DNV

WHEN TRUST MATTERS

ENERGY TRANSITION OUTLOOK
CCS TO 2050

Carbon capture and storage: from turning point in 2025 to scale by mid-century

FOREWORD

I am delighted to introduce this report on DNV's global forecast for CCS through to 2050. The reason for issuing this report now is that we believe CCS is at a turning point. The CCS project pipeline has grown significantly, and, in the next five years, we expect operational capacity to increase substantially.

The surge in installation reflects a widening appreciation of the decarbonization role of CCS. So far, the heavy lifting on carbon capture development has been done within oil and gas production – for natural gas processing and enhanced oil recovery. But after 2030, the market for CCS will increasingly address hard-to-decarbonize emission sources. With this shift, we forecast that North America will be joined by Europe as a leading region for CCS deployment.

In the hierarchy of emissions reduction strategies, the first consideration should always be energy efficiency. Next is the use of renewables to replace fossil energy sources. Finally, there is CCS, which occupies an increasingly important niche: tackling emissions in hard-to-decarbonize sectors. This includes CCS for process emissions in manufacturing, and in the production of low-carbon hydrogen from the steam reforming of natural gas.

Our forecast is that CCS will grow significantly: from 41 Mt/yr today to 1.3 Gt of CO_2 captured and stored in the year 2050. That is a big uplift, but it falls short of where CCS should be in a net-zero outcome. Furthermore, we forecast that energy-related emissions roughly halve from today to 2050, and so, ironically, it is in today's high-emitting world where CCS is best applied.

The biggest barrier to the very much needed acceleration of CCS deployment is policy uncertainty. Policy shifts, not technology or costs, have been responsible for many CCS project failures. However, policy support for CCS is firming across most world regions. Indeed, carbon markets and voluntary offsets will evolve to the point where even the more expensive carbon removal technologies such as direct air capture (DAC) will be widely deployed towards the end of our forecast period.

I remind readers that DNV's 'most likely' forecast of our energy system to 2050 is one associated with a dangerous 2.2°C of global warming by 2100. Yet, in this most likely future, we find that CCS will scale rapidly and will attract significant investment – some USD 700 billion over the next two-and-a-half decades, without taking into account onboard CCS for ships. However, in any net-zero future, orders of magnitude more CCS will be needed. DNV stands ready to work with customers worldwide to build safe and reliable CCS – faster.

Ditlev Engel

CEO

DNV Energy Systems

HIGHLIGHTS

1. The turning point for CCS has arrived, with capture and storage capacity expected to quadruple by 2030
2. After 2030, the strongest growth will be in hard-to-decarbonize sectors, with manufacturing accounting for 41% of annual CO_2 captured by mid-century
3. CCS will grow to capture 6% of global CO_2 emissions in 2050, which falls significantly short of what is required for any net-zero outcome
4. Carbon dioxide removal (CDR) will capture 330 $MtCO_2$ in 2050 – one-quarter of total captured emissions

Cover photo: Northern Pioneer CO_2 transport ship at Northern Lights receiving terminal in Øygarden, Norway. Photo: Ruben Soltvedt / Northern Lights.

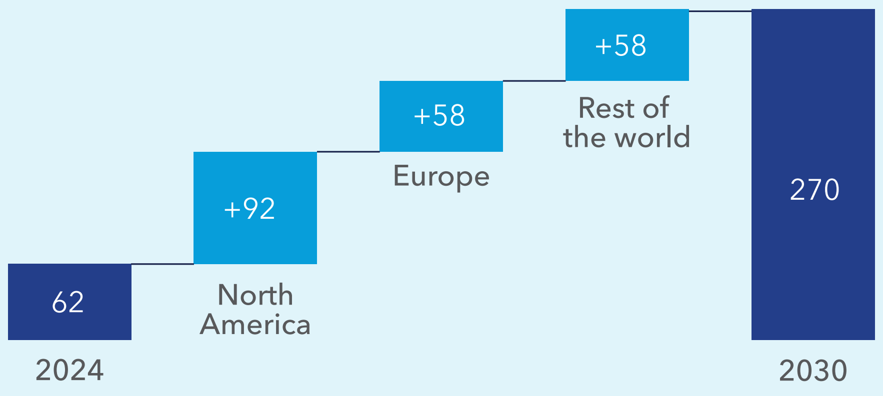
HIGHLIGHTS

1 The turning point for CCS has arrived, with capture and storage capacity expected to quadruple by 2030

- North America and Europe will drive this short-term scale up, with natural gas production still the main application. We will also see growth across many sectors and regions, including first-of-a-kind applications.
- Cumulative investments in CCS in the coming five years are expected to reach about USD 80bn.
- Global economic instability and budgetary pressures may pose risks to CCS deployment, potentially shifting priorities and removing finance needed.

CCS capacity additions to 2030

Units: $MtCO_2$/yr

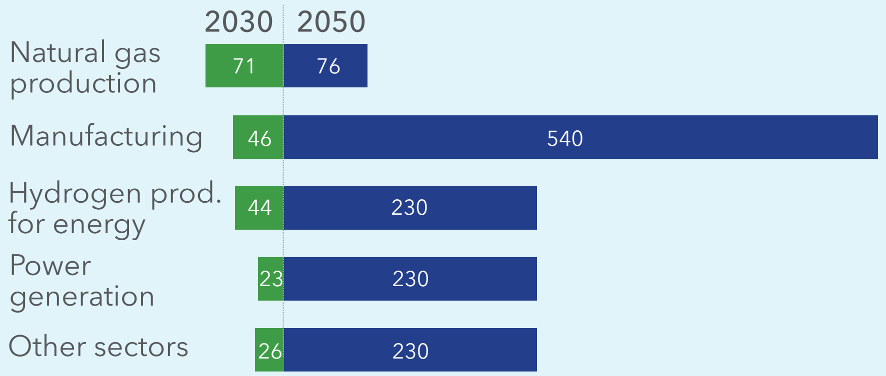


2 After 2030, the strongest growth will be in hard-to-decarbonize sectors, with manufacturing accounting for 41% of annual CO_2 captured by mid-century

- CCS is essential to address hard-to-decarbonize emissions from manufacturing sectors, like steel production, and from maritime transport, where onboard capture is expected from the 2040s in parts of the global shipping fleet.
- Manufacturing, particularly cement and chemicals, will be the biggest application of CCS in Europe; in North America and the Middle East it will be hydrogen and ammonia; in China, coal power.
- Although capture from natural gas production will continue, its share falls from 34% in 2030 to 6% of total capture in 2050.

CCS by sector in 2030 and 2050

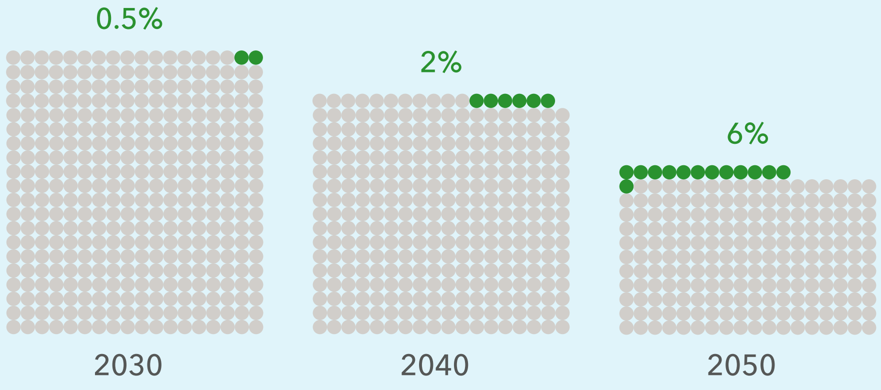
Units: $MtCO_2$/yr



3 CCS will grow to capture 6% of global CO_2 emissions in 2050; that falls significantly short of what is required for any net-zero outcome

- Uptake will grow from 41 $MtCO_2$/yr captured and stored today to 1,300 $MtCO_2$/yr in 2050.
- Despite positive policy and investment signals, CCS will need to scale to over six times the forecast level to reach DNV's Pathway to Net Zero Emissions. Scaling is particularly important in hard-to-decarbonize sectors.
- CCS is growing where there is policy support. In most sectors, it will only scale with mandates and price incentives. Europe has the strongest price incentives and will catch up with – and eventually surpass – current North American deployment dominance.
- Average costs will decline by around 40% towards 2050 as technologies mature and scale.

Share of global CO_2 emissions captured with CCS



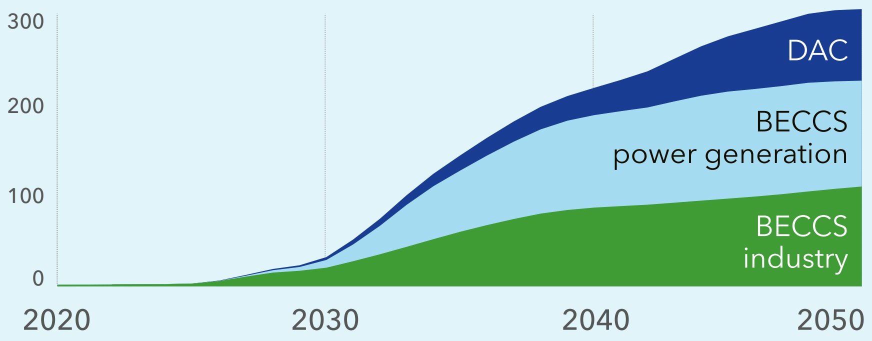
One circle represents 100 $MtCO_2$/yr. CCS numbers include carbon removal.

4 Carbon dioxide removal (CDR) will capture 330 $MtCO_2$ in 2050 – one-quarter of total captured emissions

- As global emissions continue to accumulate, CDR becomes important to reduce the large carbon budget overshoot.
- Bioenergy with CCS (BECCS) is generally the cheaper CDR option and will be used primarily in renewable biomass for power and manufacturing.
- Direct air capture (DAC) costs remain higher at around USD 350/tCO_2 through 2050, but voluntary and compliance carbon markets still ensure the capture of 32 $MtCO_2$ in 2040 and 84 $MtCO_2$ in 2050.
- Beyond our forecast period, an enormous amount of CDR, alongside nature-based solutions, will be required to ensure net-negative emissions.

