Carbon capture and storage: What can we learn from the project track record?

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CLEAN AIR TASK FORCE

Table of Contents

Executive Summary

Carbon capture and storage (CCS) is a pollution control technology that can be used to prevent the emission of CO_2 to the atmosphere, permanently storing it deep below the Earth's surface. The technology can also remove historic CO_2 emissions directly from the air. Meeting international commitments to limit global warming will require billions of tonnes of CO_2 capture and geologic storage by midcentury – a scale many times greater than seen today. While components of CCS have been available for decades, policies to drive its application to mitigate climate change are newer, and the scope of these policies has grown in recent years.

This report examines 13 significant projects that have employed CCS technologies at a large scale. Several of these projects have captured and stored CO_2 primarily for commercial motives, such as increasing oil production. Some have sought to demonstrate new or existing technologies in a specific industry or at larger scales, or to gain experience with particular storage geologies. Relatively few have been required to adopt CCS to meet a regulatory requirement. The technical performance and operational challenges recorded by each of these projects are summarised and placed within the context of the diverse motivating factors behind their development.

Based on these case studies, the report highlights the following key points:

- Several large-scale projects, including Sleipner, the Alberta Carbon Trunk Line, and Quest have consistently met high levels of technical performance, demonstrating an achievable standard that should – and must – be built upon by an increasing proportion of projects so climate goals remain in reach.
- Commonly cited 'large-scale' CCS projects represent a fraction of the many commercial technologies actively capturing, transporting, and storing CO_2.
- Operational experience, technological learning, and innovation can help overcome technical challenges that arise as CCS is used at larger scales or in more diverse applications. Several large-scale CCS projects have been developed primarily to gain such experience and have led to clear improvements in reliability and performance. Maximizing continuous technical performance, however, is often subordinate to this goal.
- To help build public confidence and accelerate technology improvements, CCS projects should be encouraged or required to report their performance data and challenges as transparently as possible.
- The right policies and regulations can ensure that new CCS projects are designed and operated to maximize their climate impact. As the current wave of planned CCS deployment is increasingly driven by climate-focused policies, project performance can be expected to steadily improve.

SECTION 1

Background

To prevent atmospheric concentrations of CO_2 reaching levels that would cause dangerous global warming, there is broad scientific consensus that the geological storage of CO_2 will play a significant role. Greenhouse gas mitigation pathways developed by the International Panel on Climate Change (IPCC) and the International Energy Agency (IEA) require on the order of several billion tonnes of CO_2 to be stored annually by 2050.[1] Technologies known as carbon capture and storage (CCS) encompass the processes by which CO_2 is separated from emissions sources, transported, and injected deep below the earth's surface for permanent storage.

The fundamental technologies that comprise carbon capture and storage have been available for decades:

- Capture – The first patents for CO_2 separation or 'carbon capture' were issued in the 1930s. By the 1960s, industries could choose from diverse commercial capture processes.[2]
- Capture – At least 160 million tonnes of CO_2 are captured every year for use in industries such as food, drink, and fertilisers.[3]
- Transport – Over 8,500 kilometres of pipelines carry CO_2 in the United States. Over the last 50 years, they have transported over 500 million tons of CO_2.[4]
- Storage – Injecting CO_2 deep underground is well understood. Over 20 million tonnes of CO_2 have been injected into dedicated geological storage sites for climate purposes in Norway since 1996. In the U.S., over 850 million metric tons have been injected safely since the 1970s for a process known as enhanced oil recovery.[5]

However, combining these technologies to combat climate change is relatively new and can be more costly. The commercial production of CO_2 has historically focused on higher purity emissions sources from which the CO_2 can be more easily separated. But to combat climate change, carbon capture must be applied to a more diverse set of industries with few alternatives to decarbonise – such as cement, steel, and petrochemicals – where the cost of CO_2 capture is often much higher. Although CO_2 has long been stored geologically as a side effect of increasing profitable oil production,

1 IPCC (2023) Working Group III contribution to the 6th assessment report of the Intergovernmental Panel on Climate Change. IEA (2023) Net zero roadmap: A global pathway to keep the 1.5°C goal in reach. International Energy Agency.

