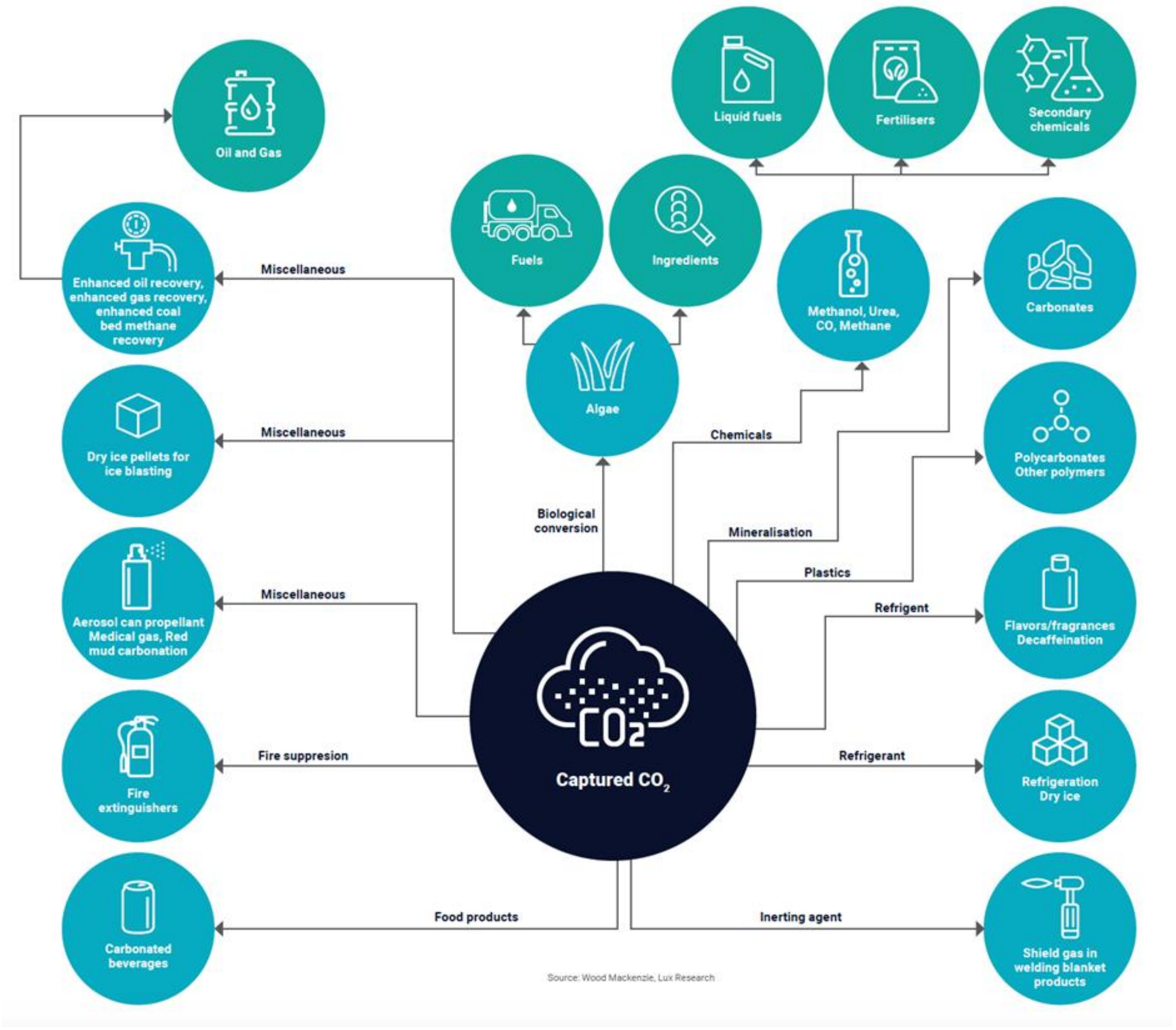
Technology	TRL	Status	Vendor(s)
Mineral Carbonation	8	O.C.O operates 3 factories in UK and have operations globally	O.C.O Technology (UK), Solidia (UK)
Fertilisers	9	CCm operates full scale demonstration plant for over 2 years	CCm Technologies (UK)
Protein Fish Feed	2-3	Received investment to build a pilot-scale plant	Deep Branch (UK), Kiverdi (US)
Methanol	8	George Olah facility – converts around 5,600t of CO_2 to 4000Mt pa of methanol per year[10]	Antency (Netherlands)
Methane	8	Audi 6Mwe e-gas plant in Wretle	Audi e-gas (Germany)
Algae Cultivation	5	Antency have tested the technology in laboratory environment now looking for funding for pilot scale.	ASLEE (UK), Antency (Netherlands)
Polymer Processing	6	Econic have a pilot scale plant and are now working towards commercial scale after receiving funding.	Econic Technologies (UK), Dream Production (Germany)

Carbon Black	7	Monolith Materials completed manufacturing of commercial-scale plant for carbon black and hydrogen production via methane pyrolysis.	Monolith Materials (US)
Carbon Nanotubes	4	Component/ System validation in laboratory environment	Carbon Corp (Canada)

4.4.2 Introduction

At present, the storage of CO_2 is generally still preferred over utilisation due to the current lack of largescale demand for CO_2 in industry, typically lower costs, and the scalability of subsurface storage. However, carbon utilisation has an important role to play in creating a market demand for CO_2 and will likely be essential to provide a cost-effective route to decarbonisation for certain assets without low-cost access to transport and storage infrastructure. If CO_2 can be utilised to reduce the cost of an existing process, then this will of course be favourable.

As identified in Net Zero Technology Centre's Closing the Gap Report [139], there are numerous CO_2 utilisation routes that are in various stages of development.



Source: Wood Mackenzie, Lux Research

Figure 60 – Utilisation pathways for CO_2 [139]

This section of the report explores some of the main CO_2 and solid carbon utilisation pathways that are currently under development and deemed most applicable to the roadmap project.

4.4.3 Mineral Carbonation

Mineral carbonation is comparable to an accelerated version of ‘natural weathering’. It involves reacting captured CO_2 with metal oxides – the most prevalent being magnesium and calcium oxide. The process fixes the CO_2 as a stable and insoluble carbonate. The chemical reactions for calcium and magnesium oxide:

$$CaO + CO_2 \leftrightarrow CaCO_3$$

$$\boldsymbol{MgO + CO_2 \leftrightarrow MgCO_3}$$

These metal oxides can occur in their natural form or can be obtained from metal oxide rich residues, on which this report will focus. Metal oxides provide the alkalinity needed in waste streams required for carbonation. An example is steel slag, whose composition is around 45-60% CaO, making this very useful for mineral carbonation. The equation below can show the carbonation reaction of steel slag [140]:

$$(Ca, Mg)SiO_3 + CO_2 \rightarrow (Ca, Mg)CO_3 + SiO_2$$

Using waste materials means that this technology will help cut CO_2 emissions and prevent alkaline wastes from going to landfills or being stockpiled. Suitable alkaline wastes [141] [142] [143]:

- Slag
- Air pollution control residue (APCr)
- Fly ash
- Bottom ash
- Cement waste
- Sludge ash
- Paper pulping and mill waste
- Wastewater treatment sludge
- Bauxite residue

O.C.O. Technology is a company based in UK with three operating factories in England and operations globally. They work by using naturally reactive waste and mixing this with water and CO_2 to form calcium carbonate, which they refer to as manufactured limestone. They claim that every thousand tonnes of manufactured limestone produced is equivalent to planting 4000 trees annually. Customers can use this technology to form bricks, blocks, tiles, and slabs [144]. O.C.O. Technology recently surpassed a milestone of having reprocessed half a million tonnes of air pollution control residue (APCr) [145].

Advantages – Utilisation of otherwise discarded waste streams. Doing so reduces the risk of dust-generating on landfills or rainwater infiltrating and leaching into groundwater. A vital benefit of this technology that makes it stand out compared to others is its potential to sequester a large volume of CO_2 permanently. Not only can this be used in industry, but it can also be stored safely underground as a method of carbon storage and requires minimal monitoring. Unlike with most other CCU applications, the process can work directly from flue gas [138]. Additionally, carbonation is an exothermal reaction and therefore releases energy that can be used elsewhere in the process to help reduce costs [146].

Challenges – Availability of waste may become a constraint in the far future as the abundance of steel and power plants decline in the UK. Another challenge expected is that waste products need to meet the UK end of waste regulation and not pose a threat to the environment or human health before turning waste into products [147]. Due to long established traditional methods in the building industry, it is likely a difficult market to penetrate.

Applications –An overview of carbonates formed by CO_2 mineralisation, and applications is shown in Figure 57.

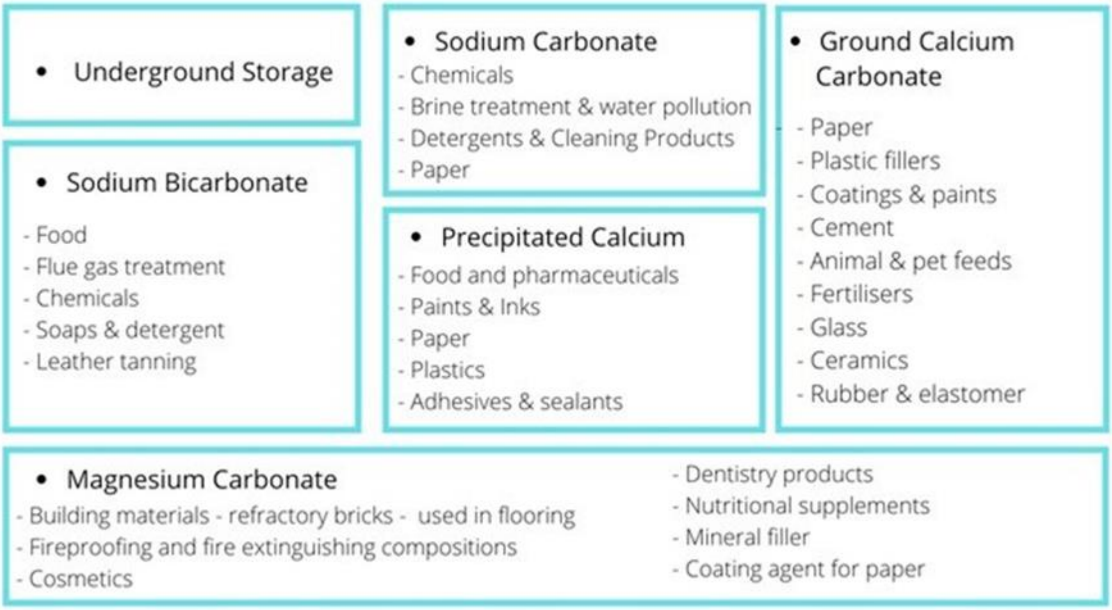


Figure 61 - Applications of mineral carbonation

According to the Scottish Environment Protection Agency, the UK uses around 200 million tonnes of aggregates in the industry. Scotland makes up 29 million tonnes of this [148]. The UK current situation holds a promising outlook for mineralisation due to the decreasing availability of aggregates from natural resources, and the expected increase in cost of landfilling waste [149]. When considering deployment of this technology, the location should be near accessible alkaline waste streams and appropriate CO_2 sources. O.C.O. Technology's plant is strategically placed next to an industrial site [144].

