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TECHNOLOGY READINESS AND COSTS OF CCS

GLOBAL CCS INSTITUTE

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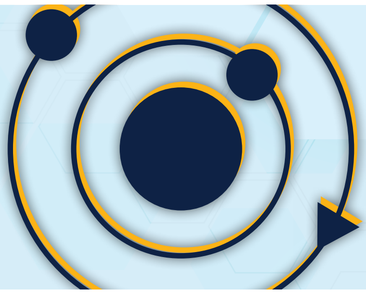

THE CIRCULAR CARBON ECONOMY: KEYSTONE TO GLOBAL SUSTAINABILITY SERIES assesses the opportunities and limits associated with transition toward more resilient, sustainable energy systems that address climate change, increase access to energy, and spark innovation for a thriving global economy.

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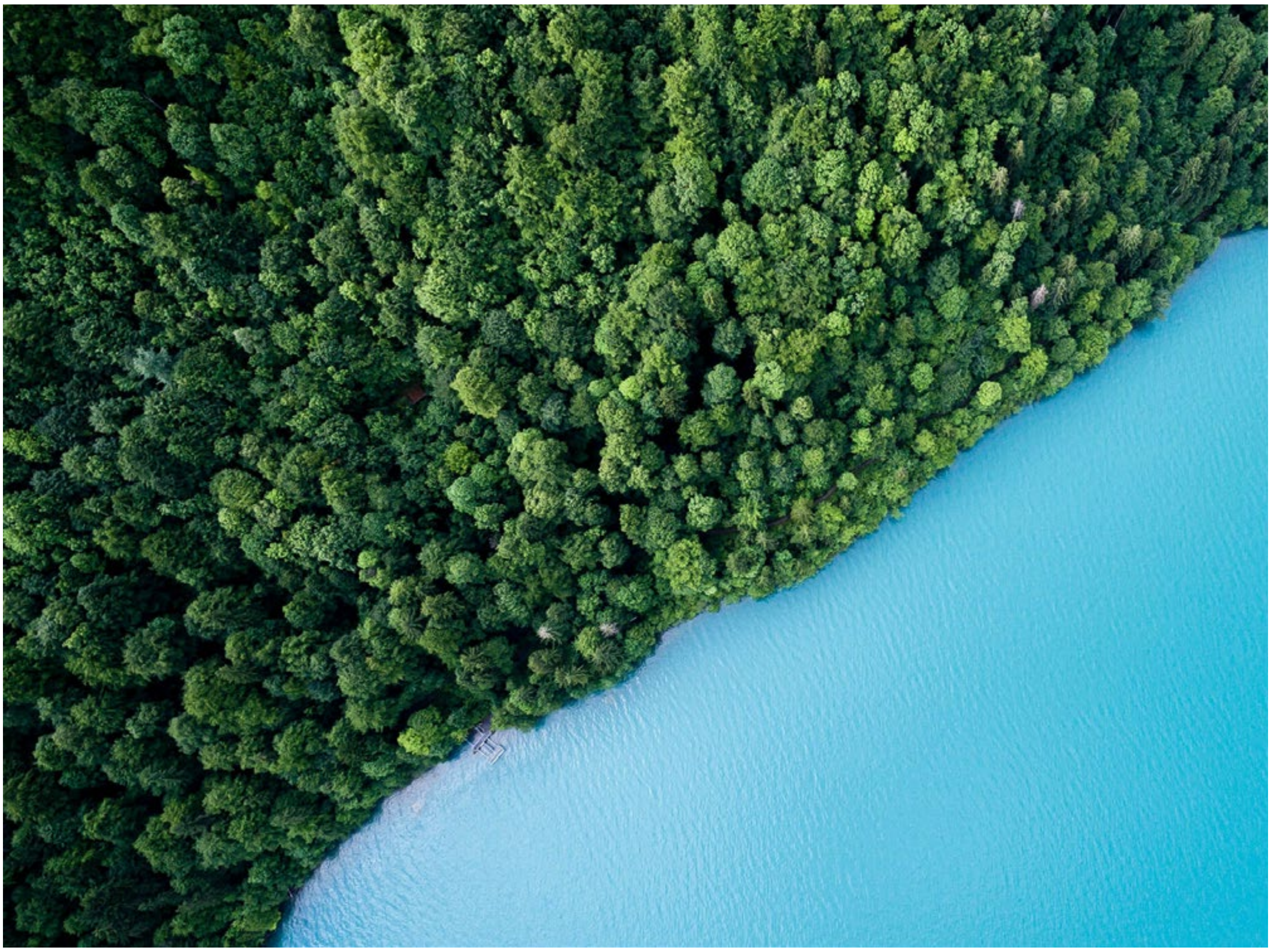

INTRODUCTION

Stopping global warming requires net greenhouse gas emissions to fall to zero and remain at zero thereafter. Put simply, all emissions must either cease, or be completely offset by the permanent removal of greenhouse gases (particularly carbon dioxide - CO_2) from the atmosphere. The time taken to reduce net emissions to zero, and thus the total mass of greenhouse gases in the atmosphere, will determine the final equilibrium temperature of the Earth. Almost all analysis concludes that reducing emissions rapidly enough to remain within a 1.5°Celsius carbon budget is practically impossible. Consequently, to limit global warming to 1.5°Celsius above pre-industrial times, greenhouse gas emissions must be reduced to net-zero as soon as possible, and then CO_2 must be permanently removed from the atmosphere to bring the total mass of greenhouse gases in the atmosphere below the 1.5° Celsius carbon budget.

This task is as immense as it is urgent. A conclusion that may be drawn from credible analysis and modelling of pathways to achieve net-zero emissions is that the lowest cost and risk approach will embrace the broadest portfolio of technologies and strategies, sometimes colloquially referred to as an "all of the above" approach. The King Abdullah Petroleum Studies and Research Center (KAPSARC) in the Kingdom of Saudi Arabia developed the Circular Carbon Economy (CCE) framework to more precisely describe this approach. This framework recognizes and values all emission reduction options.[1] The CCE builds upon the well-established Circular Economy concept, which consists of the "three Rs" which are Reduce, Reuse and Recycle. The Circular Economy is effective in describing an approach to sustainability considering the efficient utilization of resources and wastes however it is not sufficient to describe a wholistic approach to mitigating greenhouse gas emissions. This is because it does not explicitly make provision for the removal of carbon dioxide from the atmosphere (Carbon Direct Removal or CDR) or the prevention of carbon dioxide, once produced, from entering the atmosphere using carbon capture and storage (CCS). Rigorous analysis by the Intergovernmental Panel on Climate Change, the International Energy Agency, and many others all conclude that CCS and CDR, along side all other mitigation measures, are essential to achieve climate targets.

The Circular Carbon Economy adds a fourth "R" to the "three Rs" of the Circular Economy; Remove. Remove includes measures which remove CO_2 from atmosphere or prevent it from entering the atmosphere after it has been produced such as carbon capture and storage (CCS) at industrial and energy facilities, bio-energy with CCS (BECCS), Direct Air Capture (DAC) with geological storage, and afforestation.

This report examines CCS technology from two perspectives. First, an examination of the technology readiness of each component of the CCS value chain is explored. Second, a review of the factors that influence the current and future costs of carbon capture, compression, transport and storage is presented.

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[1] KAPSARC (2019). Instant Insight, November 06, 2019. Achieving Climate Goals by Closing the Loop in a Circular Carbon Economy.

1.0 EXECUTIVE SUMMARY

Carbon Capture and Storage are essential technologies to help achieve the ambition of net zero anthropogenic greenhouse gas emissions by 2050.

As with all solutions, the cost of deployment of CO_2 capture, transport and storage systems is of vital economic and environmental importance. This importance will continue to increase as the scale and breadth of CCS deployment grows around the world.

The Global CCS Institute has developed this report to describe the factors that drive current and future costs of the technology. Key drivers of CCS cost include economies of scale (which incentivises the development of CCS hubs to build scale); partial pressure of CO_2 in the source gas (lower partial pressures are more challenging), which mean there is variation in CCS costs from industry to industry; energy costs (in the forms of heat and electricity); and technological innovation.

The lessons learned from early deployments of CCS are shown to play an essential role in reducing CCS project costs for subsequent developments.

The strong importance of capital cost on overall CCS costs means that there are financial and policy levers available to make capital more available and lower cost for large-scale CCS projects. Tax policies also play a vital role in the incentivisation of CCS projects.

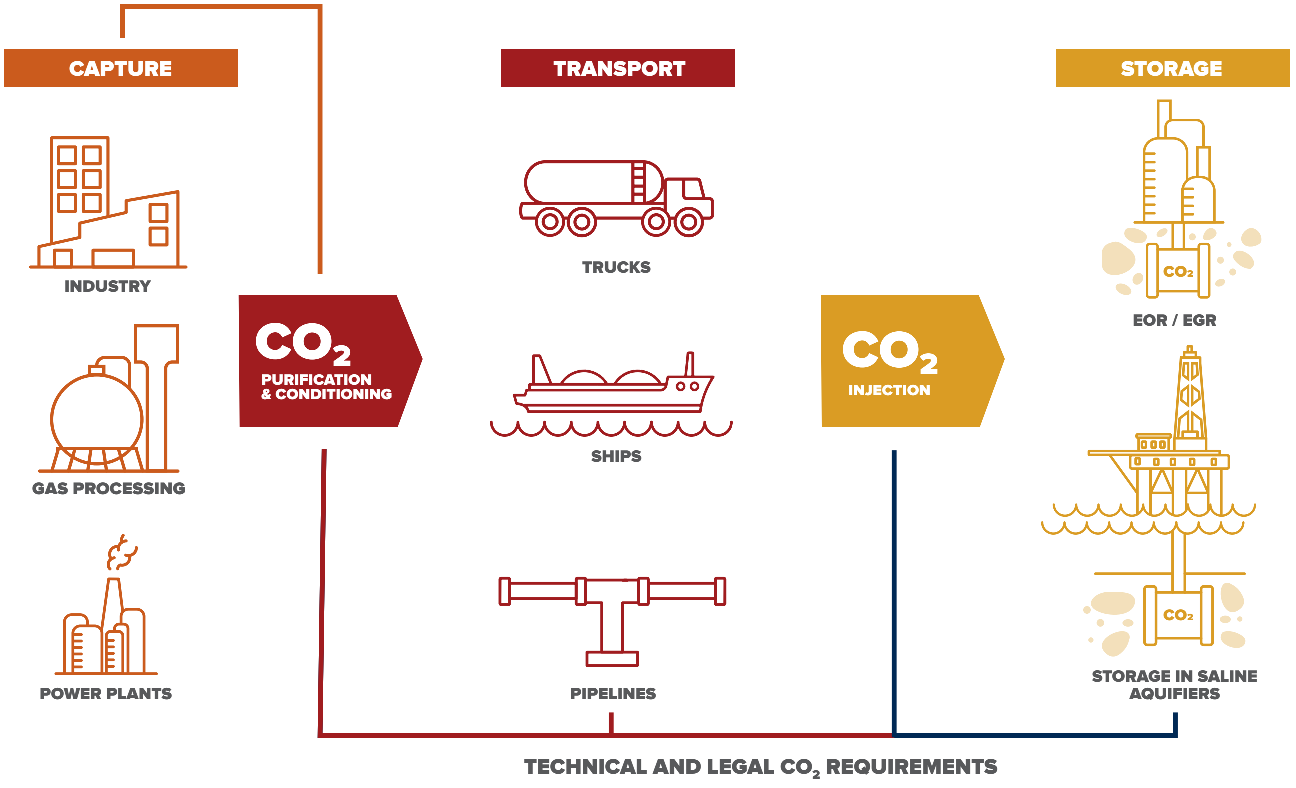
This report also surveys the technology readiness of mature and emerging technologies in the capture, transport and storage of carbon dioxide. Technological development will be a key element of driving future cost reductions in CCS, and indeed making CCS possible for some hard-to-abate sectors such as cement, steel, and direct air CO_2 capture.

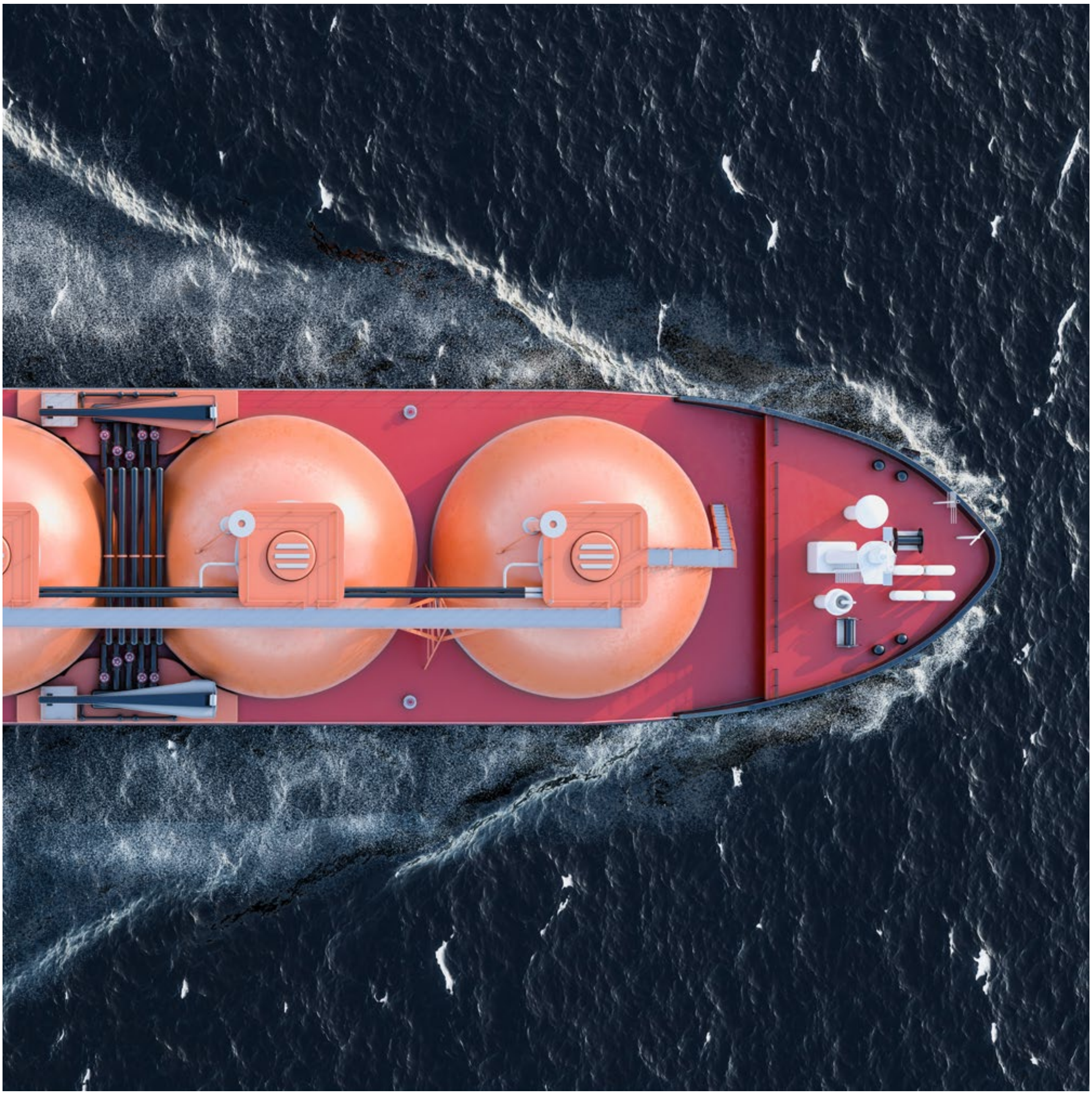
2.0 ABOUT CARBON CAPTURE AND STORAGE (CCS)

CCS is a proven and safe technology that prevents carbon dioxide (CO_2) from being released from point sources into the atmosphere or removes it directly from the atmosphere. The technology involves capturing (purifying) CO_2 produced by industrial plants (such as steel mills, chemicals plants and cement plants), coal and natural gas-fired power plants, and oil refineries, compressing it for transportation and then injecting it deep underground – at least 800 meters below the surface – into a carefully selected and safe geological storage site, where it is trapped and permanently stored in porous rock – see Figure 1.

CCS is an essential technology for the world effort to achieve net-zero greenhouse gas emissions by 2050. CCS can reduce emissions across most industry sectors directly, both as a retrofit technology for existing industrial and energy facilities, as well as incorporated into new developments. It can also remove CO_2 from the atmosphere (through bioenergy with CCS, as well as Direct Air Capture of CO_2 from the atmosphere), providing the possibility of deep removal of CO_2 from the climate system at scale (International Energy Agency 2020a).

Figure 1 - Carbon capture and storage – a conceptual diagram





Due to the need for broad and deep deployment of CCS around the world over the next 30 years, a clear understanding of its costs and economics is important. The costs of CCS can vary widely depending on the application, location, and scale of each source of CO_2. Technology development is also playing a key role, as is the operating experience gleaned from CCS facilities that are operating today.

This report outlines key factors that influence the cost of carbon capture and storage today. It also summarises key drivers that will drive the cost of future deployments of CCS. Finally, as technology is one of those key drivers, it outlines the technology readiness of a range of CO_2 CCS technologies at varying stages of development – from early research through to full-scale commercial availability.

3.0 TECHNOLOGY AS A DRIVER OF COST REDUCTION AND ENABLER OF CCS DEPLOYMENT

The technologies that enable CO_2 capture, transport and storage are not static. As the world moves towards higher ambition for emissions reductions and CO_2 removal from the atmosphere, there is a relentless focus on driving down the costs of all parts of the CCS value chain. This is driving considerable research and development across the world into better and more cost-effective CCS technologies.

As described earlier in this report, technology will play an important role in reducing the costs of CCS. We are observing improvements in technology that are both incremental (improvements of existing technologies) and breakthrough (new developments in form and/or function).

Incremental improvements tend to be lower risk and more predictable. In CCS this is observed in the development of new CO_2 capture solvents, improved adsorbents, enhanced or more robust membranes, and through the use of engineering techniques like modularisation.

Breakthroughs can enable CCS to be deployed in new applications outside of industries where it has previously been rolled out, or to achieve step-change cost improvements over existing technologies. Examples include direct air capture (DAC) and inherent CO_2 capture technologies.

4.0 TECHNOLOGY READINESS OF CO_2 CAPTURE TECHNOLOGIES

Technologies develop from initial observations and concepts, through laboratory studies and bench scale equipment, all the way through to pilot-scale and eventually full-scale commercial service.

