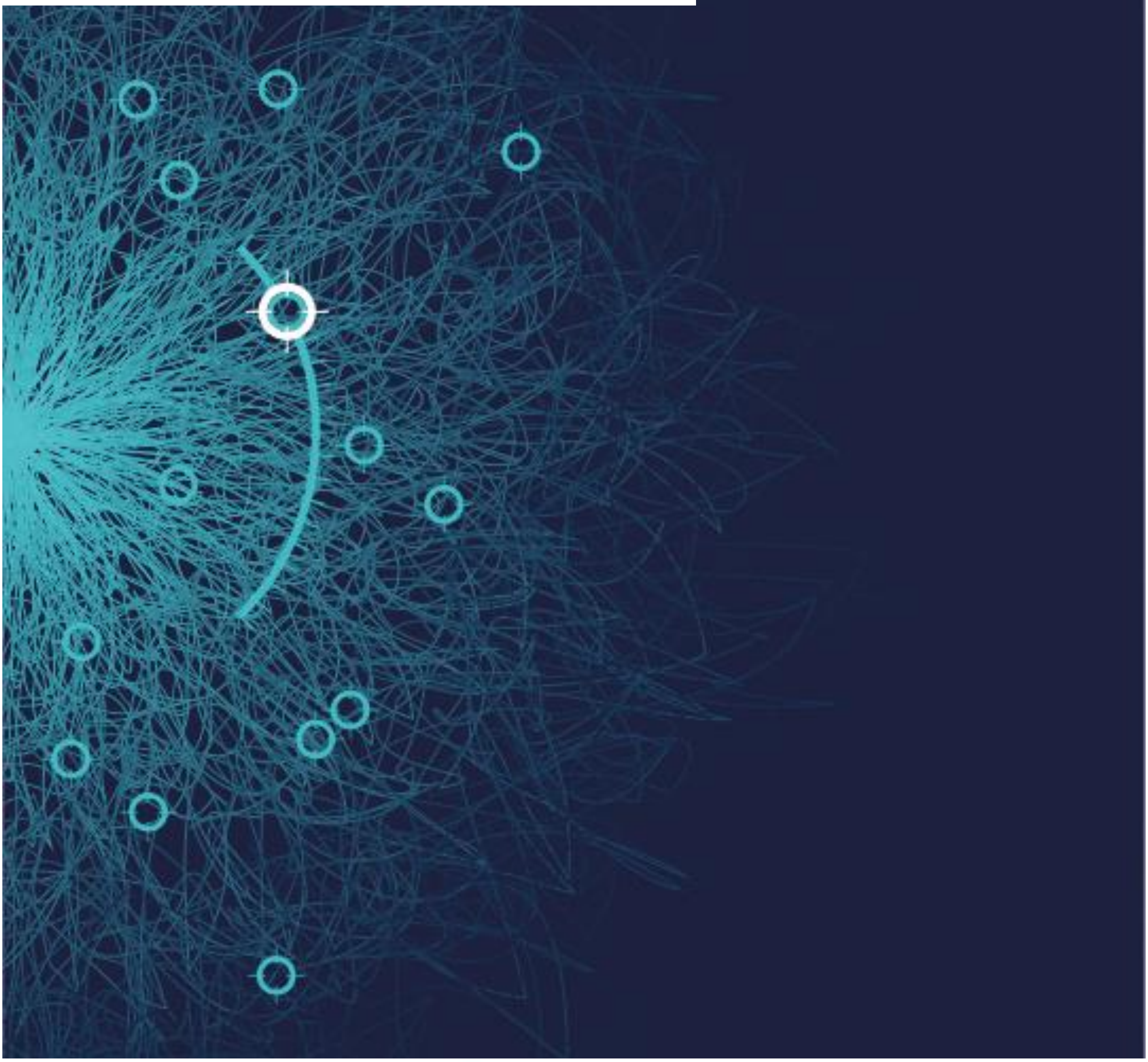
WP3 Technology Scanning

A NECCUS / OGTC report for the
Scottish Net Zero Roadmap



NECCUS

The Oil & Gas Technology Centre

INDUSTRIAL STRATEGY

UK Research and Innovation

WP3: Technology Scanning

Table of Contents

Background **2**

Data Sources **3**

European Union Emission Trading System **3**

National Atmospheric Emissions Inventory **3**

Stakeholder and Industry Engagement Data **4**

Discussion Topic List – Emitters 4

Technology Scanning **7**

List of Potentially Attractive Technologies **7**

CCUS Technologies **7**

Modular CCUS / Flue Gas Capture 9

Direct Air Capture 11

Sequestration 13

Utilisation 15

Transportation 15

Electrification **17**

Power from Grid / All electric systems 17

Renewables Integration 18

Battery Storage 19

Efficiency Optimisation 200

Hydrogen Economy **200**

Hydrogen Generation (SMR with CCUS) 21

Green Hydrogen production through Electrolysers 22

Hydrogen as a Fuel Gas 23

Hydrogen Fuel Cells 24

Hydrogen Storage 25

List of Potentially Attractive Technologies **26**

References ***27***

Background

The OGTC Net Zero Solution Centre aims to support the oil and gas industry as well as supporting trades to develop and deploy technologies to decarbonise operations and diversify its activities to position for a long-term sustainable future as the world's first net-zero hydrocarbon basin. The Centre focuses on two clear programmes;

1. **A Cleaner Industry:** Focused on the development of a cleaner oil and gas industry that contributes to emission reductions. Driving technology that delivers energy efficiency improvements, whilst lowering the sector's carbon footprint by reducing unnecessary activity, methane gas leaks, waste and operational emissions from flaring and gas turbines, ultimately decarbonising daily operations.
2. **Net Zero UKCS Basin:** Where we will develop, de-risk and deploy technologies that can be coupled with other offshore sectors, or industrial activities (renewables, hydrogen production, carbon capture usage and storage and others) to increase the flexibility of the North Sea infrastructure system. The re-use and re-purposing of existing infrastructure and systems will play a key role in delivery of a net zero basin which addresses not only the industry's 14.63 million tonnes (or) 3% emissions footprint, but also provides a service to other industrial clusters, thus contributing to the bigger net zero UK and Scotland goals.

This report outlines the technical requirements of achieving Net Zero across multiple industrial clusters and geographical locations/regions within Scotland. The aims of WP3 are to:

- Develop a plan for technology scanning to identify technologies in different maturity categories
- Establish a method to define technology adoption and scaling assumptions, and cost improvement/learning curve assumptions.
- Identify current technologies in ongoing deployment projects and how these could be more widely used.

In order to achieve Net Zero there is a requirement for large scale adoption for both new and existing technologies as well as a significant review of internal processes and products in order to reduce Scope 1 emissions. A comprehensive technology scan, through cross industry knowledge and technology development projects, coupled with publicly available information and vendor engagement, will define a list of available technology as well as foreseen gaps.

By investigating and understanding the long-term cost reduction, scalability and development of these outlined technologies in addition to the knowledge and experience gained from stakeholder and industry engagement, the report will Identify a 'Key Technology Shortlist' ranked by key metrics such as:

- TRL & R&D Gaps
- Economics
- Scale required
- Identified Risks
- Timescale for technology deployment
- Infrastructure requirements and constraints

For Phase 2, this report will develop into a more in-depth and focussed technology assessment with procedures, guidelines and KPIs on how methodology is to be implemented.

Data Sources

European Union Emission Trading System

The Environmental and Emission Monitoring System is the primary tool implemented by the UK Government to monitor emissions from Offshore Installations and Onshore Terminals. Operators are required to follow reporting guidelines and do so on an annual basis. The method of calculating carbon dioxide emissions is thorough for installations covered under the EU ETS and therefore considered relatively reliable. Estimates of methane emissions is less well monitored and regulated and poses a weakness in greenhouse gas emission totals.

Many of the UK's offshore oil and gas installations, as well as onshore terminals, fall under the criteria for participating in the scheme. The system covers CO_2 emissions and all installations must comply by reporting annual releases.

Emission allowances are allocated to each installation and can be bought and sold on the market. If an installation's emissions exceed that of tier allowances, fees are issued accordingly. The EU ETS datasets are available online [1]. Under the ETS, not all installations have the same reporting criteria to adhere to. Installations are categorized under A, B or C dependent on their CO_2 emissions. The measurement and calculation methodologies are assigned tiers, or 'data quality levels', dependent on their accuracy and thoroughness. An installation must meet the tier threshold to which they are assigned, based upon their emission source size (i.e. larger sources have to follow higher their thresholds) [2].

Implementing emissions reduction technologies will not only reduce the likelihood of charges for exceeding emission limits but excess credit will be tradeable on the market offering an incentive for CO_2 reduction techniques. It is also expected that there will be a reduction in credits as the transition to a net zero industry increases the likelihood of potential charges or leaving a business in a position to purchase credits at increased rates from other operators. There are indications that in 2030, emissions from sectors covered by the EU ETS will be cut by 43% from 2005 levels [3].

National Atmospheric Emissions Inventory

The National Atmospheric Emissions Inventory (NAEI) collates emissions or activity data from all UK sectors and reports national emission values annually. Emissions from terminals are no longer under the jurisdiction of the EEMS reporting and are covered by the Environmental Agency (EA) of the country in which they are located. Data is reported annually by each EA as well as through the Department for Environment, Food and Rural Affairs (DEFRA).

The inventory acts as a tool for compliance with the Kyoto Protocol, in which member states are required to monitor and report their annual emissions. The database is maintained by Ricardo Energy on behalf of the UK Government and the data is utilized by both the EU and United Nations Framework Convention on Climate Change (UNFCCC).

As previously mentioned, the EU ETS also covers onshore oil and gas terminals. Operators for these installations report to the environmental agency of the country in which they are located (e.g. SEPA for Scottish terminals). Ricardo Energy extract the data from each of the environmental agency bodies to help form the NAEI.

As previously indicated, an awareness of individual, cluster and countrywide emissions statistics ensures the correct technology roadmap is established that makes both commercial and financial sense. Financially speaking, certain technology can be adopted that can benefit a cluster of companies more than the individual company and can constitute a greater CO_2 reduction.

Stakeholder and Industry Engagement Data

Both industry stakeholders (emitters) and the supply chain (technology providers) are to be engaged throughout the process of defining Phase 1, with a series of 1:1 meetings held in collaboration with WP1 and WP2 leads and focused on gathering high level input, emissions data, technology gaps and insights into the challenges, issues and concerns facing that particular industry. Follow-up interviews by WP leads on their respective topics will be organised separately if required.

The approach for these engagements is to have a list of discussion topics to cover the main aspects, but to also adapt to meet the specific situation of each interviewee and to pursue any areas that the interviewee is particularly interested in. In this way, the review will cover the same topics in each interview and get more in-depth comments on areas of specific interest to each interviewee. Note it can be seen, in the list of discussion topics, that some issues arise more than once, but applying to different situations / angles, so no overlap exists.