Carbon dioxide removal through 2050 by sector

Units: $MtCO_2$/yr



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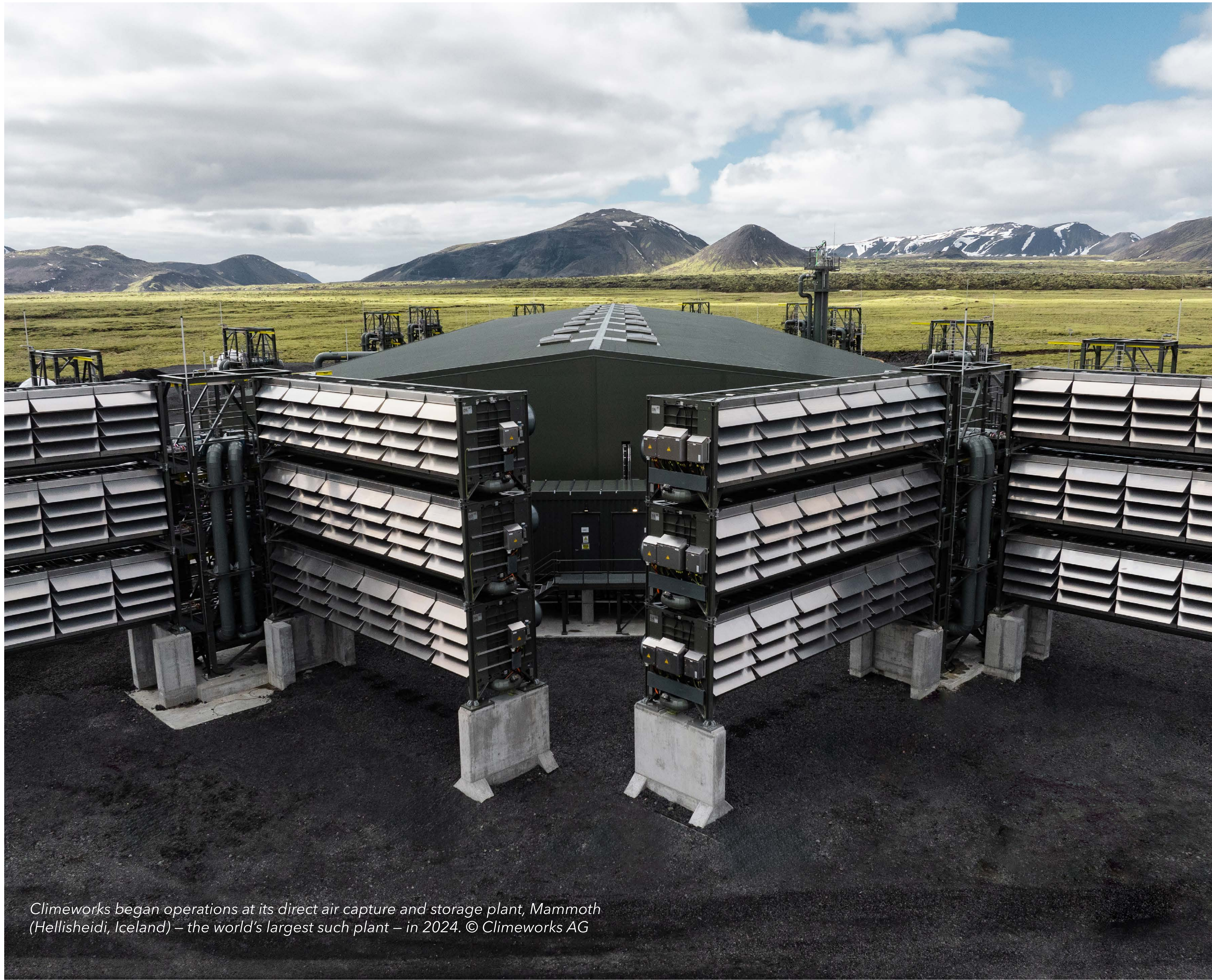
1 INTRODUCTION

This report is part of DNV's annual Energy Transition Outlook suite of publications and is our first dedicated global forecast for carbon capture and storage.


Climeworks began operations at its direct air capture and storage plant, Mammoth (Hellisheidi, Iceland) – the world's largest such plant – in 2024. © Climeworks AG

1 INTRODUCTION

Carbon capture and storage (CCS) is a suite of climate change mitigation technologies designed to capture CO_2 emissions, generally from flue or exhaust gases, to prevent their release into the atmosphere, and to safely store captured CO_2.

CCS involves three key steps:

1. **Capture of CO_2** at the source of emissions
2. **Transport of the captured CO_2** to a storage site
3. **Storage of CO_2** in deep geological formations for permanent isolation.

In this report, we include carbon dioxide removal (CDR) technologies – such as direct air capture (DAC) of CO_2 – within the broader definition of CCS. While captured CO_2 can, in limited volumes, be put to productive use, giving rise to the term carbon capture, utilization, and storage (CCUS), the scale of such utilization remains relatively small. Therefore, we use the term CCS throughout this report, unless referring to utilization specifically.

In many cases, CCS builds on technologies that have been used commercially for decades. For instance, amine-based CO_2 capture has been successfully deployed at scale in coal-fired power plants and natural gas processing. In this sense, CCS is not a leap into the unknown; it simply repurposes existing industrial technologies for climate mitigation.

However, applying CCS across a wider range of sectors – such as aluminium smelting – presents new technical and economic challenges. Given the diversity of emission sources and gas compositions, it is necessary to adapt existing capture technologies and, in some cases, develop entirely new approaches.

There is broad international consensus – particularly among scientific bodies, climate experts, and major energy organizations – that CCS will play a vital role in a decarbonized energy future. This is especially true in hard-to-decarbonize sectors such as cement, steel, and chemical production, where CO_2 is emitted not just from fossil fuel use but as an inherent part of industrial processes. Since the release of the *IPCC Special Report on Carbon Dioxide Capture and Storage* (2005), CCS has consistently featured in scenarios developed by the Intergovernmental Panel on Climate Change (IPCC), the International Energy Agency (IEA), and as an important part of DNV's own *Energy Transition Outlook* (ETO).

The purpose of this forecast is not to state what the scale of CCS in the 2050 energy system *should* be, but – in line with the forecast approach of the ETO – the scale it is *likely* to achieve.

Our approach

This report is part of DNV's annual ETO suite of publications. The CCS forecast to 2050 is derived from the ETO Model, which simulates the global energy transition across 10 world regions. As such, our CCS outlook is not a standalone assessment – it is embedded in a comprehensive, system-wide simulation that reflects the complex interdependencies shaping both global and regional energy landscapes. Further details on our modeling approach and assumptions are available in the main ETO 2024 report (DNV, 2024a).

Unlike most energy forecasters, DNV does not develop multiple future scenarios. Instead, we provide a single 'best-estimate' forecast that represents the most likely trajectory of the energy system, based on expected policy developments, technological progress, and cost trends. While we do explore key uncertainties and sensitivities, this approach avoids presenting potentially unrealistic futures – enabling us to focus on actionable insights. The key principles guiding our methodology are illustrated below.

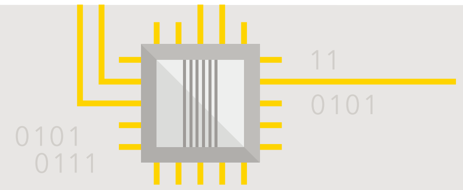
Chapter guide

Chapter 2 covers the technological and economic dimensions of the CCS value chain, examining each stage – capture, transport, and storage – in detail. Chapter 3 addresses the safety considerations associated with CCS, along with key technical challenges that may hinder its large-scale deployment. Chapter 4 describes the policy landscape and business models most likely to support CCS deployment. It also examines the critical issues of public acceptance, and the evolving regulatory frameworks needed to enable scale-up. Finally, Chapter 5 presents the results of our CCS deployment modeling, offering quantitative insights into the most likely uptake through to 2050.

Our **best estimate**, not the future we want

A single forecast, not scenarios

Long-term dynamics, not short-term imbalances



Continued development of proven **technology**, not uncertain breakthroughs

Main **policy** trends included; caution on untested commitments, e.g. NDCs, etc.

Behavioural changes: some assumptions made, e.g. linked to a changing environment

2 TECHNOLOGIES AND COSTS

CCS technology is not new. Carbon capture has been deployed in natural gas processing for decades, and CO_2 has been transported by pipelines since the 1970s and ships since the 1980s. But many new applications of CCS technology are emerging, which pose new technical and economic challenges.

This chapter details the technological and cost considerations for each stage of the CCS value chain – capture, transport, and storage – and includes a deep dive into onboard carbon capture, direct air capture (DAC), and CO_2 utilization. Coordinating the entire CCS value chain for optimization is also covered.

The Petra Nova carbon capture facility (shown on the right of this image) retrofitted at NRG Energy's W. A. Parish coal-fired power plant in Texas. Image: RM VM published under creative commons license CC-BY-SA-4.0

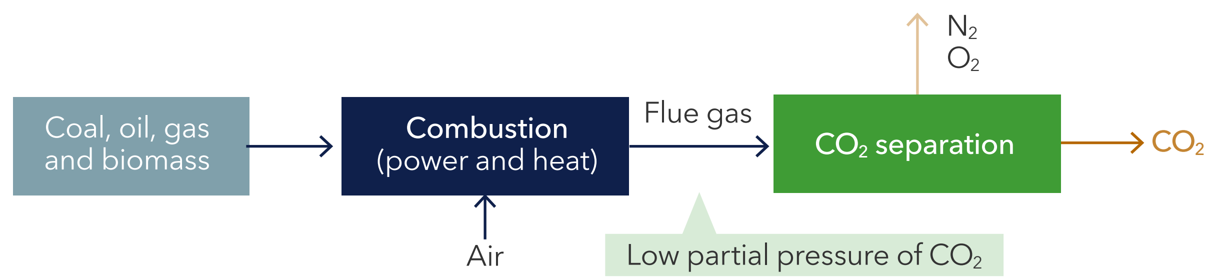
2.1 CAPTURE

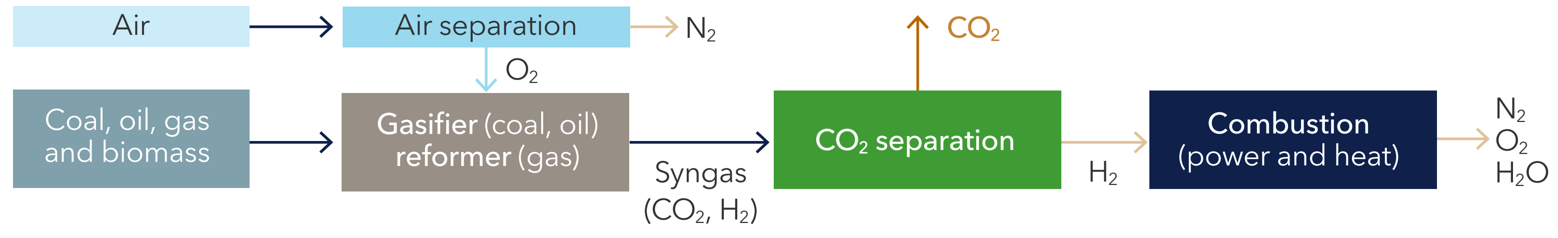
Carbon capture is the process of separating and removing CO_2 from other components in a mixed gas stream. In point source capture, CO_2 is removed from the exhaust or flue gases produced by major emission sources – for example power generation or cement production facilities – capturing industrial emissions at the source. DAC, on the other hand, removes CO_2 from ambient air and is a negative emission technology. DAC is described further in the fact box on page 13.