2 U.S. Patent US1783901A, *Process for separating acidic gases.*

3 IEA (2019) *Putting CO_2 to use.*

4 PHMSA (2024) *Annual report mileage for hazardous liquid or carbon dioxide systems.*

5 Hill B et al. (2013) *Geologic carbon storage through enhanced oil recovery.*

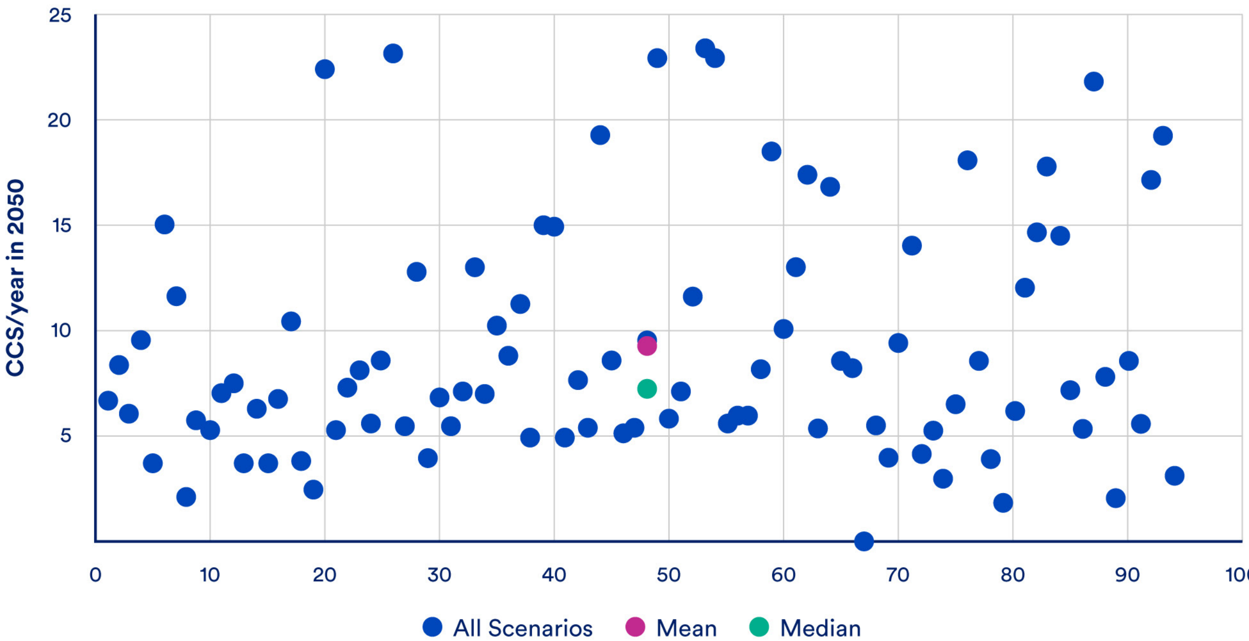
climate-oriented projects will increasingly have to store CO_2 in deep saline aquifers: essentially a waste disposal activity which only adds cost. In many cases, CO_2 transportation will also become more costly and complex, as industrial emission sources far from underground storage are required to send CO_2 to distant injection sites.

41 commercial carbon capture and storage projects are identified by the Global CCS Institute (GCCSI) as operating today; these are large-scale facilities that both capture and store the CO_2 produced by industrial facilities or fossil power plants.[6] However, most of them were not developed for climate purposes and are not required to operate in a way that minimises CO_2 emissions to the atmosphere or maximises the CO_2 they store. Many are purely commercial endeavours, where readily available by-product CO_2 could be sold to oil field operators for use in the oil production process known as enhanced oil recovery (EOR). Some have been developed to test new capture technologies, signal a corporate decarbonisation strategy, or achieve some degree of CO_2 reduction, but very few are incentivised or required to maximise their climate benefit.

At the same time, many of the component technologies that will be required for the wider application of carbon capture and storage are operating successfully and at large scale as part of facilities which do not make the GCCSI's list. The separation of CO_2 during the production of natural gas and fertiliser is commonplace, with hundreds of facilities operating worldwide. Even the capture of CO_2 from more challenging sources such as coal and gas combustion has been widely used for the production of CO_2 for its commercial use.[7] Around 80% of the CO_2 used for EOR is not captured from industrial processes, but 'mined' from natural CO_2 reservoirs.[5]

The 41 commercial projects therefore represent merely a snapshot of places where commercial or political incentives have led these existing technologies to align.