Prior to the interviews, a short brief of the questions and topics to be covered, will be provided to the interviewee in advance (by email) that summarises our project, the expected follow-on roadmap project and details on the expected scope and scale of the roadmap.

Results of the interview will be collated to develop a collective view of the best way forward for the roadmap whilst establishing the consensus on highlighted or interested technology areas of focus.

Following the interview style engagement sessions, will be number of interactive workshops held on the following dates:

1st Interactive Workshop	**2nd June**
2nd Interactive Workshop	**5th June**
Presentation Workshop	**17th June**

The interview that the Consortium members have arranged is designed to provide the report with the evidence required to ensure that the needs of the industry are addressed.

Discussion Topic List – Emitters

1. **Current emissions**
    a. Can you quantify your current emissions (using data published by SEPA as a starting point) by chemical composition and relative percentages of each (by volume or mass)?
    b. Are these derived from heat/power generation or process emissions?
    c. How many emission points are there on your site?
    d. Can you apportion different emission profiles to each of these emission points?
    e. Geographical location of emissions (if more than one site)?
    f. How these may change in the next few years (to 2025)?
    g. What are the reasons for any changes?
2. **Drivers**
    a. What, if any, are your company's drivers for reducing emissions?
        i. Ambitions of local management
        ii. Corporate

iii. Customer
iv. Investors
v. Others

b. Or are you still gathering evidence before deciding how to proceed?

3. **Scope and objectives**
   a. What is the scope of your emission reduction activities?
      i. Energy switching
      ii. Reducing process emissions
      iii. Both
   b. Why did you make this choice?
   c. What are your objectives (e.g. % decrease in overall emissions, removing emissions of a specific type and/or from a specific emission point, valorise carbon collected, time to achieve net zero, implement changes that provide cash positive outcomes in your transition to net zero, etc.)?
   d. How were these developed? E.g. internally or in consultation/partnership with others
   e. Or are you still to define your objectives?
4. **Barriers**
   a. Are you experiencing any barriers to progress?' If yes, what are these?
      i. Corporate
      ii. Financial
      iii. Technical
      iv. Supply chain
   b. Which do you see as most difficult – and why?
   c. How are you addressing these?
   d. Do you believe that these would affect your competitiveness?
5. **Route to Net Zero**
   a. What strategies and technologies (if any) are you considering / implementing?
   b. Why were these selected?
6. **Expectations**
   a. How do you see CCUS developing over the next 5 years? From the perspective of your company and from wider industry?
   b. And over 10 years? As above
   c. What will be the main drivers of this change?
7. **Technology Supply Chain**
   a. Are you engaging with CCUS specialists?
   b. How have you done so? E.g. discussions, NDAs, participated in joint projects (either commercially or publicly funded)
   c. Have you identified any attractive technologies?
   d. What challenges / barriers have you identified to implementation?
   e. What information / support would help you to overcome these barriers?
8. **Progress to Date**
   a. What investments in emission reduction have you made to date?
   b. Have these been successful or not? Please explain/expand on why/why not?
   c. What barriers have you have encountered?
   d. Could any of these be analysed to prepare (anonymous) case studies?
   e. Do you know of success stories elsewhere?
9. **Financial Implications**
   a. Do you see the implementation of CCUS technologies having a net positive, or negative, financial return for your company?
   b. What financial conditions need to be met for you to proceed with adoption of CCU technologies?
   c. When do you expect that these conditions will be met? And what is required to get to this position?

    d. How do you think such investments are best financed?

10. Speculating on Potential Financial Implications

    a. If you were to speculate, based on technologies that are / will become available that would address your carbon emissions,
        i. Can you estimate the scale of the costs involved in implementing these technologies?
        ii. Would implementing such changes affect your competitiveness?
        iii. Can any of these be quantified?
        iv. What would be the impact? in terms of:
            1. Loss or gain of market share
            2. Ability to spend in your supply chain
            3. Turnover / jobs over 5 years?
        v. Could the impact potentially lead to plant closures?
    b. Are competitiveness issues the main barrier to implementing solutions?
    c. What would be required to catalyse change?
        i. Better technologies
        ii. Viable opportunities to valorise emissions
        iii. Financial incentives
    d. Should others be sharing the cost of implementation? If so, which players?
    e. Are government regulations / incentives required?
    f. What type of support would be attractive?

11. Developing the Roadmap

    a. How could the roadmap be structured to be helpful to your company? e.g. would it support you to implement new technologies, understand wider implications including costs, timescales and other technical requirements of doing so
    b. Who should be its main audience? E.g. government, industry
    c. What would you like to get out of it? E.g. clear models for implementing CCUS in your sector, or economic and technical modelling for representative emissions
    d. What should its scope be? e.g. timescales, external considerations (such as government policy and regulations), other?
    e. What scenarios should it include?
    f. What information should it seek to provide? e.g. models that industry can make use of to calculate its own costs and timescales to implement

12. Your interest in involvement in the roadmap development project

    a. Would you be willing to make your emissions data available to the roadmap development project? How easy it would be to do so, and would there be any constraints on our use of your data?
    b. Would you be interested in participating in the project?
        i. As an industry advisor
        ii. To develop / test specific data sets for the project
        iii. As a contributor of funding

13. Impact of COVID-19

    a. How is the impact of COVID-19 affecting your activities / competitiveness?
    b. Will it affect your ability to invest in issues such as reduction of carbon emissions?

14. Any important issues we haven't covered?

15. Any other comments?

Technology Scanning

For this draft report, what follows is a technology framing/scanning exercise, defining potentially attractive technologies that could be adopted in the roadmap to net zero. Within each topic area is a focus on 'Initial Technology Screening' identifying preliminary understanding of challenges and gaps to be expanded on as the report progresses. Following the framing exercise will come a detailed review with the following content:

- TRL & R&D Gaps
- Economics
- Scale required
- Risks
- Timescale for technology deployment

List of Potentially Attractive Technologies

CCUS Technologies

Carbon Capture Utilisation & Storage (CCUS) refers to the capture, usage or storage (sequestration) of carbon dioxide that has been already been emitted into the atmosphere or is in the process of being released. As indicated, CO_2 can either be captured directly from the air, commonly referred to as Direct Air Capture (DAC) technology, or it can be captured from process-based flue gas emissions. The latter is the more established process of CO_2 capture, with 51 global operational largescale CCS projects (over 400,000 tons of CO_2 capture per year) [4] with only 19 in operation as of 2019. Also, at the end of 2019, within Europe, the Global CCS Institute published that 10 large scale CCS facilities were now in various stages of development (6, of which, were in the UK, 2 in the Netherlands, 1 in Norway & 1 in Ireland) [4]. Of the 6 in the UK, the following diagram iterates the development of 4 key developments:

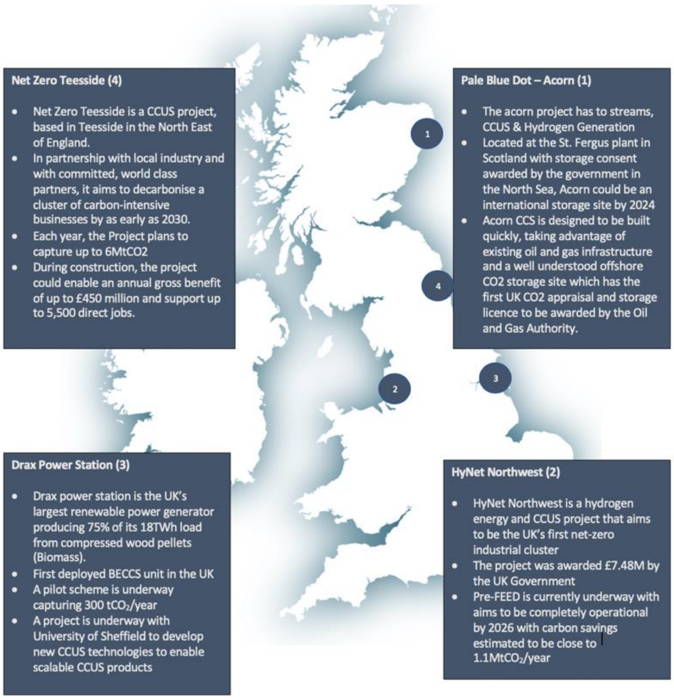


Figure 1 - UK CCUS Projects

CCUS technology can be used at a variety of different industrial facilities, including power generation, natural gas processing, petroleum refining, cement production, hydrogen reforming and chemical production. However, considering alternatives such as DAC, as opposed to flue gas capture, the application can be limitless provided the infrastructure to store and/or transport the CO_2 is available. In addition, depending on the application and adopted technology, CCUS technology can reduce carbon emissions from industrial processes by over 90%.

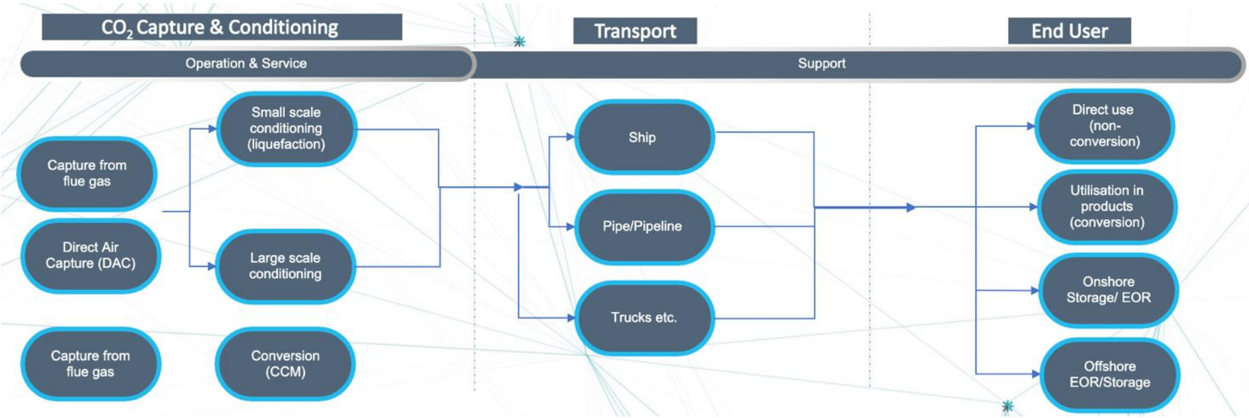


Figure 2 - Typical CCUS Process Flow (Source OGTC)

According to the Global CCS Institute, there is an estimated 78,000 $MtCO_2$ storage potential in the UK, of which 8,000 $MtCO_2$ is in depleted Oil and Gas fields. In addition, a study conducted by ETI in 2016 identified that over 20 Oil and Gas reservoirs were suitable for CO_2 storage, 5 of which went on to be shortlisted as the ones with greatest potential [5]. The UK's very strong ties to the UKCS Oil and Gas industry has unlocked a wealth of knowledge and understanding of subsurface data and analytics coupled with decades of injection and subsea experience, that is leading to a rapid development of potential CCS projects moving forward. A key opportunity for the onshore industries to capture and store captured CO_2.