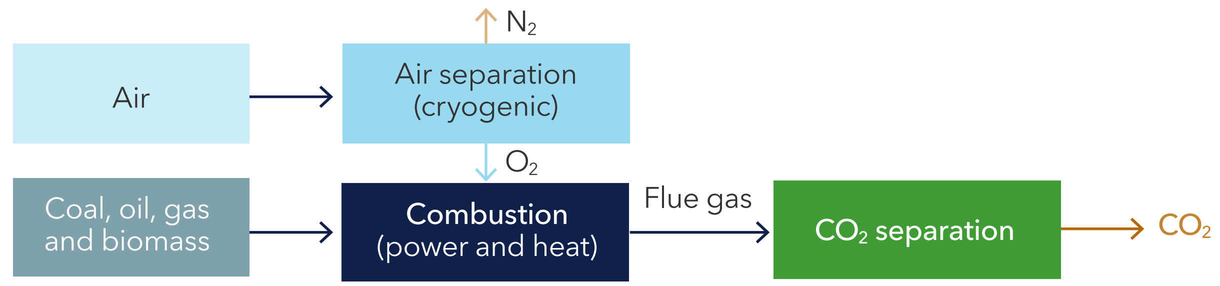
Currently, 62 $MtCO_2$/yr of operational capture capacity is installed. This is supported by a strong development pipeline including many first-of-a-kind applications of capture technology. For instance, coupling CCS with dispatchable gas power generation to produce predictable low-carbon baseload power to supplement variable renewables generation. This approach is planned in the UK's NZT Power project, which reached a final investment decision in 2024 (Net Zero Teesside, 2024). The term carbon capture often includes other processing steps such as flue gas pre-treatment, purification of captured CO_2, compression and/or liquefaction, and integration of the capture facility with the host emitter site.

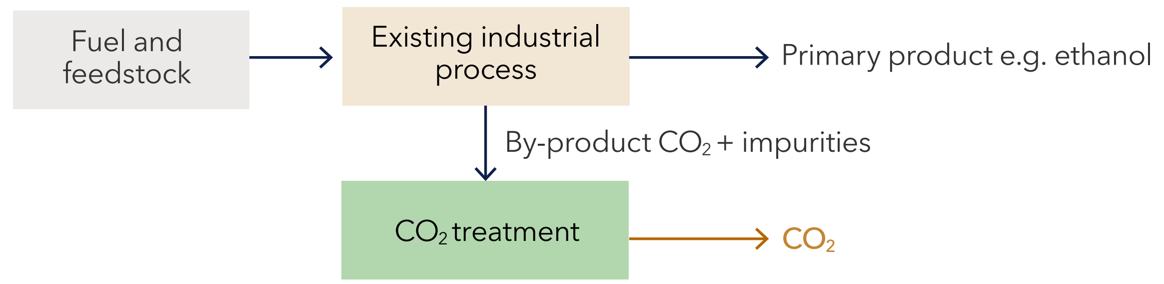
Four families of point source capture applications

Point source capture technology	Application
Post-combustion Capture from exhaust gases of combustion processes such as power generation, generally with a low CO_2 concentration.	– Coal- and biomass-fired power plants – Gas turbines – Industrial facilities – Waste-to-energy plants
Pre-combustion Capture before combustion, often at elevated operating pressure, for example natural gas processing or hydrogen production.	– Integrated Gasifier Combined Cycles (IGCC) – Hydrogen production – steam methane reforming
Oxy-combustion CO_2 capture from a combustion process using pure oxygen instead of air, giving a higher CO_2 concentration.	– Coal- and biomass-fired power plants – Gas turbines (Allam Cycle) – Industrial facilities (glass, cement)
Inherent capture Certain industrial processes already produce CO_2 as a by-product, typically at high concentration with minimal processing required.	– Ethanol production – Biomethane production – Ammonia production



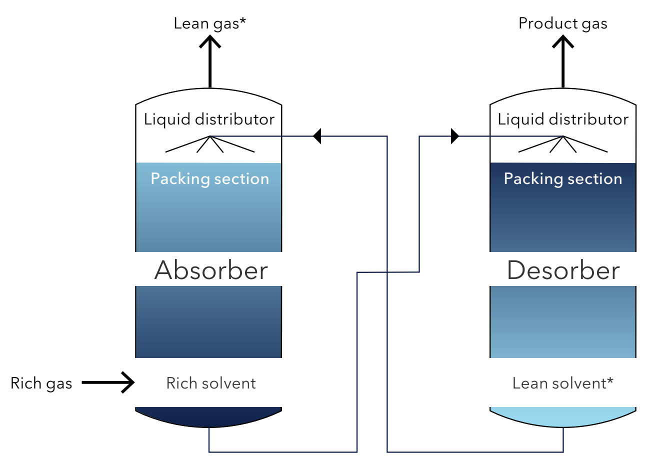






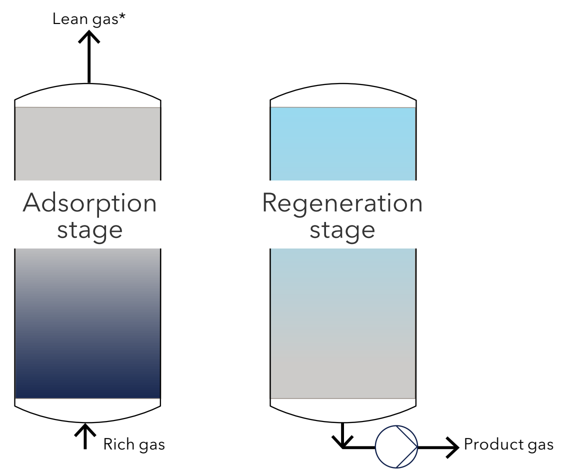
Four main families of capture technology

Absorption



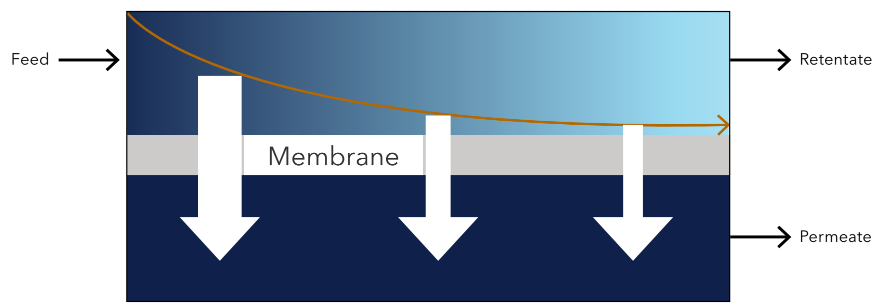
In **absorption**, CO_2 is selectively removed by physical or chemical interaction with a regenerable liquid solvent solution, including amine, non-amine chemical, and physical solvents.

Adsorption



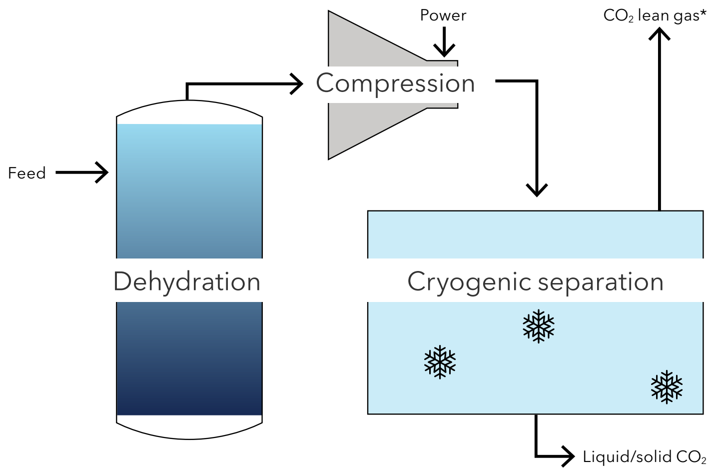
In **adsorption**, CO_2 is selectively trapped on the surface of a solid material through chemical or physical bonds before thermal- or pressure-driven regeneration of the solid material.

Membrane



Membrane capture uses materials which selectively allow CO_2 to permeate through a thin barrier medium under the influence of a driving force such as a pressure difference.

Cryogenic



Cryogenic technologies separate CO_2 from other gases through differences in volatility by cooling to low temperatures.

*Very low CO_2 concentration

Point source capture: applications, maturity, and technologies

Point source capture can be deployed to decarbonize a wide range of industrial emission sources. These are grouped into post-combustion, pre-combustion, and oxy-combustion capture applications. Additionally, certain industrial processes, such as ethanol production, already inherently produce a high purity CO_2 by-product.

A range of technologies are used in carbon capture, often adapted from other common industrial gas separation processes that have an extensive track record of removing CO_2 from gas mixtures.

Capture technologies with narrower applications such as chemical looping, which uses metal oxide carriers to alter the combustion process, and industry-specific CO_2 capture technologies, such as Leilac for the cement industry (Hills, 2017), are also available. Ongoing research and development efforts are exploring novel capture approaches and hybrid systems that combine two or more capture technologies.

> When assessing technical maturity, it is important to consider both the capture technology itself and the application in which it will be deployed.