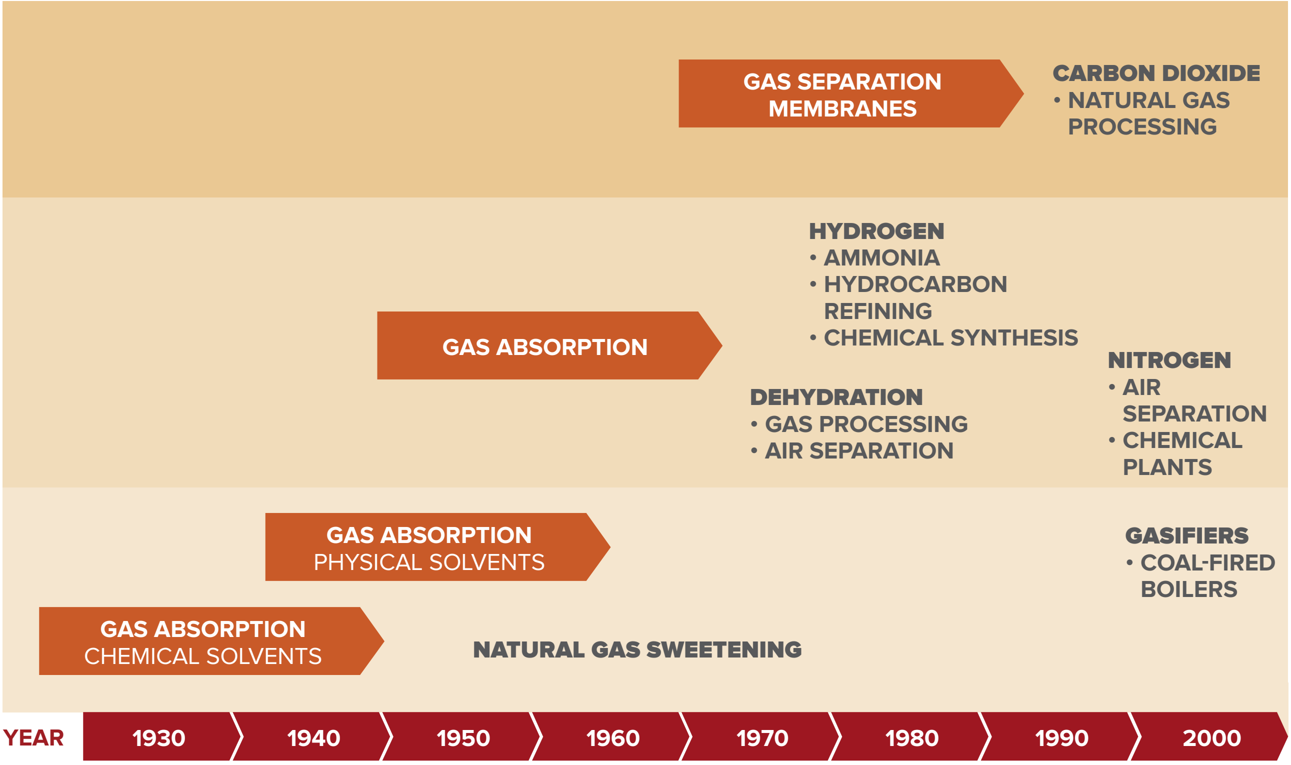
A qualitative scale known as the Technology Readiness Level (TRL) defines the maturity of technologies within an increasing scale of commercial deployment; see Table 1.

Lower TRL levels are typically concerned with the possibility that a technology might work, whereas higher levels are more concerned with commercial viability. The following sections of this report provide a high level summary of categories of CCS technologies and ascribes a TRL score to each. In summary, CCS technologies span the full range of TRL, from new technologies in fundamental research and development through to mature systems that have been in commercial operation for decades.

Table 1 - Simplified definitions of Technology Readiness Level (TRL) (IEAGHG 2014) for CCS technologies.

CATEGORY	TRL	DESCRIPTION
Demonstration	9	Normal commercial service
	8	Commercial demonstration, full-scale deployment in final form
	7	Sub-scale demonstration, fully functional prototype
Development	6	Fully integrated pilot tested in a relevant environment
	5	Sub-system validation in a relevant environment
	4	System validation in a laboratory environment
Research	3	Proof-of-concept tests, component level
	2	Formulation of the application
	1	Basic principles, observed, initial concept

Figure 2 - Development of carbon captures technologies (Global CCS Institute 2016).



The deployment of carbon capture in industrial processes dates back to the 1930s, when carbon dioxide (CO_2) absorption with chemical solvents, such as amines in aqueous solutions, were used in the natural gas industry to separate CO_2 from methane (Figure 2) (Global CCS Institute 2016).

Starting in the 1940s, processes using physical solvents emerged for CO_2 capture from process gas streams that contained higher CO_2 concentrations (25 to 70 per cent) and under higher-pressure conditions (approximately 100 bar). Two commercial examples of physical solvents are Selexol™ and Rectisol®. These solvents are used at gasification plants using coal, petroleum coke, and biomass feedstocks.

In the 1950s and 1960s, adsorption processes using solid sorbents, such as pressure swing adsorption (PSA), enabled gas separation in hydrogen production (refineries), nitrogen production, and dehydration applications (Siqueira et al. 2017). In the 1970s and 1980s, membranes were developed to capture CO_2 for use in natural gas processing.

However, carbon capture is increasingly being applied to decarbonize the power sector and other industries with low-concentration dilute gas streams. The application of carbon capture to gas streams with dilute CO_2 concentrations, such as from power generation is more costly due to the laws of thermodynamics. Consequently, the US Department of Energy (DOE) has set targets to improve state-of-the-art capture technologies to reduce the cost of capture from dilute gas streams. (Miller et al. 2016). Second-generation technologies, yet to be deployed commercially, are targeted to reduce costs by 20 per cent from current state-of-the-art technologies. Second generation capture technologies are expected to be available for demonstration by 2025. Transformational technologies are targeted to reduce costs by 30 per cent from the first of a kind technology and be available for demonstration in the 2030 timeframe.

Other innovative technologies with inherent CO_2 capture process have also emerged, for example, 8 Rivers Capital's Allam-Fetvedt Cycle, Calix's Advanced Calciner. These unique systems require minimal capture process to produce pure CO_2 ready for transport/use.

Capture technologies in this report are categorized by the media used to separate CO_2 from a gas stream. For each sub-section, an analysis of each class of separation media is provided, including an assessment of the existing and emerging capture technologies. The overview of capture technologies TRL including how they have advanced between 2014 and 2020 is shown in Table 2.

Capture technologies in this report are categorized by the media used to separate CO_2 from a gas stream. For each sub-section, an analysis of each class of separation media is provided, including an assessment of the existing and emerging capture technologies. The capture technologies described in the following sections are selected based on their suitability and readiness level. Hence some technologies, especially those in the early research phase (TRL less than 5), may not have been included.

Table 2 - TRL assessment and key technology vendors of the CO_2 capture technologies. Global CCS Institute analysis in comparison to (IEAGHG 2014).

TECHNOLOGY		KEY VENDORS	TRL 2014	TRL 2020	PROJECTS
Liquid Solvent	Traditional amine solvents	Fluor, Shell, Dow, Kerr-McGee, Aker Solutions, etc	9	9	Widely used in fertilizer, soda ash, natural gas processing plants, e.g. Sleipner, Snøhvit, and used in Boundary Dam since 2014
	Physical solvent (Selexol, Rectisol)	UOP, Linde and Air Liquide	9	9	Widely used in natural gas processing, coal gasification plants, e.g. Val Verde, Shute Creek, Century Plant, Coffeyville Gasification, Great Plains Synfuels Plant, Lost Cabin Gas plant
	Benfield process and variants*	UOP	-*	9	Fertiliser plants, e.g. Enid Fertiliser
	Sterically hindered amine	MHI, Toshiba, CSIRO, etc	6-8	6-9	Demonstration to commercial plants depending on technology providers, e.g. Petra Nova carbon capture
	Chilled ammonia process*	GE	6*	6-7	Pilot tests to demonstration plant feasibility studies
	Water-Lean solvent	Ion Clean Energy, CHN Energy, RTI	4-5	4-7	Pilot test and commercial scale FEED studies: Ion Clean Energy's Gerald Gentleman station carbon capture, CHN Energy's Jinjie pilot plant
	Phase change solvents	IFPEN/Axens	4	5-6	DMX™ Demonstration
	Amino acid-based solvent*/ Precipitating solvents	Siemens, GE	4-5	4-5	Lab test to conceptual studies
	Encapsulated solvents	R&D only	1	2-3	Lab tests
	Ionic liquids	R&D only	1	2-3	Lab tests
	Enzyme Catalysed Absorption	CO_2 solutions	1	8	30 tpd commercial facility in Quebec
Solid adsorbent	Pressure Swing Adsorption/Vacuum Swing Adsorption	Air Liquide, Air Products, UOP	3	9	Air Products Port Arthur SMR CCS
	Temperature Swing Adsorption (TSA)	Svante	1	5-7	Large pilot tests to FEED studies for commercial plants
	Sorbent-Enhanced Water Gas Shift (SEWGS)	ECN	5	5	Pilot tests, e.g. STEPWISE
	Electrochemically Mediated Adsorption	R&D only	1	1	Lab test

TECHNOLOGY		KEY VENDORS	TRL 2014	TRL 2020	PROJECTS
Membrane	Gas separation membranes for natural gas processing	UOP, Air Liquide	-*	9	Petrobras Santos Basin Pre-Salt Oil Field CCS
	Polymeric Membranes	MTR	6	7	FEED studies for large pilots
	Electrochemical membrane integrated with MCFCs	FuelCell Energy	-*	7	Large pilots at Plant Barry
	Polymeric Membranes / Cryogenic Separation Hybrid	Air Liquide, Linde Engineering, MTR	6	6	Pilot studies
	Polymeric Membranes/ Solvent Hybrid	MTR/ University of Texas	-*	4	Conceptual studies
	Room Temperature Ionic Liquid (RTIL) Membranes	R&D only	2	2	Lab tests
Solid-looping	Calcium Looping (CaL)	Carbon Engineering	6	6-7	Feasibility/cost studies for commercial scale
	Chemical Looping Combustion	Alstom	2	5-6	Pilot tests
Inherent CO_2 capture	Allam-Fetvedt Cycle	8 Rivers Capital	2	6-7	50 MW Demonstration Plant in La Porte
	Calix Advanced Calciner*	Calix	-	5-6	Large pilot LEILAC

* not assessed in IEAGHG 2014/TR4 report.

4.1. Liquid solvents

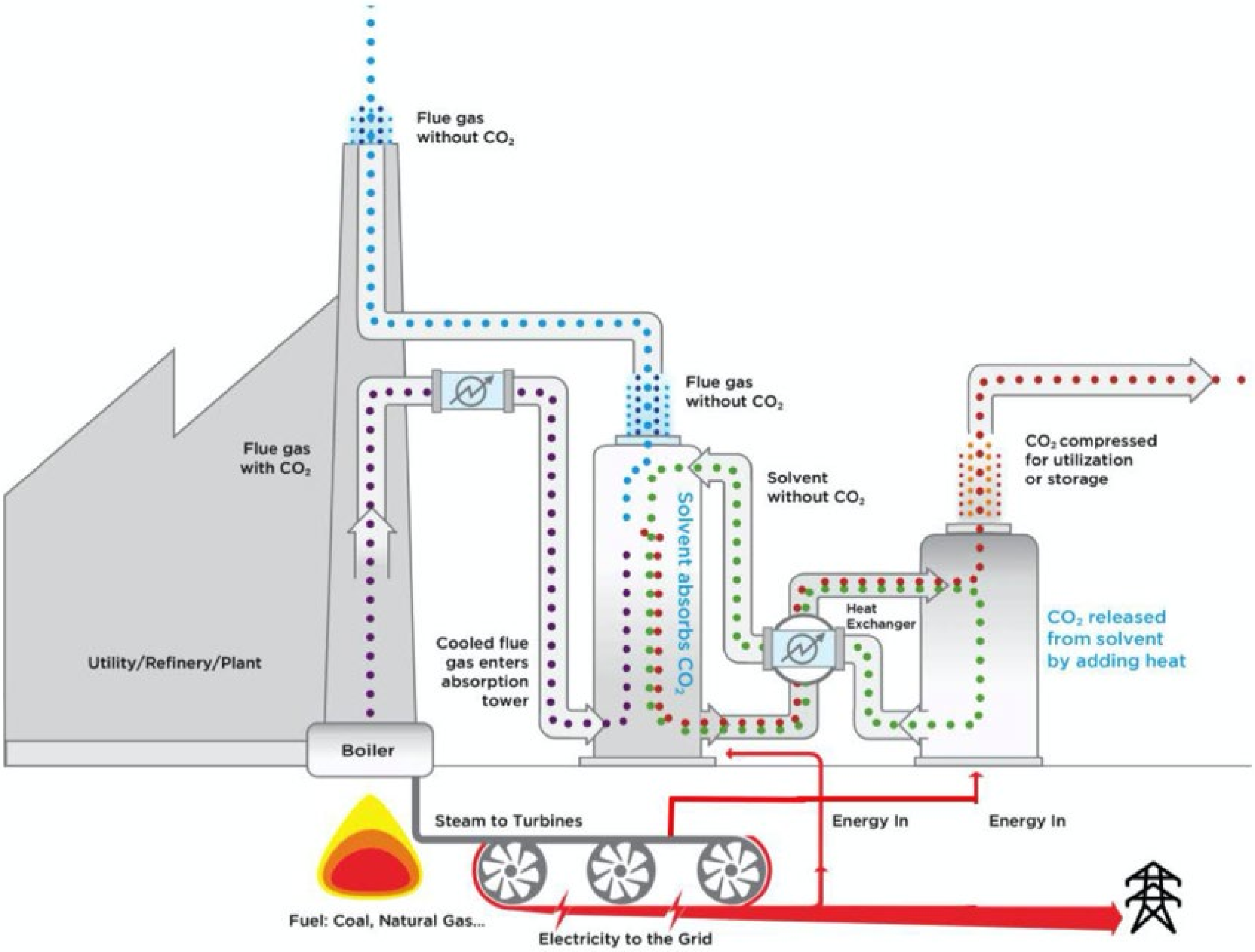
Absorption employing chemical solvents (which use chemical bonds to capture CO_2) or physical solvents (which use only intermolecular Van der Waals force to capture CO_2) is the most common technology used for gas separation. In an absorption process, a gaseous component dissolves into a liquid solvent forming a solution (Global CCS Institute 2016). Due to the different solubilities of the gas components in a particular solvent, the solvent can be used for selective separation. 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.

In the solvent regeneration process, chemical solvents are usually regenerated by raising the temperature to release CO_2. For physical solvents, the pressure is reduced.

The most widely used physical solvent-based technologies are the glycol-based Selexol™ and methanol-based Rectisol® systems (Mohammed et al. 2014). The Selexol process operates at around ambient temperature, whereas the Rectisol process operates at a temperature as low as -60°C. These solvents are operating at large-scale facilities separating up to 4,000 tonnes per day (tpd) of CO_2 in synthetic gas (syngas) purification and natural gas processing.

Chemical solvent-based systems available commercially or near commercialization commonly use amine-based solvents. There have been concerted efforts to drive down the cost and energy requirement of chemical solvent technologies.

Figure 3 - Illustration of process schematic in Ion Clean Energy's Water-Lean solvent capture. Source: (Ion Engineering 2019).



Ion Clean Energy's water-lean solvent carbon capture system (see Figure 3) is an example of a next-generation solvent. Ion Clean Energy's initial feasibility study at the Nebraska Public Power District's Gerald Gentleman Station Unit 2, a coal fired generator, estimated capture costs of US$39 – 44 per tonne of CO_2. This is a 25 - 33% cost reduction in comparison to the cost of current industry-standard amine solvents used for coal-fired power plants.

CO_2 Solutions, now owned by Italian-based energy company Saipem, has developed a novel absorption technology based on mature potassium carbonate solvents. Conventional potassium carbonate solvents, used for decades in chemicals and natural gas processing, are an effective carbon capture solvent. However, they have the disadvantage of slow rates of absorption of CO_2, which has made them suitable only for high CO_2 partial pressures.

CO_2 Solutions have added a proprietary biologically-derived enzyme, known as 1T1, to the potassium carbonate solution. This enzyme acts as a catalyst, speeding up the conversion of dissolved CO_2 in the solvent. This enzyme transforms a relatively slow absorption technology into a much faster one.

This increased capture rate means a given CO_2 capture duty can be achieved with a much smaller absorber and stripper, making potassium carbonate solvents more cost-effective for post-combustion and other low partial-pressure applications.

The process is also competitive from an energy perspective – using hot water rather than steam as a heat source, with a claimed reboiler heat rate of 2.4 GJ/tonne of CO_2 captured (Saipem CO_2 Solutions n.d.). The hot water is a distinct advantage – it means lower temperature waste heat can be used to partially or fully supply the process with energy for the reboiler. Most absorption-based technologies require higher temperature steam, which requires additional heat.

Saipem has published a claimed total capture cost of USD 28 / tonne of CO_2 for a specific case where waste heat is available at zero cost (Fradette, Lefebvre & Carley 2017, p.1108). This is for a case operating at 0.45 Mtpa of CO_2. If waste heat is not available, the cost will be higher. If the scale were greater, there is additional scope to reduce the total capture cost.

A pilot plant operates with CO_2 Solutions technology at the Resolute pulp mill in Québec, Canada (Figure 4). This plant is capturing 30 tonnes/day of CO_2 at high purity.

Figure 4 – Saipem CO_2 Solutions' Pilot Plant in Québec, Canada (Source: Saipem)

4.2. Solid adsorbents

Different molecules have different affinities to the surface of a solid sorbent, which allows for the separation of a specific gas component from a mixture. Based on the interaction between gas molecules and the sorbent surface, adsorption can be characterized as chemical adsorption or physical adsorption (Global CCS Institute 2016).

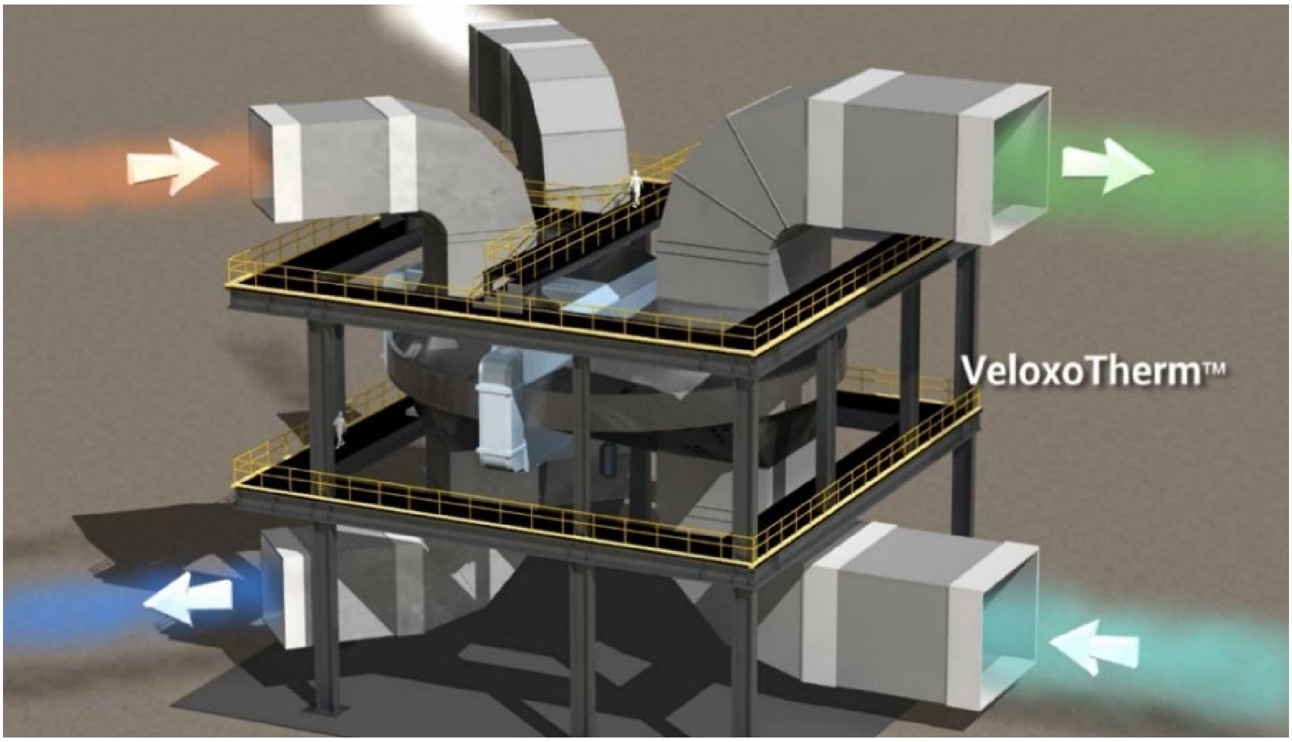
Chemical adsorption - via chemical bonding - results in a strong interaction between the gas molecule and sorbent, and is an appropriate choice for low-concentration gas streams. Regeneration is typically accomplished using a thermal swing adsorption (TSA) process - the adsorbent is regenerated by raising its temperature (Hedin et al. 2013) to liberate the CO_2.