Of the projects identified in the ETI report, it was established that these sites could theoretically store between 3 and 10 $MtCO_2$/year storage capacity over a minimum 15-year period, and that this could be done cost effectively [5].

With projects such as 'Acorn' for Pale Blue Dot, with a qualified injection site established and infrastructure in development or already in existence (Goldeneye Pipeline and Feeder 10), as well as existing clusters being in very close proximity to that infrastructure (see WP1 for more detail), there is a significant opportunity to make largescale CCUS in Scotland feasible.

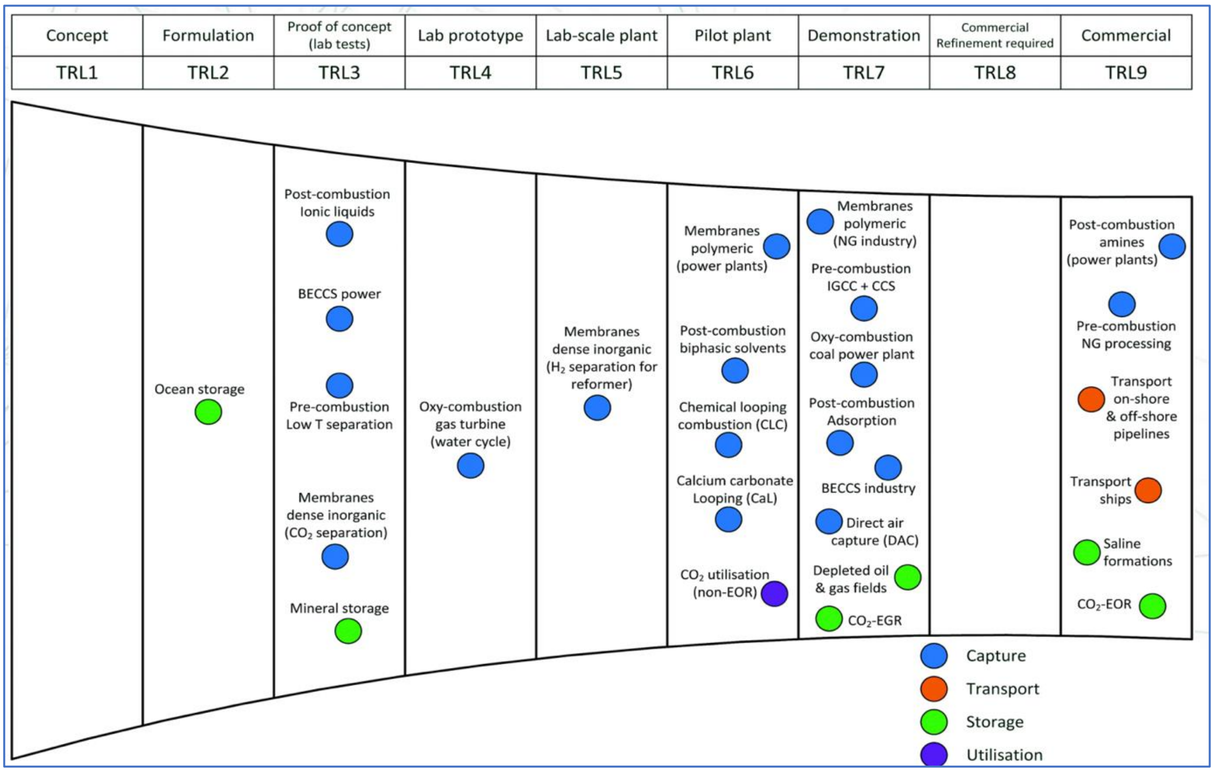


Figure 3 - CCUS Technology & TRL. Source: [AD]

Modular CCUS / Flue Gas Capture

As iterated previously, CO_2 capture, at present, is split into two main forms of technology, flue gas capture and DAC. Flue Gas capture refers to the capture of CO_2 from exhaust gases in a process, which may be a large singular source, or multiple sources mingled into one exhaust stream for processing.

Typically, the physical makeup of competing CC technologies is the same, composing of processing equipment, electrical control, absorber and boiler columns as well as processing and pipework infrastructure. This is beneficial as it allows for the development of modular systems which prompts cost reduction and scalability development. Generally, the differentiating technologies with CCUS flue gas capture comes in the form of the amine-based solvents and the ability to efficiently capture and separate the CO_2 from the rest of the exhaust gas stream. Amine solutions can offer a range of CO_2 capture efficiency factors, all dependant on the composition of the gas to be processed, but other alternatives offer significantly “greener” options that further enhance the final gas composition to be exhausted into the atmosphere.

Further development of modular CCS systems will provide a solution for capture and storage of these onshore, decentralised emission sources, as well as offering a solution for dispersed offshore sites and this modular approach would reduce costs, reduce size and industrialise and scale the technology to deliver a commercially viable solution.

Figure 4 - Aker Solutions' Modular CCUS Offering

Information gathered in the offshore oil and gas industry by the OGTC, outlined that by capturing 30% of current operational emissions offshore (4.3MT) a modular CCUS technology has the potential to save the industry £171M per annum in carbon tax abatement (assuming £40/T). Extrapolated to the onshore industry, at a similar carbon tax abatement figure, the industry savings could be significant.

Current onshore based CCUS product solutions range from small scale to industrial scale, with some providers claiming capture rates of up to 400,000 tCO_2 capture per annum. The bulk of future CO_2 capture in the UK is most likely to occur at onshore industrial hubs, such as Teesside, the Humber, or St. Fergus.

Initial Technology Screening

In addition to flue gas capture, both **Pre-combustion capture** (Solid or liquid fuels are first reformed or gasified, yielding a combination of hydrogen and CO_2) and **Oxy-combustion capture** (Solid or liquid fuel is combusted using a pure oxygen stream instead of air, yielding a near-pure stream of CO_2 and water which can easily be separated) have also been trialled for capturing CO_2.

Many technologies can be used to separate CO_2 from gas streams. First generation capture technologies are primarily chemical amine solvents [V] that selectively absorb CO_2 from gas streams in a packed bed absorber and release it when heated in a stripper. The solvent is thus regenerated, and pumped back to the absorber for cyclic use, and, depending on the intended use, the pure CO_2 gas is either vented, or moves to a compressor to prepare for transportation, utilisation, or storage.

Other next generation technologies for separation include selectively permeable membranes, solid sorbents, cryogenic separation (using cooling and condensation to separate CO_2), calcium or chemical looping (reversible binding of CO_2 to calcium or a metal oxide, respectively).

Direct Air Capture

Direct Air Capture technologies offer a differentiator from flue gas capture technology that could benefit both single operators and cluster developments. Where flue gas capture requires a large scope of Brownfield modification capital expenditure, with the collation of multiple point sources, often across a large area footprint, into one common exhaust source to be processed and captured, DAC can be installed as a completely stand-alone system.

In its simplest form, DAC, exploits the same process adopted by plants to extract CO_2 during photosynthesis. The technology draws in atmospheric air, then through a chemical process, the CO_2 is extracted, processed and compressed for utilisation and storage.

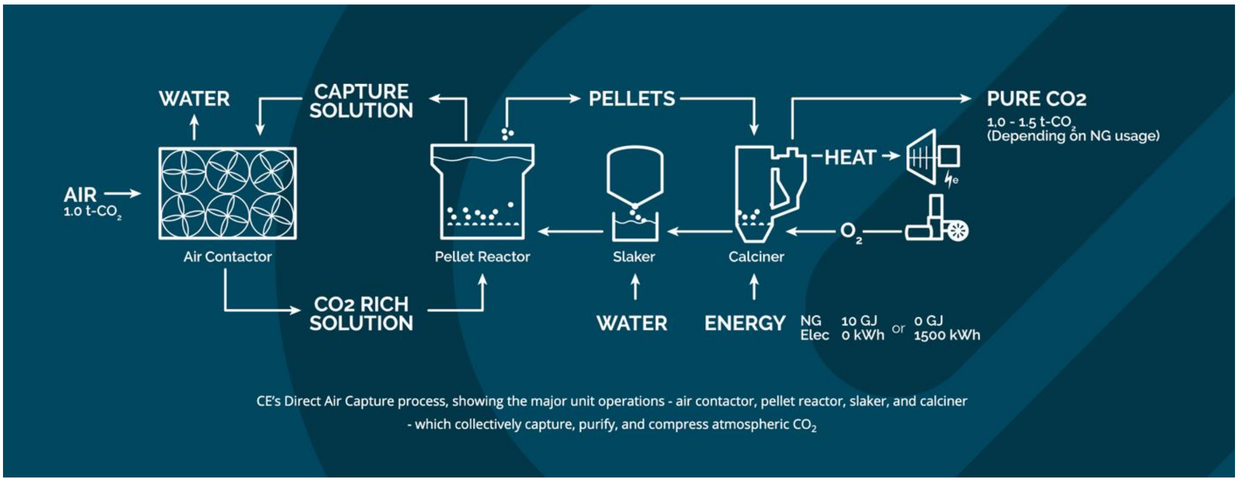


Figure 5 - Carbon Engineering's DAC Solution (Source: Carbon Engineering)

Advantages of DAC include:

- Independence from the main emitting plant or cluster
- No brownfield modifications required
- Location agnostic – can be closer to the export or storage site
- Potential to offset 100% of operation emissions
- Constant output that can potentially be sold to the utilisation sector
- Can support offsetting of other industries
- Can be a cluster owned project/solution
- Process agnostic – can still capture long after shutdown and abandonment of operations (with a revenue stream in Utilisation sector and offsetting for other industries).

As it stands, DAC is a proven concept, with multiple vendors offering solutions in the space and at varying stages of development. However, cost reduction is required to further enhance the offerings. Currently, costs range from \$94 - \$232/tCO_2 (£72 - £178/tCO_2) [6] however, as opposed to the flue capture solutions, DAC is generally more effective with regards to finances, with significantly larger plants meaning current offerings are for 1 MtCO_2 capture per year (approx. £777M at this scale). Smaller scale solutions do also exist but are tailored for personal use rather than for industrial scale opportunities. By driving the cost down to a level comparable with conventional carbon capture, and by codeveloping commercial carbon utilisation opportunities, the UK could secure a significant portion of the estimated £100Bn [7] global market in 2050.