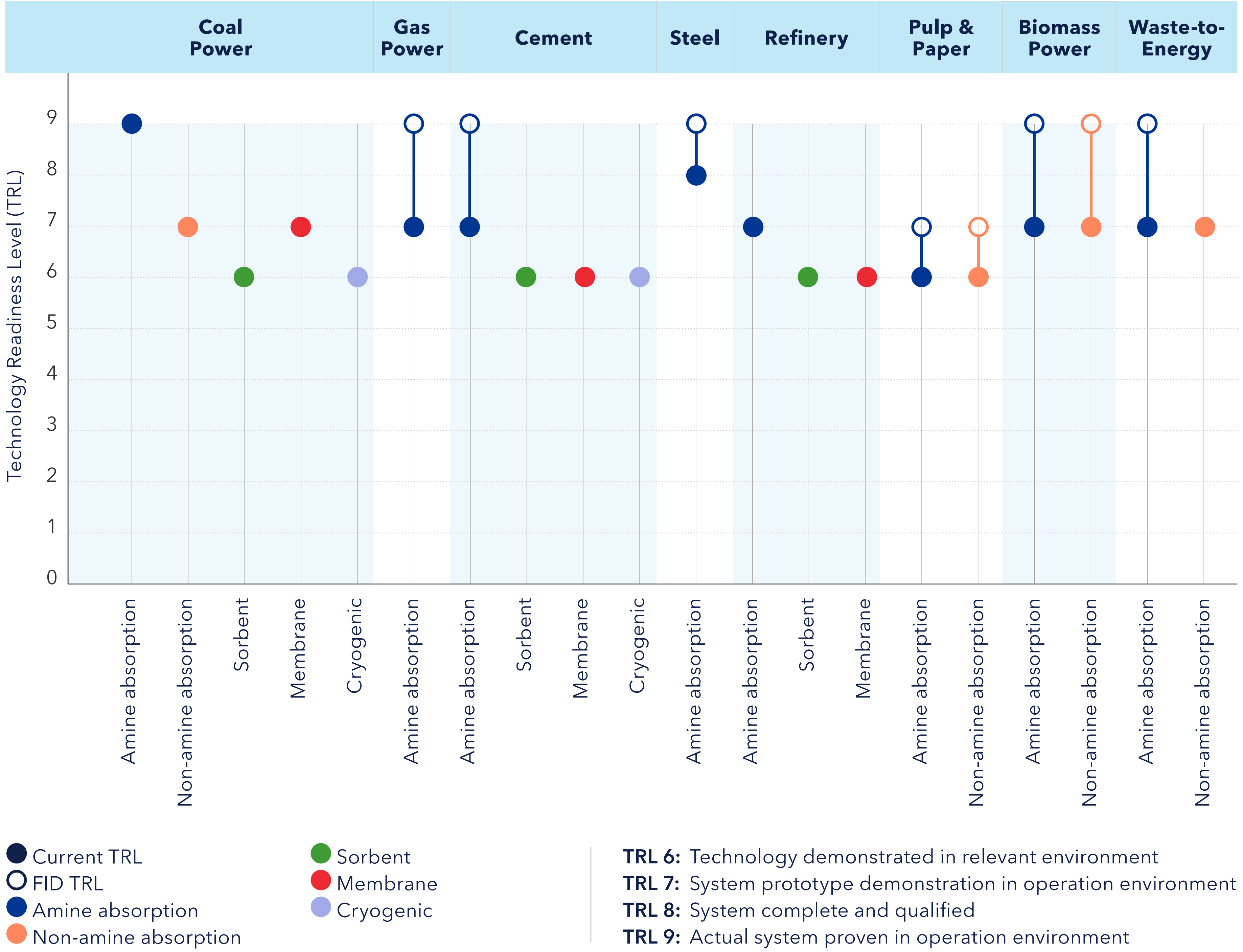
Brevik carbon capture facility at Heidelberg Materials cement plant in Brevik, Norway. Photo: Heidelberg Materials AG.

When assessing technical maturity, it is important to consider both the capture technology itself and the application in which it will be deployed. For example, amine absorption has been demonstrated at a commercial scale for coal power capture, but not on aluminium smelters, which present different technical challenges.

Amine absorption is the most mature technology for commercial scale carbon capture from most emission sources. However, concerns remain around the capital intensity, energy consumption, environmental impact, and solvent degradation of this technology.

Research and development efforts are focused on both improving amine technologies and maturing alternative capture technologies. A robust technology selection process is critical to successful capture projects. Key selection criteria such as flue gas characteristics, including CO_2 concentration and impurity levels, must be aligned with the operational envelope of the capture technology. Site characteristics – including availability of space and utility systems – must also be considered. For example, amine absorption systems require a low pressure steam for regeneration, which is more readily available in industries such as power generation than in others such as cement production.

The feasibility of capture technologies has been demonstrated in a variety of sectors



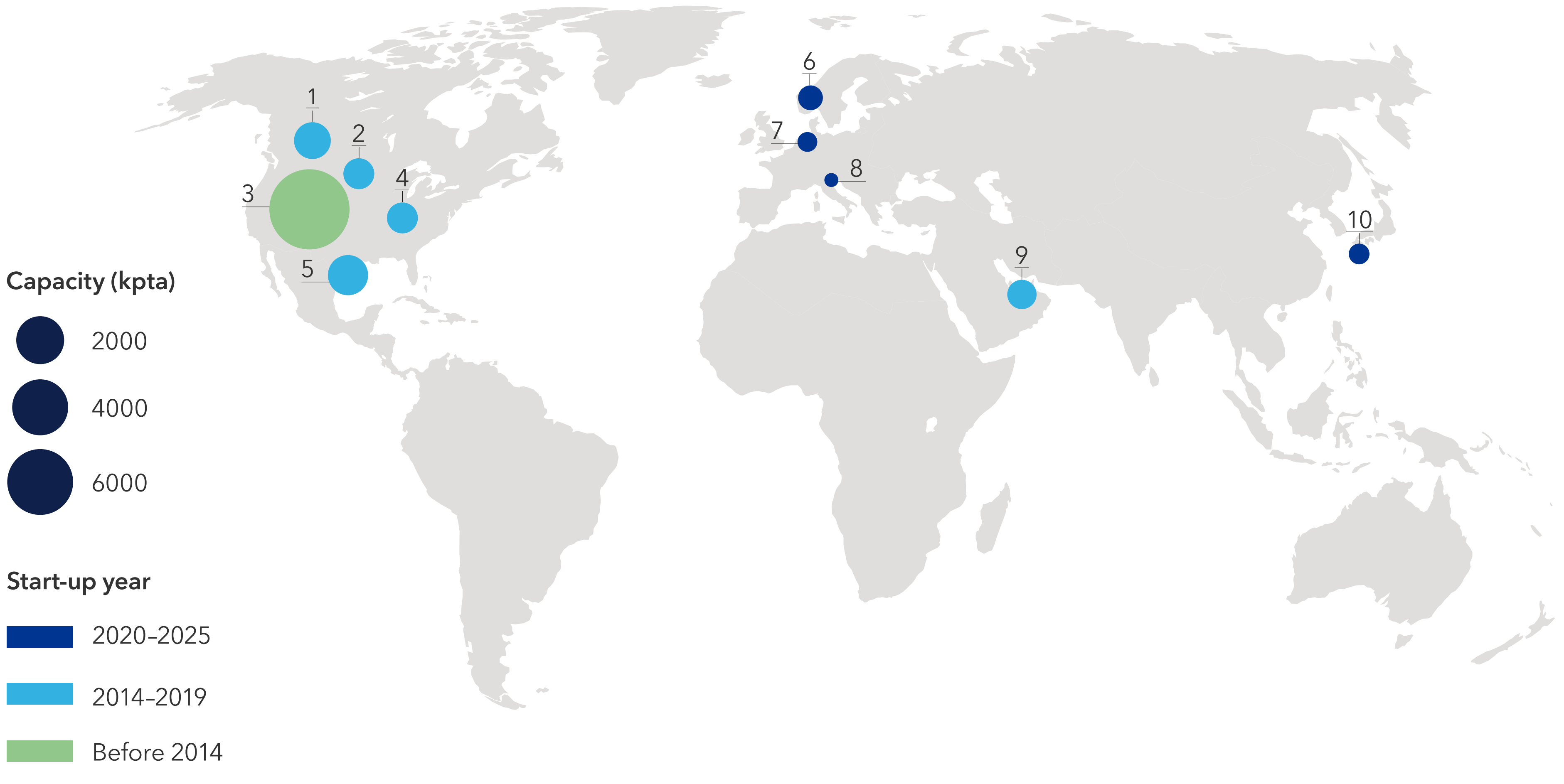
Technology readiness level as of Q1 2025.
Capture Technology Readiness Level by Application & Technology, EU H2020 TRL Scale.

Reference facilities

Selected operational capture reference facilities in various industries

Nr	Name and Location	Industry	Design Capacity (ktpa)	Technology	Start-up year
1	Quest, Canada	Hydrogen	1 200	Amine, Shell Adip-X	2015
2	Boundary Dam, Canada	Coal Power	1 000	Amine, Shell Cansolv	2014
3	Shute Creek, US	Natural Gas Processing	9 100	Physical Solvent, Selexol	1986
4	ADM Illinois, US	Ethanol	1 000	Inherent	2017
5	Petra Nova, US	Coal Power	1 700	Amine, MHI	2017
6	Heidelberg Materials Brevik, Norway	Cement	400	Amine, Capturi	2025 (in commissioning)
7	Twence, Netherlands	Waste-to-Energy	100	Amine, Capturi	2025
8	Ravenna, Italy	Gas Turbine	25	Amine, MHI	2024
9	Al Reyadah, UAE	Steel	800	Amine, MEA	2016
10	Mikawa, Japan	Biomass Energy	180	Amine, Toshiba	2020

Mature capture technologies have been deployed across various industries



Capture deployment and reference facilities

The majority of CO_2 capture deployment up to 2030 will utilize amine absorption capture technologies due to their relative maturity and established commercial-scale deployment in several industries. However, over the same period, we expect the market share of non-amine technologies to increase.

Recent trends show region-specific and industry-specific technology trends emerging, such as the use of hot potassium carbonate chemical absorption in Europe and cryogenic capture in the cement industry. Flagship operational or commissioning capture facilities in many common capture applications are summarized in the table above.