A high potential use of mineralisation that requires further attention is the production of concrete. This involves mixing CO_2 with waste streams to create cements with similar properties to the traditional Portland cement. The aggregates formed consist of calcium and magnesium carbonates, dependent on waste stream used, and can be blended with the likes of rock and additional materials to produce concrete. Table 18 below summarises several ongoing technology developments.

Table 19 – Cement and concrete technology developments using CO_2

Company	Location Base	Technology Description
Solidia	UK	Mixing cement with sand and filling open gaps with water and CO_2. Cement and CO_2 react to form calcium carbonate and silica, hardening the material by 10-25% [150].
Carbon Cure	Canada	Injects CO_2 and water into concrete forming calcium carbonate, improving the strength by 10-20% [151].
Blue Planet	US	Uses CO_2 from flue gas to produce carbonate rocks that can replace limestone used in cement [152].

The main advantage of this technology is the ability to sequester CO_2 permanently. Research has also shown this concrete can exhibit better qualities such as strength and fire resistance [153].

Costs – Huijgen et al. analysed costs for sequestering CO_2 by aqueous mineral carbonation and using CO_2 steel slag as a feedstock to be £46.5/Te_{CO2} sequestered [154]. Another paper researched waste cement as a feedstock to produce $CaCO_3$ at a cost of £16.4/Te_{CO2} sequestered [155]. The cost of aggregate production is estimated at around 20% higher than the selling price of the conventional process [156].

4.4.4 Fertilisers

Carbon dioxide emissions can be used to produce a pelletised carbonate type fertiliser. Farmers can spread this across fields to boost crop productivity. There are several types of fertilisers that can utilise CO_2.

An example is Calcium Ammonium Nitrate (CAN) which is conventionally made using ammonia combined with mined limestone ($CaCO_3$). This limestone could be replaced by $CaCO_3$ produced from the mineralisation of CaO using CO_2 emissions captured from the ammonia plant [157].

An example involving UK based company that produces fertilisers from waste streams are CCM Technologies. This company relies on three inputs that are combined to form a sustainable fertiliser [158]:

1. Fibrous materials – such as grass, straw, woodchip.
2. Ammonia – waste streams such as sewage and food waste have high nitrate, phosphate, and potassium volumes (the breakdown of organic waste is a natural source of ammonia).
3. CO_2 – recovered from waste streams such as biomass.

A more common use of CO_2 and ammonia is in the production of Urea. This fertiliser is a fundamental chemical in the agriculture sector and is formed from ammonia and CO_2 [159]. A flow diagram of how urea can be made using an ammonia plant CO_2 is shown:

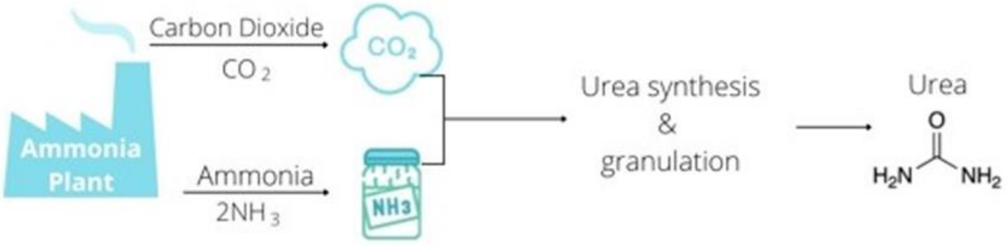


Figure 62 - Flow diagram of urea production using CO_2, adapted from [157]

Advantages – The process involving utilising ammonia from food waste is beneficial as 3.6 million tonnes of food is wasted by the food industry every year in the UK [160]. The process can remove up to 3.5 tonnes of CO_2 for every tonne of fertiliser. These fertilisers can provide all the same nutrients as the traditional fertilisers and be used in the same machinery making the transfer over to this technology very easy for farmers [143] [158].

Challenges – The demand for fertiliser in Scotland is seasonal and will depend on the crops in season. In contrast, industries will emit most waste streams of CO_2 at a constant rate. Therefore, a plan for storing excess fertiliser must be in place. Most of the UK's fertilisers are imported, while some research says this is an opportunity for Scotland to produce its own, others say this market is already established and saturated for urea production. This also highlights the lack of expertise in this sector within Scotland and may limit growth [161].

Applications – The main application of fertiliser is for farming purposes and spreading over crops. However, urea can also form resins, glues, beauty products, and health products [162].

Another similar use of CO_2 in promoting plant growth involves horticulture. This process requires diffusing CO_2 into greenhouses to accelerate plant production, which may be worth researching further [143]. Climeworks is involved in a project in Zurich which captures 900 Te_{CO2}/yr through DAC, which is supplied to a greenhouse to help promote the growth of tomatoes and cucumbers [163].

Deployment areas are best suited to applications producing high purity biogenic CO_2 such as whisky distillery fermentation or anaerobic digestion. This form of CO_2 is relatively simple to capture and is an ideal purity for produce fertilisers [161]. Glasson Fertilizers, a fertiliser plant located in Montrose, specialises in CAN fertilisers. There are also three whisky distilleries located in the same area, therefore presenting an opportunity for these industries to work together [164].

Costs – A paper investigating CO_2 utilisation in the production of urea estimates the cost to be £272.6/Te_{CO2}. This is around £109.4/Te_{CO2}more expensive than the traditional cost. However, this paper is from 2011 and may be outdated [165]. A future plant could theoretically look to remove 0.5 MTe_{CO2}/yr with an input cost of around £395 million and producing 1.7 Mt of fertiliser with a market value of £500 million [161].

4.4.5 Renewable and Low-Carbon Methanol

In comparison to conventional fossil fuels, combustion of pure methanol (CH_3OH) releases no sulphur oxides (SOx) and fewer nitrogen oxides (NOx) [166]. Compared to petrol, methanol emits 15-20% less carbon during combustion due to its high hydrogen to carbon ratio. Methanol is also less reactive and willingly biodegradable in the atmosphere – formaldehyde is its one toxic element, whilst petrol emits formaldehyde as well as dozens of more hazardous compounds. The half-life of benzene, a toxic additive found in petrol, ranges from 10-730 days in groundwater. In comparison, methanol in groundwater is only 1-7 days. Overall, using methanol can help companies meet emission targets for vehicles, especially ones that are harder to decarbonise, such as the aviation or marine sectors [167].

Methanol can be synthesised in several ways with varying carbon emissions. Traditionally, methanol is produced on an industrial scale through conversion of coal and gas feedstocks into syngas. After conditioning, syngas is hydrogenated into methanol [168]. Without carbon capture or renewable power input, this route is classed as high carbon intensity (brown and grey methanol).

If methanol can be produced with lower carbon footprint by utilising waste CO_2 or using a bio-material feedstock, whilst powered by renewable electricity, the net carbon impact can be reduced by as much as 95 % [169]. Renewable methanol can be produced using renewable energy and renewable feedstocks via two routes [170]:

- **Bio-methanol** is produced from biomass feedstocks including forestry and agricultural waste, biogas from landfill, sewage, municipal solid waste and black liquor from the pulp and paper industry.

- **Green e-methanol** is obtained by using CO_2 captured from renewable sources (i.e., BECCS and DAC) and combining with green hydrogen.

Additionally, **low-carbon methanol** (or blue methanol) can be produced when the carbon intensity of the traditional methanol process is significantly reduced. This can be done through injecting CO_2 from another process into the methanol synthesis loop or by decarbonising syngas production from natural gas. Further, combining captured CO_2 with green hydrogen is another way to lower the carbon intensity and is similar in process to green e-methanol production, however, CO_2 is not derived from renewable resources.

The pathways of particular interest to this project are green e-methanol and low-carbon methanol production as they are highly scalable methods of production that can utilise large quantities of CO_2.

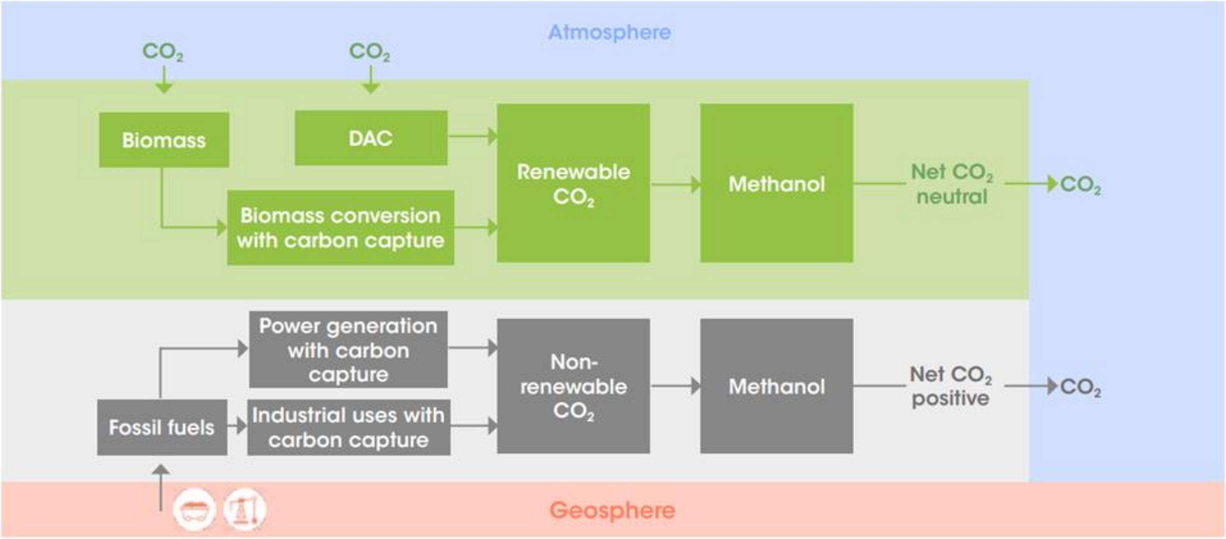


Figure 63 - Methanol Production with CO_2 feedstock [170]

Carbon Recycling International (CRI) has been operating a commercial 'CO_2 to methanol' demonstration plant since 2011. This is known as the George Olah plant, operating in Iceland. The plant has a capacity of 4000 t of methanol a year. CO_2 is sourced from emissions at a geothermal plant. Similarly, geothermal energy is used for the electrolysis of water to obtain H_2. The methanol produced from this plant is mixed with gasoline, utilised for biodiesel generation and wastewater denitrification. There are plans for this plant to produce 50,000-100,000 t of methanol yearly in the future [170].