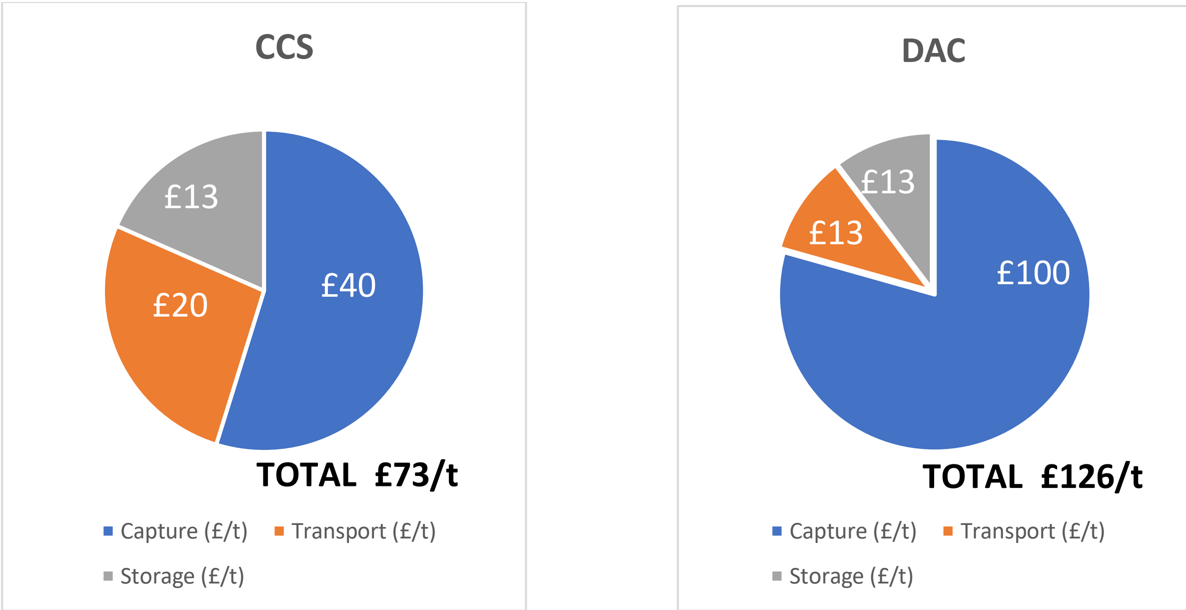


Figure 6 - Levelized cost for CCUS Technologies (Source: OGTC)

Initial Technology Screening

Internationally, DAC is gaining momentum, with proposals in place for deployment in multiple states. Within the USA, DAC technology is eligible under California's LCFS framework and amounts to nearly $200 per tonne of CO_2 captured which makes its case for deployment in the shorter term. With both incentives to invest in CO_2 and a growing CO_2 injection market in the Gulf of Mexico, the USA market for DAC is growing. With similar incentives in the UK required for full-scale commercialisation. Figure 8 outlines the growing market of DAC technology, some of which are actively progressing opportunity in the UK.

Additional Technology Descriptions				
Technology Providers	CO_2 Capture	CO_2 Transport	CO_2 Storage	How it works - in brief
CCM Carbon Capture Machine	From the tail pipe / smoke stack	Via solid materials	In solid materials	CCM (UK) Ltd is a spin out from University of Aberdeen who developed a technology that profitably converts CO_2 from any source to carbonate ions. The carbonate solution is then reacted to yield Precipitated Calcium Carbonate, PCC and Precipitated Magnesium Carbonate, PMC. Both materials have application across several industries. CCM's technology represents a reliable, integrated carbon 'CAPture' and 'CONversion' (CAPCON) technology with low capital investment needs and able to use off-the-shelf components.
Global Thermostat	Direct Air Capture from air, Tail pipe/ smoke stack	To storage as CO_2, or to distribution if Air to Fuel	Underground, or reuse as fuel if Air to Fuel option	GT uses custom equipment and proprietary (dry) amine-based chemical "sorbents" that are bonded to porous, honeycomb ceramic "monoliths" which act together as carbon sponges. The captured CO2 is then stripped off and collected using low-temperature steam (85-100° C), ideally sourced from residual/process heat at little or no-cost. The output results in 98% pure CO2 at standard temperature and pressure. Plants are completely modular – from a single 50,000 tonne/yr. Module to a 40-Module, 2MM tonne/yr. Plant, and. GT Plants also have a small footprint – capturing from 20-500 tonnes of CO_2/yr./m2 or more, depending on the embodiment used.
ZEF Zero Emissions Fuels	Direct Air Capture from air, solar powered	As Methanol	No storage. Reuse as fuel.	ZEF is developing solar methanol farms by connecting a micro-plant add-on to a conventional solar panel. CO_2 and water are collected through direct air capture and alkaline electrolysis is applied to split water into hydrogen and oxygen. These are then used to synthesize methanol, CH_4. The synthesis process works but must reach ¼ of the current production costs to be competitive. A 12MW solar-methanol farm consists of 40.000 solar panel + micro-plant systems. The modularity of the system enables scaling up to any size, and the system size enables discontinuous operation by fast heating/cooling.
Carbon Engineering	Direct Air Capture from air, electricity powered	To storage as CO_2, or to distribution if Air to Fuel	Underground, or reuse as fuel if Air to Fuel option	C.E. produces and licences plants to capture CO_2 straight from the air, with two possible applications: CCS, removing the need to transport the CO_2 from the production site to the storage site. An emissions market would enable a plant to keep producing and emitting, and be carbon neutral or even negative by capturing more CO_2 from the air straight above the storing location. Fuel production: combining the CO_2 with Hydrogen from electrolysis produced from excessive capacity, it can generate jet fuel, gasoline or diesel that is carbon neutral, as the emissions from the engine exhaust are compensated by the CO_2 captured from the air, so it's a possible way to decarbonise transport.
Climeworks	Direct Air Capture from air, electricity powered	To Storage, as CO_2, piped	Underground	Climeworks is a spin off from ETH (University of Zurich, Switzerland) commercializing a highly efficient technology for CO_2 capture from ambient air. The plants capture atmospheric carbon with a filter which chemically bounds the CO_2. Once the filter is saturated, it is heated to around 100 °C. The CO_2 is then released and collected as concentrated CO_2 gas to supply to customers or for negative emissions technologies. CO_2-free air is released back into the atmosphere. This continuous cycle is then ready to start again. The filter is reused many times and lasts for several thousand cycles.

Figure 7 - Technology Screening for DAC

Sequestration

As outlined previously in the document, the process for sequestration will involve, in part, a vast amount of knowledge and expertise of the Oil and Gas industry to develop and progress large scale sequestration of CO_2. Whether through reuse of existing infrastructure (for instance the Goldeneye pipeline or CATS pipeline) for transportation or the reuse of subsea equipment and offshore assets for offshore injection, the Oil and Gas industry has a part to play. Even if utilising new infrastructure for the injection of CO_2, well data, subsurface imagery and analysis, pipeline manufacturing, offshore structures etc. will all be required thus also securing a long-term vision of the UKCS.

Advances in the methods for identifying and surveying potential sites as well as methods for injection into either existing wells or abandoned wells either using existing infrastructure or new technologies in key for the development of CCS in the UK.

There are 2 main storage options of large-scale sequestration; depleted hydrocarbon fields and saline aquifers, however these differentiate with structure and subsurface conditions.

A comprehensive analysis of CO2 storage locations was released in 2016, outlining the volume and types of storage locations [5].

Site Numbers	Unit Designation				
Storage Unit Type	**Saline Aquifer**	**Oil & Gas**	**Gas Condensate**	**Gas**	**Total**
Fully confined (closed box)	228	3	1	8	240
Open, with identified structural/ stratigraphic confinement	20	0	0	0	20
Open, no identified structural/ stratigraphic confinement	62	0	0	0	62
Structural/ Stratigraphic confinement	50	85	15	101	251
Uncategorised	1	0	0	0	1
Total	**361**	**88**	**16**	**109**	**574**

Figure 8 - Sequestration sites and topography [5]

Depleted hydrocarbon fields and Saline aquifers make the UK a prime candidate for CO_2 storage given that is now a mature basin and has a potential 8Gt capacity (37 shortlisted areas from above) for storage.

Figure 9 shows an overview of a typical CO_2 storage project with identified steps and highlights the range of technologies required to implement.

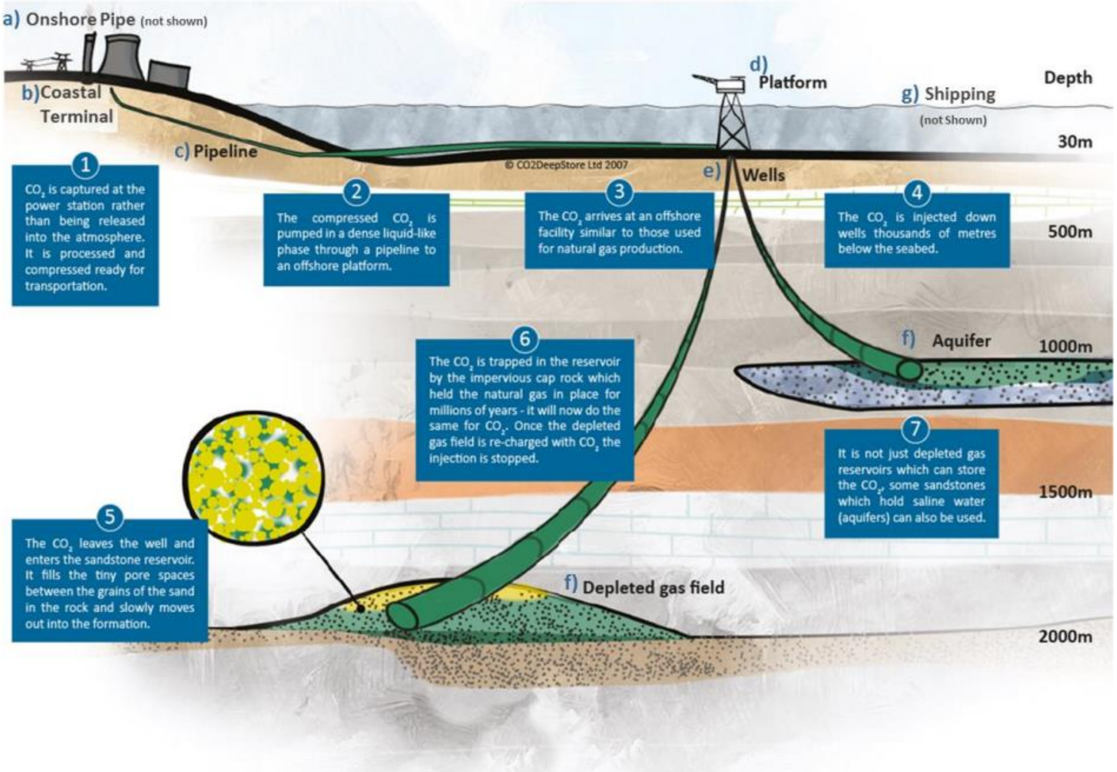


Figure 9 - Figure source [5]

Initial Technology Screening

Despite familiarity and availability of geospatial data characterising UKCS basins, many technology and knowledge gaps exist, centred around data availability, interoperability of different data sets, and the resulting ability to model the behaviour of CO_2 over time.