Physical adsorption — via van der Waals forces — has a weaker interaction between the gas molecule and sorbent and is typically applied to high CO_2 concentration feed streams. Regeneration is generally based on a pressure swing adsorption (PSA) mechanism.

In PSA, the gas mixture containing CO_2 flows through a packed bed of adsorbent at elevated pressures until the adsorption of the desired gas approaches equilibrium with the solid. The bed is then regenerated by stopping the feed mixture and reducing the pressure (Global CCS Institute 2016) to liberate the CO_2.

A typical emerging adsorption technology is the Svante (formerly Inventys) VeloxoTherm™ system in Figure 5. It is based on a rapid-cycle temperature swing adsorption (TSA) process. This technology uses a patented adsorbent architecture arranged in a circular structure to simultaneously expose different sectors of the structure to each step in the process, as shown in Figure 5. VeloxoTherm™ is claimed to be 40 to 100 times faster than conventional TSA processes, due to its use of innovative adsorbent materials which enable rapid temperature swings from 40 to 110°C (NETL 2018a).

Figure 5 - Svante VeloxoTherm™ rotary adsorption machine concept. Source: (bctechnology 2017; Paul, Ranjeet & Penny 2017).



4.3. Membranes

A membrane is a barrier or medium that can separate chemical constituents of a gas mixture based on permeation of the constituents through the membrane at different rates (i.e. particular components of a mixture pass through the barrier faster than the other components) (Drioli, Barbieri & Brunetti 2018; Global CCS Institute 2016).

Generally, gas separation is accomplished by some physical or chemical interaction between the membrane and the gas being separated. Membrane separation uses partial pressure as the driving force and is usually more favourable when the feed gas stream is at high pressure.

Process innovations such as the incorporation of countercurrent sweep[2] in Membrane Technology and Research's (MTR) Polaris™ process, and the integration of molten carbonate fuel cells (MCFCs)[3] in capture systems have enabled the use of membranes in low-concentration CO_2 applications.

Figure 6 shows MTR's modular membrane system. It consists of banks of pressure vessels that are combined to form a single "mega-module". For a 240 MWe coal-fired power plant (e.g. the flue gas stream from Petra Nova unit 8), around 60 mega-modules with a membrane area of approximately 0.2 to 0.4 million m^2 would be required to capture 1.4 Mtpa CO_2.

Figure 6 - Photos of spiral-wound membrane vessels (left) used in a commercial scale membrane system (right). Source: (NETL 2018).

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[2] The countercurrent sweep process means flowing in the opposite direction with respect to the flow in the other process side.

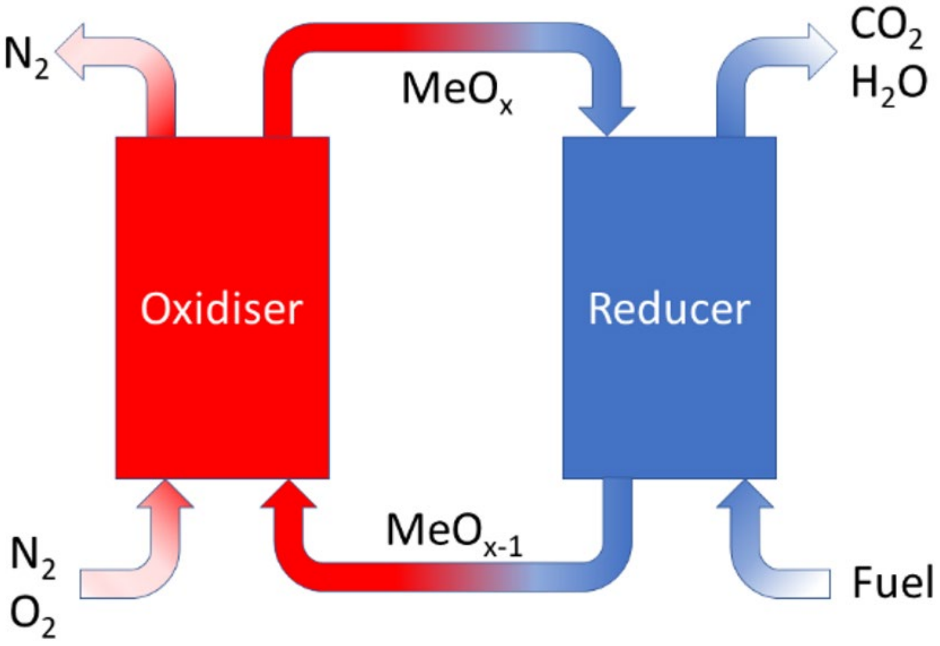
[3] MCFCs are high-temperature fuel cells operating approximately 650 oC. MCFCs use a mixture of molten potassium and lithium carbonate as an electrolyte.

4.4. Solid-looping

Calcium and chemical looping technologies (solid looping) involve the use of metal oxides (MeOx) or other compounds, as regenerable sorbents to transfer either CO_2 or oxygen from one reactor to another as shown in Figure 7 (Global CCS Institute 2016). Circulating fluidized beds (CFBs), which are in commercial use now in other applications, can be used as one or both of the reactors. Both technologies have emerged in recent years as second-generation CO_2 capture technologies utilizing high-temperature streams to significantly reduce the energy penalty associated with CO_2 capture.

The use of calcium looping in Carbon Engineering's direct air capture technology is discussed in detail in the case studies in the next chapter.

Figure 7 - Process schematic of chemical looping



4.5. Inherent CO_2 capture

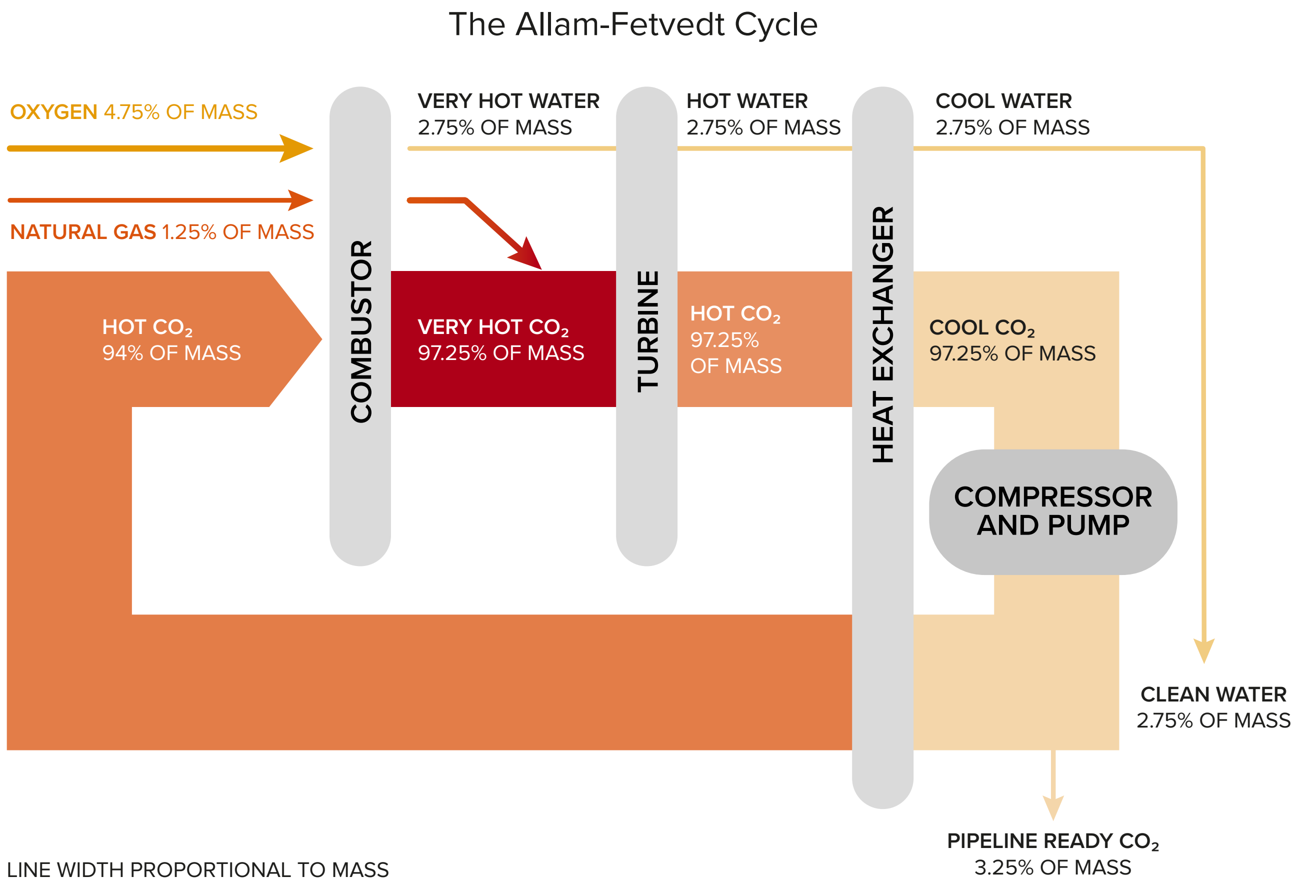
There are breakthrough technologies which are enabling inherent CO_2 capture in, which require no additional work or energy to separate CO_2. These offer considerable promise for a step change reduction in capture costs, but are not able to be retrofitted to existing plants as they incorporate CO_2 capture into their fundamental process design.

Typical examples are the Allam-Fetvedt power generation cycle and the Calix Advanced Calciner for lime and cement manufacturing.

The Allam-Fetvedt Cycle is an innovative natural gas (or syngas from gasification of coal) fired power generation technology. The technology produces pipeline-ready CO_2 without the need for add-on carbon capture equipment. It involves oxy-fuel combustion and the use of the produced CO_2 as the working fluid to drive a turbine which enables inherent CO_2 capture, compression, and dehydration as well as the elimination of NOx / SOx (Allam et al. 2017; Lu et al. 2017), shown in Figure 8.

This technology can produce electricity with >97% CO_2 capture at a levelised power price approximately 22% higher than conventional natural gas combined cycle

Figure 8 - The Allam-Fetvedt Cycle process flow. Source: 8 Rivers Capital (supplied)

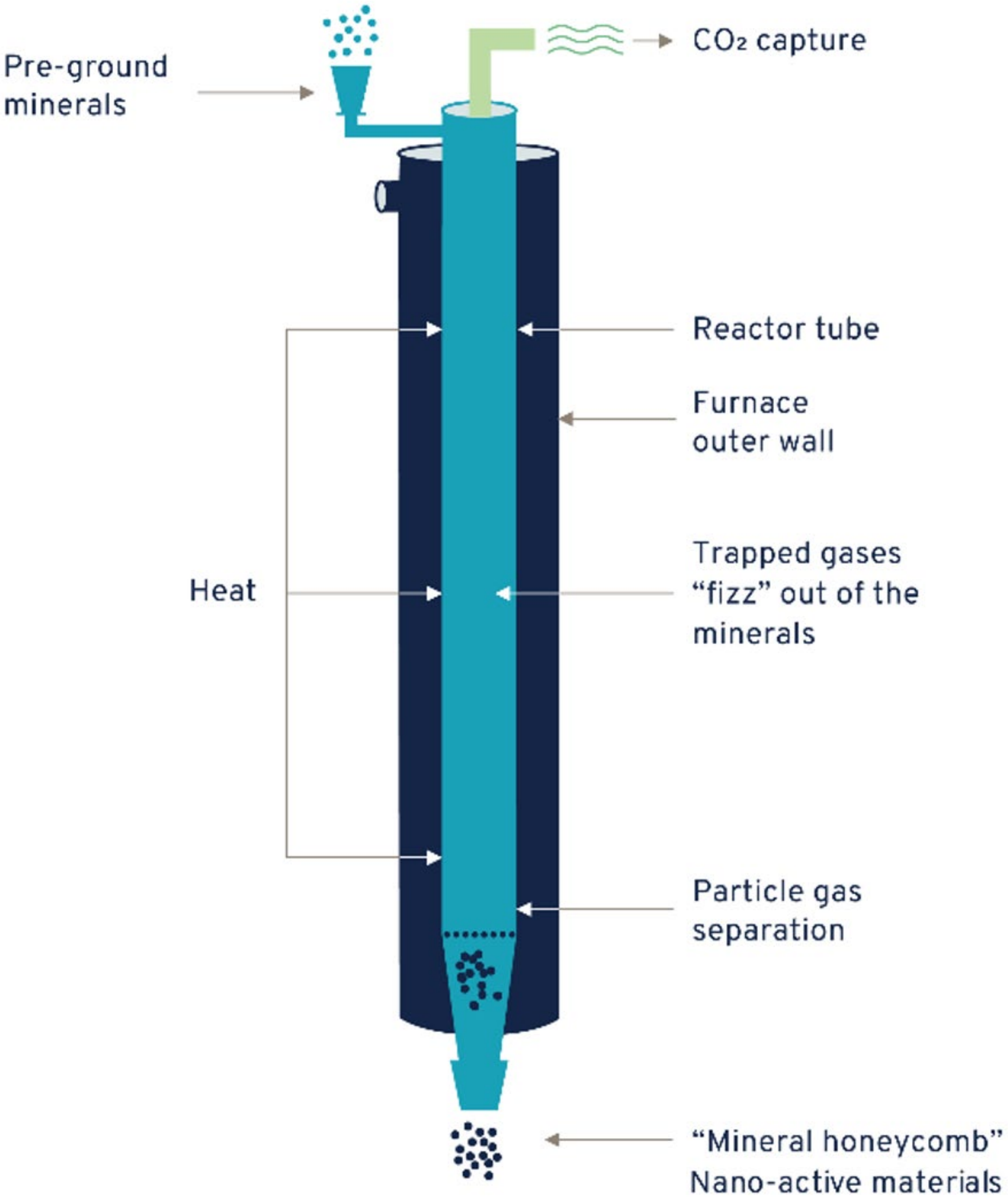


today. It can also be integrated with hydrogen production and other processes to create a plant that can efficiently produce power, hydrogen, ammonia and urea.

The cost premium above unabated natural gas combined cycle power generation is projected to reduce to less than 10% by 2050. CO_2 transport and storage costs are additional. An integrated power and hydrogen plant with 100% capture of CO_2 could produce clean hydrogen at costs which are competitive with conventional production from steam methane reformation.

Calix has developed a new type of calciner to replace the traditional rotary kiln designs found in conventional cement and lime plants. Its advanced calciner employs a "reversed" application of the calcium looping technology, where calcination is carried out at a lower temperature (650 – 760 oC) than the carbonation (760-850 oC). This together with the inherent CO_2 capture eliminates some of the key technological challenges of calcium looping processes, i.e., decay in CO_2 capture capacity through multiple cycles, process heat integration, etc. Figure 9 show the configuration of Calix Advanced Calciner with inherent CO_2 capture.

Figure 9 - Calix advanced calcination reactor detailed view. Source: Calix (supplied)

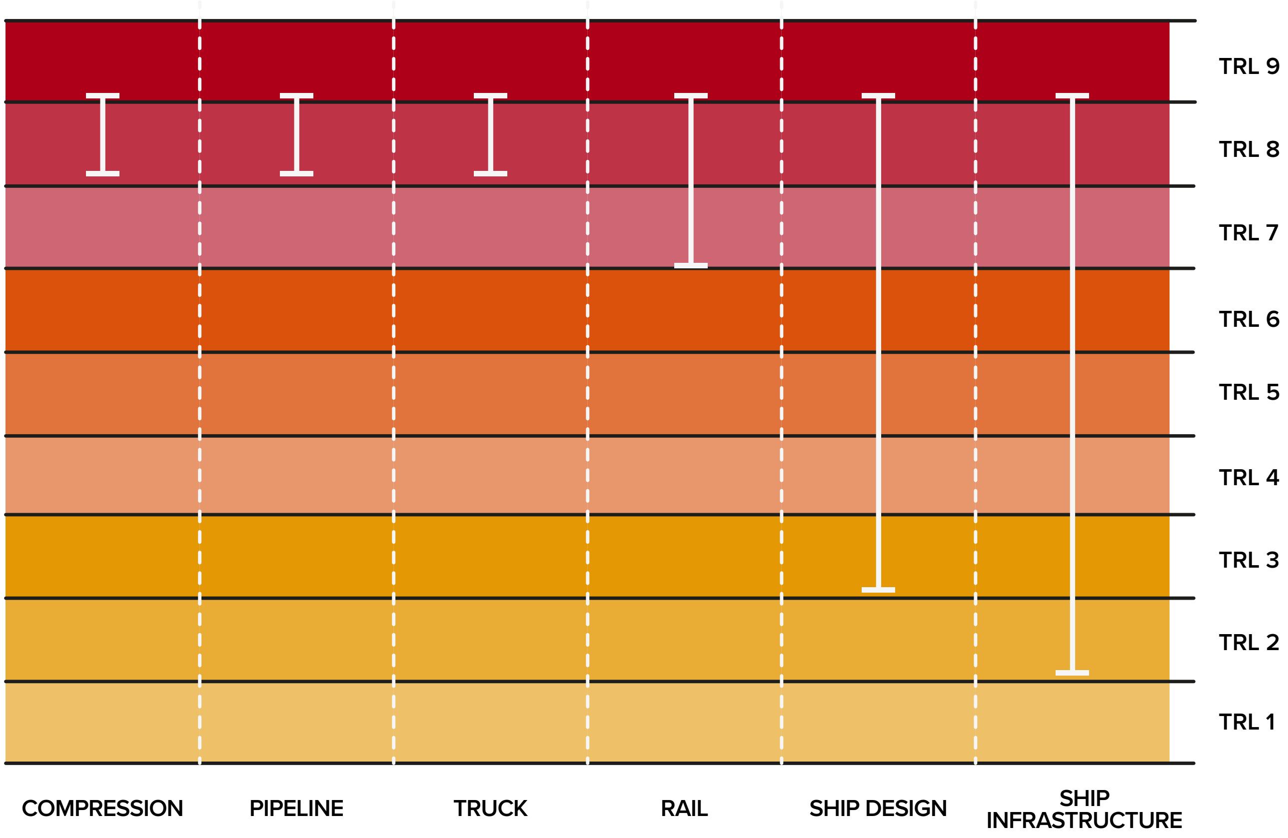


5.0 TECHNOLOGY READINESS OF CO_2 TRANSPORT TECHNOLOGIES

The transport of CO_2 is an essential part of the CCS chain, connecting CO_2 source(s) to CO_2 storage sites. Today, CO_2 is compressed and transported primarily through pipelines and by ships. CO_2 is also transported by truck and rail. Fundamentally, the transportation of gasses and liquids via any of these methods is mature (i.e. TRL 9). However, transportation of CO_2 at the very large scale associated with CCS has not yet been achieved using ships or rail (Figure 10).