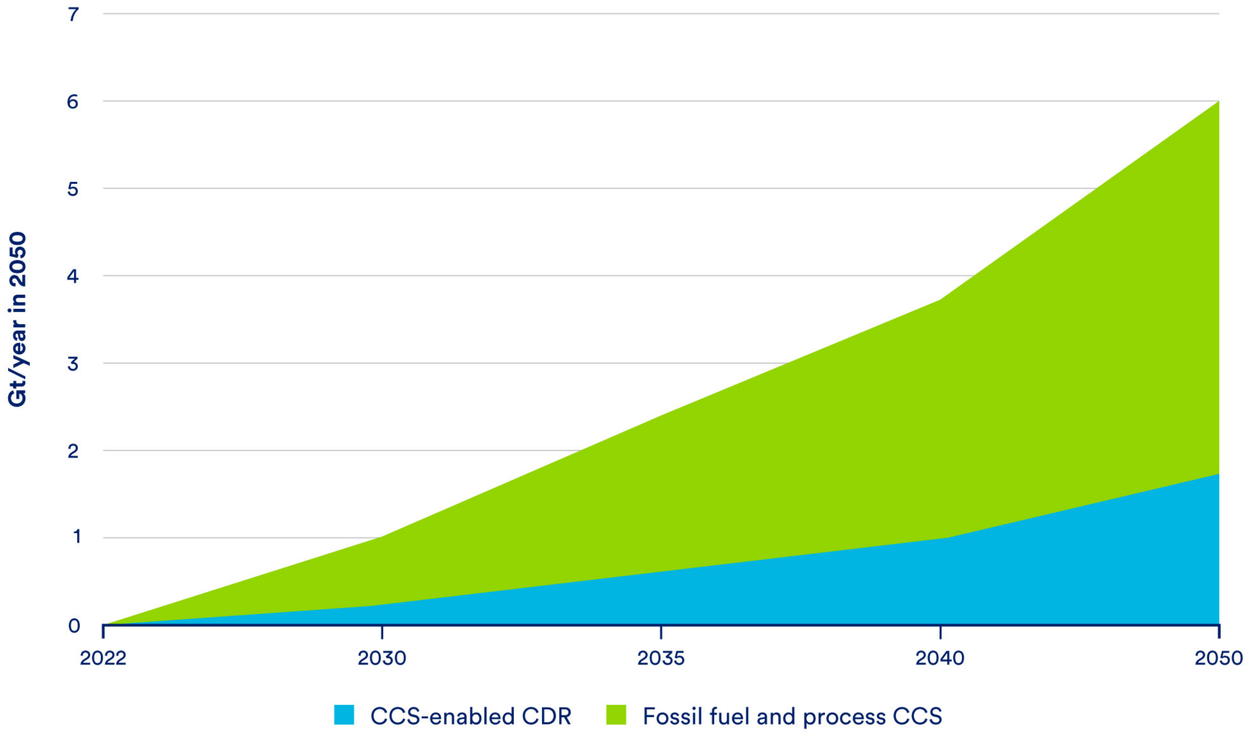
Figure 1. a) Billion tonnes (Gt) of CO_2 stored annually in 2050 across the 95 IPCC scenarios that are compatible with 1.5°C of global warming with limited temperature 'overshoot'



6 GCCSI (2023) *Global Status of CCS 2023.*

7 IEAGHG (2004) *Improvement in power generation with post combustion capture of carbon dioxide.*

Figure 1. b) The scale-up of CO_2 storage in the International Energy Agency's 'Net Zero by 2050' scenario[8,9]



Analysis of global decarbonisation pathways suggest we will need to capture and store billions of tonnes of CO_2 annually to limit warming to 1.5°C – this will undoubtedly present new technical, economic, and political challenges (**Figure 1**). In many cases it will require these existing technologies to be used at much greater scales, capture greater proportions of CO_2, or be applied to different gas compositions, which will bring engineering challenges and carry greater costs. CO_2 will be geologically stored in new locations which may not always respond exactly as predicted. Scientists and engineers in these fields are confident that any technical challenges can and must be overcome, and there is already ample evidence of such improvements being made as experience grows.