Antecy is a company based in the Netherlands that has developed a pilot scale plant to capture CO_2 directly from the air to produce renewable methanol. Their technology harnesses solar energy to supply energy for the synthesis of methanol. The methanol also acts as seasonal storage of this energy in periods such as summer, where there is excess sunlight [171].

Advantages – Methanol is one of the most valuable industrial chemicals as it is critical for synthesising various chemical compounds [172]. Renewable methanol can reduce carbon emissions by substituting varying amounts of fossil fuels in different combustion processes. Substitution can decrease CO_2 emissions by 65- 95% depending on the carbon intensity of production and feedstock used. Methanol can also be used as a hydrogen storage and transportation medium with only minor modifications of existing infrastructure required [170].

Challenges – Methanol production is energy intensive, and so the high cost of production is a significant drawback. The use of excess renewable electricity can reduce costs; however, a consistent supply of energy is required. Research suggests that methanol using CO_2 from a cement plant is 2 – 2.5 more costly than the conventional process [173] [174]. CO_2 is also a linear molecule; therefore, it is very stable and does not react without a catalyst. Research is ongoing, investigating more efficient and affordable catalysts to reduce the energy required for conversion. Another limitation is the current restrictions on methanol blending; currently, most vehicles cannot combust high methanol blends due to methanol's corrosive properties.

Applications – Methanol is a highly versatile chemical compound with many applications. It can be used as a chemical feedstock to make compounds such as formaldehyde. Table 19 outlines primary chemical feedstocks produced, and their uses. Figure 60 highlights the market share for methanol uses.

Table 20 – Applications of chemical feedstocks synthesised from methanol

Chemical Feedstock	Applications
Formaldehyde	Resins, glues, plastics
Dimethyl ether	Aerosol propellant
Acetic acid	Polyester gibers and polyethylene terephthalate
Light olefins	Ethylene and propylene
Ethers (MTBE)	Fuel additive

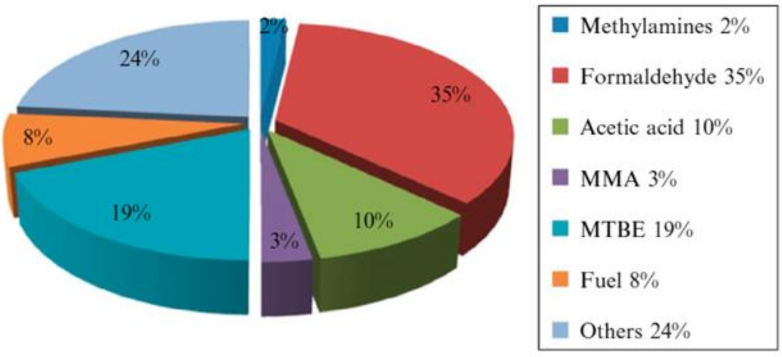


Figure 64 - Percentage share of methanol applications [175]

Costs – Work by Hepburn et al. have highlighted the process of producing methanol from capture CO_2 approximately 30% more expensive than traditional methanol production methods [156].

Excluding any carbon credits, the current production cost of e-methanol is estimated to be in the range £600-£1,200 per ton assuming CO_2 is sourced from BECCS. If CO_2 is obtained by DAC, then e-methanol production costs would be in the range £900-1,800 per ton. By 2050, this could reduce to £180 - £460 and £210 - £460 per ton, respectively [170].

4.4.6 Synthetic Methane

Like the methanol process, methane, can also be formed by the catalytic hydrogenation of CO_2, these processes are often referred to as power-to-gas (PtG) and has the following reaction [176]:

$$\mathbf{CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O}$$

Methane production using CO_2 is commonly done by either catalytic methanation or biological methanation. Catalytic methanation is performed at temperatures of 200-750⁰C and 20 bar and typically uses nickel as a catalyst [177]. In comparison, biological methanation involves using methanogenic microorganisms at temperatures between 20-70⁰C and 5 bar. Both processes can use hydrogen from electrolysis powered by renewable electricity and carbon dioxide from either direct air capture or captured from industrial emissions. This section focuses on power-to-methane based on CO_2 capture from industrial sources and H_2 produced through electrolysis. The PtG process is shown in Figure 61.

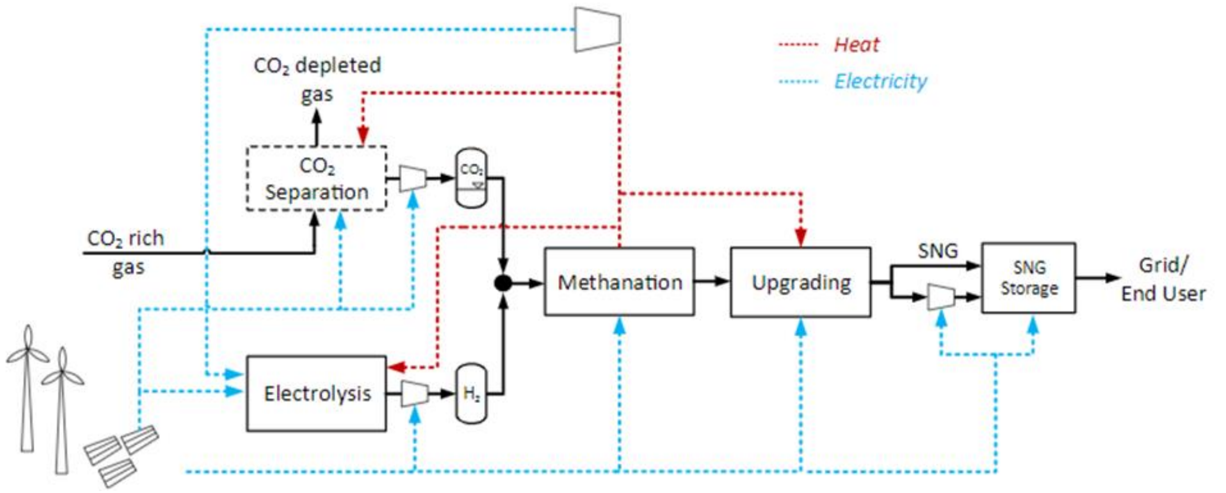


Figure 65 - PtG process flow using electrolysis and CO_2 [178]

Audi operates the first industry scale power-to-methane plant in Germany. Their process utilises surplus electricity to split water to obtain hydrogen. They hope to use the hydrogen to fuel cars eventually; however, the infrastructure was not available on the date of projection commission, 2013. Instead, they use CO_2 to react with the hydrogen to produce synthetic methane, creating by-products of water and oxygen. This gas can be used at compressed natural gas (CNH) filling stations across Germany [179].

Advantages -The biggest advantage of synthetic methane is its widescale uses across industry and existing infrastructure for transportation. Synthetic methane can be used, stored, and transported like methane from natural gas. Using surplus renewable energy allows for energy to be stored in the form of methane. Synthetic methane can be stored at large scale [180].

Challenges – If CO_2 is gathered from fossil fuel-based emissions, the CO_2 is only temporarily stored until the synthetic methane is burned again. However, carbon intensity can be effectively halved if the approximately the same CO_2 emissions result from double the energy consumption.

The most significant challenge for production of synthetic methane is the cost. Synthetic methane can cost up to 4 times more when compared to fossil alternatives so required significant concessional policies so it can compete with other green gas alternatives [181]. Power-to-gas represents a valuable product utilising CO_2, but the storage of the CO_2 is short-lived as it is re-released into the atmosphere after combustion (unless the CO_2 is produced from renewable sources such as biomass).

Applications – Synthetic methane has the same applications as fossil fuel-based methane, and it is the chemical building block to produce several chemicals, materials, and plastics. Methane can also fuel homes, heaters, automobiles, ships, ovens, and power plants. The gas can also directly replace natural gas in the national grid network and be used for electricity generation [181]. It can act as a storage for hydrogen or be stored underground.

Costs – A study carried out in 2016 by ENEA calculated the levelised costs of power-to methane. Results varied depending on the price of electricity and the availability of lower-cost electricity throughout the year. The power-to-methane process was estimated to cost between £85-172/MWh [181] [182]. Another estimated costs 380% more than conventional methane [156]. This highlights the significant work still needed in this area to lower the cost of synthetic methane production before it can become financially viable [181] [182].

A further study by Navigant [93] assumes free CO_2 from a biogas upgrading site, and free excess renewable electricity to power on-site hydrogen production (4,000 hours annually) to estimate a synthetic methane cost of £63/MWh by 2050.

Suitability – There are no known UK plants producing synthetic methane. However, plants exist across Europe, such as the one operating in Germany for Audi. This Audi plant is 6MW and produced around 1000 metric tons of e-gas annually and removed around 2,800 metric tonnes of CO_2 in the same period. This is the same amount of CO_2 22,000 beech trees would absorb in the year [179] [183]. Deployment plans would need to consider being next to a suitable CO_2 source. Access to high volumes of surplus electricity is also essential for this plant to produce H_2 at low costs, or access to low cost renewable H_2. The proximity to the gas network and a water supply for electrolysis is also important. ITM Power suggested that numerous smaller-scale plants may be more suitable for this technology. Their suggestion is due to the geographic relationship between gas and electricity grids. Locating nearby an appropriate CO_2 source is thought to be more limiting. For this reason, a 'decentralised distributed approach' could be a more attractive suggestion [143].