Of all CO_2 transport modes, only pipelines are transporting CO_2 at significant scale. Over 8,000 kilometres (5,000 miles) of pipelines stretch across the United States. The United States comprises 85% of all CO_2 pipelines, with a mix of anthropogenic and natural CO_2 moving approximately 70 Mtpa (National Petroleum Council 2019). These pipelines have been operated with an excellent safety record since the first CO_2 pipeline for a large-scale CCS facility was commissioned in the early 1970s.

Figure 10 - Technical Readiness Level of CO_2 Transport.



Outside the US, CO_2 pipelines are also operating in Brazil, China, Canada, the Netherlands and Norway. Norway hosts an offshore CO_2 pipeline (153-kilometre offshore pipeline for the Snøhvit CO_2 storage facility). It is this widespread and long-term experience of pipelines that ultimately gives CO_2 pipelines a mature rating (TRL 8-9).

In contrast to pipelines, shipping is only now being considered for large-scale transport of CO_2. Small-scale food-grade CO_2 shipping has been common practice for more than three decades but has not yet been implemented at scales suitable for CCS.

The technical feasibility and the cost of CO_2 shipping are well understood through decades of research, primarily in Europe, with additional studies from Korea and Japan. The following section presents the latest developments in CO_2 shipping for CCS, providing an overview of technical requirements, maturity, cost, safety, regulations and the main differences compared to pipelines.

The shipping of CO_2 has been practised for over 30 years, but the size of the industry is small, with only approximately 3 Mtpa of CO_2 being transported by ship in total (IEA GHG 2009). The shipping experience to date is entirely connected with the food and beverage sector.

Today, CO_2 is transported by small scale ships of 800–1,800 m3 from production sites to distribution terminals and distributed via train or truck to end-users. According to the IEAGHG (IEAGHG 2020a), the maximum load size in terms of techno-economic value would be 10,000 tonnes of CO_2.

Although CO_2 shipping experience is relatively limited, the gas industry has more than 80 years of commercial experience shipping various pressurized gases. CO_2 transport by ships and the required port infrastructure are very similar to those for Liquified Natural Gas (LNG) and Liquified Petroleum Gas (LPG). It is, therefore, reasonable to assume that the technical scale-up of CO_2 shipping to the scale required for CCS is achievable without major technical challenges.

The TRL for CO_2 shipping ranges from 3 to 9. The lowest TRL-3 relates to offshore injection into a geological storage site from a ship. The TRL-9 rating refers to conventional onshore CO_2 injection from onshore facilities (which can be delivered to the injection site by ship).

6.0 TECHNOLOGY READINESS OF CO_2 STORAGE

The geological storage of CO_2 (herein storage) is the final step in the CCS value chain. Geological storage permanently isolates CO_2 from the atmosphere.

Storage requires CO_2 to be compressed to very high pressures (above 74 bar as an absolute minimum, the critical pressure of CO_2 and typically 100 bar or more to provide a suitable safety margin and account for pressure drop in pipelines). The storage formation must be at a depth of at least 800m to ensure that this pressure is maintained. At these high pressures CO_2 is in its dense phase – a density similar to water but with properties somewhere between a liquid and a gas.

Dense phase CO_2 maximizes the mass of CO_2 that can be stored in a fixed volume, ensuring the efficient use of the target geological storage volume and CO_2 movement is easier to predict and monitor.

The CO_2 is stored in geological formations comparable to those which naturally contain water, oil or gas. The injection, storage and monitoring of CO_2 in those geological formations uses essentially the same technologies developed over nearly 50 years for enhanced oil recovery (EOR).

Three forms of geological storage are technically mature: storage through CO_2-enhanced oil recovery (CO_2-EOR), storage in saline formations, and storage in depleted oil and gas fields.

6.1. Storage through CO_2-EOR

CO_2-EOR has been in operation for nearly 50 years (TRL 9) (National Petroleum Council 2019). Currently, there are over 40 CO_2-EOR operations, the vast majority hosted in the USA (Bui et al. 2018). The primary aim of CO_2-EOR is to maximize oil recovery, not store CO_2. However, CO_2 is permanently stored in the course of EOR, becoming trapped in the pore space that previously held hydrocarbons. Additional CO_2-specific monitoring to verify the permanent storage of the injected CO_2 is required if CO_2-EOR is to be used as an emissions reduction option (International Energy Agency 2015).

Table 3 - CO_2 storage options of commercial and pilot/demonstration CCS facilities. Notes: DGOF: Depleted gas and oil field, SF: saline formation, EOR: CO_2- enhanced oil recovery (Global CCS Institute 2020).

SCENARIO		DEVELOPMENT	CONSTRUCTION	OPERATION	COMPLETED
COMMERCIAL FACILITIES					
Onshore	DGOF	1			
	SF	12		3	1
	EOR	9	3	21	
Offshore	DGOF	6			
	SF	9		2	
	EOR			1	
PILOT & DEMONSTRATION PROJECTS					
Onshore	DGOF	1		1	4
	SF	3	1	3	10
	EOR		1	8	4
Offshore	DGOF				1

6.2. Storage in Saline Formations

Storage of CO_2 storage in saline formations has a TRL of nine. Storing CO_2 in saline formations has been occurring in the North Sea since 1996. The Sleipner CCS facility has injected over 20 Mt of CO_2 into a deep saline formation. This facility is the first use of CCS as a climate mitigation tool within a commercial operation. Critically, the operation showed that:

- CO_2 could be injected at a significant rate (1Mtpa) into saline formations
- CO_2 can be monitored
- Storage is permanent

Since Sleipner, four commercial operations storing CO_2 in saline formations and numerous demonstration projects (Table 3) have commenced. The rapid advancement of the technology and knowledge developed from these facilities is significant for saline formation storage. CO_2 is being stored in different geographies, terrains, and geological conditions. Geological storage always requires site-specific analysis, modelling and monitoring. This includes storage capacity prediction, injection optimization and CO_2 verification and quantification through monitoring. The technology and tools required to identify, appraise, utilize, monitor and close a geological storage resource are all well established and mature.

6.3. Storage in Depleted Oil and Gas Fields

Geological storage in depleted oil and gas fields is technically mature (i.e. substantively no different to storage in saline aquifers) but has a lower TRL of 5-8 as it has only been applied in demonstration projects (Bui et al. 2018). Twelve pilot or demonstration projects have utilised depleted oil and gas fields (Table 3). Commercial maturity is imminent with at least eight projects in the CCS pipeline actively pursuing storage in depleted oil and gas fields especially in the North Sea (Global CCS Institute 2021a).

6.4. Unconventional Storage

There are two leading unconventional options for the storage of CO_2; storage in Basalt and ultramafic rocks and storage in coal seams through Enhanced Coal Bed Methane (ECBM) production.

6.4.1. Basalt and ultra-mafic rocks (TRL 2-6)

Storage of CO_2 in basalts and ultra-mafics depends on mineral carbonation. The mineralogy of those rock types means CO_2 reacts very rapidly to form carbonate minerals. Ninety percent of injected CO_2 is predicted to be mineralized within a period of a few months to decades (Kelemen et al. 2019) in these rock formations. Basalts are a common rock type, particularly in India, and in nearshore oceanic crust worldwide. The estimated storage potential of mineral carbonation is 60,000,000 $GtCO_2$ (Kelemen et al. 2019).

Basaltic rock has very low permeability, hence hydrologically fractured basalt or permeable zones between basalt flows is targeted for CO_2 injection.

Two pilot projects have injected and stored CO_2 into basalts for mineralization (Global CCS Institute 2021a). The pilot-scale Wallula Project (USA) injected around 970 t of CO_2. The CarbFix Project in Iceland is injecting a mix of water, 5000 tCO_2 and 3500 tH2S per year. The gases are separated from the geothermal steam from the Hellisheiði geothermal power plant.

Overall, basalt is not a naturally permeable rock and permeability is difficult to predict. Even within permeable zones, injection rates are low. The majority of tools for conventional CCS cannot be applied to monitor a CO_2 plume in a basalt. Monitoring tools for CO_2 plume verification and quantification in basaltic formations are still in the research phase.

6.4.2. Enhanced coal bed methane (ECBM; TRL 2-3)

Coal seams naturally incorporate fractures known as cleats which allow gases to permeate through the coal and are essential to the operation of an ECBM storage system. Between these fractures, the coal has abundant micropores that can hold many gases, predominantly methane. Coal has a higher affinity to gaseous CO_2 than methane. For ECBM, CO_2 is injected into the coal seam where it is diffuses into these micropores and is adsorbed, displacing the methane. The methane is then produced for sale.

Four pilot ECBM operations have been completed, one in China and three in the USA. The San Juan ECBM project in the USA was the largest pilot, injecting 18,000 t of CO_2. There are no active ECBM projects (Global CCS Institute 2021b).

ECBM is a viable technology and can increase methane production (compared to standard coal drainage) by 90% (Benson et al. 2005). The produced methane provides revenue to the operation while storing the CO_2. The major difficulty associated with ECBM is that injection of CO_2 significantly reduces the permeability of coal due to 'plasterisation' and swelling of the coal (reducing the size and connectivity of the fractures). Reduced permeability requires additional wells incurring additional costs and increasing operational complexity. Moreover, ECBM can only be applied to coal seams which will never be mined, otherwise the CO_2 stored in them would be released to the atmosphere. For that reason, deep un-mineable coal seams are potential targets for ECBM operations.

7.0 THE COST OF CO_2 CAPTURE AND STORAGE

The total cost of CCS consists of the costs of:

- CO_2 capture at the emission source – purifying CO_2 from a gas stream up to over 95% purity by volume.
- CO_2 dehydration and compression/liquefaction, depending on the transport method.
- CO_2 transport by pipeline, ship or mobile vehicle.
- CO_2 injection, and monitoring and verification of stored CO_2.

The cost of each CCS component varies from project to project, primarily due to differences in the size and location of the CCS facility and the characteristics of the CO_2 source.

Technology is a vital consideration in CCS, but it is not the only factor. A range of other factors feed into costs across the CCS value chain.

8.0 COST OF CO_2 CAPTURE

A key factor in CO_2 capture cost is the properties of the source gas.

Table 4 summarises the CO_2 characteristics of various power and industrial flue gas streams.

Table 4 - CO_2 characteristics in typical industrial flue gas streams (Bains, Psarras & Wilcox 2017; Global CCS Institute 2015; IEAGHG 1999; Grantham Institute 2014)

INDUSTRY	POINT SOURCE	CO_2 PARTIAL PRESSURE (WET) (KPA)	GAS STREAM PRESSURE (KPA)	INHERENT CO_2 CAPTURE
Power	Natural gas combined cycle (NGCC) power plant	3.8 – 4.6	Atmospheric***	No
	Coal fired-power plant	12.2 – 14.2	Atmospheric***	No
	Biomass/waste-fired power plant	10.1 – 12.2	Atmospheric***	No
Power/ Industrial Heat	Natural gas-fired power and/or heat plant (Open Cycle)	4.1 – 8.1	Atmospheric***	No
Petroleum Refining / Petrochemicals	fluid catalytic cracking	10.1 - 14.2	Atmospheric***	No
	Process heater	8.1 - 10.1	Atmospheric***	No
	Ethylene production steam cracking	7.1 - 12.2	Atmospheric***	No
	Steam methane reforming hydrogen production	300 – 480	2000 – 3000	No
	Ethylene oxide production	> 92	Atmospheric***	Yes
Cement	Kiln flue gas	~ 18	Atmospheric***	No
	Pre-calciner	20 - 30	Atmospheric***	No
Pulp and paper	Lime kiln	~ 16	Atmospheric***	No
Iron & Steel	COREX smelting reduction process	32 - 35	Atmospheric***	No
	Hot Stove	24 - 28	Atmospheric***	No
	Lime calcining	7.1 – 8.1	Atmospheric***	No
	Sinter plant	3.7 – 4.2	Atmospheric***	No
Aluminium	Aluminium smelter	0.8 – 1.1	Atmospheric***	No
Fertiliser	Coal gasification syngas	750 - 2500	3000 – 6000	Yes*
	Natural gas reforming syngas	300 - 1200	2000 – 3000	Yes*
Natural gas processing	Natural gas processing	Varies, up to 5000	900 – 8200+	Yes, acid gas removal
Bioethanol	Ethanol fermentation	> 85	Atmospheric***	**

* CO_2 from syngas stream is captured for downstream urea production
** Only dehydration and compression required
*** Standard atmospheric pressure is 101.3 kPa, which is close to the average air pressure at sea level. However, atmospheric pressure does vary by location and altitude.

Flue gas streams in most industries are produced at close to atmospheric pressure (~100 kPa) with CO_2 concentrations between 1 vol% (aluminium smelter) to 35 vol% (Corex smelting reduction process in steel plant). This makes their CO_2 partial pressures quite low – below 40 kPa (for a description of Partial Pressure, see breakout).

In certain sectors, such as natural gas processing, fertiliser production and hydrogen production, the source gas is at quite high pressure – many times atmospheric pressure. This can make CO_2 partial pressures higher than those in the captured CO_2 stream.

CO_2 capture in the power generation and industrial sectors usually accounts for the majority of the cost in the full CCS chain.

All else being equal, CO_2 capture costs are inversely related to the partial pressure of CO_2 in the gas stream.

PARTIAL PRESSURE

Dalton's Law is an empirical observation of how mixtures of gases behave. It states that in a mixture of gases, the total pressure of the mixture is equal to the sum of the partial pressures of each individual gas species in the mixture.

Each gas species in a mixture contributes to the total pressure independently of all the others.

In an ideal gas, the partial pressure of a gas in a mixture is equal to the volume fraction of that gas in that mixture, multiplied by the total pressure.

E.g., If a gas consists of a mixture of 15 vol% CO_2 and 85 vol% nitrogen, and the total pressure is 4 bar:

Partial pressure of CO_2 is 0.15 x 4 = 0.60 bar

Partial pressure of nitrogen is 0.85 x 4 = 3.4 bar

The partial pressure of CO_2 reflects the relative ease with which CO_2 can be captured from a gas mixture. Higher partial pressures are easier and cheaper to capture than lower pressures because less external energy is required to increase the CO_2's partial pressure to that in the final captured CO_2 stream.

Higher CO_2 partial pressures are observed when the fraction of CO_2 is higher, the overall gas pressure is higher, or both.

8.1. How does CO_2 partial pressure influence cost?

The partial pressure of CO_2 affects the size of process equipment, capture plant energy requirements, and applicable capture technologies. These all contribute to the cost of capturing CO_2.

Higher CO_2 partial pressures mean that CO_2 will transfer more rapidly from the source gas to the solvent, adsorbent or other media used to capture the CO_2. This higher speed translates into physically smaller capture equipment, reducing its capital cost. Higher total gas pressures also reduce the gas volume per tonne. This also reduces equipment size, and therefore capital cost.

High CO_2 partial pressures make the task of capture easier by reducing the input of energy needed to capture and then recover the CO_2 from the source gas. Lower energy consumption means lower operating costs (all else being equal).

CO_2 partial pressure can also influence the cost of capture through the capture technologies available. For example, solvent-based capture technologies fall into two general types: chemical and physical.

Higher partial pressures enable "physical" solvents to be used. They are generally slower than chemical solvents, but this is less of a concern at high CO_2 partial pressures. They also hold CO_2 in solution through physical mechanisms rather than chemical reactions – as such, the solution of CO_2 is weaker and easier to break by heating. These processes have the advantage that the energy requirements for the regeneration of the capture media (i.e. stripping the CO_2 from the capture media so that it may be reused) are relatively low compared to other capture technologies, lowering operating costs.

At low CO_2 partial pressures, typically selective "chemical" solvents are required to capture the CO_2 stream. Chemical solvents undergo chemical reactions with CO_2 to secure it into the solvent. These are effective but can require large amounts of energy to subsequently separate the captured CO_2 from the solvent, increasing operating costs.

8.2. How does scale affect capture cost?

The other main factor that drives the cost of capture is economies of scale. In most industrial processes, higher rates of production typically drive lower unit costs. Carbon capture is no exception.

Capital costs of process plants (including CO_2 capture plants) tend to rise non-linearly with scale – typically with the capital cost being proportional to scale to the power of n (where n ranges from 0.6 (single train) to 0.8 (multiple trains in parallel)). The exponents can vary from plant to plant – these are simply typical values (Tribe & Alpine 1986).

$$Cost\ of\ plant\ A = Cost\ of\ plant\ B\left(\frac{Capacity\ of\ plant\ A}{Capacity\ of\ plant\ B}\right)^n$$

For a single train capture plant, a doubling of capture capacity can be expected to deliver an increase in capital cost in the order of 50%. This means the capital cost per unit of production (i.e. cost divided by capacity) would be expected to fall by approximately 25%.

The effect is even more pronounced for larger increases. A 10 times increase in scale yields a cost saving of approximately 60% per unit of production for a single train plant.

The effect of scale on capture cost can see significant capture plant cost savings (per tonne of CO_2 captured) when moving from small scale (e.g. pilot plant) to full-scale installations capturing millions of tonnes of CO_2 per year.

These scale effects are general and vary significantly between process plants of different types. To demonstrate the effect of scale on carbon capture, it was investigated in an Institute modelling study.

8.3. Quantifying the impact of partial pressure and scale on the Current Cost of Carbon Capture

The Institute undertook process modelling of CO_2 capture plants to quantify expected overall costs of CO_2 capture across a range of applications and scales.

A specific capture process was used for the study - a solvent-based capture process using an aqueous solution containing 30% by weight of MEA (monoethanolamine) as the capture media. MEA is a chemical solvent, which means it is suitable for lower partial pressures of CO_2 – unlike physical solvents.

This process was chosen due to its commercial availability and its capture performance over a range of CO_2 partial pressures (IEAGHG 2019; Rochelle 2009; Bains, Psarras & Wilcox 2017). 30% MEA is well explored and has been deployed in capture applications in natural gas processing and power generation.