The economic challenge has been the much greater barrier for more recent efforts to deploy CCS for climate benefit. Unlike most of the 41 projects identified by the GCCSI, it is purely a pollution control technology when used in this way. Like other pollution control technologies, it will only be implemented if there is a regulatory requirement or financial incentive to do so. In the case of carbon capture and storage, this could be a high price on carbon emissions. It is no surprise that those few projects that are driven by such regulatory measures have consistently maximised the CO_2 they store[10], and more such projects will be developed as climate policy becomes more focused on achieving net zero. Despite gaining political interest as a climate technology in the 2000s, carbon capture and storage has not been adequately supported, leading to many projects being cancelled due to simple economics – no one will capture and store CO_2 for nothing.

8 IPCC (2023) *Working Group III contribution to the 6th assessment report of the Intergovernmental Panel on Climate Change.*

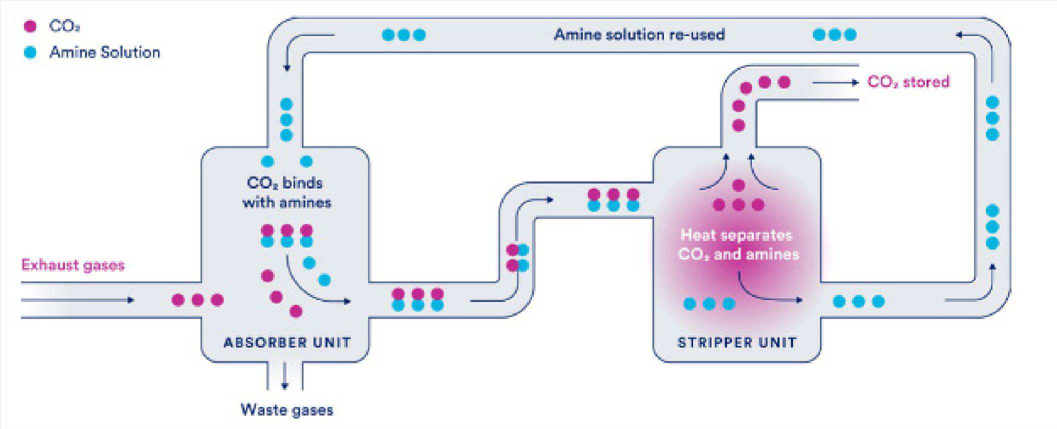
9 IEA (2023) *Net zero roadmap: A global pathway to keep the 1.5°C goal in reach.*

10 These projects include Sleipner, Snøhvit, and Quest.

Box 1: How does carbon capture work?

CO_2 needs to be in a relatively pure state before it can be safely transported and stored underground. Carbon capture refers to a wide range of processes that can be used to separate CO_2 from the other gases it is produced with during industrial processes – often this is mostly nitrogen from the air. The majority of large-scale CCS projects examined in this report use a form of the capture process shown in Figure 2, based on organic molecules called amines that can react with and bind CO_2. The gas mixture is introduced to an 'absorber' reactor in which the amine solution flows downwards and reacts with the CO_2. Now containing the bound CO_2, the amine solution is pumped to another reactor (known as the stripper or regenerator) where it is heated to release pure CO_2. The purified gas has to be compressed using special compressors before it transported and pumped into underground storage sites.

Figure 2. A schematic of a CO_2 capture process using amine absorption technology



To make this process more energy efficient, there are numerous heat exchangers – devices that help pass heat from hotter gases or liquid to colder ones. For instance, these are used to heat the amine solution with steam, and to take heat from the hot amine solution to the cold amine solution. Several of the technical challenges described in the case studies in this report relate to improving the performance and reliability of heat exchangers, as well as moving parts such as fans used to move gas through the system and compressors used to turn the CO_2 into a liquid-like state for transportation.

The amine-based capture process was first patented in the 1930s and has been used for decades to remove CO_2 from natural gas and in several other industrial applications.[11] Variants on the process are available from several different manufacturers. An alternative technology which is also used in several large-scale projects is to dissolve the CO_2 in organic solvents (such as cold methanol) rather than chemically binding it. This works best for CO_2-containing gas streams at high pressure, and is used in the petrochemical industry in particular.

11 Bottoms (1930) Process for separating acidic gases (U.S. Patent No. US1783901A).

SECTION 2

Carbon capture and storage project case studies

Natural gas processing

The majority of projects classified as commercial CCS projects operating today involve the separation of CO_2 from natural gas (methane). This CO_2 is not man-made, but is found mixed in with the methane within the subterranean porous rocks that constitute natural gas reservoirs. Natural gas can contain a wide range of concentrations of CO_2 – up to 80% for some reservoirs – which typically needs to be lowered to below 3% or lower before the natural gas can be sold for consumption.[12] Technologies to separate CO_2 from natural gas were first developed in the 1930s and are now standard industrial practice (see **Box 1**).[13] These technologies that have long been used for CO_2 separation from natural gas also form the basis of many of the CO_2 capture technologies which are now being more widely applied to other man-made sources of CO_2.