- **Robust multi-variable CO_2 modelling** – many valuable tools exist today, but there is significant room for improvement. The industry needs standard methods to model CO_2 migration and interactions [W] in different rock structures, potential cracking and chemical reactions through the different stages of storage (including pre-injection, operational lifetime, and after sealing the injection site) [Y]. This is particularly critical around existing wells, which could present a higher risk of leakage.
- **Site selection and injection strategy**– since disparate data sets are very difficult to compare to one another, using this data for apples-to-apples comparison of key metrics during site selection becomes challenging [Z]. Furthermore, different storage sites require different injection strategies to optimise storage efficiency; additional R&D combined with data on hydrocarbon behaviour prior to extraction is needed.
- **Phase management of CO_2 –** CO_2 behaves very differently in its different phases, which can significantly affect trapping mechanisms post-injection. This phenomenon needs to be carefully studied across the different rock formations present in the UKCS, particularly in highly depleted gas fields [AA].
- **Low cost long-term monitoring** – while there is some cross-project learning, the industry lacks a standard set of tools and guidelines to establish safe long-term monitoring of storage sites [AB][AC].

Utilisation

At present, the storage of CO_2 is still preferred over utilisation due to the current lack of largescale demand for CO_2 in industry and whilst the challenge of developing commercially viable carbon utilisation options are considerable, the implications of turning what is currently considered a waste product (CO_2) and recycling it into a revenue-generating commodity are enthralling.

With numerous technologies being developed to produce products such as synthetic fuels, chemicals, high-strength material and fish food/protein, this area is rapidly developing, as curtailed renewables continue to rise. The growth of this market generates a potentially more attractive financial model versus the CO_2 capture and storage option which requires significant infrastructure and transportation investment.

The utilisation market can be broadly summarised into these 4 sections each with opportunities for growth and financial gain.

Feed stock	Polymers, Polycarbonates, Urea, carbamates, sodium carbonate, carbonates concrete
Energy	Methanol, Bio based fuels, formic acid, syngas/methane/biological (algae, greenhouses)
Solvents	EOR, EGR, ECBM
Working fluid	Geothermal systems, Supercritical CO_2, Power cycle, Refrigeration, Dry ice, Fire suppression, welding, carbonate

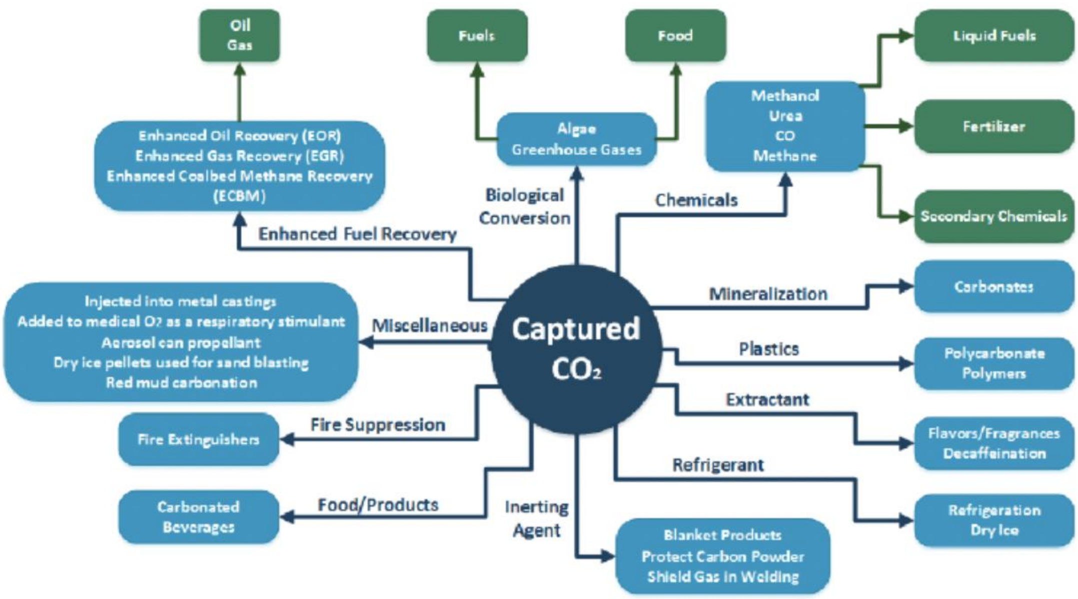


Figure 10 - Utilisation Options (Source: CCU, Smart Specialisation Platform, European Commission)

Transportation

The Feeder 10 gas pipeline situated between Grangemouth and St Fergus gas terminal is ideally situated to transport significant quantities of CO_2 captured from large emitting clusters in Grangemouth, Fife and Glasgow. Initial figures from SCCS indicate a potential scope to collect and transport 3.5 to 10 million tonnes per year (Mt/yr) of CO_2. Grangemouth is the cluster in this region with the greatest concentration of CO_2 and is also within the shortest distance to Feeder 10 pipeline. It is estimated that between 2 – 3.8 Mt of CO_2 could be captured and transported from Grangemouth with a further 1.7 Mt from Fife and other areas in and around the River Forth.

According to the SCCS, 'Around 80% of Scotland's large-point sources of CO_2 emissions are within 40km of the Feeder 10 pipeline'. Re-use of this pipeline would roughly halve the capital cost of transporting these CO_2 volumes from Central Scotland to St Fergus in the north east for connection to offshore storage facilities.

Transportation capacity of the Feeder 10 pipeline of course dictates the amount of cluster companies can utilise the transportation links, however, this provides a development opportunity for the development of alternative transportation methods such as shipping (Grangemouth, Rosyth and Edinburgh harbours within a short distance) as well as transportation by tanker.

The Feeder 10 pipeline will require technology assessment in the form of asset integrity to ensure that it can be re-purposed, along with performance monitoring as well as a significant upstream processing and handling process changes to accept and transport the CO_2 to St. Fergus. Safe and secure transportation on vehicle and by ships will also be required for emitters situated far away from the Feeder 10 pipeline, in addition to development of local ports and harbours for shipping transportation of both Hydrogen and CO2 for storage.

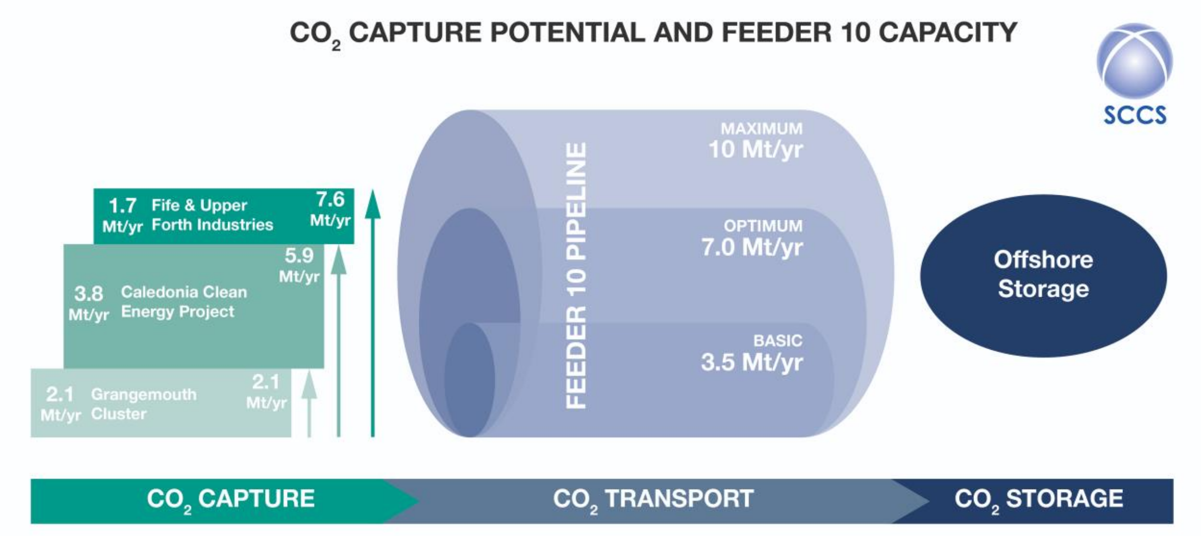


Figure 11 - A ready-made transportation solution? [Source: SCCS]

Initial Technology Screening

CO2 transportation is technologically well-understood, and it is ultimately cost that is deterring build out. However, there are still technology challenges related to retrofits, long-term integrity, and monitoring, which could be solved through knowhow from the oil and gas industry. Key technology challenges include:

- **Corrosion** – Characterisation and coatings & material to prevent corrosion from contaminated in the CO2.
- **Crack propagation** – Predictive maintenance and asset integrity solutions
- **Pressure Control** – Low cost control valves to maintain pressures over long distances
- **Retrofit ability of aging existing gas infrastructure** – Cost and modelling for effective use of existing gas systems and infrastructure

Electrification

Currently, many of the manned onshore largescale industrial clusters in the UK (such as St. Fergus and Grangemouth generate their own power and heat via dedicated generation packages using either natural gas or diesel (usually the former with diesel used as back up). Only in a minority of cases, and in smaller applications, is the power provided through cables tied into the national grid. In some cases, the connection to the grid already exists, with additional power generated by the plants being sold on to the grid in times of increased capacity.

Industry electrification would allow the provision of highly reliable, low-carbon renewable power from a distributed power grid which should increase production efficiency, lower OPEX and significantly lower CO_2 emissions from power generation.

Power from Grid / All electric systems

For replacement of onshore power generation from the burning of fossil fuels, the following power demands will need to be met by an electrical supply:

- **Base Load -** Electrical power distribution
- **Heat -** Process heat demand
- **Sub system demand**

If some of the internal processes in the specific plant also utilise fossil fuels as a feedstock, the implications of the transition to electric are that these systems would be replaced with equivalent electrical motors and process heat load would be serviced by electric heating. This results in a significant increase of electrical power demand per facility, when compared to the capacity of currently installed electrical generation.

It is recognised that hybrid solutions, with different supply options are being used in some areas and may provide an optimum solution which should be assessed.

In order to convert a facility from onsite power generation to running from an all electrical supply the following key modifications are expected (which are common to all of the supply and distribution concepts):

- Connection to national grid (if not already incorporated) including power cables and ancillary equipment
- Modification or change out of facility switchgear, switchboards and electrical distribution systems to accommodate electrification
- Replacing or modifying subsystems to utilise new power source
- Replacing process heat input with an electrical equivalent.

For all of the above items the extent of modifications, time to procure equipment, time to make changes and the associated costs will be installation specific. Each facility will have different access, space and weight loading constraints, as well as existing electrical equipment at differing operating parameters and conditions.

Replacing natural gas with low-carbon fuels like hydrogen or ammonia can provide a decarbonisation pathway for platforms where switching mechanically driven compressors is not feasible.

Renewables Integration

In the UK there is a growing offshore and onshore wind power sector and the region is considered to be the best in Europe. Wind power contributed nearly 18% of UK electricity generation, and accounting for 52% of electricity generation from renewable sources in 2018. Currently, in the UK, there are a number of operating onshore wind farms as well as offshore wind farms that are either generally close to shore or close to the clusters.