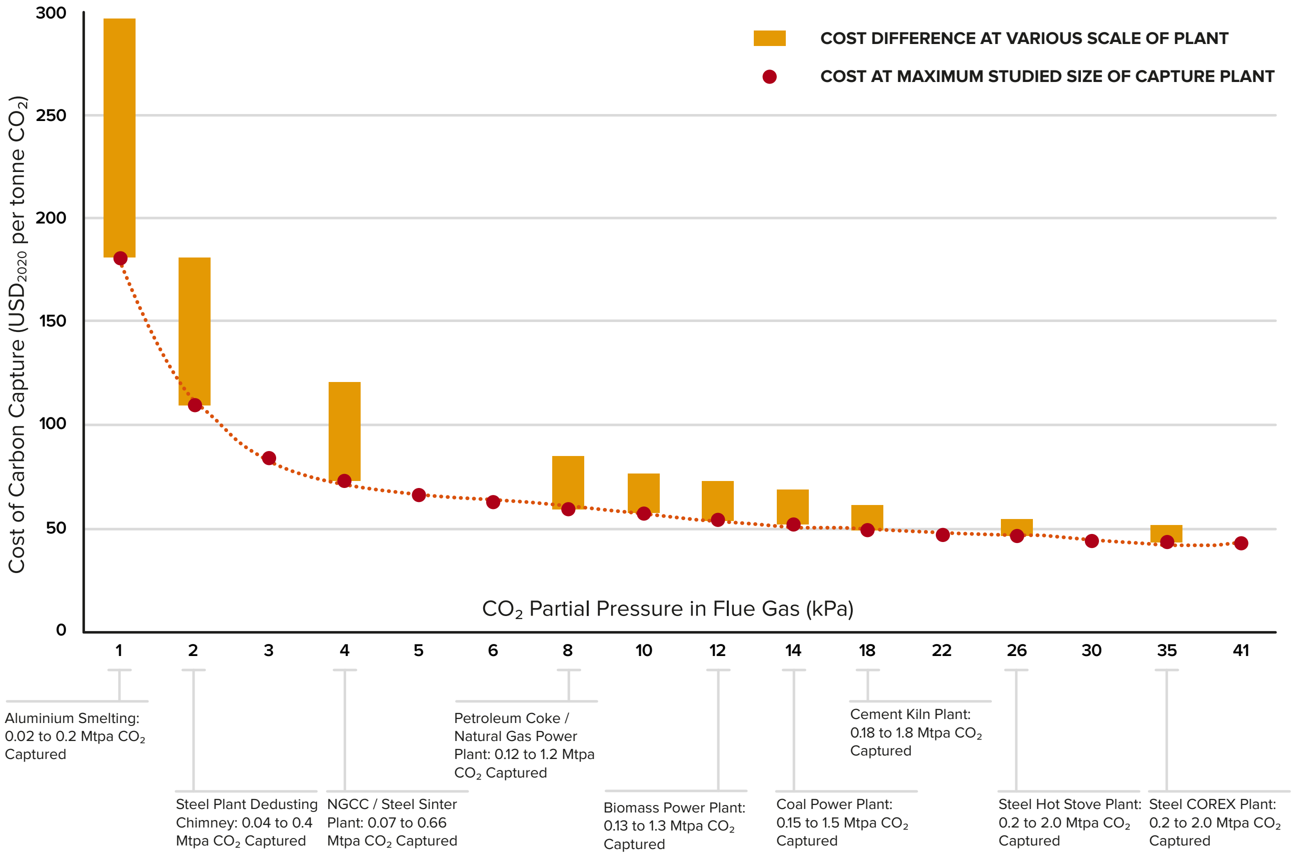
Although costs of other technologies will be different, how the costs of capture vary with scale and with the application can be interpreted as applicable for other capture processes as well.

Capture cost was estimated as the combination of capital and operating cost for the plant, assuming an 8% cost of capital over 30 years, expressed in US Dollars per tonne of CO_2 captured. This is a form of levelised cost for CO_2 capture and is a consistent basis for comparison between capture plants operating at different scales across different applications.

Other assumptions in the modelling are included in the appendices.

Figure 11 shows the cost results of carbon capture from flue gas streams with various source gas CO_2 partial pressures over a range of scales for each application.

Figure 11 - Impact of CO_2 partial pressure and scale on the cost of carbon capture. Studied flue gas streams are at atmospheric pressure. The circle marker indicates the cost at the maximum studied size of a single carbon capture plant. Each grey bar indicates the capture cost ranges from 10% to 100% of the scales shown in the callouts for that particular application.



Two general trends are observed in Figure 11.

The first is that capture cost is very high (over USD 180 / tonne CO_2) when CO_2 partial pressure is very low (1 kPa) and falls significantly for higher partial pressures.

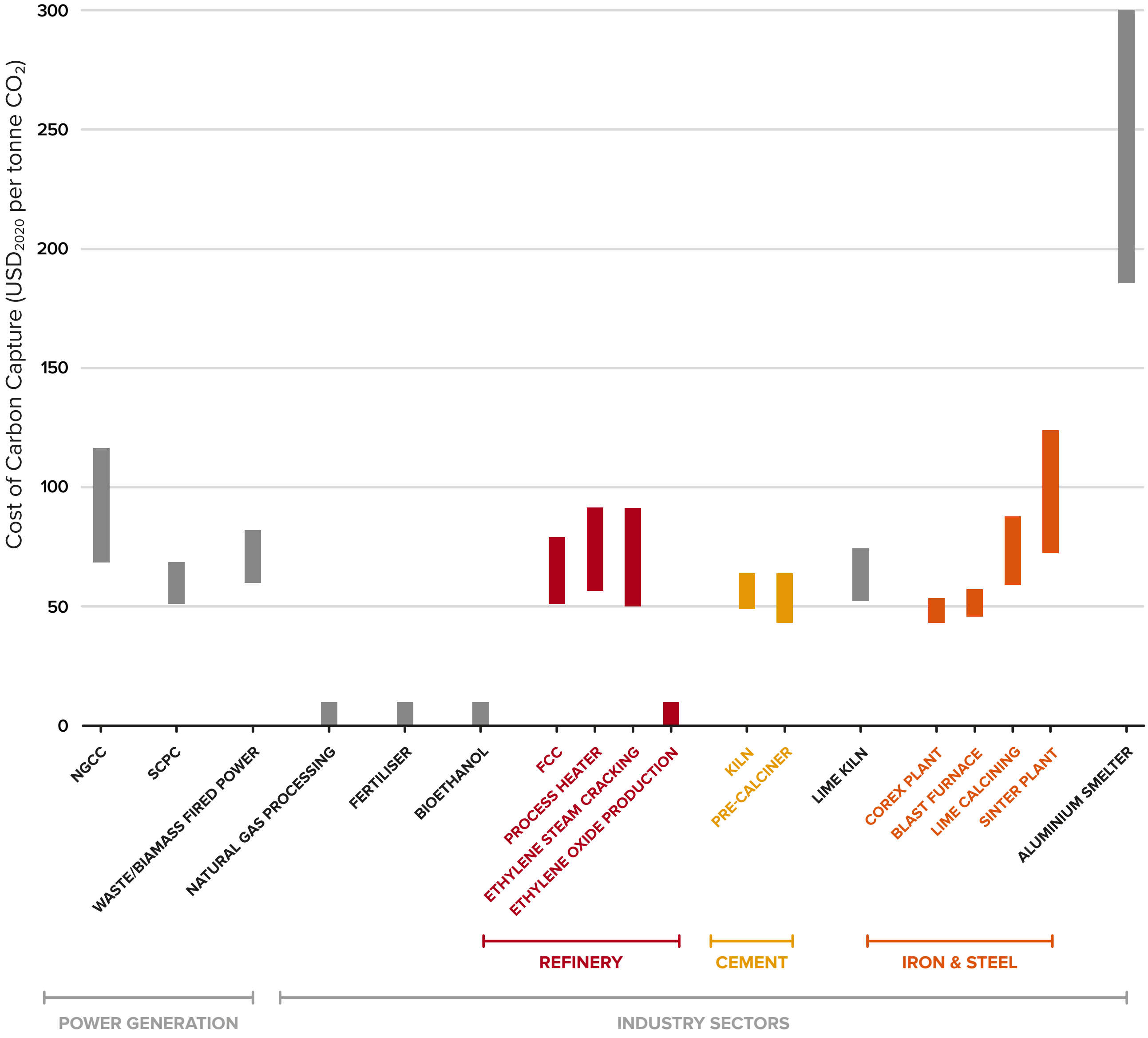
The second is that economies of scale become increasingly important as partial pressures get smaller. Although the percentage savings from a 10-times increase in scale are similar (from top of each bar to the bottom), the much higher absolute cost numbers make scale a more vital contributor to cost savings at lower partial pressures.

Understanding how cost varies between industries is useful at the macro scale when deciding where to make CCS investments.

However, for a given CO_2 source, it is unusual to have control over CO_2 partial pressure or the scale of the stream from which capture will occur. If multiple CO_2 sources are physically close, they can be aggregated to form a larger source gas stream. It is also possible (albeit expensive) to compress the source gas to increase the CO_2 partial pressure. But more typically, the scale and CO_2 partial pressure will need to be taken as given.

The following section outlines additional ways to reduce the cost of CO_2 capture for specific source gas streams.

Figure 12 - Cost of carbon capture in various types of power and industrial processes, excluding downstream CO_2 compression.[4]



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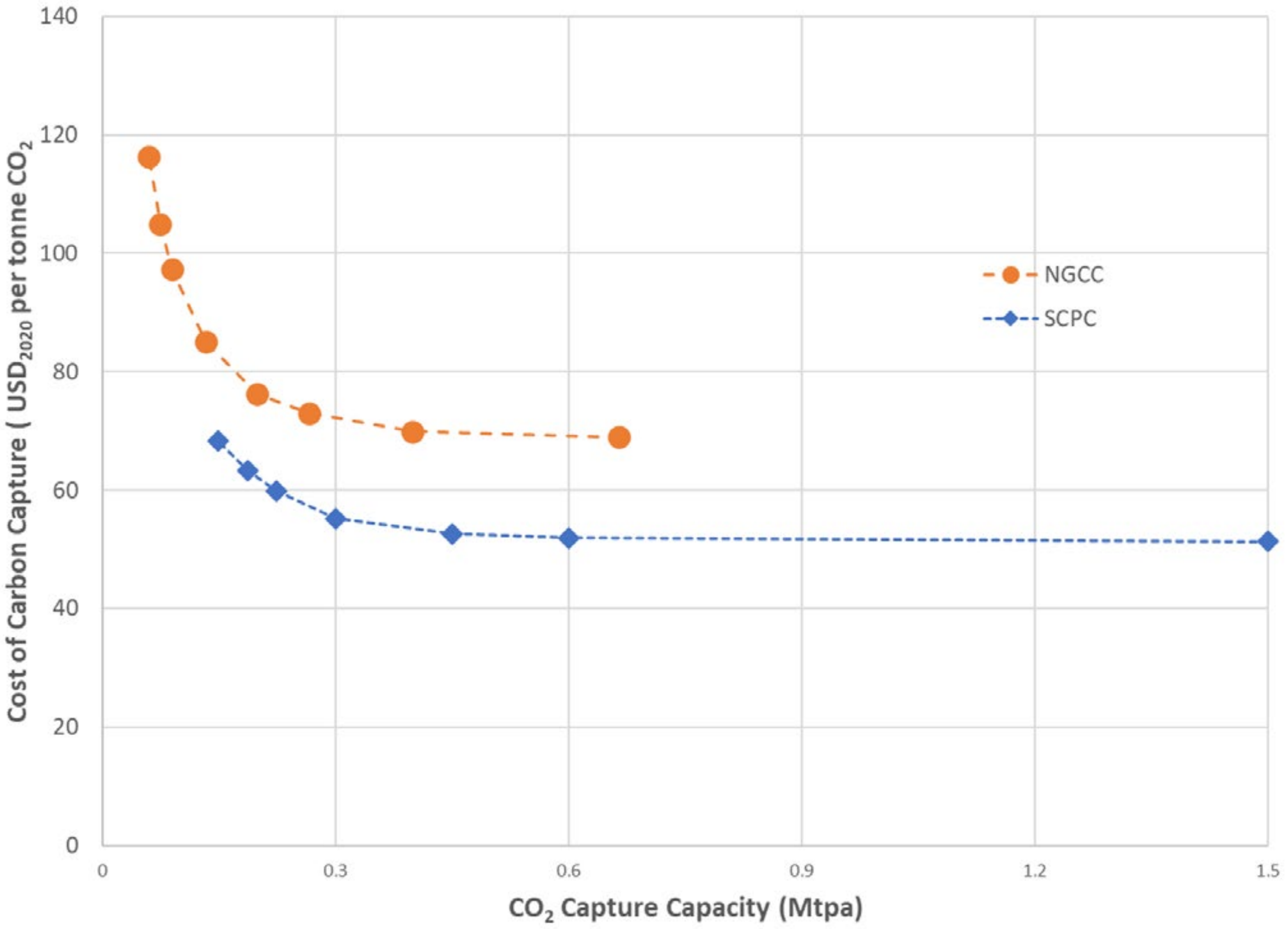
[4] For industrial processes with high concentration CO_2/inherent CO_2 capture process, e.g., natural gas processing, fertiliser, bioethanol, ethylene oxidation production, a cost range of \$0 – 10 per tonne of CO_2 captured is assumed for CO_2 conditioning. The cost is adjusted according to the prices of feedstock in the United States, e.g., \$2.11 per GJ coal and \$4.19 per GJ natural gas prices (James et al. 2019), as well as \$8.8 per GJ wood pellets biomass (Canadian Biomass Magazine 2020).

9.0 COST REDUCTION OPPORTUNITIES IN CARBON CAPTURE

9.1. Economies of scale and modularisation

The impact of economies of scale was further investigated over a range of flue gas volumes in two power generation applications: Natural gas combined cycle (NGCC) and Supercritical Pulverised Coal (SCPC) (Figure 13). This was to further examine the cost trends when the flue gas CO_2 partial pressure is set, but the scale is not.

Figure 13 - Impact of plant scale on the cost of carbon capture in NGCC and SCPC. The coal and natural gas reference prices (United States) applied are $2.11 per GJ and $4.19 per GJ (HHV) respectively (James et al. 2019). A construction lead time of 3 years for all cases is assumed.



As scale increases, capture cost declines considerably as the capture plant scales up. The cost reductions diminish above around 0.3 Mtpa of CO_2 captured, eventually levelling off by 0.5-0.6 Mtpa.

These findings are useful when specifying future power generation units with CCS or retrofit of CCS to existing units. To minimise capture costs, the capacity of CO_2 capture units should be at least 0.4-0.45 Mtpa. There are certainly other advantages of scale not considered here, such as building generation facilities with more competitive electricity production costs – but these factors are normally considered during the usual development of new power generation facilities.

The key finding is that it is essential not to make future generation units too small. The CCS costs become much higher at small scales and should be avoided if possible.

The fact that the costs of capture level off above a certain scale provides an excellent opportunity to further reduce costs through modularisation – the standardised production of carbon capture plants. By specifying standard units at a sufficiently large scale (say ~0.5 Mtpa), the full economies of scale can be exploited. For applications requiring larger capture rates, multiple capture units can simply be deployed in parallel.

9.2. Modularisation

Modular carbon capture plants are those built in a standardised way under mass production techniques. Typically, they are manufactured offsite in purpose-built facilities and delivered in discrete, modular components (often in shipping containers). For example, Aker Carbon Capture presently markets its modular carbon capture plant under the "Just Catch" brand.

Modular systems can reduce plant capital costs through increased economies of plant manufacturing scale. Modular carbon capture plants also help reduce costs through (Global CCS Institute 2020):

- Standardised plant foundations
- Standardised plant designs, including all engineering drawings
- Remote or automated operation
- Modular packaging, which greatly reduces on-site construction time and costs.

The reduced construction time, enabled by modularisation, yields additional project financial benefits. Shorter construction periods require shorter periods of insurance, lower costs associated with accessing or acquiring land, shorter deployment of temporary site construction facilities or worker facilities, less time spent in the management of community and compliance matters related to construction, and a reduced requirement for the use of project management staff.

A shorter construction period also brings forward operational commencement and thus the benefits of operation. Delays in revenue generation for any project can significantly impact the net present value of the project as future revenues (and costs) are discounted.

By using modularisation to shorten construction times, significant savings in the above areas can be made. Acting together, these factors may make the difference between a project meeting financial hurdles and proceeding to investment or failing.

9.3. Utilising low-cost energy supply strategies

A significant contributor to the cost of carbon capture is the cost of energy. For solvent-based capture plants, that energy is mostly provided in the form of steam.

The Institute undertook a study on the cost of capture using different regeneration heat supply strategies, as summarised in Figure 5. The solvent-based carbon capture technology requires low-pressure steam for solvent regeneration. In modern power plants and well-heat-integrated industrial plants, the energy penalty for carbon capture is generally reflected as either a loss of electricity generation or the investment and operation cost of a new boiler.

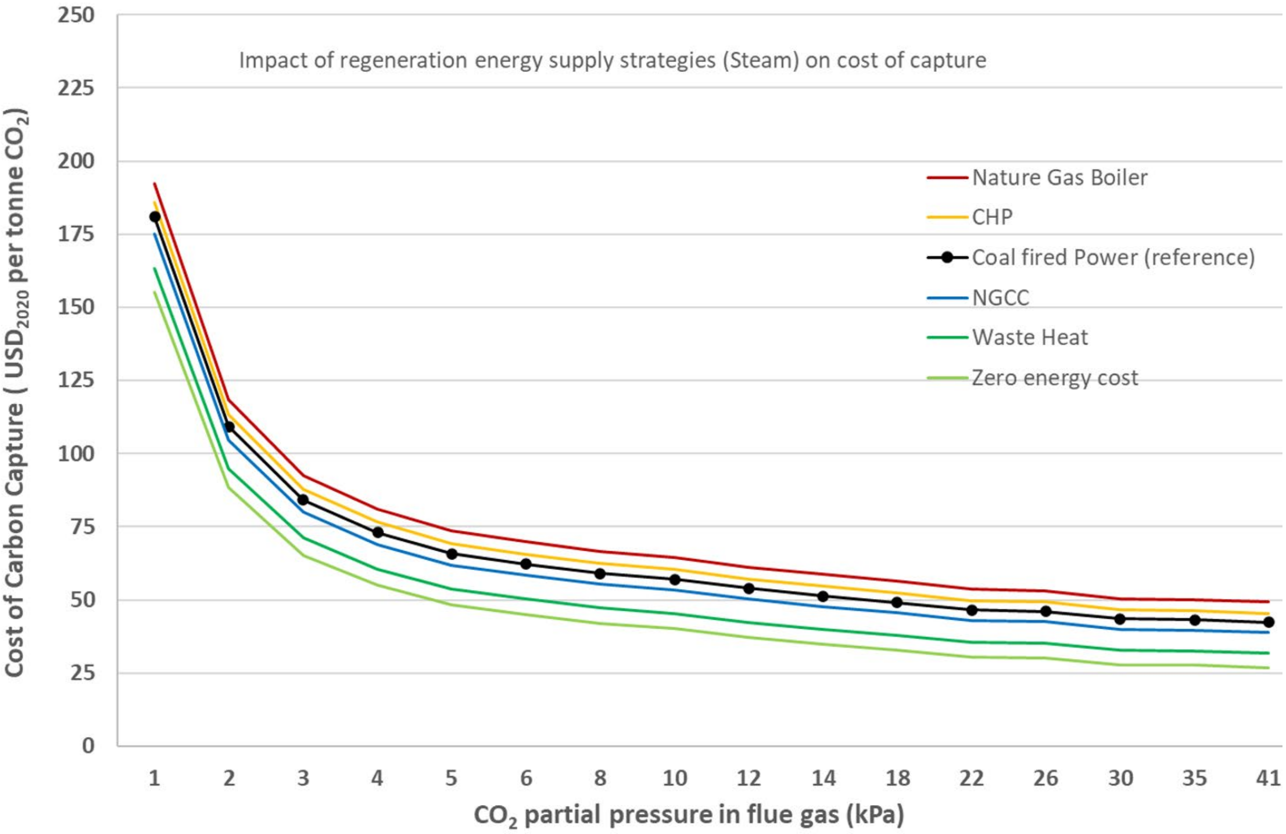
In large industrial plants, such as steel, pulp and paper, and waste to energy plants, the heat supply from the combined heat and power (CHP) plants can be used. This heat, in turn, supports the efficient carbon capture process integration without building a new boiler. CHP plants can be deployed rapidly and cost-effectively with little geographical limitation. CHP plants can use a variety of fuels, both fossil and renewable-based.