Capturing (industrial) biogenic CO_2 emissions, those that originate from the natural carbon cycle, uses identical capture technologies as fossil or process-based CO_2 emissions. This is known as bioenergy with CCS (BECCS) and is an important carbon dioxide removal (CDR) technology. BECCS is gaining significant momentum due to the revenue opportunities from credit generation in both compliance-driven and voluntary carbon markets. BECCS with ethanol production, supported by the 45Q tax credit (detailed in Section 4.1), is a rapid growth area in North America, while in Europe numerous BECCS projects are being developed at waste-to-energy, bioenergy, and biomethane facilities.

CO_2 capture can be complementary to other decarbonization measures, most notably through the production of low-carbon hydrogen. In this process, fossil-fuel-derived hydrogen, produced by natural gas reforming or coal gasification processes, is coupled with carbon capture to reduce the carbon intensity of the produced hydrogen. The Quest CCS project, operated by Shell in Canada, is a notable operational example. It uses a chemical solvent and has been operational since 2015 with a capacity of 1.4 $MtCO_2$/yr (Duong, 2019).

Reducing costs and delivering performance

CO_2 capture, as well as compression and liquefaction to prepare CO_2 for transport, are all energy-intensive processes. This is the largest contributor to the operating cost of a capture project, often referred to as the 'energy penalty'. The form and quantity of energy required will vary between technologies and applications. For example, amine capture systems require thermal energy to regenerate the solvent. This energy is often provided from fossil fuel sources and can decrease the net avoided CO_2 emissions.

The gap between CO_2 captured and CO_2 avoided can be reduced by including the energy source emissions within the boundary of the capture project or by implementing electrification, heat recovery, and energy efficiency measures to reduce the emission intensity of the energy source. Reducing the energy penalty remains a priority for capture technology development, and improvements in materials, processes, and site integration strategies all show promise.

The partial pressure and concentration of the CO_2 in the inlet stream are also primary cost drivers. Due to low chemical and physical driving forces, achieving very high capture rates (the percentage of CO_2 entering the capture system that is separated and removed) can require significant additional energy input and can also increase CAPEX through unit sizing.

Targeted capture rates have steadily increased over the last decade. A capture rate of 90% is now typically considered the minimum standard for point sources, with higher rates of 95% or above increasingly targeted. The UK *Dispatchable Power Agreement* business model for CCS in gas power generation is a recent example (BEIS, 2022). For current amine technologies, we expect no or modest cost increases when moving from a 90% to 95% capture rate, with some analysis even predicting marginally lower costs at 95% (NETL, 2022) (Global CCS Institute, 2025). However, costs will increase significantly and non-linearly as capture rates approach 100%, driven by substantial increases in the energy required to regenerate the solvent. This is demonstrated at pilot scale with the CESAR1 solvent (Morlando, 2024; Benquet, 2021).

Modularization is an increasingly popular pathway for capture cost reduction. Modular plants use standardized designs and parts, are constructed off site, and can be scaled up by replication. This reduces costs and project delivery times through economies of scale, supply chain simplification, and transferable experience. This trend is currently most prevalent in amine absorption technologies but is also expected to help accelerate the maturation of alternative technologies, such as adsorption and membrane capture.

Capture technologies can be applied in both retrofit and new-build applications. Retrofit applications can benefit from existing infrastructure in some cases, but often face challenges with footprint, integration complexity, and parasitic loads on the host emitter facility. Building CCS into new facilities also has benefits, including heat recovery opportunities, where excess heat from one process is utilized in another. However, new-build applications may face increased total investment costs, lengthy permitting processes, and increased public scrutiny.

Connecting capture and transport

To ensure the integrity and efficiency of CO_2 transport and storage networks, capture plants must achieve a particular CO_2 purity specification that often requires additional treatment and purification. The purity of the CO_2 stream produced by capture systems is typically above 90 mol% CO_2, with some technologies able to achieve far higher purities. However, trace impurities from the flue gas and the capture process can still be present. These can pose integrity risks and operational challenges to CO_2 transport and storage networks.

Achieving the required purity specification almost always requires additional CO_2 treatment and purification. While treatment units for dehydration and oxygen removal are widely demonstrated in other gas processing industries, challenges remain in the online measurement of CO_2 quality and the removal of other impurities such as NO_X.


Northern Lights receiving terminal, Øygarden, Norway. Photo: Ruben Soltvedt / Northern Lights.

At the interface between the capture system and the transport and storage network, CO_2 must be compressed and/or liquified. The required phase and conditions of the product CO_2 will depend on the transport network type. CO_2 compression has been demonstrated widely in North America both in enhanced oil recovery (EOR) networks and in commercial-scale capture facilities such as Petra Nova (1.7 $MtCO_2$/yr). Commercial-scale liquefaction is less mature, and typically more expensive due to the need for additional equipment such as purification units and liquid buffer storage. The Heidelberg Materials Brevik cement capture project, currently in commissioning, will demonstrate liquefaction for transport by ship at a scale of 0.4 $MtCO_2$/yr.

Direct Air Capture (DAC)

Solid-sorbent, liquid-solvent, and emerging DAC technologies
DAC is a promising CDR technology due to its flexibility and ability to remove CO_2 directly from the air. Two leading DAC technologies are readily scalable: solid-sorbent and liquid-solvent DAC (IEA, 2022). In the solid-sorbent method, solid adsorbents selectively capture CO_2 from the air, which is then released using changes in temperature, pressure, or humidity. The sorbent is regenerated at 80–120°C with minimal degradation, enabling continuous reuse.

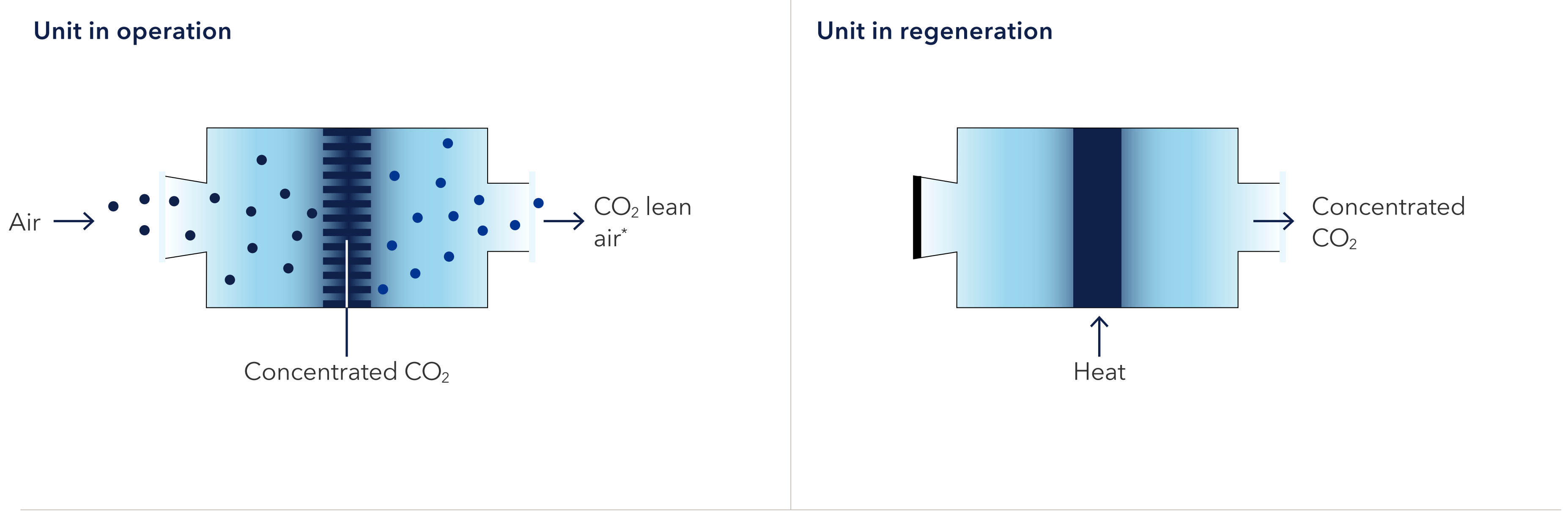
The liquid-solvent method uses strong hydroxide solutions (e.g. potassium hydroxide) to absorb CO_2, which then reacts with calcium to form calcium carbonate. To release CO_2, high temperatures (900°C) are required.

Several emerging DAC technologies are in the early stages of development, such as electro-swing adsorption (Voskian et al., 2019) and membrane-based separation (Fujikawa et al., 2022). These emerging approaches offer certain advantages to help solve several challenges of traditional DAC technologies. For example, electro-swing adsorption directly uses electrons for sorbent regeneration, potentially yielding higher energy efficiencies. However, many emerging DAC techniques have only been tested in laboratory settings and have lower technology readiness levels (TRL).

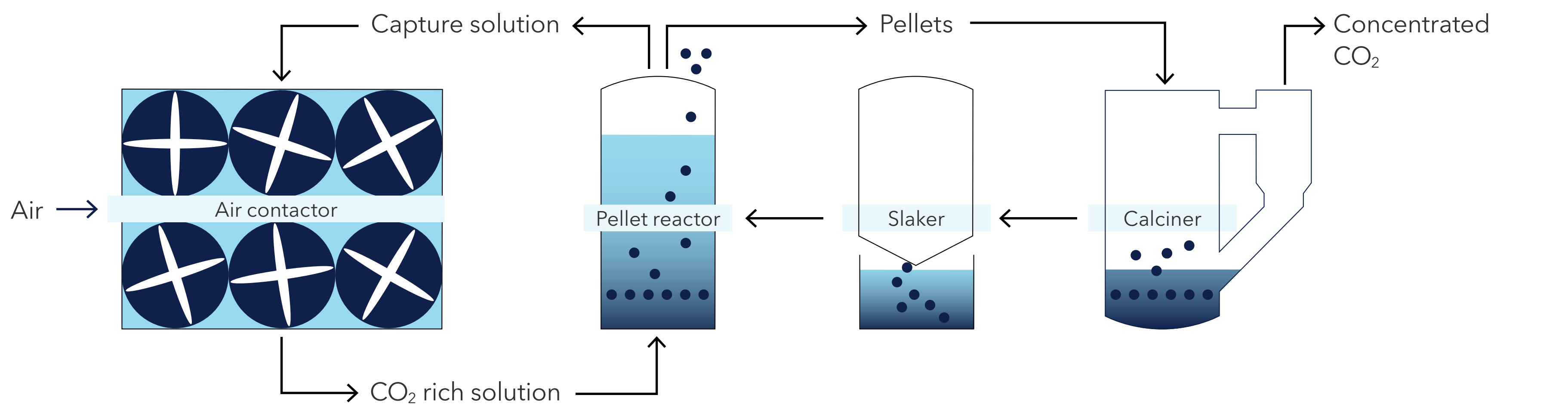
> DAC is a promising CDR technology due to its flexibility and ability to remove CO_2 directly from the air.