4.4.7 Algae Cultivation

Algae is a photosynthetic organism that requires growth-promoting nutrients such as CO_2. They play an interesting role in the future for forming renewable, carbon-neutral biomass and oil products. The CO_2 is required for photosynthesis but supplying higher concentrations of CO_2 than already in the ambient air is expensive. CO_2 can be captured from nearby point sources, as well as through DAC, which might be more suited to a remotely located site. It is not currently understood the percentage of CO_2 that is transferred to the algae and permanently stored.

Various solutions are being developed to maximise process efficiency and uptake of CO_2 by algae cultivations. CO_2 can be transferred to the algae culture in multiple ways:

- **Bubbling** – CO_2 can be bubbled through cultivation sites to accelerate growth. The smaller the bubble size, the greater the absorption rate. This technique requires has high energy requirements and an intricate control system [184].
- **Bicarbonate Solution** – formed through the Solvay process which involves adding CO_2 to ammoniated brine water [143]. This method involves dissolving liquid bicarbonate solution into the algae cultivation and allows for a more efficient CO_2 transfer than bubbling. This method must be monitored closely due to nitrogen levels and pH stability that may affect the optimal growth of algae [185].
- **Microencapsulation** – highly permeable shells with the core comprised of liquid carbonate. The surface area of these is vast due to their minute diameters (100-600 micrometers). This method is in its earlier stages of research and development for the optimal system. However, research has noted that capsules may potentially block or scatter light reaching the algae [186].
- **Membrane Mediated Delivery** – Membrane technologies are advantageous as they are inert and therefore require less maintenance and energy. CO_2 concentrations gradients can allow for the delivery of the nutrient to algae. However, membranes require a reasonably large surface area and control systems [184].

The ASLEE project in Scotland aims to use renewable energy to produce microalgae. This alga can be an excellent source of proteins for hatcheries and fish feeds, such as salmon farms. The project also uses local waste streams of CO_2 and nutrient wastes from the whisky and agriculture industries. This project has received £2 million of investment and looks to deliver 40,000 litres of photobioreactor capacity [187].

Antecy, also involved in producing synthetic fuels, has developed a CO_2 algae system that takes CO_2 from the air or flue gas and is fed into algae tanks. Their technology has been tested in representative environments but is now looking for funding to pilot the technology [188].

Advantages – Algae are photosynthetic organisms and therefore absorbs CO_2 whilst releasing oxygen, improving the air quality, and providing various end uses. Biofuel systems often rely on food crops such as corn and soybeans, which may lead to competition in food production and raise global food prices; however, algae are a more attractive feedstock as they are not in direct competition with food production and can be harvested any day of the year [189]. Algae also have a much higher growth rate and productivity than on-land plants. The carbon impact of algae-based biofuels is estimated to be up to 70% better than fossil fuels [190].

Challenges – Despite the many benefits algae can bring to a low carbon future, many challenges are still to be addressed to deliver carbon reductions on an impactful scale. Algae cultivation has high water and energy usage due to the constant mixing of the cultivation system and dewatering of the microorganism [191]. Algae also require many other nutrients, such as nitrogen and require a steady pH. Thus, extra refinement steps are needed for contaminated CO_2 streams because contaminants such as sulphur oxide will increase the alkalinity [184].

Most existing power plants emit more CO_2 than the average cultivation plant needs. Therefore, a challenge faced is how to manage excess CO_2. Furthermore, algae cultivation is demanding in terms of locating near several necessary resources and therefore finding suitable locations may be challenging [184].

Applications – There are many algae applications, and these include biofuels, pharmaceuticals, pigments, cosmetics, fertiliser, fibres for paper, wastewater treatment, and proteins. An example is MicroBio Engineering, a company based in California with expertise in microalgae production, some of their uses mentioned are [192]:

- **Biofuels –** Algae are an attractive feedstock to biofuels due to their high production rates, ease of cultivation and use of wastewaters on which industry can cultivate algae.
- **Aquaculture feeds** – Algae are a valuable source of proteins and essential oils, vital for aquaculture growth and health, such as in the use of fish farms or hatchery.
- **Animal feeds –** Similarly**,** the algae are an attractive source of protein and fatty acids – vital for animal health. Algae has also been shown to out-perform soybeans in delivering more essential amino acids.
- **Nutraceuticals –** Algae are at the vanguard of this industry. They can be used in the makeup industry or to create food supplements due to their attractive qualities such as antioxidants, phytonutrients and omega-3's.

Costs – There is little information available on the direct cost of utilising carbon emissions to supply an algae plant. However, research suggested that the distance and transportation of CO_2 will represent a considerable cost. Hence, DAC may be a solution to the transport issue; however, this needs to become commercially affordable [184].

Suitability – One tonne of algae has the potential to sequester almost two tonnes of CO_2. A large algae cultivation plant, 1M-litre, could capture 2,700 tons of CO_2; this is equal to taking 600 cars off the road annually [193]. Currently, there are around 447 algae production sites across Europe [194].

A deployment base is challenging for algae cultivation. This difficulty is due to the need for access to water, nutrients such as CO_2 and nitrogen, and substantial land requirements that may not be available next to industrial plants. Therefore, the infrastructure required for transporting and storing CO_2 will be costly [191]. Algae cultivation farms may better suit a smaller scale CO_2 emitting industry. This assumption is due to the algae requiring less CO_2 than the average emissions from a plant, so it will have less excess CO_2 to manage and store, even though research suggests this is costly compared to CO_2 from a larger plant [184].

4.4.8 Polymers

Carbon dioxide can be used to synthesise polymers such as polypropylene carbonate (PPC) and polyethylene carbonate (PEC) for use in various products and applications [138]. An example is reacting CO_2 with propylene oxide to produce polycarbonate polyols. This can sequester CO_2 for long periods, replace fossil-based feedstocks and be used in various applications.

CO_2 is a very stable compound; therefore, an advanced catalyst and efficient co-reagent are necessary to utilise CO_2 whilst using the minimum amount of energy to convert it into other compounds. Conventional CO_2 polymerisation takes place under high temperatures and pressures, but now, can occur at lower pressure and temperature due to catalyst developments [143] [195].An illustration of how these polymers are made can be seen below for propylene oxide and cyclohexene oxide.

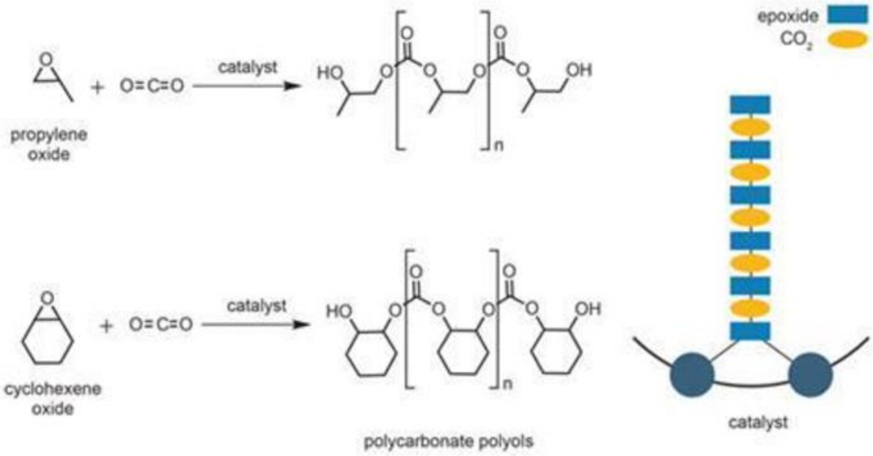


Figure 66 – Synthesis of different polymers [196]

Econic is a UK based company that develops catalysts that can effectively utilise CO_2 to produce polymers. They can produce polymers that contain up to half their weight of CO_2. The catalysts they use can also operate at similar pressures in the existing polymer manufacturing industries. Drax power station in England has recently partnered with Econic to use CO_2 captured from their biomass generation to replace oil in plastics generation. This opportunity represents a significant advancement that could enable other sectors to do similar [197].

Covestro, based in Germany, utilises carbon to make polymer products. Their process replaces up to 20% of fossil feedstock with CO_2. Their CO_2 based polyols take the name cardyon and are used in multiple applications such as mattresses, clothes, shoes, and cars [198].

Advantages – Econic claims that if 30% of the polymer market were to adopt this by 2026 this would result in 3.5M tons/year less CO_2 emissions, the same effect as taking 2 million vehicles off the road each year. This process would also decrease the dependence on fossil fuel-based feedstocks. Using CO_2 based polymers also brings several benefits to the product itself. Econic claims the following benefits of polymers derived from CO_2 [199]:

- Good rigidity
- Lighter weight – reduced material needed but similar strength
- Advanced chemical resistance
- Less flammable
- Improved abrasion protection
- Improved endurance to weather variations – extending coating life

Although polymers do not sequester CO_2 permanently, they can store it away for decades. If the UK adopts this technology, it will lead to a reduction in petroleum-based polyols. If a processing plant could directly use waste streams of CO_2, transportation and purification costs could be reduced and result in a more cost-effective and efficient system [196].

Challenges – A significant barrier to technology adoption is market acceptance. Although these new polymers are expected to bring many benefits to their customers, their viability in downstream processes is unknown. As there are so many applications for polymers, the acceptability is likely to vary from each application. The CO_2 utilised is also presumed to need purifying, depending on the source, which will add to costs [143]. The catalysis therefore must be strong enough to cope with impurities in the CO_2. However, Econic's catalyst, cyclohexene oxide, was used on two CO_2 streams; one using pure CO_2 stream from a cylinder and one from a coal-fired CCS plant. The resulting polymers for base cases had no differences [196].

Applications – Table 20 highlights several companies producing polymers using CO_2 and their applications.

Table 21 – Companies and applications of CO_2 based polymers

Company	Location Base	Applications
Econic	UK	Rigid and flexible foams, coatings, elastomers, sealants, and adhesives
Cardia Bioplastics	Australia	Biodegradable plastic bags
Covestro	Germany	Mattresses and upholstery
Empower Materials inc	US	Binders and sealants
Novomer Inc	US	Plastics, coatings and adhesives, sealant
SK Polymer	Thailand	Packaging and automotive

Costs – The cost of production of polymers on average is estimated to be £1007 per ton produced. This is around 30% cheaper than the selling price (~£1468) [156].

Suitability – The production of polymers in the UK has great potential due to their expertise in catalyst research. The CO_2 demand for polycarbonate in the UK has been estimated to reach 100 kTe_{CO2}/yr by 2030. This would be the same as operating two commercial-scale plants, producing approximately 100 kTe_{CO2}/yr of PEC/PCC with CO_2 taking up 50% of the weight [143].