In cement, iron and steel production, there are also ample opportunities to use waste heat from the production processes to bring the capture cost down.

For example, the temperature of the calcination process in cement production is over 800°C (Ali et al. 2018). There is a substantial amount of excess heat from the outlet gas that can be utilised for carbon capture. In iron and steel production, there are opportunities to recover excess heat from dry slag granulation and coke dry quenching processes (Biermann et al. 2019).

As can be seen from Figure 14, using waste heat, where available, can reduce the cost of capture by around USD 10-20 / tonne.

Figure 14 - Overview of the cost of carbon capture using different regeneration energy supply strategies; natural gas boiler, combined heat and power (CHP), coal-fired power, NGCC, waste heat and zero energy baseline.



9.4. Financing Support to Scale Up

According to the International Energy Agency (IEA)'s Sustainable Development Scenario (SDS), the operating capacity of CCS needs to increase to around 5.6 gigatonnes (Gt) per annum by 2050. The SDS is the IEA's future scenario where energy-related sustainable development goals for emissions, energy access and air quality are met (International Energy Agency 2020b).

Presently the global operating CCS capacity is only around 40 Mtpa, less than 1% of the required capacity (Global CCS Institute 2021a).

The gap between current and required CCS capacity will require scale-up of CCS incentives to accelerate its deployment. Financial and policy measures will be essential to achieve the required speed and extent of capacity growth required. Improving the availability and cost of finance has a significant impact on the cost of capture. Opportunities exist through bringing down interest rates through the provision of low-cost finance, loan guarantees, master limited partnerships[5] and private activity bonds[6] (Brandl et al. 2021).

Figure 15 shows the cost of CCS, including downstream CO_2 compression, transport and storage. As a familiar point of reference, this is compared with the USD 50/ tonne tax credit provided by the US §45Q tax credit

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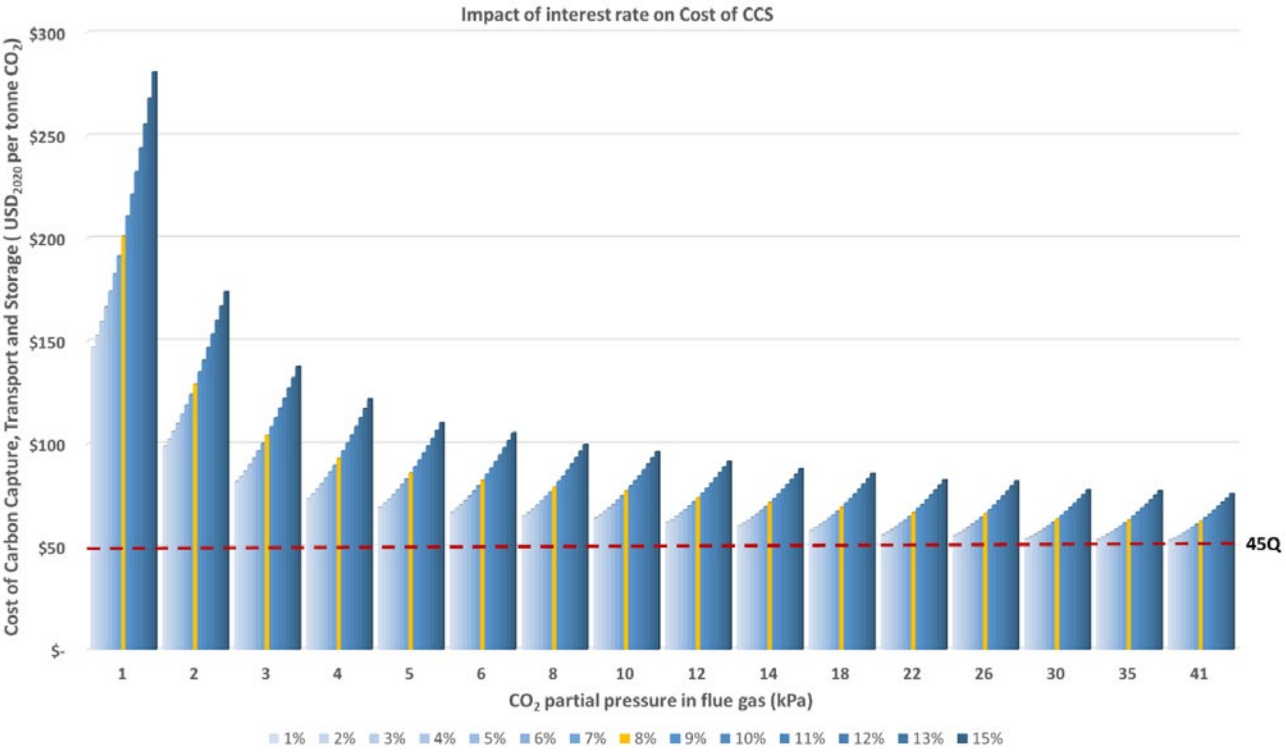
[5] Master Limited Partnerships (MLP) are US Federal tax structures that provide favorable treatment of partnerships for Federal tax purposes. They are allowed to raise funds by issuing and trading equity shares similar to a public corporation, thus reducing the costs of financing projects. The opportunity to utilize the tax structure of these particular partnerships would be advantageous to CO_2 pipelines for CCUS.

[6] Private Activity Bonds (PABs) are tax-exempt bonds that are similar to municipal bonds which can lower the cost of capital for a project by making debt available on more favorable terms.

Figure 15 - The cost of carbon capture, transport and storage as a function of the cost of capital and CO_2 partial pressure. A 30 year project lifetime is assumed.



policy (see breakout box) displayed on the chart by the red dotted line.

In Figure 15, a uniform allowance of USD 20 / tonne was made for CO_2 compression, transport and storage. This is consistent with storage close to the capture site, at significant scale, with a high quality storage resource.

For all costs of capital and all CO_2 partial pressures, the 45Q incentive is not enough to cover the full cost of the CCS value chain, though for high partial pressures and a low cost of capital it comes close. Therefore, additional incentives would be required.

These additional incentives could include:

- Revenue for the sale of CO_2 for enhanced oil recovery
- Capital grants to reduce the investment required by proponents
- Regulation of CO_2 emissions (e.g. requiring projects to have an emissions intensity below a legal limit, or applying emitters to pay for CO_2 emissions).

This analysis explains what has been observed in the USA; CCS facilities have all benefitted from additional incentives such as EOR revenue or capital grants and/or have access to very low cost CO_2 transport and storage.

The cost of capture for each flue gas stream decreases with interest rates (lower cost of capital). However, the magnitude of change is more obvious at lower CO_2 concentration flue gas streams. This is because carbon capture at lower CO_2 concentrations is more capital intensive per tonne CO_2 captured. This makes financial support more important for more dilute CO_2 streams such as for capture from natural gas power generation or aluminium smelting.

§45Q - TAX CREDIT FOR CO_2 STORAGE

The 45Q tax credit in the United States was introduced under the Energy Improvement and Extension Act of 2008 and was recently amended under the Bipartisan Budget Act in 2018. It provides capture operators with credits for each tonne of CO_2 stored or utilised, including for CO_2-EOR, which can be used to reduce the capture operator's tax liability.

The 45Q tax credit scheme is open to power plants, industrial plants and DAC facilities, provided they meet the minimum eligibility requirements specified in the Internal Revenue Code. This includes the need for new projects to be under construction by 1 January 2024 and meet minimum annual capture thresholds.

The revised scheme provides a tax credit of $31 per tonne CO_2 in 2019 for CO_2 stored in dedicated geological storage, rising to $50 per tonne CO_2 by 2026. Thereafter, the tax credit value rises with inflation. For CO_2-EOR and other CO_2 utilisation processes, the scheme provides a tax credit of $19 per tonne CO_2 in 2019 rising to $35 per tonne CO_2 in 2026. Operators can claim the credit for 12 years.

(Global CCS Institute 2021c)

9.5. Learning by doing

The cost of CO_2 capture from low-to-medium partial pressure sources such as coal-fired power generation has been reducing over the past decade or so, and is projected to fall by 50% by 2025 compared to 2010. This is driven by the familiar learning-processes that accompany the development and deployment of any industrial technology.

Studies of the cost of capture and compression of CO_2 from power stations completed ten years ago averaged around $USD_{2020}95/tCO_2$. Comparable studies completed in 2018/2019 estimated capture and compression costs could fall to approximately $USD_{2020}50/tCO_2$ from 2025 as shown in Figure 16.

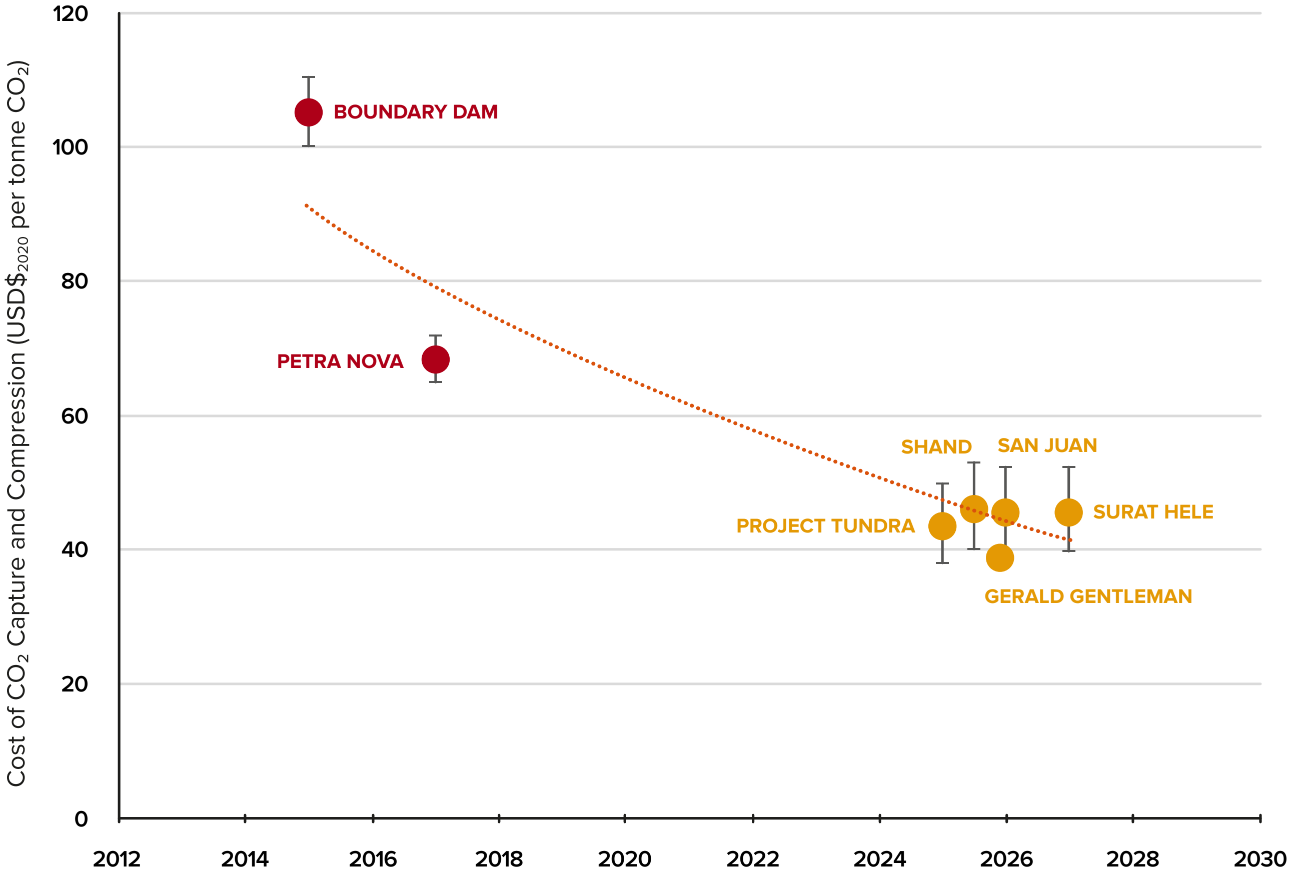
For example, two coal-fired power plant CCS retrofits have been constructed in Canada and the United States. These two facilities used different proprietary capture technologies and adopted different retrofit strategies with respect to the integration of the capture plant with the power plant, so they are not directly comparable. However, the difference in actual capture and compression costs observed in these two facilities is consistent with the trend observed in studies.

Capture costs for Boundary Dam in Canada, which commenced operation in 2014, are approximately USD_{2020} 105/tCO_2 (International CCS Knowledge Centre 2018). The subsequent Petra Nova CCS retrofit in the United States, which commenced operation in 2017, achieved capture and compression costs of approximately USD_{2020} 70/tCO_2 (Petra Nova Parish Holding LLC 2017).

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.

This "learning by doing" effect is observed across all industrial technologies. Lessons relevant to plant design, maintenance, operation and financing are highly valuable to subsequent projects. Sharing of non-proprietary learnings from CCS projects will enable future projects to be developed at lower cost.

Figure 16 - The cost of CO_2 capture and compression at commercial post-combustion CO_2 capture facilities at coal-fired power plants, including the ones in operation and in advanced development (Front End Engineering Design, FEED)



9.6. Technology innovation

There have been concerted efforts aimed at reducing costs associated with carbon capture systems, including the next generation technologies that are emerging and transformational technologies in R&D stage(NETL 2020):

- Next generation technologies are defined as those that have progressed through the laboratory/ bench development stage and are now (or soon will be) undergoing testing at pilot scale. These technologies are specifically targeting cost reductions through the development of enhanced materials, processes, and equipment to facilitate the deployment of CCS.
- Transformational technologies are anticipated to offer significant reductions in capture costs beyond those achieved for second-generation technologies. Most transformational technologies are currently being tested at the laboratory/bench scale.

In general, three key factors influence the capital costs of capture systems: the size of the equipment; the selection of materials; and the complexity of the process and its integration with the base facility:

- Large equipment sizes are partly a function of the volume of gas that requires treatment to remove CO_2. Capture media with faster uptake and regeneration kinetics or with higher CO_2 capacity require smaller vessels. In addition, different process operating regimes, such as higher pressures, may allow for decreases in equipment size.
- In terms of materials, the use of reaction vessels fabricated using stainless steel (or other high-cost materials) can have a major impact on capital cost. If lower-cost materials can be used (e.g., carbon steel or concrete), capital costs can be reduced. This needs to be balanced against the need for good corrosion resistance and equipment integrity.
- For retrofit applications, a significant part of the capital cost is required to integrate the new system

into the existing asset (e.g., power plant). This can take the form of integration of the steam and condensate systems, expansion of the cooling systems, flue gas and exhaust connections, gas recycling systems, and others. Steam extraction can be particularly complex and costly when significant modifications are necessary on a steam turbine; in the worst scenario, complete replacement of the steam turbine may be needed.

Savings on operating expenses have been achieved through the development of advanced solvents with lower regeneration energy and high degradation resistance. For example, the energy required for amine regeneration applied to coal combustion flue gas has significantly improved from around 5.5 to 3.0 GJ per tonne CO_2 captured for advanced amines, and to below 2.5 GJ per tonne CO_2 in the latest enhanced solvent technology. This translates directly into a reduced cost of steam for the capture plant.

Solvent degradation occurs when repeated heating and cooling of solvents enable the chemical breakdown of the components of the solvent needed for CO_2 capture. It is a particular concern for conventional solvents such as MEA. It can contribute to significant ongoing costs to replace (makeup) degraded solvents. Technological developments have been targeted at reducing solvent degradation through new compounds and solvent additives. This can reduce demand for the makeup of the capture solvent, reducing operating costs.

Additionally, improvements in process design and optimisation such as inter-cooling, lean vapour recompression, split flow arrangement and stripper inter-heating can further drive costs down when properly used.

Heat integration is another technique to reduce operating expenses and the amount of steam/cooling water needed. This involves using sources of heat and cold in the host plant to provide some of the heating and cooling required for the capture plant. Finding the optimal steam supply method, minimising the inefficiency of the steam extraction at nominal and partial loads, and recovering waste heat from the capture system for use in the plant steam cycle are now being widely applied to the development of new generation carbon capture plant.

Other carbon capture technology platforms, such as membranes, adsorption, oxy-fuel, and others will exhibit different distributions of cost and energy consumption. If operating costs are high, then the capital costs will need to be low, and vice versa (analogous to the trade-off that often exists between capital and operating costs in most industrial processes). The sections below introduce approaches being pursued to decrease costs and energy consumption associated with carbon capture across a wide range of technologies.

Table 5 summarises a selection of next-generation capture technologies that could offer unique features, either through material innovation, process innovation and/or equipment innovation for reduced capital and operating cost and improved capture performance. More technologies are described in the CCS Technology Readiness Level section.

Among them, a few technologies are already being nominated as the carbon capture candidates for the next significant wave of CCS facilities (Global CCS Institute 2021a).