Schematic of solid-sorbent DAC and liquid-solvent DAC

Solid-sorbent DAC



Liquid-solvent DAC



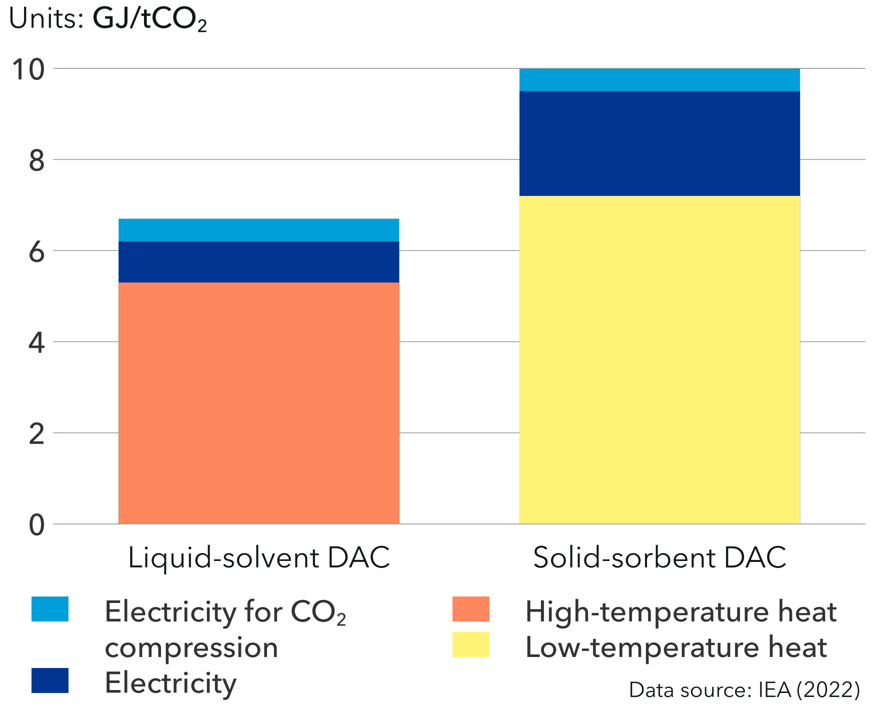
Air is drawn into the collector where the CO_2 is captured by a filter. Once the filter is saturated, the collector is closed and heated to release the captured CO_2 (regeneration). *Very low CO_2 concentration.

Energy requirements

One of the main challenges with DAC is the amount of energy required due to the low concentration of CO_2 in the atmosphere. Most DAC technologies require both electricity and heat (Figure 2.1). Electricity is needed for the fans to pull the air through the system, for pumps, CO_2 treatment, and to operate other auxiliaries. Heat is required for the desorption in solid-sorbent DAC and to regenerate the solvent for liquid-solvent DAC. For solid-sorbent DAC, which requires relatively low temperatures, it is possible to use a variety of renewable energy sources. For liquid-solvent DAC, on the other hand, natural gas or hydrogen are currently the main options for the heat supply. However, researchers are developing ways to electrify the calcination process.

FIGURE 2.1

Energy use of DAC



Data source: IEA (2022)

Carbon balance

The source of heat and electricity will influence the carbon removal efficiency or the net flux of carbon. If renewable electricity is used, carbon removal efficiency can be up to 97% (IEA, 2022). However, if natural gas is used without capturing the CO_2, carbon removal efficiency can drop to 60% (IEA, 2022).

Water balance

DAC plants can both produce and consume water. For solid-sorbent DAC, many of the adsorbents have an affinity for water, so they capture water along with CO_2. In both solid-sorbent and liquid-solvent DAC, the amount of water produced depends on the humidity of the air. In dry areas, water will evaporate in the liquid-solvent contactors, leading to a water deficit that needs to be replenished. In humid areas, the situation will be the reverse, i.e. water accumulates in the system and needs to be removed through evaporation.

Land use

The footprint of DAC will depend on the layout. While the collectors require space between them, this can be used for other purposes. The current land use estimates for capturing 1 $MtCO_2$/yr from air for liquid-solvent DAC is around 0.4 km^2, while a solid-sorbent DAC facility would require 0.9 km^2 (Webb et al., 2023). If the source of energy is included, the footprint could increase substantially.

Scalability and cost reduction

Different DAC technologies require distinct approaches to scaling up. Solid-sorbent DAC, which has a modular design, benefits from economies of volume manufacturing, where mass production of smaller units reduces costs over time. Further research and development on high-efficiency sorbent materials – e.g. metal-organic frameworks (MOFs) and porous polymers – with improved CO_2 capture and reduced degradation is crucial to the adoption of solid-sorbent DAC at scale.

In contrast, centralized DAC plants, like liquid-solvent DAC, rely on economies of scale, where larger facilities lower costs by processing higher volumes of CO_2 more efficiently. As DAC adoption grows, continued innovation and optimization will be crucial to improving affordability and accessibility.

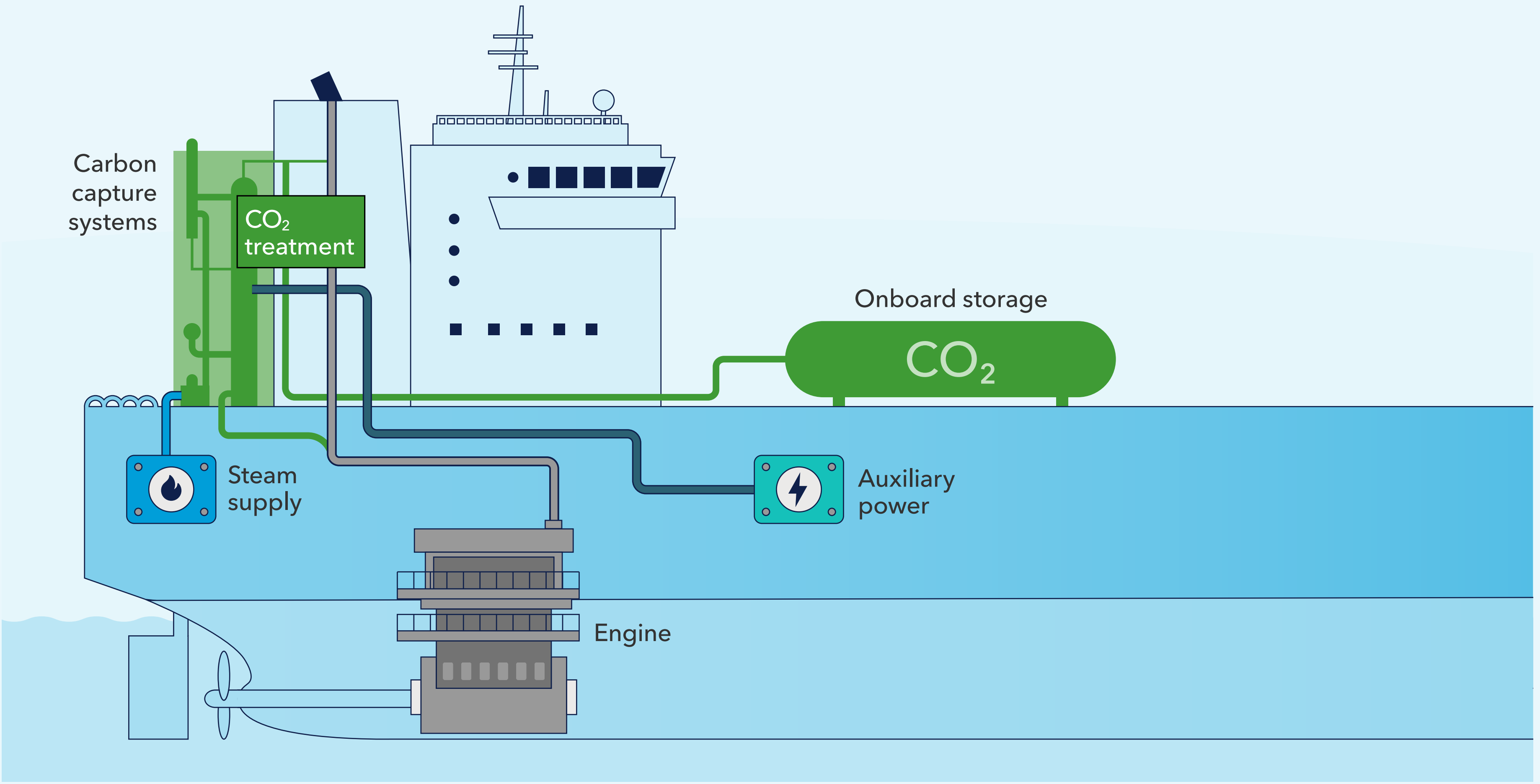
Climeworks' direct air capture and storage plant in Iceland. © 2024 Climeworks AG.

Onboard CCS

While many efforts to reduce greenhouse gas (GHG) emissions from shipping focus on switching to carbon-neutral fuels, another option is to capture the CO_2 produced by carbon-based fuels – whether fossil or carbon-neutral – and store it underground or use it in industrial processes approved by emission regulations.

Onboard carbon capture is based on technology that captures the carbon in the ship exhaust gas before it is emitted into the atmosphere. This can lead to significant emission reductions but requires additional energy and storage space.

Simplified subsystems in an onboard carbon capture system



The key technical and practical factors that affect the feasibility of onboard carbon capture for a dedicated ship are: size, operational profile / trading pattern, the machinery capacity for power and heat production, and the space available. One way to balance the trade-off between high capture rate and low fuel penalty (the additional fuel required to operate the capture system) is to optimize the capture rate according to the ship's operational profile and the availability of CO_2 offloading facilities along the way. Capture technology integration with the rest of the ship machinery system is essential to enhance the overall performance and reduce the fuel penalty. For newbuilds, the system can be optimized to minimize fuel consumption and to accommodate the system to the ship. Not all existing ships will be relevant candidates for retrofits due to the space and heat required to operate the system.