A suitable deployment base would require a stream of CO_2 and proximity to a chemical plant. Ideally, a cleaner source of CO_2 stream is preferable, such as biomass. However, Econic claims their catalyst is suitable for less pure CO_2, such as coal plants. An appropriate location in Scotland could be Grangemouth, which is the home to a large refinery and petrochemical plant with an abundance of CO_2 emissions and experience producing epoxides [143].

4.4.9 Carbon Black

Carbon black is a microscopic black fluffy particle that is produced through the incomplete combustion of hydrocarbon-based products and is used predominantly as pigmentation and reinforcement of tyres.

Carbon black is not the same as soot and is characterised by its high surface area to volume ratio and negligible content of polycyclic aromatic hydrocarbon. There are two primary methods to form carbon black:

Oil furnace process - The oil furnace is the most standard process for forming carbon black. It begins by heating oil and air and feeding this into a reactor. Air and hydrocarbons then undergo several reactions, including partial combustion and thermal breakdown. Water is injected into the reactor to cool down and stop the reaction, resulting in a black smoke stream leaving the reactor. This black stream then passes through a fabric filter, which captures carbon black. The carbon black is then pelletised and dried, so it is ready for transportation [200].

Methane pyrolysis – Methane pyrolysis, also referred to as methane cracking, is the chemical breakdown of methane at high temperatures to form hydrogen gas and carbon particles (see Section 2.2.9). All the carbon produced is collected in a fabric filter and can be sold as carbon black. Sales of carbon black can help offset the cost of hydrogen production and reduce emissions [201]. Decomposition of methane can be expressed by the following:

$$CH_4 \rightarrow 2H_2 + C$$

Applications – Carbon black has an extensive list of applications. Due to its qualities such as: strengthening, electric and thermal conductivity, light-absorbing and dark pigmentation. About 70% of all carbon black manufactured goes into tyres [200]. Other main uses are summarised below:

- Colouring agent for inks and paints
- Resin and film colouring agents
- Electric conductive agent
- Electronic equipment related materials such as displays and magnetic recording materials

Costs – For a methane pyrolysis plant producing 1500 kg-H_2/day, to ensure a production cost of H_2 at around £1.5/kg, the predicted minimum carbon selling price is £6.4/kg. Similarly, for a plant producing 100,000 kg-H_2/day, the minimum is estimated to be £1/kg of carbon black [202].

Suitability – Each year around 13 million tonnes of carbon black are created globally. For every kg of methane, approximately 0.82kg of carbon black is produced. A theoretical plant facility could produce up to 19,710 Te-carbon black, and 6,570.5 Te-H_2 per year. For comparison, a plant using steam methane reforming (without CCS) producing the same quantity of hydrogen would release 72,270 Te_{CO2}/yr [203].

4.4.10 Protein for Fish Feed

Although this application is mentioned less in most research surrounding carbon utilisation, it is necessary to note its relevance to Scotland. Salmon farming is at the core of Scotland's food industry and is worth £1.8 billion annually. They are the largest producer of farmed Salmon in the EU and third globally [204].

A company based in the UK and the Netherlands, Deep Branch, has developed a product referred to as Proton. This product is a CO_2 based aquafeed. The process entails capturing CO_2 and feeding this into a fermentation vessel alongside hydrogen, water, and a biological catalyst. The hydrogen is attained via the electrolysis of water. The resultant product is a single cell protein, which can be dried and powdered. 70% of the remnants of this are ready to provide aquacultures with the necessary proteins [205].

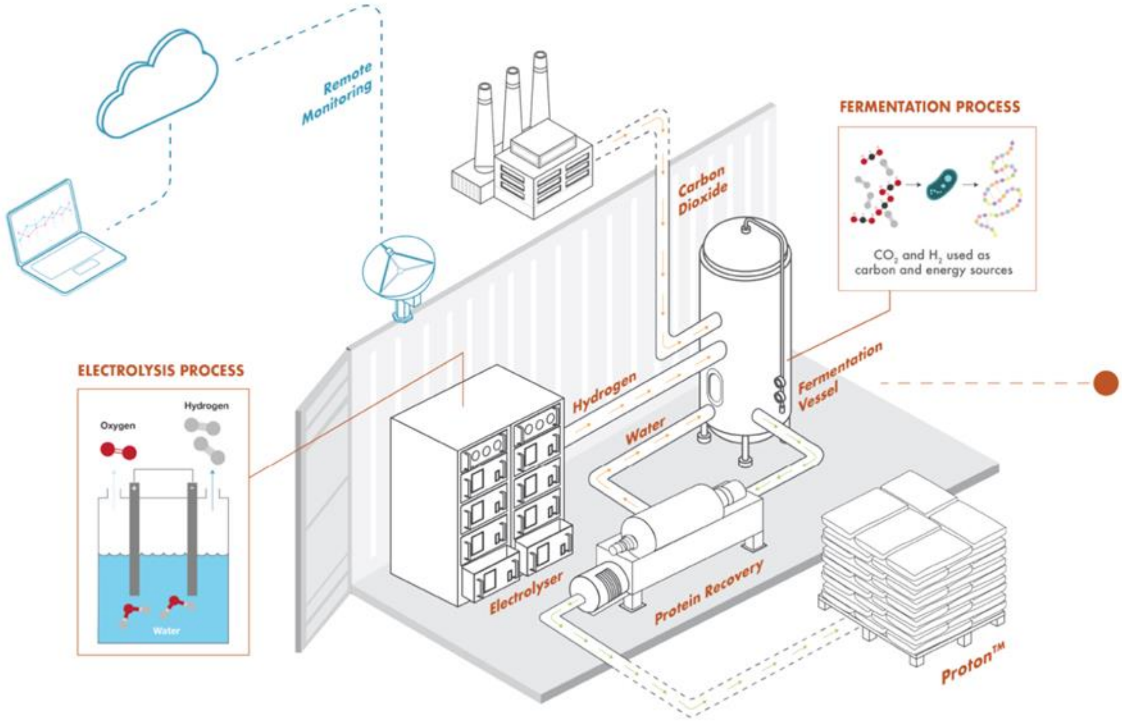


Figure 67 - Process of making fish protein from CO$_2$ [205]

Advantages – Sustainable is improved due to its ability to be scaled quickly without the necessity to catch other fish for feed. Many animal supplies rely on soy production; about a third of all earth's cropland grows feed crops for livestock. Therefore, if deployed globally, this process can free up farmable land for other uses. Thus, also cutting carbon emissions associated with these conventional on-land crops. Additionally, this will result in less fluctuation in prices or output as there is no dependence on seasons or food security. Deep Branch can also deploy the technology without the consideration of optimal weather conditions [206].

Challenges -For a system to have a meaningful impact on reducing CO$_2$ emissions, the deployment of this would need to be large scale. Currently, this technology is still at a lower TRL (2-3); therefore, a large scale is not feasible for the time being. However, Deep Branch hopes to be fully scalable by 2025. While the protein offered by Deep Branch is of remarkably high protein content (70%), it lacks omega-3s. Therefore, incorporating these must also be considered [207].

Applications – Although this technology focuses on fish culture, it has the potential to be used in many other protein-related products, i.e., animal feed and possibly even further down the line, such a protein for humans.

Costs – As this technology is very new, there is limited information available on the economics of this process.

Suitability – A full-scale plant operated by Deep Brach is expected to produce 100,000 t-Proton annually. Every ton of Proton made requires 2 tons of CO_2. Therefore, it has the potential to use 200,000 MTe_{CO2}/yr. According to the CEO of Deep Branch, the UK is dependent on importing most of their animal feed protein sources. Therefore, this presents an opportunity for domestic growth of this industry. However, locating close to CO_2 emission sources and end users of the protein, will minimise costs [207].

4.5 Carbon Dioxide Storage

4.5.1 Summary

Analysing the benefits and challenges with respect to all performance factors (capacity, injectivity, containment) shows that depleted oil and gas reservoirs and deep saline reservoirs both offer potentially attractive targets for geological storage of CO_2, mostly for complementary reasons. Uncertainty on capacity and injectivity is clearly lower for depleted reservoirs, giving them a potential net economic advantage, whereas uncertainty on well containment favours saline formations, which are intersected by fewer wells. Injectivity in depleted reservoirs may be much more difficult to ensure than for saline formations or oil and gas reservoirs where pressure has been maintained.

4.5.2 Introduction

Capturing CO_2 and permanently isolating this from the atmosphere can most easily be done at the large scales required by storing in deep onshore or offshore geological formations. CO_2 storage in these environments uses many of the same technologies that have been developed by the oil and gas industry over decades and have been proven to be economically feasible.

CO_2 Enhanced Oil Recovery (EOR) is a widely used technique and is used to produce around 20 % of global CO_2. A portion of this CO_2 remains below the ground and some returns to surface, but if reinjected to form a closed loop, this can result in permanent CO_2 storage. For the purposes of this report, only CO_2 injection for the sole purpose of permanent storage is considered – although many of the technologies are analogous. Depleted hydrocarbon fields and saline aquifers make the UK a prime candidate for these forms of CO_2 storage.

CO_2 can be trapped by various mechanisms over different timescales.

- Structural trapping—gaseous CO_2 can be trapped by cap rock or structural features (important in injection and post-injection phases while gas is highly mobile)
- Residual trapping—the gas phase is immobilised because of relative permeability and capillary pressure (important in injection and post-injection phases while gas remains mobile)
- Solubility trapping—CO_2 dissolves into the aqueous phase (a slower process that can take hundreds or thousands of years to complete)
- Mineral trapping—the acid formed by CO_2 dissolution reacts with the reservoir rock and mineral generation occurs (a long-term process that can take many thousands of years to complete)

An overview of the technology development status of saline and depleted oil and gas formation CO_2 storage is provided in this section.

4.5.3 Offshore Saline Formations

Saline formations are widespread deep sedimentary rocks saturated water containing high concentration of dissolved salts – unsuitable for human or agriculture consumption. When CO_2 is injected into a saline aquifer, it forms a gaseous plume that migrates underground, influenced by pressure gradients, gravity, and buoyancy forces.

Advantages – Deep saline aquifers have the largest potential for CO_2 sequestration in geological media in terms of volume, duration, and minimum or null environmental impact. CO_2 dissolved in brine will eventually become denser and sink, minimising the risk of long-term leakage [208].

CO_2 behaviour subsurface well understood and accurately predictable as proven through the Sleipner project.