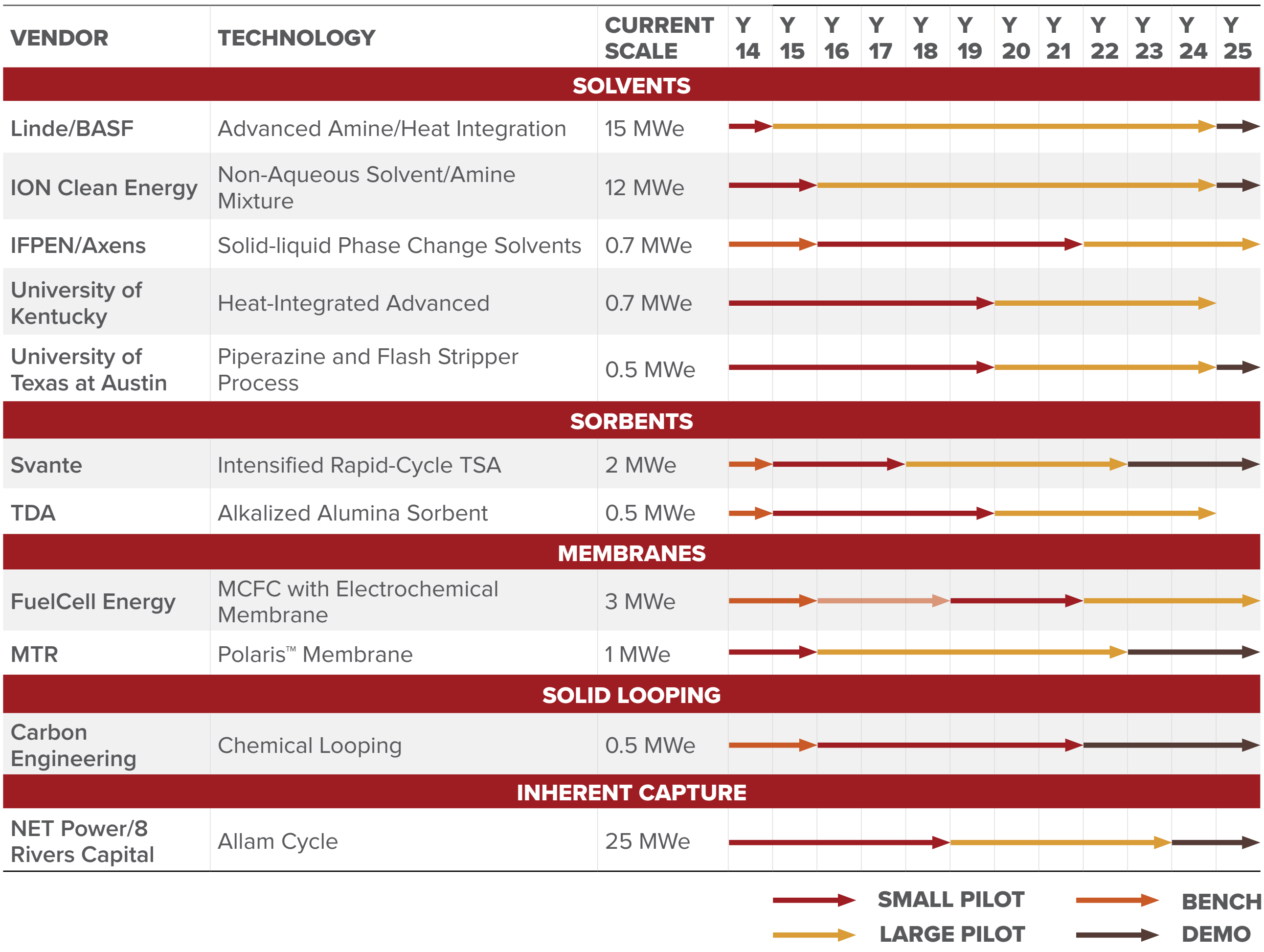
- Ion Clean Energy's non-aqueous ICE-21 solvent has been selected for a Front-End Engineering Design (FEED) study of retrofitting CCS to Nebraska Public Power District's Gerald Gentleman Station.
- Membrane Technology and Research's PolarisTM membrane system has been selected for a FEED study at Basin Electric's Dry Fork Station.
- Mitsubishi Heavy Industries' new KS-21TM solvent has been selected for a FEED study of retrofitting CCS to Prairie State Generating Company's Energy Campus.
- Linde-BASF's lean-rich solvent absorption/regeneration cycle technology has been selected for a FEED study at Southern Company's natural gas-fired power plant.
- The University of Texas's piperazine advanced stripper (PZAS) process has been selected for a FEED study at the Mustang Station of Golden Spread Electric Cooperative.
- Svante's VeloxoThermTM has been selected for a FEED study to capture CO_2 from the flue gas of the cement kiln and natural gas fired boiler in a Lafarge Holcim cement production facility

To summarise, there are ample opportunities to drive down the cost of carbon capture and to shorten project deployment timelines, through economies of scale, modularisation, heat integration, process optimisation, combined with next-generation technologies.

However, all of these require scale-up to facilitate learning-by-doing and learning by innovating. It would be simplistic to draw up the future cost of carbon capture through a single learning rate to factor all the cost reduction drivers, as carbon capture has only just begun in many power and industrial sectors.

There are also many capture technologies in the near-commercial pipeline (for example, advanced chemical solvents, high CO_2 permeance membrane and adsorbent technologies) that could be more cost-effective and efficient in capturing CO_2.

Table 5 - Selected next-generation capture technologies being tested at 0.5 MWe (10 t/d) scale or larger with actual flue gas.



VENDOR	TECHNOLOGY	CURRENT SCALE	Y 14	Y 15	Y 16	Y 17	Y 18	Y 19	Y 20	Y 21	Y 22	Y 23	Y 24	Y 25
SOLVENTS														
Linde/BASF	Advanced Amine/Heat Integration	15 MWe												
ION Clean Energy	Non-Aqueous Solvent/Amine Mixture	12 MWe												
IFPEN/Axens	Solid-liquid Phase Change Solvents	0.7 MWe												
University of Kentucky	Heat-Integrated Advanced	0.7 MWe												
University of Texas at Austin	Piperazine and Flash Stripper Process	0.5 MWe												
SORBENTS														
Svante	Intensified Rapid-Cycle TSA	2 MWe												
TDA	Alkalized Alumina Sorbent	0.5 MWe												
MEMBRANES														
FuelCell Energy	MCFC with Electrochemical Membrane	3 MWe												
MTR	Polaris™ Membrane	1 MWe												
SOLID LOOPING														
Carbon Engineering	Chemical Looping	0.5 MWe												
INHERENT CAPTURE														
NET Power/8 Rivers Capital	Allam Cycle	25 MWe												

10.0 COST OF TRANSPORT AND STORAGE

Captured CO_2 needs to be transported to a storage site for injection into a geological formation.

There are two ways by which large amounts of CO_2 may be transported:

- Compression of CO_2 to dense phase (> 74 bar) for pipeline transport
- Refrigeration of CO_2 to liquid phase for transport by ship, truck or other vehicles

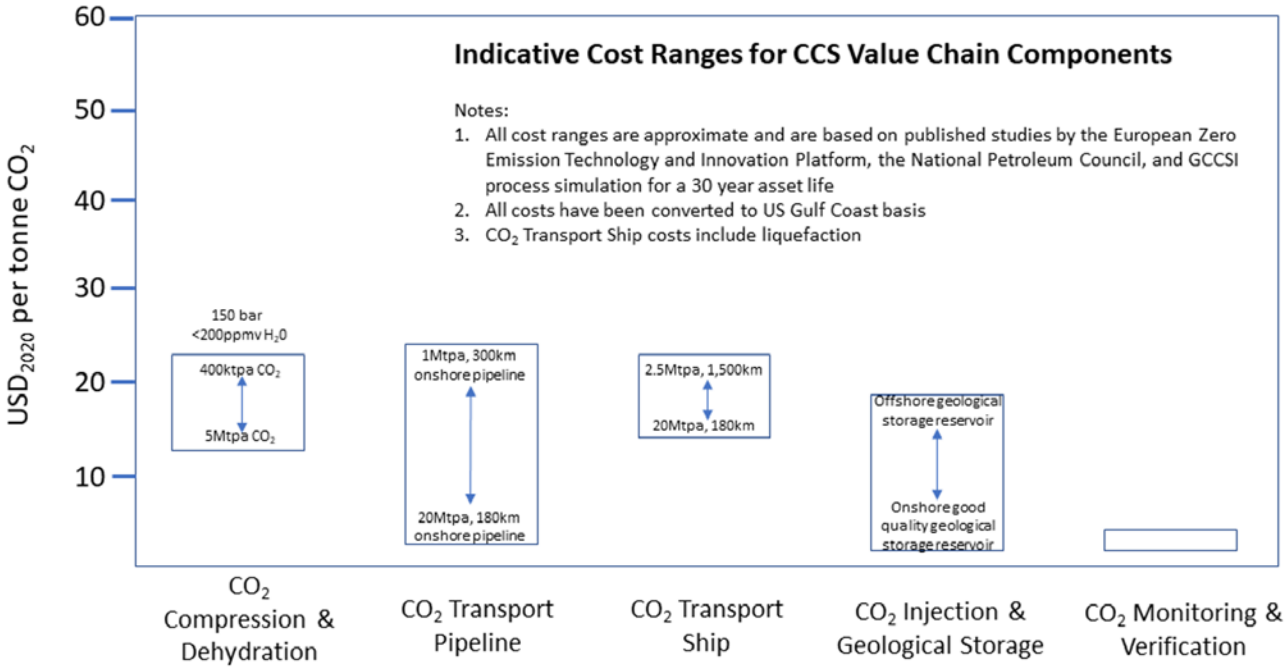
Captured CO_2 usually contains water. Water must be removed prior to transport to prevent CO_2 and water forming acids that can corrode pipelines and other equipment. Dehydration is typically done in conjunction with compression or refrigeration.

The indicative costs of pipeline and shipping transport modes vary significantly with scale and with transport distance. The CCS value chain consists of various components, each with a range of costs that vary with different drivers.

CO_2 must be captured, compressed and dehydrated, then transported to the injection site and finally injected and then monitored. Figure 17 provides indicative costs for each part of the value chain (noting that transport will be by ship or pipeline, and generally not both) assuming construction on the US Gulf coast.

Figure 17 costs are indicative only. The costs are always project specific. There are significant variations in the cost of capital, of capital equipment, of labour, of energy and other consumables between locations.

Figure 17 - Indicative Cost Ranges for CCS Value Chain Components (excluding capture) – US Gulf Coast[7]



Notes:
1. All cost ranges are approximate and are based on published studies by the European Zero Emission Technology and Innovation Platform, the National Petroleum Council, and GCCSI process simulation for a 30 year asset life
2. All costs have been converted to US Gulf Coast basis
3. CO_2 Transport Ship costs include liquefaction

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[7] Based on GCCSI process simulation and analysis of: ZEP 2019, The cost of subsurface storage of CO_2, ZEP Memorandum, December 2019. IEAGHG ZEP 2011, The Costs of CO_2 Storage, Post-demonstration CCS in the EU. National Petroleum Council 2019, Meeting the Dual Challenge, A Roadmap to at-scale deployment of carbon capture use and storage. National Petroleum Council 2019, Topic paper #1, Supply and Demand Analysis for Capture and Storage of Anthropogenic Carbon Dioxide in the Central US.

Project characteristics also determine project costs in any location. For example, the Northern Lights project, which plans to transport CO_2 by ship from various ports to a storage site under the seabed of the North Sea, is targeting storage costs of €35-50/tCO_2 which is considerably higher than the shipping costs shown in Figure 5.[8]

10.1. CO_2 transport cost drivers

Pipeline costs are strongly affected by economies of scale. This is the case for dense phase pipelines (>74 bar) or gas phase pipelines.

All else being equal, gas-phase pipelines are larger in diameter than dense phase pipelines – this tends to make them more expensive. As such, bulk transport of CO_2 is usually done under dense phase conditions.

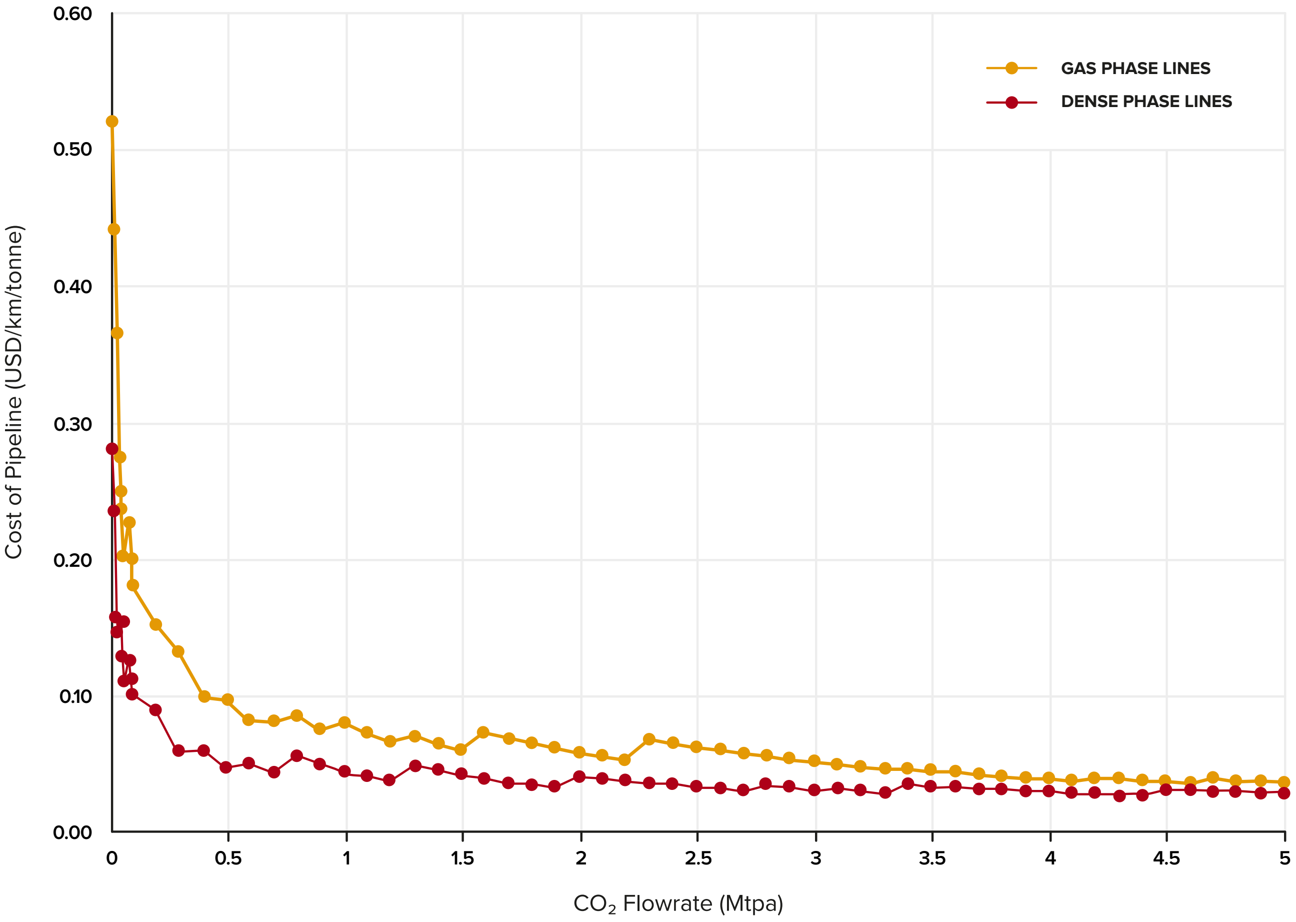
Figure 18 shows an estimate of the cost of CO_2 pipelines, based on an internal analysis of CO_2 pipeline costs in Australia. The analysis included annualised capital cost and operating costs.

Although specific pipeline costs vary from country to country, the general pattern of these cost curves will be observed in all locations. Pipeline costs are remarkably high at small flowrates, falling rapidly with increasing flow before effectively levelling off once flows reach the megatonne range.

The strong influence of pipeline economies of scale is a key driver of the development of CCS hubs. Megatonne CO_2 sources such as power stations, gas processing plants or other large industrial sources should be able to support an economical CO_2 pipeline on their own. These can then serve as anchor customers for a hub, enabling smaller CO_2 sources to also use the pipeline without incurring the much higher pipeline costs observed at small flowrates.

For very long transport distances and mid-range tonnages, shipping can become more economical than pipelines. Shipping does not have the same economies of scale as pipelines, but has the advantage that it can be deployed in a modular fashion – starting with one ship and scaling up over time as needed. It can also be directed to different storage sites, which may be useful if price competition between storage sites emerges.

Figure 18 - Indicative Costs of CO_2 pipelines - dense phase (> 74 bar) and gas phase



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[8] Aasen E.I., and P. Sandberg. 2020. Northern Lights. A European CO_2 transport and storage network. Presentation by Equinor to the Zero Emissions Platform (ZEP) Conference, European Parliament. 28 January 2020; Brussels

10.2. CO_2 compression drivers

CO_2 compression to the dense phase (>74 bar) is required for storage, thus making the best use of the available void space in the storage formation. For pipeline transport, compressing to dense phase also reduces the cost of the CO_2 pipeline compared to gas-phase transport (refer figure 18).

CO_2 compression cost has two main components: capital cost of the equipment, and energy cost to drive the compressor.

Compression energy costs scale linearly with flow – doubling the flow will double the compression energy cost, all else being equal. As such, there is no cost advantage to increasing the scale for energy cost.

Compression capital costs do experience economies of scale, up to a point. Commercially available CO_2 compression systems are available up to a maximum power rating in the order of 40 MW (Mccollum & Ogden 2006, p.3). For CO_2 flows requiring more power than this (over around 3 Mtpa of CO_2), multiple compression trains will be required. At this point, the economies of scale will have been exploited.

As compression systems rated over 40 MW become available, it may be possible to extend the economies of scale to somewhat higher flowrates.

Although there continue to be incremental improvements in compression technology – mainly aimed at increasing efficiency and reliability – significant improvements in CO_2 compression costs are not anticipated due to the maturity of compressor technology.

10.3. Drivers for cost in storage and future cost reductions

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.

10.3.1. Site Selection

The maturity of the technology adopted from the oil and gas industry and environmental services provides higher confidence in cost estimates.

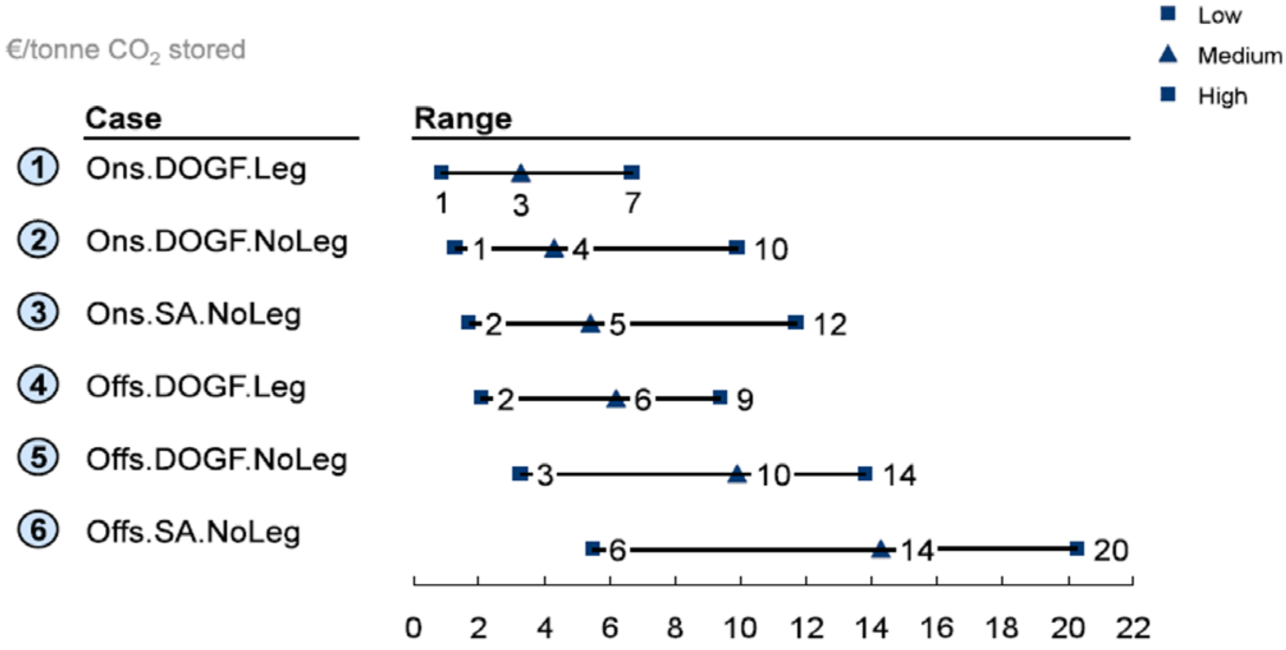
There is a broad range of geological storage costs. For example, the National Petroleum Council estimated storage in the United States at $1 to $18 per tonne of CO_2 (National Petroleum Council 2019).