The application and uptake of onboard carbon capture technology on vessels is dependent on cost and price factors such as the capital costs of the system, fuel penalty level, operating costs, loss of cargo carrying capacity, and CO_2 discharge and storage costs, as well as economic factors like carbon pricing and fuel prices. Uptake also depends on the establishment of infrastructure for discharge and safe storage of CO_2 on a global (or regional) level.

Regulatory factors will also influence uptake. Today, only the EU Emissions Trading System (ETS) has adopted a regulatory framework that provides incentives for the use of carbon capture on board ships. However, the International Maritime Organization's MEPC 83 agreed to a work plan for the development of a regulatory framework for the use of onboard carbon capture. The work is set to be finalized in 2028 (IMO, 2025). The EU will also consider including onboard carbon capture in the next review of the *FuelEU Maritime* regulations (DNV, 2024b).

The *Maritime Forecast to 2050* (DNV, 2023a) evaluated the commercial feasibility of onboard carbon capture against carbon-neutral fuel alternatives for a 15,000 TEU container vessel. The study compared four fuel strategies (fuel oil, LNG, methanol, and ammonia) against onboard carbon capture with a 70% capture rate. The case study showed that onboard carbon capture was economically viable for a low-cost scenario (15% fuel penalty and deposit cost of USD 40/tCO_2) and competitive for a high-cost scenario (30% fuel penalty and deposit cost of USD 80/tCO_2)

For more information regarding onboard carbon capture, see DNV's whitepaper *The potential of onboard carbon capture in shipping* (DNV, 2024b).

2.2 TRANSPORT

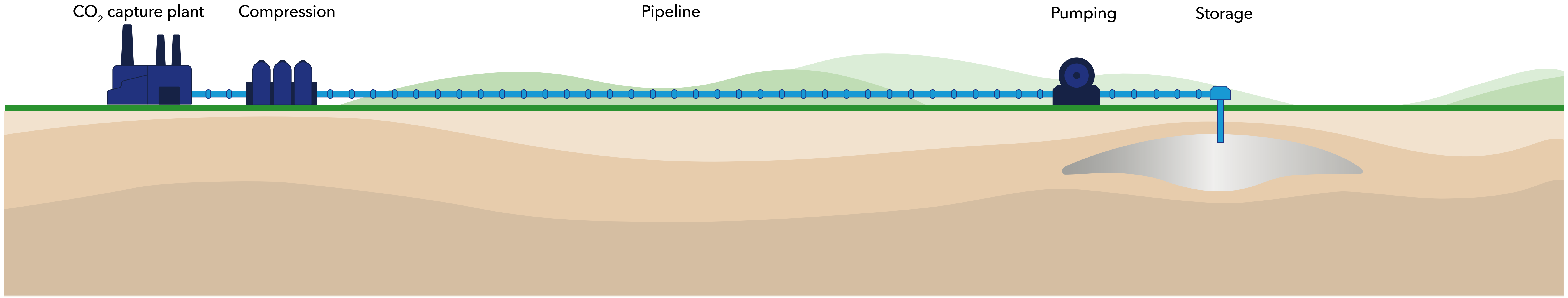
CO_2 transport is a critical component of the CCS value chain. It can be accomplished through pipelines, ships, trains, and trucks. Each method presents unique challenges that must be assessed based on parameters such as distance, terrain, and mass flow rate. In some situations, a multimodal approach that combines two or more transport methods offers the most effective solution.

Pipelines

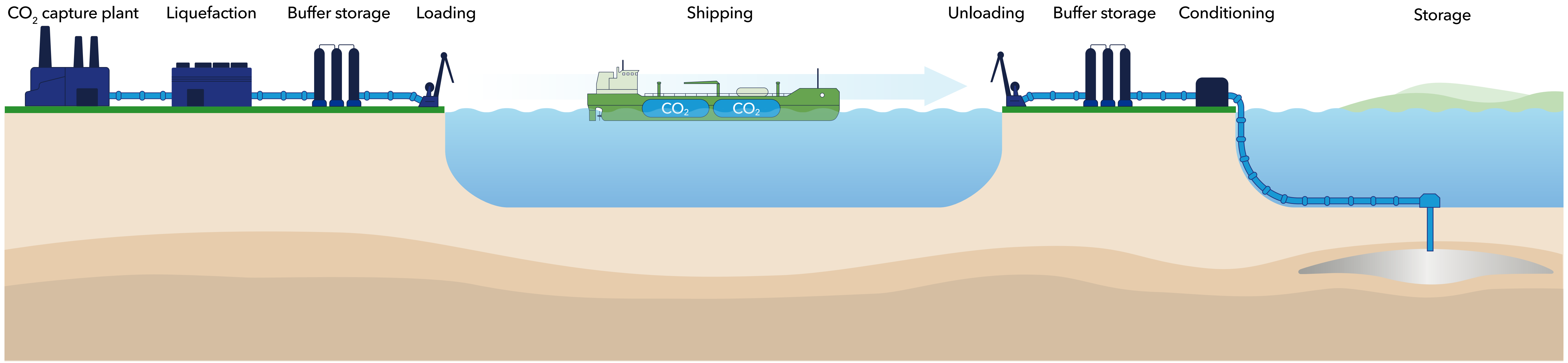
Pipelines have been used to transport CO_2 since the 1970s in the US, primarily for EOR purposes. Over 8,000 km of CO_2 pipelines are operational in the US today, making this a well-established technology. The typical pipeline value chain is relatively simple, involving the compression of CO_2 and the pipeline infrastructure itself.

There are two different conditions under which CO_2 can be transported: dense phase and gas phase. Dense phase transport (where CO_2 is maintained either in liquid or supercritical state), is preferred for high-volume, long-distance applications. Gas phase transport is generally employed for specific applications such as repurposed pipelines, early-stage operations with lower volumes, or certain onshore applications like those in urban areas. International standards generally recommend maintaining CO_2 entirely in either dense or gas phase during pipeline transport. Since temperature control is limited, pressure becomes the primary means to achieve the

Pipeline value chain



Shipping value chain (shore-to-shore configuration)



necessary thermodynamic conditions: dense phase operations typically require pressures above 80 bar, while gas phase conditions are maintained below 50 bar, depending on ambient temperature.

Shipping

Shipping CO_2 in the liquid phase for the food and beverage industry has been practiced since the late 1980s, but in considerably smaller volumes than will be relevant for CCS.

A ship-based CCS infrastructure is different to a pipeline infrastructure largely due to the fact that ship-based CO_2 transport occurs in batches. This leads to some key implications. First, CO_2 must be transported in liquid form to minimize volume and reduce the ship size required. Second, buffer storage is essential to accumulate sufficient volumes of CO_2 for the ship capacity and logistics.

As a result, the shipping value chain is more complex than pipeline transport. It generally requires a liquefaction unit, buffer storage at both departure and arrival points, specialized vessels, and usually an additional conditioning stage before final storage. The CO_2 can either be transported to a shore-based terminal or to an offshore facility where it is injected either into the reservoir directly from the ship or through a moored or fixed offshore structure.

An alternative option to carrying the CO_2 in a liquid state may be to transport it as dry ice. This could allow for the utilization of existing logistics infrastructure such as containers. However, this would also impact the rest of the CCS infrastructure.

Shipping CO_2 is often categorized in terms of operating and design pressure – low pressure, medium pressure, and high pressure. The pressure regimes have different temperatures, pressures, and density (Table 2.1). These regimes influence the ship design and liquefaction and conditioning costs, which ultimately impact the overall costs. The required ship size for the given trade and length of the voyage is a key factor in selecting pressure. Low pressure value chains generally allow for larger cargo tanks and larger vessels, which reduces shipping costs compared to medium pressure. The main benefit of high pressure is the reduced cost for liquefaction and conditioning. With a high-pressure vessel, however, the cargo containment system will be heavier and the density of the CO_2 is lower than for lower pressure conditions (low/medium pressure and low temperature).

TABLE 2.1
Pressure and temperature regimes for liquid CO_2 cargo tank designs[a]

Cargo designation	Cargo vapour pressure (operation) bara	Equilibrium temperature[a] °C	Density of liquid CO_2[a] kg/m³	Density of vapour CO_2[a] kg/m³
Low pressure	5.7 to 10	-54.3 to -40.1	1 170 to 1 117	15 to 26
Medium pressure	14 to 19	-30.5 to -21.2	1 078 to 1 037	36 to 50
High pressure	40 and above	5.3 and above	894 and lower	116 and higher

[a] Applies for pure CO_2 and properties taken from National Institute of Standards and Technology (NIST) database. Properties will depend on the other components in the CO_2 stream.

Source: International Organization for Standardization (2024)

Trains and trucks

For small-scale projects or scenarios with pre-existing infrastructure, trains or trucks can be viable transport solutions. Trains produce lower emissions but are limited by fixed infrastructure. In contrast, trucks provide greater operational flexibility but tend to generate higher emissions. Trains and trucks feature a value chain very similar to the ship-based one: they both make use of insulated but not refrigerated tanks and usually transport under low or medium pressure regimes.

Overall, the choice of transport method is dictated by a combination of technical, economic, and logistical factors. As the CCS sector continues to evolve, we see a variety of transport solutions being adopted. In some cases, multiple modes of transport will be used within a single value chain.

CO_2 transport ship, Northern Pathfinder. Photo: Northern Lights.

2.3 STORAGE

CO_2 storage requires the injection of CO_2 deep underground, where it must remain permanently. The most common and efficient method of permanent CO_2 storage is within basins comprised of sedimentary rocks. There are two main types of storage settings within such basins:

1. Depleted oil and gas fields
2. Deep saline aquifers

Repurposing depleted oil and gas fields for permanent CO_2 storage offers several advantages. These locations have proven subsurface traps and seals that have already retained hydrocarbon accumulations for millions of years and they are well-characterized after years of exploration, appraisal, and operation. This provides operators with extensive knowledge that reduces uncertainty regarding capacity, injectivity, and containment. Existing infrastructure can also be repurposed. For example, hydrocarbon production wells can sometimes be converted into CO_2 injection wells, potentially reducing costs. However, any repurposed infrastructure must be suitable beyond the operational life for which it was originally designed and be compatible with CO_2.