Typically, saline aquifers may have had few, or no wells drilled into them during their lifetime, meaning that risk of leakage from older or abandoned wells can be eliminated.

Saline aquifers of suitable depth and pressure will encounter fewer issues relating to phase change of CO_2 when injecting. If bottomhole/ reservoir pressure is high enough to ensure dense or supercritical phase injection, injection operation can be simpler with fewer issues experienced due to difficult to predict transient flow behaviour resulting in extreme pressure, volume, and temperature changes.

Challenges – Saline formations have a lower, mostly unproven, safety margin between injection and fracturing pressure, resulting in a potential advantage for depleted reservoirs where repressurisation will lead to a final pressure close to or equal to the original value. Each reservoir type has a different risk profile, different advantages, and a rightful place in a portfolio of injection sites.

The interactions between CO_2, water, and salts affect not only solubility trapping and mineral trapping in the long term, but also injectivity due to near-wellbore behavior. As the gas is injected, H_2O in brine evaporates into CO_2 resulting in “dry-out” in the region near the injection well, when residual water saturation can reduce to zero. This increases the effective permeability to CO_2 and injectivity increases. On the other hand, in high-salinity brine there is a risk of “salting-out” as H_2O evaporates. Increasing salinity leads to halite precipitation: permeability and porosity reduce and so injectivity decreases.

Overcoming public perception on injecting into a water-based formation is challenging as many will jump to the conclusion that it would be more likely to contaminate a clean water source compared with injecting into a depleted oil and gas reservoir.

Technology Development Status – In the Norwegian Continental Shelf, Equinor in the Sleipner project has been injecting CO_2 back into the reservoir for several years, enabled by the topside and subsea oil and gas infrastructure and extensive mapping of subsurface. 106 tonnes of CO_2 are extracted annually from the Sleipner Gas Field and injected into the 250 m thick Utsira aquifer at a depth of 1,000 m below the seabed [209]. The findings from this project along with geological data, plume migration, injection and monitoring data are widely available for the scientific community to further develop and build on.

Although CO_2 injection into aquifers not widely deployed, the technologies required are well understood through many years of operation, hence, **TRL 9**.

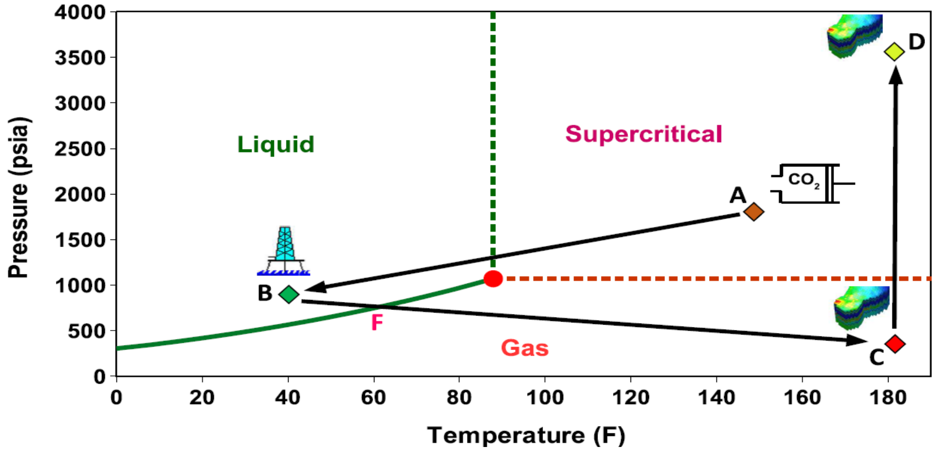
4.5.4 Depleted Hydrocarbon Reservoirs

Advantages – Depleted oil and gas reservoirs are an attractive proposition for the success of long-term storage of CO_2 owing to their known hydraulic integrity of both the geological formations that bound it, and the wellbores that penetrate it. These reservoirs have a seal to confine liquids or gases for thousands or millions of years. Geological properties have been extensively studied and characterised and computer models exist to model the behaviour and trapping of hydrocarbons. Existing infrastructure may be repurposed CO_2 storage, including wells, pipelines and topsides.

Challenges – Reusing depleted oil and gas reservoirs presents further challenges that must be considered in the evaluation of performance factors and the associated risks. Depletion can cause pore collapse in the reservoir, with an associated loss of capacity and injectivity. This can weaken caprock and bounding faults or even well completions, leading to possible containment losses because of mechanical failure. Depleted reservoirs are also intersected by many wells, and it is likely that stricter regulatory requirements on well integrity and the quality of zonal isolation will force operators to recomplete or work over wells that will be exposed to CO_2, with an obvious impact on cost. Inspecting abandoned wells for suitability of CO_2 containment can be very challenging.

Low reservoir pressure may mean that injection of CO_2 in a dense phase would result in reservoir fracturing and very strong thermal effects that may lead to injectivity problems [210]. With a lower reservoir pressure, dense CO_2 will expand into the gas phase and experience extreme cooling due to the Joule-Thomson (throttling) effect. Depending on pressure, this can happen at the wellbore/ reservoir interface, or further up the wellbore, causing components to fail, hydrates to be formed or fracturing due to thermal stress. There are therefore key operational challenges related to phase behaviour of CO_2 when reservoir pressure is below bubble-point pressure- which is often the case at least in early stages of CO_2 injection.

Injecting in the gas phase avoids these effects due to phase change, however, many more injectors are required to inject the same volumes of CO_2. Another solution is to heat CO_2 at the wellhead so that CO_2 is injected in its supercritical state. This heat requirement depends on initial and final temperature of CO_2 and is a function of pressure but can be estimated at approximately 60-70 kWh/Te_{CO2} [211]. This heating requirement increases operating costs.



itions,

Figure 69 - CO_2 phase profile at capture, wellhead, initial reservoir conditions, and later reservoir conditions (after repressurisation) [211]

Technology Development Status – Although a well understood proposition, with well-developed enabling technologies, other than in small demonstration projects or for EOR, there are no known operational CO_2 storage projects that are injecting into offshore depleted oil and gas reservoirs. Hence, until this the technology is demonstrated at scale in an offshore environment the **TRL is in the range of 5-7.**

4.5.5 Technology Developments to Enable Cold Temperature CO_2 Injection into Depleted Reservoirs

ACT 3 RETURN Project

As discussed, injection of dense phase CO_2 into low pressure depleted oil and gas reservoirs can cause extreme cooling and impact performance and integrity of a range of components and the reservoir itself. If the phase changes can be properly predicted and managed, then components and operations can be designed accordingly to deal with such extreme conditions. A major enabler of cold CO_2 injection is the development of suitable software to model the coupled CO_2 response between wellbore and reservoir.

Net Zero Technology Centre are part of a consortium of operators, industry, and R&D partners, funded through ACT (Accelerating CCS Technologies), which aims to develop novel solutions for overcoming injection challenges – with a particular focus on enabling dense-phase cold CO_2 injection.

Four scientific work packages are to be delivered which will examine (i) Coupled well-reservoir flow modelling, (ii) Near wellbore processes, (iii) Wellbore integrity and (iv) Enabling 'cold' CO_2 injection. Through experimental and numerical modelling, the project aims to understand how CO_2 flows down the well and into depleted reservoirs – with special focus on Joule-Thomson cooling effects, phase transformations, pressure and temperature cycling, and the impact on wellbore-reservoir-caprock system. The output of the project will be advanced numerical models, able to accurately predict the thermo-hydro-mechanical response of the wellbore-reservoir-caprock system to CO_2 injection. These new models will be able to identify safe operational windows for CO_2 storage, which will be assessed through a selection of international case studies and integrated into workflows and procedures for 'cold' CO_2 injection into depleted reservoirs.

The **TRLs of various subcomponents vary from 2-3** up to 6-7, indicating that fundamental research will be undertaken to address knowledge gaps in reservoir flow modelling. The project aims to progress quickly to TRL 7 by 2024

Cold Temperature Subsurface Safety Valve Joint Industry Project

Further related to cold temperatures, a major safety component that needs to be developed is the Subsurface Safety Valve (SSSV) – to ensure containment of CO_2 if a leak to surface occurs. In this instance, the Joule-Thomson effect can cause extreme cooling across the wellhead as high-pressure CO_2 is exposed to the atmosphere, causing extreme low temperatures down the wellbore and component failure. Therefore, the SSSV must be capable of operating to shut-in the wellbore as a last line of defence, at temperatures as low as -78C.

Currently, there are no known SSSV's available from developers that can guarantee operation at these temperatures with CO_2 service – whilst conforming to relevant safety standard API 14A. Hence a new valve must be designed and qualified for such conditions.

Net Zero Technology Centre are leading a Joint Industry Project (JIP) to deliver such a technology, supported by funding from oil and gas operators and energy companies. The project aims to work with several well-known suppliers of SSSVs to deliver a technology that can meet these industry standards under these extreme low-temperature conditions.

The **TRL of this technology is currently 5**, however, is expected to progress quickly depending on the extend of design changes that need to be made to existing SSSVs.

4.6 CCS Cost Reduction Opportunities

4.6.1 Carbon Capture

The most significant barrier to widespread commercial deployment of CCUS technologies is the associated cost. The greatest costs are associated with the equipment and energy needed for the capture and compression phases. Capturing the CO_2 can decrease plant efficiency and increase water use, and the additional costs posed by these and other factors, can ultimately render a CCS project financially nonviable.

Since commercial deployment of CCUS is in its early life, acceptable financial returns on a CCUS project are not guaranteed. As a result, project investors impose higher risk premiums which further increases the private cost of the necessary capital [212]. The relative cost effectiveness of carbon capture technology is determined by three primary drivers, which are, in order [138]:

1. CO_2 concentration of source gas streams

2. Degree of contamination of the gas stream

3. Mass flow rate of the source

Since commercial deployment of CCS is in its early life, acceptable financial returns on a CCS project are not guaranteed. As a result, project investors impose higher risk premiums which further increases the private cost of the necessary capital [212].

The cost of CO_2 capture from low concentration sources (post-combustion) has reduced by approximately 50% over the past decade. Studies of the cost of CO_2 capture from power stations completed ten years ago averaged around \$90 (£65)/Te_{CO_2}. Comparable studies completed in 2020 estimated capture and compression costs of approximately \$60 (£45)/Te_{CO2} with next generation technologies boasting even lower capture costs at around \$45-50 (£33-37)/Te_{CO2} as shown in Figure 66 [116].