Powering an onshore facility from a wind farm is a valid concept and is being trialled in a number of applications in the UK (FMC, Dunfermline). Utilisation of an onshore wind farm would allow the powering of the onshore industry, with any balance of power requirements coming from the national grid. Any onsite modifications would be similar to that stated in the previous section and the onshore wind farm could also be retained at the end of the lifecycle of the industrial company or cluster to sell power directly to the grid.

The components required will depend on the distance from the facility to the wind farm and the amount of power to be transferred. For a facility in relatively close proximity, 50 – 100 km, then an AC direct link may be applicable with HVDC required at longer step out distances. Adoption of this solution would require the following activities:

- HVAC cable connection at wind farm sub-station
- HVAC cable routing to individual facility or hub
- Step-down transformer at facility or hub

However, converting onshore AC power to DC power for transmission, and back to AC power for usage can cost approximately £0.2/W [A] depending on voltage and power rating, which can lead to a significant capital cost for two conversion stages.

An additional consideration for projects with power from shore – either through wind farms or direct connection to the grid – is the potential strain that electrified platforms can put on onshore power grids. This can result in the need for grid upgrades, leading to additional costs for operators.

Initial Technology Screening

The business case for electrification depends on plant conditions and location. Connecting grid power to facilities involves a significant investment. To justify infrastructure outlay, new plants are generally more suitable for electrification, though factors such as the overall power consumption, types of loads, and plant size will have an impact on the decision to electrify. For brownfield application, electrification will only be viable if the benefits from saving fuel and CO_2 emissions (rising tax etc.) compensate for the platform conversion investments as well as the lost earnings from production downtime – in the case of full electrification – while transitioning to an electrified system. Electrifying a cluster of companies within short distances helps to share these capital costs and considered to be economically feasible in comparison to gas-to-power projects over long distances.

Battery Storage

Published in 2019, a report from the Energy institute indicated that at the time of publication, '8GW of battery storage has been given planning consent in the UK, but a further 12GW may be needed by 2021' [8].

This, new to industry, technology is crucial for storage of power for the likes of the 'intermittent' renewables industry and the application of renewables into the offshore and onshore industry as well as key for enabling balance of power to the national grid in times of high demand. Currently, the UK power grid works off a balance type approach where generation must meet the demand, therefore the adoption of storage at scale offers advantages of power when the demand is greater than the supply source or when there is a significant portion of the grid capacity that comes from irregular sources like wind energy.

Electricity can be stored in many ways including Electrochemical products such as batteries, Pumped hydroelectric storage & Mechanical flywheels.

Currently, Battery systems can store power for seconds or minutes for power quality (voltage or frequency regulation) or minutes to hours for peak shaving or load shifting, improving both grid stability and revenue potential. Deployment of grid storage solutions is at an early stage, with nearly 1 GW of battery devices currently being used across the UK [U]. Seasonal storage is currently not possible using Batteries, and instead other solutions, such as long-term gas storage, will need to be developed.

Initial Technology Screening

Buoyed by massive scale-up and cost reductions in the last few years because of the increase of electric vehicles, Lithium ion (Li-ion) batteries are currently the preferred energy storage option. Li-ion batteries primarily differ by cathode chemistry, and each has its own benefits and drawbacks. Lithium iron phosphate (LFP) batteries' long lifespan, high safety, and relatively low price point can make it a common option, though improvements and massive scale-up of nickel manganese cobalt oxide (NMC) li-ion batteries for electric vehicles has sufficiently lowered costs to start making this a viable and more energy dense option.

Besides Li-ion, Flow Batteries, like Vanadium redox or Zinc Bromine, have been growing in applications requiring larger capacities. Because of the variability associated with wind power, there is a need for at least 10 MW-100 MW batteries with shorter discharge durations (seconds to minutes), and energy storage in the minutes to hours (MWh to GWh) range to counter cannibalisation of power prices. challenges addressed by producers, mostly targeting electric vehicles, include commercialising new electrode materials, packaging, and battery management systems to improve capacity, safety, and cycle life.

While there are a few use cases for batteries offshore, energy storage is primarily required onshore to ensure power coming from the UK Continental Shelf (UKCS) can be reliably integrated with the national grid, like the Batwind project, announced by Equinor and Masdar, connecting the 30 MW Hywind farm to an onshore battery storage farm.

Efficiency Optimisation

With regards to efficiency optimisation, there are a lot of 'low hanging fruits' and quick wins that companies can implement through a detailed and extensive review of data and processes within each individual case. By modelling power generation and power demand requirements against expected costs and rising taxes on fuel gas and CO_2 emissions, each operator can evaluate the value addition of all the CO_2 reduction proposals whilst also determining the short, medium- & long-term plans.

Some potential quick wins include:

1. Emissions quantification (modelling)
2. Optimising production to utilise spare plant capacity;
3. Resizing pumps & compressors to meet current plant demand and minimise recycle;
4. Optimisation of compressor and pumps controls such as pump and compressor recycle;
5. Optimisation of plant pressure and temperatures to reduce energy consumption;
6. Reduce plant air leaks;
7. Optimise testing of standby combustion plant;
8. Upgrade lubrication to reduce plant energy consumption;
9. Optimise utility cooling and heat system to meet plant demand;
10. Electrical motor upgrades to higher efficiency options / VSD;
11. Reduced the electrical line frequency to minimum acceptable levels to slow down the pumps to save energy;
12. Electrification of main drivers;
13. Energy optimisation of the offices & sustainable electricity sourcing
14. Smart metering & Continual monitoring

Whilst may of the examples given may already be implemented, there will be shared process knowledge and best practice adopted by other industries and operators that may provide additional savings.

Hydrogen Economy

In 2019, the Committee on Climate Change (CCC) indicated in its 'Net Zero' report, that two technologies were crucial in the UK's ability to reach net zero by 2050 (2045 in Scotland), these technologies are Hydrogen generation and CCUS [9]. A report, published by Element Energy in November 2019 on 'A summary of four studies assessing the role of hydrogen in the UK net-zero transition' [10], indicated that this adoption could benefit the UK industry by as much as £18 Billion and create in excess of 200,000 jobs.

Whist onshore industrial plants can adopt CCUS as a means to decarbonise assets, some, who utilise natural gas in GTGs for power generation, can implement Hydrogen fuelled power generation systems in stages that can offer a net, or even negative, zero solution.

As it stands, Blue Hydrogen, the generation of Hydrogen from Natural gas through methods such as Steam Methane Reforming, SMR, (with incorporated CCUS), is more cost effective than Green hydrogen, with the likes of Grey hydrogen (generated from Coal) being phased out in the UK [X].

By 2050, the CCC have indicated that the likely demand for hydrogen will be close to 270TWh (27TWh in 2017), with majority of that provision coming from blue hydrogen with CCUS and the rest from Green Hydrogen. The report [9], suggests that industry will remain the largest contributor to demand of Hydrogen, with Heat, Transport and Shipping the other key demand centres. Hydrogen supply in the UK will be heavily reliant on;

- Re-using and expanding the existing gas infrastructure
- Use of the significant wind resource availability in the UK
- Creating a Green hydrogen partnership with other countries. Europe has large amounts of wind power potential that can be used whilst other countries such as Norway have large amounts of hydroelectric power.

At present, there are a number of Hydrogen production projects in progress across the UK, with a large focus on industrial clusters as potential locations, with hydrogen as a potential fuel gas alternative to natural gas (or) as a product to sell to the growing market. The projects in progress are:

Hynet - £7.48m – Low carbon hydrogen plant
Gigastack - £7.5m - Gigawatt scale polymer electrolyte membrane (PEM) electrolyser
Acorn Hydrogen Project - £2.7m – Advanced reformation process
Bulk Hydrogen Production by Sorbent Enhanced Steam Reforming (HyPER) - £7.44m pilot scale demonstration of the sorption enhanced steam reforming process.

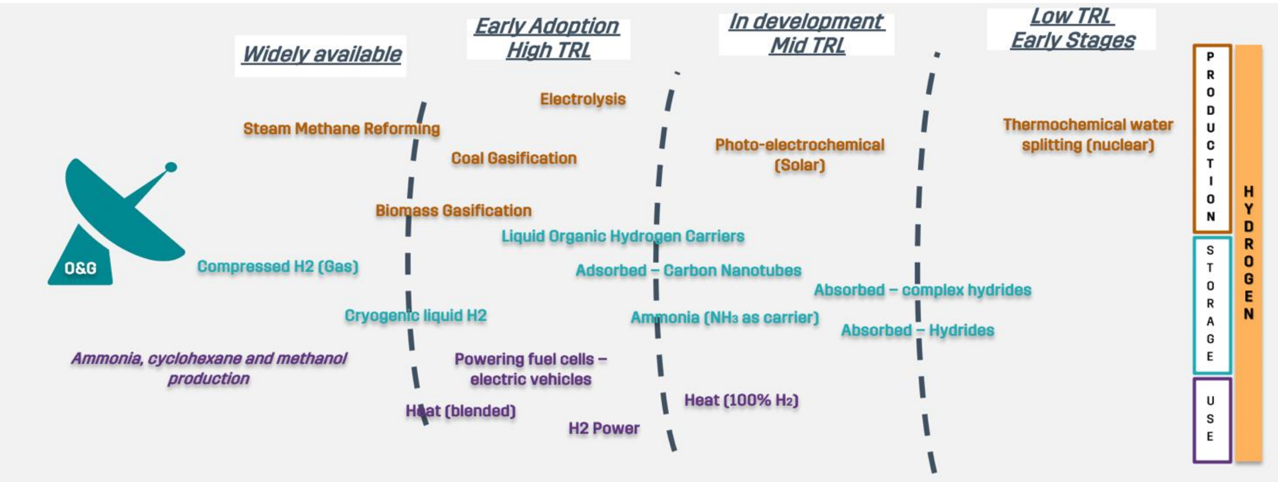


Figure 12 - Hydrogen Technology Radar (Source: OGTC)

Hydrogen Generation (SMR with CCUS)

Hydrogen could have a potentially high impact on economies across the globe. It offers a single energy vector to link currently disparate energy markets. At present, the main process to manufacture Hydrogen, is through Steam methane reforming of natural gas (SMR) and is widely used in industry today. Hydrogen is produced by the SMR process in large industrial plants for use across the industry, including chemical manufacturing and petroleum refining.

Steam reforming of natural gas offers an efficient, economical, and widely used process for hydrogen production; however, CCUS is required in conjunction as the exhaust gases from the process without capture are high (70% efficiency factors for SMR).

The development of SMR technologies in parallel with CCUS technology is, therefore, critical for the upscale of blue hydrogen generation and use in the UK.

The below figure outlines the roadmap of technology development required in both blue and green hydrogen in order to meet the UK targets as agreed upon by government.