Depleted fields also present challenges for CO_2 storage including limited capacity, containment risks, and monitoring difficulties. The storage capacity of individual depleted fields is generally more limited than saline aquifer options. Injected CO_2 can fill the available pore space previously occupied by trapped hydrocarbon accumulations, but years of hydrocarbon production may have negatively impacted the reservoir and sealing formations and their suitability for CO_2 storage. The greatest CO_2 containment risk is also often attributed to pre-existing (legacy) wells, which represent potential leakage paths. If needed, remediating wells to ensure CO_2 compatibility and modifying platforms and pipelines can be costly. With respect to CO_2 monitoring, the residual hydrocarbons within the depleted field may inhibit the effectiveness of geophysical monitoring solutions, such as seismic surveys, making it more difficult to detect the injected CO_2.

The second type of storage is deep saline aquifers. These are underground formations composed of porous and permeable rocks saturated with water that is typically much saltier than seawater and unsuitable for drinking. An advantage of CO_2 storage in saline aquifers is that they have not been used for fossil fuel extraction except in cases where they share the same formation as neighbouring oil and gas fields and the subsurface environment (e.g. formation pressure) has been altered. Additionally, saline aquifer storage locations typically host fewer wellbore penetrations, which reduces the number of potential well-related leakage pathways. From a capacity standpoint, saline aquifers have greater flexibility because they represent a much larger segment of available pore space than oil and gas fields. Another benefit is that the feasibility of detecting and monitoring CO_2 injected into a saline aquifer using seismic surveys is generally better than in depleted field locations in which the CO_2 shares pore space with residual hydrocarbons. However, there are also disadvantages to consider. New infrastructure and storage wells will be necessary, which may increase costs compared with depleted field projects that repurpose infrastructure. Additionally, the storage performance of saline aquifers is initially less certain due to limited data availability from fewer wellbore penetrations and the lack of evidence that the intended trap and seal is viable. Such uncertainty can be mitigated through pilot projects, data collection, and testing at the beginning of the project and will continue to reduce over the project's lifespan.

Another way CO_2 can be stored underground is through CO_2 EOR. Although this is considered a form of utilization, much of the CO_2 remains trapped and permanently stored in the subsurface. EOR has

Storage projects

US: Saline aquifers account for approximately 80% of the total estimated geologic storage capacity in the US, whereas depleted hydrocarbon fields make up about 20% (NETL, 2015). However, 59% of the CO_2 captured from industrial processes and nearly all the CO_2 produced from natural sources (i.e. extracts from natural subsurface CO_2-bearing formations) are utilized for EOR in the US (EPA, 2021).

Europe: In some parts of Europe, there is a strong preference for saline aquifers near hydrocarbon fields (e.g. the proximity of the Northern Lights project in Norway to the Troll field), but storage potential in depleted fields exists as well (e.g. Greensand CCS project, Porthos CCS project, Aramis project).

APAC: A number of projects in this region are designed to store CO_2 in depleted hydrocarbon fields, including Duyong Petronas CCS in Malaysia, as well as Moomba Santos CCS and Angel Woodside CCS in Australia. Until recently, the SEA Exxon CCS project was among these (EPBC Act Public Portal, 2025), but it has been put on hold. On the other hand, the Gorgon CCS project (Chevron Gorgon CCS, 2025) has been storing CO_2 in a saline aquifer on Barrow Island in northwestern Australia since 2019. While it has faced criticism for not achieving targets, the project remains the largest commercial CCS project and CO_2 injection operation in the world.

been carried out mostly in the US and the Middle East since the 1970s, where injected CO_2 is used to extract additional oil from a mature field after the primary and secondary recovery methods have been exhausted. Produced CO_2 can then be separated from the oil and either recycled for continued EOR or vented. The experience gained from EOR has strengthened understanding of CO_2 storage in the subsurface, as well as the handling of large volumes of CO_2.

Carbfix on-site storage at Climeworks' Mammoth plant in Iceland. © 2024 Climeworks AG.

What about carbon mineralization?

Below-ground:

Carbfix in Iceland is pioneering a below-ground method of carbon storage known as 'in-situ CO_2 mineralization'. The captured CO_2 is first dissolved in water at the surface, to create a carbonated water solution. This solution is then injected into basaltic rock formations deep underground. Once in the basalt, the CO_2 reacts with minerals like calcium, magnesium, and iron to form stable carbonate minerals. This effectively turns the reacting CO_2 into solid minerals, permanently storing it within the rock. This method is particularly promising, but may be more difficult to implement and may benefit from more testing, since basaltic formations are less common than sedimentary rocks (i.e. those that host depleted oil and gas fields or saline aquifers).

Above-ground:

Above-ground carbon mineralization involves accelerating natural stable carbonate formation processes which result from CO_2 reactions with various minerals. There are three main types:

1. Ex-situ mineralization involves the production of carbonated aggregates, such as those used in low-carbon concrete. In this method, CO_2 is combined with an alkaline feedstock – e.g. mine tailings or industrial by-products – under high pressure and temperature to form stable carbonates.
2. Surficial mineralization occurs passively on land, coastlines, or oceans. CO_2 reacts with an alkaline feedstock, which is a basic, water-soluble material. The reaction can be accelerated by increasing the surface area of the mineral, e.g. by grinding certain rock-types into dust. This dust can be spread on agricultural soil, fields, forests, or along coastlines, where it reacts with CO_2 and stores it as carbonates.
3. Industrial by-product mineralization uses materials such as slag from steel production to capture and store CO_2. The by-products are treated with CO_2 to form stable carbonates, effectively sequestering the carbon and repurposing waste materials.

At present, the most efficient method for storing large volumes of CO_2 is permanent subsurface storage in geological formations, such as depleted fields and deep saline aquifers.

The experience gained from EOR has strengthened understanding of CO_2 storage in the subsurface, as well as the handling of large volumes of CO_2.

2.4 COSTS

The CCS industry is shifting towards a model where emitters are primarily responsible for capture facilities and will pay dedicated operators a tariff to oversee CO_2 transport and storage. The reasons behind this trend will be explored in more detail in Section 2.5.

Capture

Capture costs per tonne of CO_2 vary widely, reflecting the large range of applications in which it can be used. Factors influencing capture costs include CO_2 concentration, the scale of the capture facility, the transport method, and site-specific conditions.

It is important to distinguish between the cost of CO_2 captured (COC) and the cost of CO_2 avoided (COA) (i.e. the cost of reducing a tonne of CO_2 emissions, considering the entire system). These can differ significantly due to the emissions related to operating the capture plant, such as regeneration energy. The COA considers the net emissions reduction and will be higher than the COC: for example, around 25% higher according to a US study on a gas power plant (NETL, 2022). This conversion from COC to COA depends on both the energy demand and the carbon intensity of the energy source. As this varies widely between projects and regions, the COC is examined in this section.

The concentration or partial pressure of CO_2 within the gas stream entering the capture plant is an important cost driver because it influences the type of capture technology and the type and size of process equipment selected. Typically, higher CO_2 concentrations will deliver lower capture costs. For example, capturing CO_2 from bioethanol production costs USD 30 to 36/tCO_2 (greater than 90 mol% CO_2), compared to USD 60 to 120/tCO_2 from power generation (3-15 mol% CO_2) (IEA, 2020).

The scale of the capture facility also impacts costs. Larger facilities can leverage economies of scale, reducing process equipment capital cost. This is particularly important for low CO_2 concentration applications that process large volumes of flue gas. A study by the Global CCS Institute found that natural gas power (4 mol% CO_2) capture costs decreased from USD 120/tCO_2 to USD 75/tCO_2 as capture capacity increased from 0.07 to 0.66 MtCO_2/yr (Global CCS Institute, 2025). Operating costs, often dominated by energy consumption, tend to scale more linearly with capture capacity.

> It is important to distinguish between cost of CO_2 captured (COC) and cost of CO_2 avoided (COA).

The recent trend towards modular capture systems (Section 2.1) may offer a different cost relationship compared to bespoke capture plant designs. Standardized modular units could reduce costs for small-to-medium scale plants, but as capture capacity increases, we expect costs to scale more linearly. This is because increased capture capacities are achieved by replicating modular units. Other site-specific factors influencing capture costs include whether the capture plant is being retrofitted to an existing facility or is part of a new build project, the availability of utilities such as steam and cooling water, and regional labour and material market prices.

We expect capture plants producing liquefied CO_2 to be transported by ship, rail, or truck to incur higher capture costs than those compressing CO_2 for pipeline transport. This is because of the additional equipment requirements, including liquid buffer storage, and higher energy consumption.

Energy is typically the dominant operating cost in capture processes, with capture technologies requiring significant amounts of heat, electricity, or both. The main pathways to reduce energy OPEX are process and material improvements and enhanced site integration, such as waste-heat recovery from warm flue gasses.

In most CCS value chains, we expect capture to carry higher costs than transport and storage. The exceptions to this trend include cases with complex multimodal transport concepts or with very low capture costs, such as those with high CO_2 concentration flue gases typical of bioethanol production.

Transport

Accurate cost calculations for CO_2 transport facilities are impossible for a general case because transport costs tend to increase with the distance between the emitter and the storage site, the volume, the selected transport method, and other parameters. Nevertheless, a reasonable cost for compression and pipeline transport may range from USD 6 to 28/tCO_2, while transport by ship, train, and truck tend to suffer somewhat higher costs. In addition, pipeline transport is largely CAPEX driven, while train and truck transport is largely OPEX driven. Ship transportation has a more balanced split between CAPEX and OPEX. Usually, when multiple solutions are viable, the choice is made based on economic considerations.

Transport costs vary significantly depending on several factors such as transport mode, distance, fluid phase (gas/dense), mass flow rate, terrain, and region. Although transport costs will be project specific, there are some general trends.

The transport method is a key cost driver. This choice will be driven by a combination of the economic, technical, and regulatory factors discussed in Section 2.2. Generally, pipeline transport is more cost effective for large volumes (several Mt/yr) of CO_2 over short-to-medium distances (up to a few hundred kilometres). Liquid CO_2 transport methods, such as shipping, are more cost efficient for longer distances, geographically dispersed emitters, and lower CO_2 volumes. Multimodal transport concepts will incur higher costs than single stage transport networks.