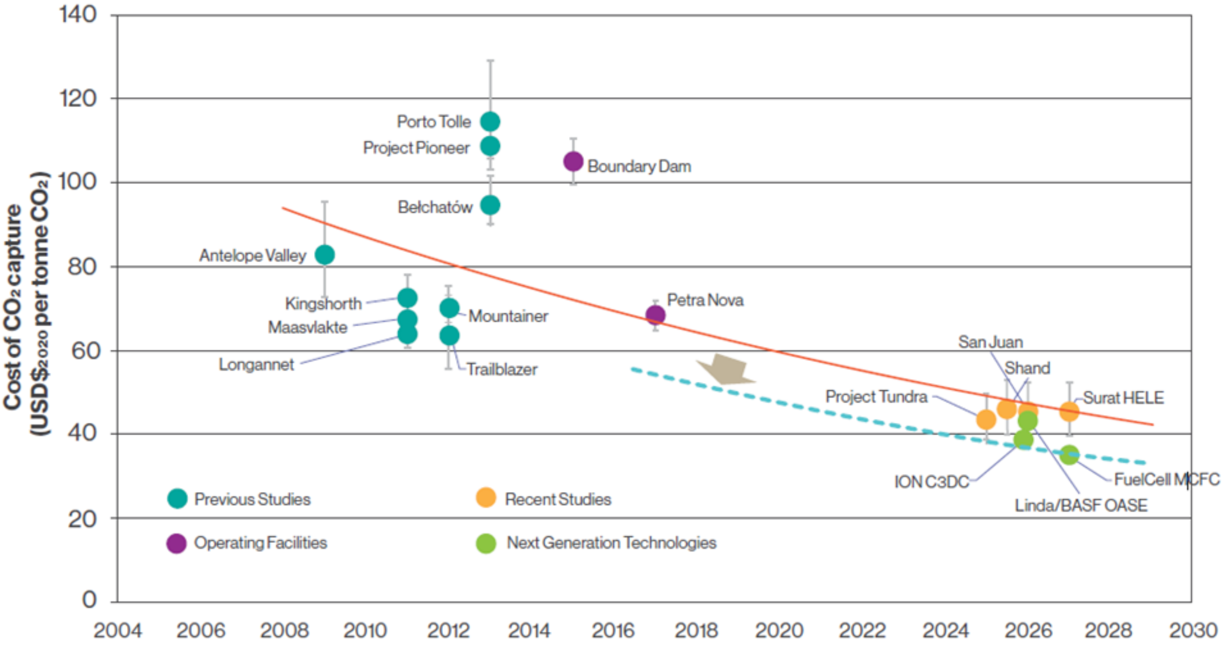


Figure 70 – Evolution of CO_2 Capture Costs (ION C3DC, Linde/BASF and Fuel Cell MCFC are claimed cost by technology developers) [116]

The two largest retrofits for post-combustion carbon capture are at the Boundary Dam (commenced 2014) and Petra Nova (commenced 2017) power stations. Capture costs for Boundary Dam are approximately £75-80/Te$_{CO_2}$ compared to £50/Te$_{CO_2}$ observed at Petra Nova. In both cases, the developers of these facilities advised that if they built the facility again, they could reduce the capital cost by at least 20% by applying what they had learned from their first project [100]. Lessons learned from historical projects are a large driver behind the future reduction in CO_2 capture costs.

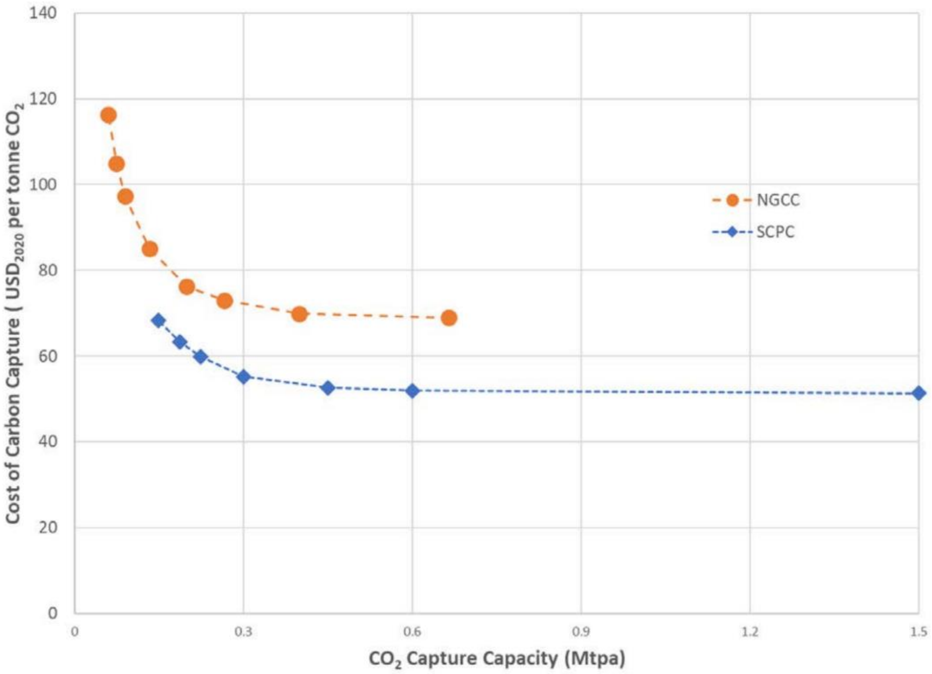


Figure 71 - Impact of plant scale on the cost of carbon capture [100]

Like most industrial processes, cost reductions can be driven by increasing **economy of scale**. Higher rates of CO_2 capture result in lower unit costs. Capital costs are expected to rise non-linearly with scale as shown in Figure 67.

For a single train process, a 2-fold increase in CO_2 capture capacity would be expected to deliver a 50% increase in capital costs. In other words, the capital cost per unit of production would fall by around 25%. Cost reductions are expected to diminish above 0.3 MTPA of CO_2 captured, eventually levelling off capacity of around 0.6 MTPA.

A significant contributor to the cost of carbon capture is the **cost of energy**. For solvent-based capture plants, energy is mostly provided in the form of steam for solvent regeneration. A study carried out by the Global CCS Institute examined the effect of heat supply strategies on the cost of solvent-based carbon capture (Figure 68).

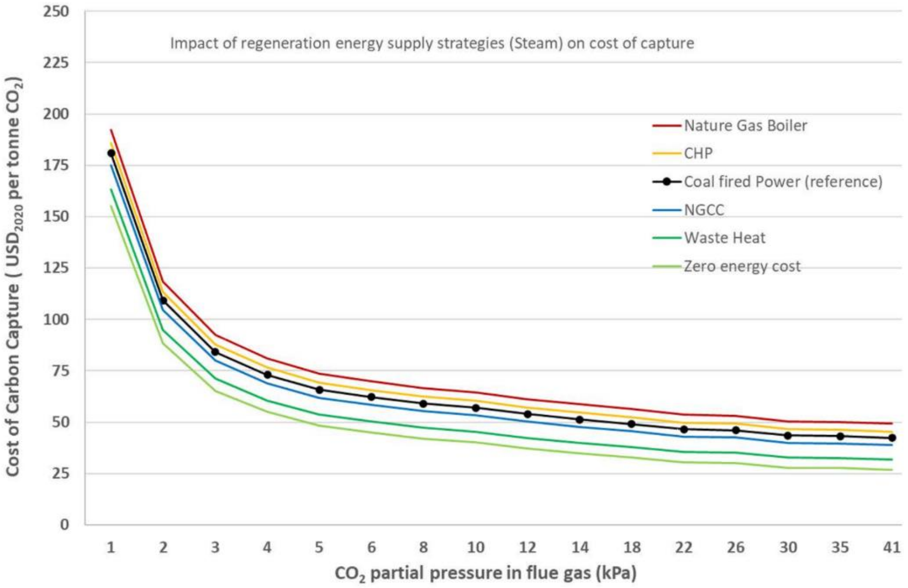


Figure 72 - Overview of CO_2 capture costs using different regeneration energy supply strategies [100]

Utilising waste heat from other parts of a polluting process can significantly reduce carbon capture costs. For example, there are substantial amount of excess heat that can be utilised for carbon capture in the cement, iron and steel production processes that could significantly reduce the overall energy penalty and drive down CO_2 capture costs.

4.6.2 Carbon Storage

Injecting, storing and monitoring CO_2 within the subsurface are well established. The drivers for cost and future cost reductions are found in three key areas: site selection, deployment, and technology advancement.

- **Site selection** refers to the location of the geological storage site. For example, an onshore site with existing data and infrastructure is cheaper than an offshore site with little data and no existing infrastructure. Future CCS operations comprise a mix of deep saline formations and oil and gas fields. The primary driver for developing deep saline formations with large capacity and high injection rates appears to be increasing CO_2 storage rates and improving economies of scale.
- Increasing the rate of **deployment** of CCS overall will also reduce the costs for CO_2 storage operations. To date, the manufacturing of CO_2 -specific materials and experience in CO_2 operations, although mature, is still small scale compared to the oil and gas industry. In 2018, around 80 Mtpa of natural and anthropogenic CO_2 was injected. To meet climate targets, over 5,000 Mtpa of anthropogenic CO_2 must be injected by 2050.
- **Technology Advancement** is expected to deliver reductions in the cost of storage. Future savings are seen in the refinement of existing measurement and verification equipment, automation, and preventive maintenance. As exploration and appraisal for CO_2 storage sites become routine, a 20% reduction in appraisal costs is expected due primarily to the

development of CO_2-specific seismic and well drilling processes. If the technology can be developed to gain a better understanding of flow conditions when injecting into depleted reservoirs in the dense phase, components can be designed appropriately, and this can enable CO_2 injection without heating – resulting in significant OPEX savings.

4.7 CCUS Deployment Barriers

Several carbon capture and storage technologies have been proven at a commercial scale over the past few decades. In addition, geological storage resources are sufficient to meet the CO_2 storage requirements necessary to achieve climate targets. There are no technological barriers to worldwide commercial deployment of CCUS. Despite this, CCUS is not yet being deployed at the rate required to meet the world's climate change obligations.

The predominant reason for lack of deployment is due to the lack of financial incentive for a developer to bear the costs of constructing and operating a capture plant. There are several market failures across the CCUS value chain that directly affect the business case for CCUS as summarised in Figure 69.