The factors that contribute to this range in costs are attributed to the site; and include:

1. Access: offshore is significantly more expensive than onshore storage; existing land uses and access can impact costs onshore.
2. Knowledge: a well-characterised site (previous oil and gas, CO_2 exploration or development) has lower development costs than un-explored sites. For example, depleted oil and gas fields have a significant amount of data, attained during production of hydrocarbon, requiring less additional data to prove the suitability of the storage formation.
3. Existing infrastructure: surface facilities, offshore platforms, pipes and wells can be re-used reducing the capital investment required.
4. Storage capacity/injectivity: large storage formations with higher injection rates require fewer injection wells per tonne of CO_2 injected.
5. CO_2 volume and purity: a large volume of near-pure CO_2 improves injection efficiencies over an operation's lifetime.
6. Monitoring: ease of deployment, CO_2 footprint, post-closure requirements all impact the ongoing costs of monitoring an operation.

A comprehensive but theoretical analysis in Europe highlighted the cost differences depending on site choice, re-use of infrastructure, and existing knowledge (Figure 19). As detailed above, the analysis found an onshore site with existing data and infrastructure re-use is the lowest cost. The most expensive is an offshore site with little data and no existing infrastructure to be re-purposed for CO_2 storage (Zero Emissions Platform 2013).

Figure 19 - Storage cost ranges for different scenarios; Ons: Onshore, Offs: Offshore, DOGF: Depleted Oil or Gas field, SA: saline formation, Leg: re-use infrastructure, Noleg: no re-use of infrastructure (Zero Emissions Platform 2013).



According to the CO_2RE database, the majority of operating projects to date have targeted onshore, deep saline formations (Global CCS Institute 2021b) (Table 3). However, offshore saline formations are increasingly being developed, especially in the North Sea of the UK, EU, and Norway. Depleted oil and gas fields have only been used for pilot and demonstration projects to date, undoubtedly reflecting the lowest cost R&D. Despite the lower overall costs, commercial CCS facilities in the development pipeline are not solely pursuing oil and gas fields.

Future CCS operations comprise a mix of deep saline formations and oil and gas fields, as seen in Table 6. Access to depleted fields is not the primary reason for this mix. 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. This increased CO_2 storage rate is evident in that the majority of CCS hubs in development which are pursuing these options, including CarbonNet (Australia), Northern Lights (Norway), and PORTHOS (The Netherlands).

Table 6 - Selected storage scenarios for commercial and pilot/demonstration CCS facilities. DOGF: Depleted Oil or Gas field, SA: saline aquifer formation (Global CCS Institute 2021b). - Selected storage scenarios for commercial and pilot/demonstration CCS facilities. DOGF: Depleted Oil or Gas field, SA: saline aquifer formation, re-use refers to oil and gas production infrastructure (Global CCS Institute 2021b).

STORAGE SCENARIO	COMMERCIAL CCS/ HUBS	PILOT
Onshore; DOGF; Re-use	2	11
Onshore; DOGF; No re-use	2	1
Onshore; SA; No Re-use	16	18
Offshore; DOGF; Re-use	4	
Offshore; DOGF; No re-use	0	
Offshore; SA; No Re-use	12	

10.3.2. Deployment

A high injection rate per well and CO_2 stored per site is not the only way to achieve 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 (Global CCS Institute 2020; National Petroleum Council 2019). To meet climate targets, over 5,000 Mtpa of anthropogenic CO_2 must be injected by 2050 (Global CCS Institute 2020). 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 (IEAGHG 2020b) processes.

The IEAGHG estimates that 30-60 storage sites must be developed each year to meet the IEA SDS (Burnard 2017). In terms of new wells, this equals 300-1200 wells annually. This roll-out of infrastructure (rigs, platforms, wells, piping) may result in a material reduction in costs overall as CO_2 corrosion-resistant steel, cement, and other components are manufactured at greater scale. The Quest CCS Facility in Canada has cited improved future economies of scale of infrastructure and refinement of the CO_2 storage process will reduce future operational costs (Shell 2015).

10.3.3. Technology Advancement

Technology advancement is expected to deliver modest reductions in the cost of storage. Future savings are seen in the refinement of existing equipment, digital innovation and automation. Cost reductions of over $45 million in CAPEX and $60 million in OPEX are estimated for a theoretical future CCS facility storing in an offshore saline formation according to the IEAGHG (2020). These cost reductions are mainly attributed to digital innovations (automation and predictive maintenance).

Much like CO_2 injection, the equipment for monitoring, measurement and verification (MMV) are mature and adopted from related industries. These technologies are being optimised for CO_2 monitoring to reduce costs. Three key areas include:

- Development: improved prediction of CO_2 movement, verification and quantification in the storage formation.
- Experience: improved processing and real-time testing.
- Innovation: increased autonomy and remote operation; predictive and advanced analysis.

The primary area for cost reductions in MMV is the quantification of the CO_2, particularly with diffuse or small volumes of CO_2. In storage operations, these conditions occur at the edges of the CO_2 plume, or during phases of residual trapping and dissolution. To date, the cost of deploying equipment to detect small volumes of CO_2 is high. Several wells in close proximity to each other, or permanent seismic systems are required. Refinement of the technology, which will result in lower costs, is being pursued at the Aquistore (Canada) and Otway (Australia) sites.

In addition to small volumes of CO_2, the quantification of CO_2 out of the storage formation, into either the surrounding geology or atmosphere CO_2 is also an area of high costs as this leakage has no equivalent industrial monitoring analogues. Several technologies are being pursued globally (IEAGHG 2020c).

11.0 CONCLUSION

All elements of the carbon capture and storage value chain are mature and have been in commercial operation for decades. However incremental improvements in those technologies have, and will continue to reduce their cost. For example, the cost of capture from a coal fired power station has reduced by around 50% over the past 10-15 years. Those improvements arise from learning by doing, through competition between vendors, through larger developments that take advantage of economies of scale, and through commercial synergies that reduce the risk and therefore the cost of investing in CCS. In addition, new technologies are being developed that will deliver step-change cost reductions. With respect to performance improvements and cost reductions, CCS really is no different to any other industrial technology. CCS is following the familiar pattern of cost reduction with increased deployment.

Regardless of the particular technology used, the dominant drivers of the cost of CCS are:

- The characteristics of the gas stream from which the CO_2 is being captured: The higher the concentration of CO_2 in the gas stream, the lower the capture cost.
- The scale of the CO_2 capture facilities and transport infrastructure: The cost per tonne of CO_2 captured from dilute sources rises rapidly as the capacity of the capture plant falls below approximately 250kt of CO_2 per year. Similarly, the cost of CO_2 transport rises rapidly as the capacity of the pipeline infrastructure falls below approximately 500kt CO_2 per year. Transport costs fall significantly as the capacity of pipeline infrastructure increases from 500kt CO_2 per year up to 4Mt CO_2 per year.
- The cost of energy: CCS requires significant energy to regenerate CO_2 capture media and to compress CO_2 to very high pressures necessary to achieve a dense phase suitable for transport and geological storage.
- The cost of capital: CCS is capital intensive.
- The characteristics of the geological storage resource: Costs will be lower for storage resources that are well characterised (requiring less new data to be collected), are closer to the capture facility, are onshore as opposed to offshore, that have high injectivity (requiring fewer wells), and for which existing infrastructure may be re-tasked for storage purposes.

Thus, there is a very large range in the cost of CCS. For the lowest cost opportunities, for example large scale natural gas processing, CCS may cost less than $20/t CO_2. For relatively dilute sources of CO_2 such as the flue gas from a gas power station, or where transport distances are long or storage costs are high, CCS may cost over $120/t CO_2.

It is clear that there are many opportunities to deploy CCS today that can deliver material emission abatement at costs that are very competitive with other options. To achieve climate targets, those opportunities must be realised to rapidly accelerate the rate of deployment of CCS. This will require strong policy to remove barriers and incentivise private sector investment in CCS. The policy options are all familiar and have proven successful in other industries. They will be explored and described in another report in this series.

12.0 APPENDIX

Carbon Capture Techno-economic Assessment Methodology

The chemical solvent processes, especially those using amine-based solvents, are the most widespread technologies for carbon capture. They have been used extensively in natural gas sweetening and post-combustion capture in power sectors.

To provide insight into the current cost of carbon capture in various industries, a detailed techno-economic study using chemical absorption-based solvent capture technology was performed. The chemical solvents, especially the amine-based solvents, are the current state-of-the-art technologies for carbon capture. They have been extensively used and studied in natural gas sweetening and post-combustion capture in power plants (Global CCS Institute 2021a). The 30 wt% aqueous monoethanolamine (MEA) is used for the cost benchmarking study, due to its commercial availability and preferred properties for carbon capture of flue gases under ambient pressures (IEAGHG 2019; Rochelle 2009; Bains, Psarras & Wilcox 2017).

The capture cost studied here does not consider downstream CO_2 compression, which is discussed separately in the compression section. It should be noted that there are other project-specific factors impacting the capture cost, such as business model, location, labour, heating/cooling supply strategies, process variations, different technologies etc (Global CCS Institute 2017), which are not extended in this analysis.

The flue gas streams with CO_2 concentrations ranging from 1 vol% to 40 vol% were considered and the maximum volume of flue gas flow was limited by the absorber size (Φ11 x 20 m) in a single CO_2 capture train (one absorber and one desorber configuration). This corresponds to a 90% CO_2 capture plant at the capture capacity of 0.6 Mtpa in a 240 MW NGCC plant (4 vol% CO_2 gas stream), and 1.4 Mtpa in a 230 MW supercritical pulverised coal (SCPC) power plant (14 vol% CO_2 gas stream) (James et al. 2019). Larger scales of power and industrial plants can be equipped with multiple trains of capture plants (Feron et al. 2019).

A rigorous, rate-based model developed in Aspen Plus® was applied to evaluated technical performance. This is a bottom-up approach based on a detailed process flow sheet. The whole amine CO_2 capture process is described below and shown in Figure A1:

1. The flue gas is initially cooled in the direct contact cooler using the water wash. The caustic scrubbing in the direct contact cooler is included for flue gas streams containing SO2.
2. The cooled flue gas is then fed to the bottom of the absorber column, which consists of packed beds in the CO_2 absorption section(s), and a water wash section.
3. The flue gas is contacted with a semi-lean amine solvent in the packed bed where the CO_2 in the flue gas is absorbed. The intercooling process is applied improves the efficiency of the absorption process.
4. The flue gas leaving the CO_2 absorption section is scrubbed in the top water wash section and passes through a demister section to remove any MEA and/or degraded solvent.
5. The rich amine solvent leaves the bottom of the absorber. This is divided into two different streams (rich amine split process). The first rich amine stream enters the Lean-Rich Heat Exchanger and is heated by the hot lean amine coming from the bottom of the desorber. The heated rich amine is then sent to the top of the desorber. The second rich amine stream is sent directly to the top of the desorber above the first rich amine stream.
6. The rich amine solvent is regenerated in the desorber column which is heated by a reboiler situated at the base of the desorber column. The reboiler is heated by the low-pressure steam.
7. Periodically, some of the circulating amines are sent to the filtration unit to remove any heat-stable salts and trace impurities. Fresh MEA from the amine storage tanks is added to replenish the lost solvent.
8. The overhead vapour from the desorber column passes through a demister and is sent to the condenser which is cooled by the cooling water. The wet CO_2 is separated in a reflux drum, while the separated liquid is recycled back to the column as reflux or water storage tank for water balance.

A comprehensive techno-economic analysis model was used to determine the required capital investment and economic performance using the Aspen Capital Cost Estimator (ACCE) V12, based on the equipment parameters, materials and energy balance from process simulation. The lean-rich heat exchanger is the major cost component in the carbon capture plant. It was optimised using the Aspen Exchanger Design Rating (EDR) V12 to produce the feasible and economically optimal design for cost analysis. ACCE uses the equipment models contained in the Icarus Evaluation Engine to generate preliminary equipment designs and simulate vendor-costing procedures to develop detailed cost estimates. The association for the Advancement of Cost Engineers (AACE) international Recommended Practice (Class IV) and the DOE economic analysis were used here to guide estimates of capital costs and calculate the total capital investment within an expected accuracy range of ±40%.

Table A1 lists the key assumptions, parameters and methodologies for the techno-economic analysis in CO_2 capture.

Figure A1. Conventional aqueous amine solvent plant process flowsheet integrated with process optimisation using the intercooling and rich split processes.

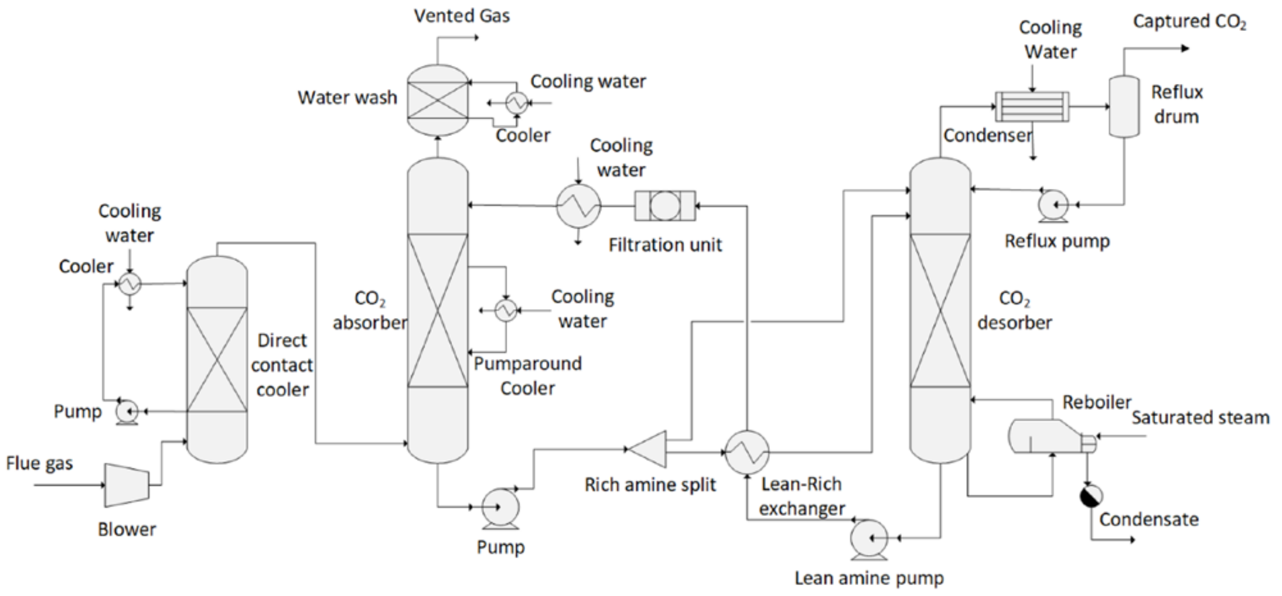


Table A1. Technoeconomic analysis parameters, assumptions and methods.

DESIGN PARAMETERS	
Location	Texas, United States
Present Value	2020 USD cost escalated[9] from Aspen V12 2019 USD cost basis
Construction years	3
Cost Recovery Factor (CRF)	8.88% based on 8% discount rate
Operating life	30 years
Capacity factor	90 %
CO_2 capture rate	90 %

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[9] Using the average escalation value of the 2011-2018 per cent change over time within The Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2018 – Cost Trends of Gas Utility Construction across the six regions. (Whitman, Requardt and Associates 2018)

TOTAL CAPITAL REQUIREMENT[10]	
Bare Erected Cost (BEC)	• Process equipment • Installation • Supporting facilities • Direct and indirect labour
Engineering Procurement and Construction (EPC)	0.15 BEC
Process Contingency	0.159 (BEC + EPC)
Project Contingency	0.207 (BEC + EPC + Process Contingency)
Total Plant Cost (TPC)	**Sum of the above**
Start-up costs	• 6 months operating labour • 1 month maintenance materials • 1 month chemical and consumables • 1 month waste disposal • 25% of one month fuel cost • 2% TPC
Inventory Capital	• 2 months fuel • 0.5% TPC
Financing cost	2.7% TPC
Other Owners' costs	15% TPC
Owner's Cost	**Sum of the below**
Total Overnight Cost (TOC)	TPC + Owner's costs
Distribution of TOC over the Capital Expenditure (before escalation)	10%, 60%, 30%, in 3-year period
Escalation Multiplier (dependant on CRF)	1.16 (base case)
Total As-Spent Capital (TASC)	Escalation multiplier X TOC

FIXED OPERATING COST	
Maintenance costs	2.2% of TPC/year
Maintenance labour	40% of maintenance costs
Maintenance materials	60% of maintenance costs
Operating labour cost	$ 75,000/person-year
Number of operators	3 (base case)
Number of shifts	5
Administrative/support labour	30% operating labour + 12% of maintenance cost
Insurance cost	0.5% TPC
Local taxes and fees	0.5% TPC

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[10] Parameters used to calculate the total capital investment were under guideline of Association for the Advancement of Cost Engineers International Recommended Practice (AACE 2011), the United States National Energy Technology Laboratory (NETL) Quality Guidelines for Energy Systems Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance (US DoE/NETL 2019a) and Process Modeling Design Parameters (US DoE/NETL 2019b).

VARIABLE OPERATING COST	
Raw process water	$2/cubic metre
Activated carbon	$2.2/kg
Diatomaceous Earth	$2.75/kg
MEA amine	$2/kg
Corrosion Inhibitor	20% of MEA cost
Soda ash	$0.68/kg
Special waste disposal costs (non-hazardous)	$88.2/tonne [11]
Sewage cost	$2.7/cubic metre

FEEDSTOCK COST	
Coal	$2.11/GJ
Natural gas	$4.19/GJ
Biomass (wood pellets)	$8.8/GJ

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[11] Taken from the special waste disposal cost of (James et al. 2019)

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