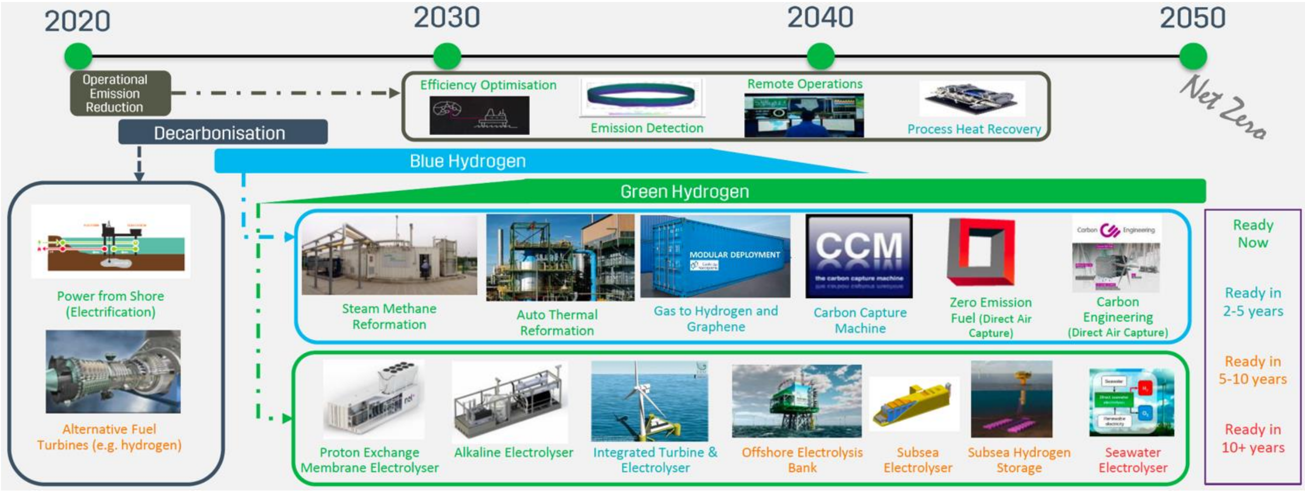


Figure 13 - Hydrogen Technology Roadmap (Source: OGTC)

Reformation of Natural Gas involves methane reacting with steam at 750-800°C to create a synthesis gas (syngas), a mixture primarily made up of hydrogen (H2) and carbon monoxide (CO). The second step is known as a water gas shift reaction, where the carbon monoxide produced in the first step reacts with steam over a compound to form hydrogen and CO_2. This process occurs in two stages, consisting of a high temperature shift (HTS) and a low temperature shift (LTS).

Initial Technology Screening

Like most thermochemical processes, both SMR and CCUS are more economical at large scales, and with high construction costs and space constraints make it a difficult proposal for brownfield modifications. However, several organizations [B][C] are developing methods to increase the efficiency both of reforming and CO_2 capture and decrease system footprint to offer potential for more modular deployment.

Incremental improvements to SMR units have been under development [E][F] for well over a decade and are readily available [D] and can benefit incumbent grey hydrogen production process as well as blue hydrogen. These improvements include better heat transfer and heat recovery in the systems and lower amounts of catalyst materials.

Novel reforming technologies for Blue hydrogen production can increase hydrogen yields and CO_2 capture ratios while reducing the system footprint, for example, membrane CO_2 removal technology.

Green Hydrogen production through Electrolysers

Green hydrogen is produced using one of several types of electrolysers, with a process that splits water molecules into hydrogen and oxygen, using renewable electricity. Electrolysers are predominately situated onshore; however, the offshore green hydrogen production market is growing with the technology to develop electrolysation from seawater underway.

Electrolyser type	Benefits	Drawbacks
Alkaline (AE)	• Lower costs – cheaper catalyst metals • Long performance history	• Liquid electrolyte is hazardous, corrosive, and susceptible to leakage • Requires several minutes to ramp up and down
Proton exchange membrane (PEM)	• Rapid response time, better suited to pair with intermittent energy sources • Operates at high current density and wide load range	• Higher CAPEX • Relatively unproven technology
Solid oxide electrolysis cell (SOEC)	• Operates at very high temperature (>700 °C) and efficiency	• Moderate time to ramp up or down • Not suited for intermittent use because of need for high heat • Unproven in commercial use

For Green hydrogen, which is to say, Hydrogen generated specifically from wind power utilising water to Hydrogen electrolysers, the key technology enabler is Alkaline Electrolysers and at scale. There has already significant development on this front with Nouryon who has recently received €11m in EU funding to build a 20MW alkaline electrolyser. The process will reduce CO_2 emissions by approximately 27,000 tonnes per year in its application. To enable the large-scale adoption of hydrogen for power and heat generation, the cost to implement should also reduce.

Current electrolysis methods are generally just under 70% efficient, and green hydrogen economics are almost exclusively determined by a system's power prices, load factor, and capital costs [I].

Initial Technology Screening

The high capital cost of electrolysers of £640 – £720/kW is a major bottleneck and today needs to be offset by making optimal use of lower power prices through operational improvements, consistent power supply, and digital grid control software. Costs are high today because electrolyser stack assembly is a largely manual process done in small factories. Scale-up along with robotics and automation methods like roll-to-roll manufacturing could reduce costs by 30% or more by 2030 [G], similar to how Lithium-ion battery production costs have plummeted in the last five years, and is a major focus of leading producers like ITM Power, NEL, or Siemens. These advances could reduce CAPEX to £160 – £240/kW after 2040 [H].

Another opportunity for cost reduction is cheaper electrode catalysts. PEM electrolysers today use expensive but higher-performing platinum and iridium, but advances in achieving similar performance with lower cost catalyst materials could reduce capital costs by 5% – 10%.

Hydrogen as a Fuel Gas

Many of the onshore Scottish Clusters utilise fossil fuels (i.e. natural gas) for electricity generation. Can those systems be replaced with Hydrogen as an alternative source of clean power? And with the UK gas grid being currently analysed for the commingling of Natural Gas and Hydrogen, is there a market for the clusters to drive into this new industry in an Energy Hub based approach?

Many gas turbines can already run on natural gas / hydrogen blends of up to 20% hydrogen [J] and all major turbine producers, including Ansaldo, GE, MHPS, and Siemens are developing turbines capable of running on 100% hydrogen, including in dual-fuel designs that can use multiple different fuels. Hydrogen's high flammability can even increase combustion efficiency.

Initial Technology Screening

Hydrogen's low volumetric density and potential embrittlement of some metals require changes to pipeline transportation, ducting, seals, and valves, and possible turbine retrofits for turbine blades to withstand higher flame temperatures.

Changes in burner design may also be needed to avoid risks of damage due to hydrogen's flammability and flame speed [K] [L] and nitrous oxide (NOx) formation at higher temperatures [M]. Even a relatively small 11 MW turbine, if running on pure hydrogen, uses 1.1 tonnes of hydrogen per hour [N], or one shipping container full of 500 bar compressed hydrogen every four to five hours. As a result, in the UK, hydrogen turbines would remain limited to use cases that require very high-power outputs.

Turbines fuelled by an ammonia-hydrogen blend are another alternative, as a blend of around 70% ammonia and 30% hydrogen approximates the combustion characteristics of natural gas [O]. Ammonia storage tanks' footprint and weight per kg hydrogen are 10-fold lower than cryogenic hydrogen storage, [P] and Ammonia blends also help reduce turbine NOx emissions [Q]. Besides demonstrating this in new turbines, the key challenges for this solution are demonstrating the technical and economic feasibility of using short platform shutdown periods to make the needed modifications to older turbines and setting up Ammonia barge supply lines.

Hydrogen Fuel Cells

Avoiding a gas turbine altogether translates to fewer personnel, improved safety, and auxiliary facilities. When direct electrification is not possible, natural gas/hydrogen fuel cell can be an alternative. Stationary Fuel cells can have 60% – 70% electrical efficiency, nearly twice that of an Open Cycle Gas Turbine, are substantially less complex, and operate reliably without risks like flame-out [R]. Fuel cells have been backed by major governments like USA, Japan and South Korea, developed by specialists like Plug Power, Doosan, Fuel Cell Energy, Bloom Energy, and Ballard Power Systems, and backed by major industries like the automotive sector. However, high capital costs have prevented wide adoption in mainstream uses like transportation and baseload power.

Initial Technology Screening

Technically, fuel cells are essentially electrolysers running in reverse, and have similar technology challenges such as manufacturing automation and expensive catalyst materials like Platinum. Like Electrolysers, more output requires a larger electrode surface area, limiting cost benefits of scaling up to larger devices. In the UK, fuel cells can be particularly attractive for smaller power loads, especially for applications where batteries are not the best solution.

Hydrogen Storage

Using salt caverns as hydrogen storage is proven, relatively inexpensive and is reliable. They can easily be created by dissolving the salt but ensuring maximum and minimum pressures are closely monitored and maintained for their longevity. A number of sites are already in use and have been identified for future development. Hydrogen Storage in Porous Media (HyStorPor), a University of Edinburgh spin out recently received £1m+ to explore hydrogen storage within porous rocks in a bid to stabilise and take advantage of the UK's excess energy production.

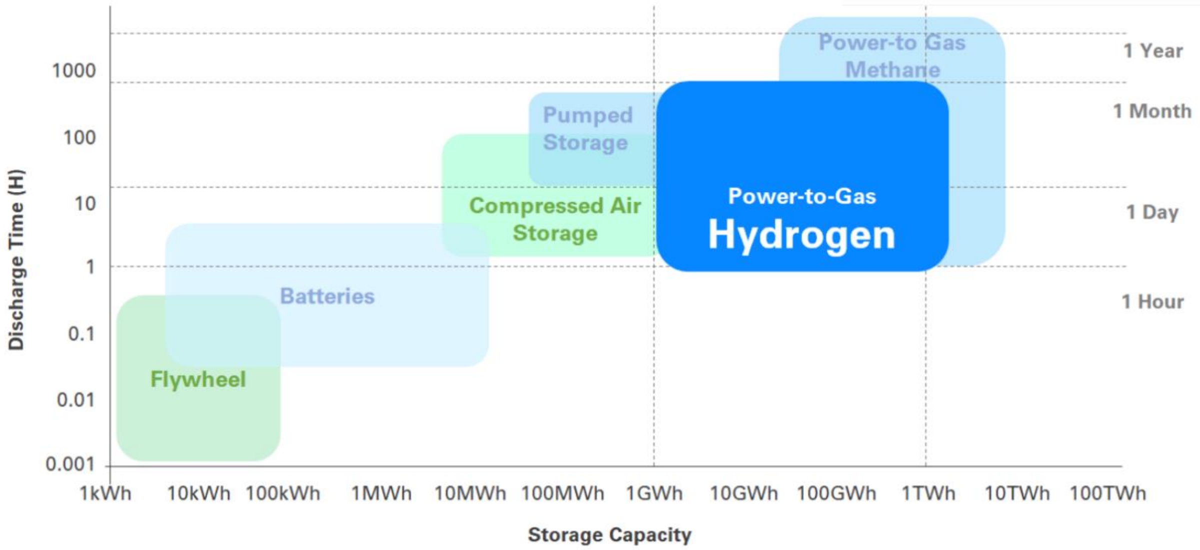


Figure 14 - Source: Hydrogen Roadmap Europe

Technology challenges

Offshore salt caverns have not yet been used for hydrogen storage, though the Central North Sea basin does offer multiple potential salt cavern locations [S]. However, it is still unclear if depleted gas reservoirs are suitable, as hydrogen may escape through low porosity rock that is otherwise impermeable to natural gas – and the hydrogen can react with remaining hydrocarbons or sulphur compounds [T], contaminating the hydrogen supply.