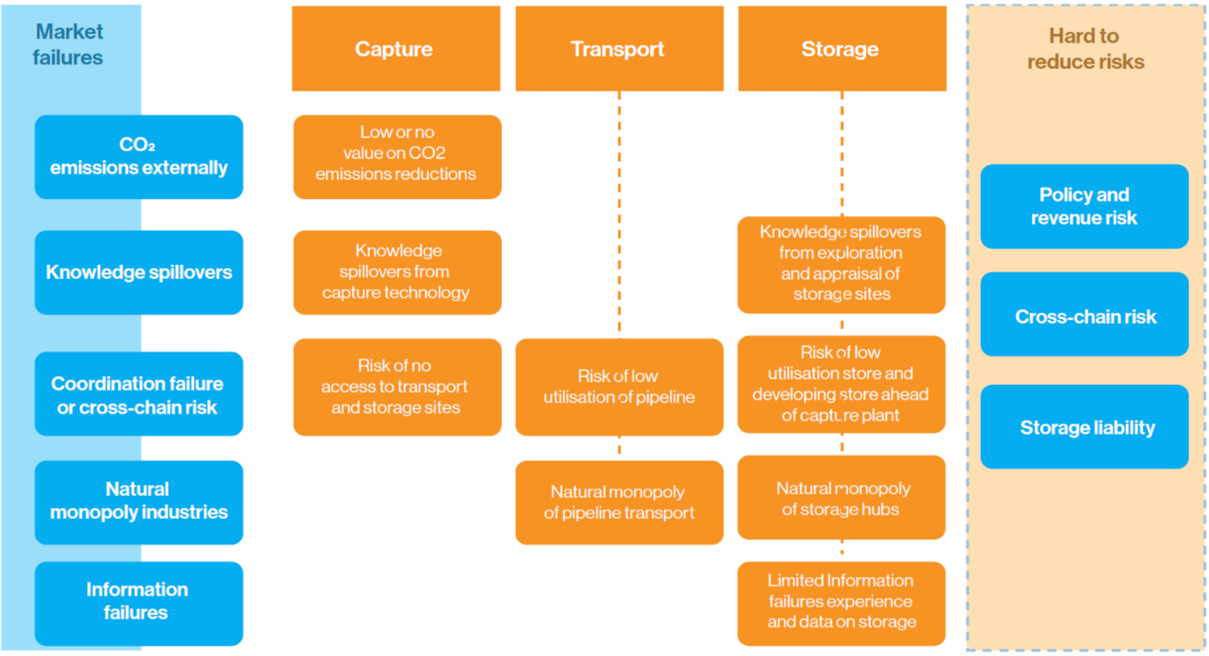


Figure 73 - Market failures across the CCS value chain [116]

Commercial readiness indicators can aid in further undserstanding the barriers to widescale commercial deployment.

Regulatory Environment – At present, a plant with CCS will always be more expensive than a plant without CCS. Enhanced oil recovery is the only exception to this. Regulatory support from government via long-term policy incentives are therefore critical in driving the uptake of CCS.

Project financiers are mostly new to CCS and are uncertain about the technology as well as its outlook. Having long-term policies in place would reduce the uncertainties and risks perceived by the financing sub-sector and provide guidance for future development pathways for CCS [213].

CO_2 storage liability is related to potential perpetual liability for regulatory enforcement action and civil claims for damages arising from leakage of CO_2 from geological storage facilities. Whilst the probability of leakage from an appropriately selected and operated geological storage facility is negligible, it is not zero and therefore will have a detrimental effect on efforts to secure project financing [116].

CO_2 geological storage is well understood and has been commercially demonstrated through decades of experience. However, compared to other industries, there remains a lack of operational data that can be used to convince project financiers of the security of their investment.

Several previously implemented policies have the potential to reduce the costs of CCS and encourage deployment. These include, but are not limited to, carbon pricing policies and clean energy standards that reward firms who are utilising CCS.

Stakeholder Acceptance – A significant risk in the widescale deployment of CCS is stakeholder acceptance, including that of local communities. Several key factors play a role in affecting public opinion on CCS and must be addressed through effective community engagement [212]. These include, but are not limited to:

- CCS may be viewed as prolonging the role of fossil fuels in the economy
- Requirement for and disruption due new pipeline construction
- Perceived safety of transportation and storage of CO_2
- Perceived effectiveness of CCS in comparison to other climate mitigating technologies (i.e., renewables, nuclear etc.)

Market Opportunities – Although predicted to accelerate at an incredible pace, the current market opportunities for CCS are small, and the future market opportunities not well enough understood to instil widespread investor confidence. Significant concessional policy support is required to drive the scale-up of CCS required to deliver a net zero energy system. For example, the Acorn CCS project is heavily funded by UK and Scottish government.

Scaling technology development can help drive market opportunities as economies of scale can start to be realised and learning by doing can help close the profitability gap. CCUS clusters and hubs can help drive these synergies between capture, transportation and use by lowering the cost of capture and providing access to low-cost transportation pipelines and storage infrastructure.

5 Conclusions

The objective of this report is to aid in the delivery of Net Zero Technology Centre's role in Scotland's Net Zero Roadmap project – to support, challenge and validate finding related to technology selection and adoption. This report aids this objective by providing an evidence base of relevant techno-economic information on industrial decarbonisation technology options that are available today, and those likely available in the near future.

Across the four key areas of focus, hydrogen generation, CCUS, electrification and fuel switching, several conclusions can be drawn:

- Many technologies exist today to deliver deep decarbonisation of industry in Scotland. **The biggest barrier to their deployment is the relative costs compared to current fossil fuel alternatives**. Based on carbon taxes and other financial penalties/ incentives, there are very few instances where switching to a new, clean energy vector, or installing CCS would be cheaper today than current methods. This, therefore, highlights the urgent need to reduce technology costs through research and development, and build local supply chain alongside policy support for commercial deployment activities that enable cost reductions through learning-by-doing and economies of scale.

- **There are numerous technologies under development for producing low-carbon hydrogen, although few have been deployed and proven at large scales**. SMR with CCS and Alkaline electrolysis are the most advanced (TRL 9), but emerging technologies such as **enhanced ATR, POx and PEM electrolysis (TRL 7 & 8) are gaining traction due to certain advantages**. All are likely to be deployed at large scale by around 2025. Other technology developments are also progressing and are at advanced stages of development – with further anticipated benefits and options for cost reduction through step change advancements in process and process integration.

- **Hydrogen presents opportunities as a clean alternative fuel in many processes**, presenting some opportunities for retrofit rather than complete replacement of existing equipment. The main challenges relate to differing combustion properties of hydrogen compared with natural gas, with impacts on health and safety, performance, NOx emissions, and materials. Most solutions can be classified at TRL 7, with further work required to demonstrate at scale, and assess impacts on product quality. Field trials of blending various compositions of Natural gas with Hydrogen are currently being undertaken. **Hydrogen fuelled gas turbines will be essential to provide future dispatchable electricity generation, gas compression, and support CHP decarbonisation while ensuring a second lease of life for existing natural gas-powered gas turbines.** However, considerable further work is required to develop dry low emission hydrogen fuelled gas turbines and this market is expected to mature by 2030.

- **Biomass presents a key opportunity to decarbonise industrial heating and is already commercially deployed**. Biomass also presents future opportunities to produce clean hydrogen and carbon neutral synthetic fuels (such as BioSNG) through gasification and further processing. However, **the biggest limitation on the use of biomass is likely to be availability of sustainable biomass feed locally.**

- **Electrification is feasible and well developed for several industrial processes (TRL 9 for heaters and boilers)**, however, has had limited commercial deployment at scale due to high CAPEX and OPEX, and unsuitability in high temperature applications. Less well developed are plasma torches, electric kilns, infra-red heaters, microwave heaters and HPHT heat pumps which may be required in certain scenarios. The technology required to integrate clean electricity and new industrial processes is commercially mature and represents a major element of cost. Certain developments are ongoing, aimed at reducing the cost of power conversion.

- **CO_2 capture from low concentration point-source emissions is commercially mature with amine-based solvents** deployed at most post-combustion flue gas capture facilities worldwide. Several pre-combustion technologies are also commercially mature and are currently used in a variety of gas processing applications (PSA, physical adsorption, and membranes). Several next generation chemical and environmentally friendly solvents offer exciting potential to reduce regeneration energy requirements and degradation. Carbon Clean Solution's CDRMax promises to reduce CAPEX and OPEX by 20% and 40%, respectively and aims to be commercially proven by the mid-2020s. If capturing CO_2 at a cement plant, waste sorbent could be used in the manufacturing process. Calcium looping presents opportunities to capture CO_2 from low concentration sources, using a sorbent derived from cheap and abundant limestone.

- **Direct Air Capture technology** has progressed immensely over the last decade and may be an incredibly important technology to reach net zero, potentially providing a lower cost CO_2 capture option for emitters who struggle to decarbonise otherwise. However, the cost must reduce to be an affordable solution. Reducing the cost of electricity, learning-by-doing, and economies of scale are all be vital in reducing the cost of CO_2 capture. **Commercial deployment is expected mid-2020s with significant CAPEX reductions by 2030** and continuing to beyond 2050.

- **Carbon capture and utilisation (CCU)** offers the opportunity to create value added products from waste CO_2 whilst avoiding the requirement for transport and sequestration. Many products are already made with CO_2, so incentives will be required to increase the demand for new and alternative products using captured CO_2. Most CCU technologies have not yet been demonstrated at commercial scale and high costs represents a major barrier to widescale deployment. **Research and development into scaling such technologies is imperative to lower the cost of producing products with captured CO_2**. Perhaps most promising is waste CO_2 utilisation in mineral carbonation which can use alkaline wastes to create a variety of saleable products – for example, calcium and magnesium carbonates can be used as aggregates in concrete. Low-carbon methanol can be produced using waste CO_2 and renewable hydrogen to significantly reduce the carbon impact. CO_2 can also be used to synthesise polymers to produce products with enhanced physical properties, at potentially lower costs.

- **Depleted oil and gas reservoirs and deep saline reservoirs both offer potentially attractive targets for geological storage of CO_2**. Uncertainty on capacity and injectivity is lower for depleted reservoirs, giving them a potential economic advantage, whereas uncertainty on well containment favours saline formations as they have often been intersected by fewer wells.

Injecting into depleted reservoirs below CO_2 bubble-point pressure presents challenges due to Joule-Thomson effects. If this can be better understood, modelled and components designed appropriately, OPEX can be reduced by eliminating the requirement for CO_2 heating at the wellhead. Net Zero Technology Centre are working on several developments in this space.

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