List of Potentially Attractive Technologies

The below table lists all the net-zero technologies that have been discussed within this report.

Technology	TRL rating
Modular CCUS	Med-High
Direct Air Capture	Med
CO_2 Transport	High
CO_2 Utilisation	Low-Med
CO_2 Sequestration	High
Electrification	High
Renewable Integration	Med-High
Battery Storage	Low-High
Efficiency Optimisation	Med-High
Hydrogen Generation (SMR)	High
Green Hydrogen	Med-High
Alternative Fuel Power Gen	Low-Med
Hydrogen Fuel Cells	Med-High
Hydrogen Storage	Low

As a next step, feedback from all stakeholders through workshops and one-to-one meetings will be incorporated and technologies will be ranked by a defined set of criteria.

References

[1] European Environment Agency, "EU Emissions Trading System (ETS) data viewer," [Online]. Available: https://www.eea.europa.eu/data-and-maps/dashboards/emissions-trading-viewer-1.

[2] Glowacki Law Firm, "Tier thresholds under the EU ETS Monitoring and Reporting Regulation," [Online]. Available: https://www.emissions-euets.com/tier-thresholds-under-the-eu-ets-mar-regulation. [Accessed 09 09 2019].

[3] European Environment Agency, 'Delivering emissions reductions' [Online]. Available: https://ec.europa.eu/clima/policies/ets_en

[4] Global CCS Institute, 'Global Status of CCS in 2019', [Online]. Available: https://www.globalccsinstitute.com/wp-content/uploads/2019/12/GCC_GLOBAL_STATUS_REPORT_2019.pdf

[5] ETI, 'Strategic UK CCS Storage Appraisal' [Online]. Available: https://www.eti.co.uk/programmes/carbon-capture-storage/strategic-uk-ccs-storage-appraisal

[6] A Process for Capturing CO2 from the Atmosphere, Published: June 07, 2018, David W. Keith, [Online]. Available: https://www.cell.com/joule/fulltext/S2542-4351(18)30225-3

[7] BEIS, 'Capture Usage and Storage: third time lucky?', BEIS Strategy Committee, April 2019, [Online]. Available: https://publications.parliament.uk/pa/cm201719/cmselect/cmbeis/1094/1094.pdf

[8] Energy Institute, 'BATTERY STORAGE GUIDANCE NOTE 1: BATTERY STORAGE PLANNING', August 2019, [Online]. Available: https://publishing.energyinst.org/__data/assets/pdf_file/0007/655054/web-version.pdf

[9] Climate Change Committee (CCC), 'Net Zero – The UK's contribution to stopping global warming', Published: 2 May 2019, [Online]. Available: https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

[10] Element Energy, 'A summary of four studies assessing the role of hydrogen in the UK net-zero transition', Published: November 2019, [Online]. Available: http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Summary-Document.pdf

[A] Hartel, P., Vrana, T. K., Hennig, T., von Bonin, M., Wiggelinkhuizen, E., and Nieuwenhout, F. (2017). Review of investment model cost parameters for VSC HVDC transmission infrastructure. *Electric Power Systems Research*, 151,

[B] Hygear.com. (2020). Hy Gen: on-site hydrogen generation. [online] Hy Gear. Available at: <https://hygear.com/technologies/hy-gen/> [Accessed 1 May 2020].

[C] Cordis.europa.eu. (2019). Biogas membrane reformer for decentralIzed hydrogen production. [online] CORDIS EU Commission. Available at: <https://cordis.europa.eu/project/id/671459> [Accessed 2 May 2020].

[D] Chemengonline.com. (2015). Modular hydrogen production technology uses modified SMR process. [online] Chemical Engineering. Available at: <https://www.chemengonline.com/modular-hydrogen-production-technology-uses-modified-smr-process/> [Accessed 28 April 2020].

[E] Ieahydrogen.org. (2011). IEA-HIA Task 23 Small-scale Reformers for On-site Hydrogen Supply. [online] iea Energy Technology Network. Available at: <http://ieahydrogen.org/pdfs/Task23_Final-Report_ISBN.aspx> [Accessed 3 May 2020].

[F] Rystadenergy.com. (2017). Electrifying the Barents Sea. [online] Rystad Energy. Available at: <https://www.rystadenergy.com/newsevents/news/press-releases/electrifying-the-barents-sea/> [Accessed 4 May 2020].

[G] Nrel.gov. (2019). Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolysers. [online] NREL. Available at: <https://www.nrel.gov/docs/fy19osti/72740.pdf> [Accessed 29 April 2020].

[H] Irena.org. (2019). Hydrogen: A renewable energy perspective. [online] IRENA. Available at: <https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective> [Accessed 30 April 2020].

[I] Offshore-technology.com. (2014). Onshore power for offshore platforms. [online] Offshore Technology. Available at: <https://www.offshore-technology.com/features/featureonshore-power-for-offshore-platforms-4330517/> [Accessed 4 May 2020].

[J] Ge.com. (2020). Hydrogen fuelled gas turbines. [online] GE. Available at: <https://www.ge.com/power/gas/fuel-capability/hydrogen-fueled-gas-turbines> [Accessed 26 April 2020].

[k] Hydrogeneurope.eu. (2020). Liquefaction systems. [online] Hydrogen Europe. Available at: <https://hydrogeneurope.eu/liquefaction-systems> [Accessed 28 April 2020].

[L] Inoue, K., Domen, S., Miyamoto, K., Tamura, I., Kawakami, T., and Tanimura, S. (2018). Development of Hydrogen and Natural Gas Co-firing Gas Turbine. [online] Mitsubishi Heavy Industries Technical Review, 55(2). Available at: <http://www.mhi.co.jp/technology/review/pdf/e552/e552160.pdf> [Accessed 3 May 2020].

[M] Taninoki, R, Abe, K., Sukegawa, T., Azuma, D., and Nishikawa, M. (2017). Dynamic Cable System for Floating Offshore Wind Power Generation. SEI Technical Review, 84.

[N] Ge.com. (2019). Power to gas: Hydrogen for power generation. [online] GE. Available at: <https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf> [Accessed 4 May 2020].

[O] Windpowermonthly.com. (2020). Siemens launches ammonia storage demo. [online] Wind Power Monthly. Available at: <https://www.windpowermonthly.com/article/1486298/siemens-launches-ammonia-storage-demo> [Accessed 5 May 2020].

[P] Siemens, (2020). 'Friday Thoughts' [PowerPoint presentation], March 6, 2020, Aberdeen.

[Q] Valera-Medina, A., Gutesa, M., Xiao, H., Pugh, D., Giles, A., Goktepe, B., Marsh, R., and Bowen P. (2019). Premixed ammonia/hydrogen swirl combustion under rich fuel conditions for gas turbines operation. International Journal of Hydrogen Energy, 44(16), p. 8615-8626.

[R] Prototech.no. (2020). Fuel Cell Power Systems. [online] Prototech. Available at: <https://www.prototech.no/applications/power-systems-fuel-cells/> [Accessed 4 May 2020].

[S] Caglayan, D., Weber, N., Heinrichs, H. U., Linßen, J., Robinius, M., Kukla, P. A., and Stolten, D. (2019). Technical Potential of Salt Caverns for Hydrogen Storage in Europe. International Journal of Hydrogen Energy, doi: 10.1016/j.ijhydene.2019.12.161.

[T] Amid, A., and Mignard, D. (2016). Seasonal storage of hydrogen in a depleted natural gas reservoir. International Journal of Hydrogen Energy, 41(12), doi: 10.1016/j.ijhydene.2016.02.036.

[U] Based on WoodMacKenzie Energy Storage data for cumulative end of 2019, comprising 880MW front-of-the-meter, grid connected energy storage, 50MW non-residential (C&I), 40MW residential.

[V] Rochelle, G. T. (2009). Amine Scrubbing for CO2 Capture. *Science*, 325(5948), 1652–1654.

[W] Jenkins, C. R., Cook, P. J., Ennis-King, J., Undershultz, J., Boreham, C., Dance, T., et al. (2012). Safe storage and effective monitoring of CO2 in depleted gas fields. *Proc. Natl. Acad. Sci. U.S.A.*, 109(35–41).

[Y] Energy.gov. (2017). *Accelerating the clean Energy Revolution*. [online] US Department of Energy and Kingdom of Saudi Arabia Ministry of Energy, Industry, & Mineral Resources. Available at: <https://www.energy.gov/sites/prod/files/2018/05/f51/Accelerating%20Breakthrough%20Innovation%20i

n%20Carbon%20Capture%2C%20Utilization%2C%20and%20Storage%20_0.pdf> [Accessed 6 April 2020].

[Z] Aminu, M., Nabavi, S., Rochelle, C. and Manovic, V. (2017). A review of developments in carbon dioxide storage. *Applied Energy*, 208, p. 1389-1419.

[AA] Palebluedot.com. (2018). *Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource*. [online] Pale Blue Dot. Available at: <https://s3-eu-west-1.amazonaws.com/assets.eti.co.uk/legacyUploads/2016/04/D16-10113ETIS-WP6-Report-Publishable-Summary.pdf> [Accessed 27 April 2020].

[AB] Energy.gov. (2017). *Accelerating the clean Energy Revolution*. [online] US Department of Energy and Kingdom of Saudi Arabia Ministry of Energy, Industry, & Mineral Resources. Available at: <https://www.energy.gov/sites/prod/files/2018/05/f51/Accelerating%20Breakthrough%20Innovation%20in%20Carbon%20Capture%2C%20Utilization%2C%20and%20Storage%20_0.pdf> [Accessed 6 April 2020].

[AC] Aminu, M., Nabavi, S., Rochelle, C. and Manovic, V. (2017). A review of developments in carbon dioxide storage. Applied Energy, 208, p. 1389-1419.

[AD] Mai Bui, Claire S. Adjiman, André Bardow, Edward J. Anthonye, Andy Boston f, Solomon Brown g, Paul S. Fennell , Sabine Fuss, Amparo Galindo, Leigh A. Hackett, Jason P. Hallett, Howard J. Herzog, George Jackson , Jasmin Kemper , Samuel Krevor , Geoffrey C. Maitland, Michael Matuszewski, Ian S. Metcalfe, Camille Petit, Graeme Puxty, Jeffrey Reimer, David M. Reiner, Edward S. Rubin, Stuart A. Scott, Nilay Shah, Berend Smit, J. P. Martin Trusler, Paul Webley, Jennifer Wilcox and Niall Mac Dowell, Carbon capture and storage (CCS): the way forward (2018), Energy Environ. Sci., 11, 1062-1176.