Although separating CO_2 from natural gas is widespread, the CO_2 is usually simply vented to the atmosphere. Some facilities located close to suitable oil fields have obtained value from the CO_2 by-product by using it for EOR. These projects are often classified as early CCS projects, but they are driven by commercial rather than climate incentives. Since 1996, some natural gas processing plants have been driven by climate regulations to simply store the CO_2 they produce – without using it for oil production. Some others have still caried out EOR but sought to maximise the CO_2 stored for climate benefit.

The Sleipner CCS project

Description: The Sleipner CCS project is an offshore natural gas production platform located in the Norwegian North Sea. The gas extracted from the Sleipner West gas field contains around 4-9.5% CO_2, which must be reduced to a maximum of 2.5% to meet commercial requirements. The separation and geological storage of this excess CO_2 has been carried out since the start of gas production from the Sleipner West field in 1996, generally injecting up to 1 million tonnes of CO_2 per year. The project is operated by the oil and gas company Equinor (originally Statoil).[14,15]

12 Burgers et al. (2011) *Worldwide development potential for sour gas*, Energy Procedia; 4; 2178.

13 Rochelle G T (2009) *Amine scrubbing for CO2 capture.* Van Roij J (2022) Introduction to amine sweetening processes. Chapter in: Corrosion in amine treating units (2nd edition); Rufford et al. (2012) *The removal of CO_2 and N2 from natural gas: a review of conventional and emerging process technologies*, J. Pet. Eng.; 94-95; 123.

14 Solbraa E (2010) *Carbon capture and storage experiences from the Sleipner Field.* In: Distillation Absorption 2010: conference proceedings.

15 Eiken O (2011) *Lessons learned from 14 years of CCS operations: Sleipner*, In Salah and Snøhvit, Energy Procedia; 4; 5541.

Sleipner Platform
Source: Equinor, https://www.equinor.com/energy/sleipner

CO_2 capture: The CO_2 is separated from the natural gas (methane) using a commercial process based on CO_2-binding chemicals known as amines. The process uses the amine monodiethylamine (MDEA) first developed by the oil company Elf (now TotalEnergies).

CO_2 storage: The captured CO_2 is stored in a saline aquifer formation known as the Utsira sandstone, 800-1000 metres beneath the seabed.[8]

Motivation: In 1991, Norway introduced a carbon tax on offshore oil and gas activity, starting at a rate of $51 per tonne of CO_2 emitted and reaching $70 per tonne in 2023.[16] This meant that it made financial sense for Sleipner to store the CO_2 it was already obliged to separate, rather than vent it to the atmosphere. Sleipner can be considered the first project globally to have implemented CCS purely for reasons of CO_2 abatement.

Cost and financing: The total capital cost for the project has been estimated at $300 million.[17] Operating costs are estimated at $0.75 million per year.[18]

Technical performance: The project has operated continuously since 1996, storing over 19 million tonnes of CO_2 by the end of 2022.[19] Although the design capacity is 1 million tonnes per year, it has averaged 0.8 million tonnes per year for the first 20 years due to lower natural gas production – this has fallen still lower in recent years as production has declined.[20]

In 2013, a news article in Nature suggested that the discovery of fractures in the seabed could lead to leakages from the storage site.[21] The fracture was emitting small volumes of water and dissolved gases. However, it was demonstrated that the fracture had been identified before CO_2 injection and the traces of

16 Energy Facts Norway (2023) *Taxes and emissions trading.*

17 Kongsjorden H et al. (1998) *Saline aquifer storage of carbon dioxide in the Sleipner project*, Waste Management; 17; 5.

18 Hansen H et al. (2005) *Tracing the path of carbon dioxide from a gas/condensate reservoir through an amine plant and back into a subsurface aquifer – case study: The Sleipner Area, Norwegian North Sea.* Presented at: SPE Offshore Europe oil and gas exhibition and conference, UK, September 2005.

19 Equinor (2023) *Equinor's annual report for 2023.*

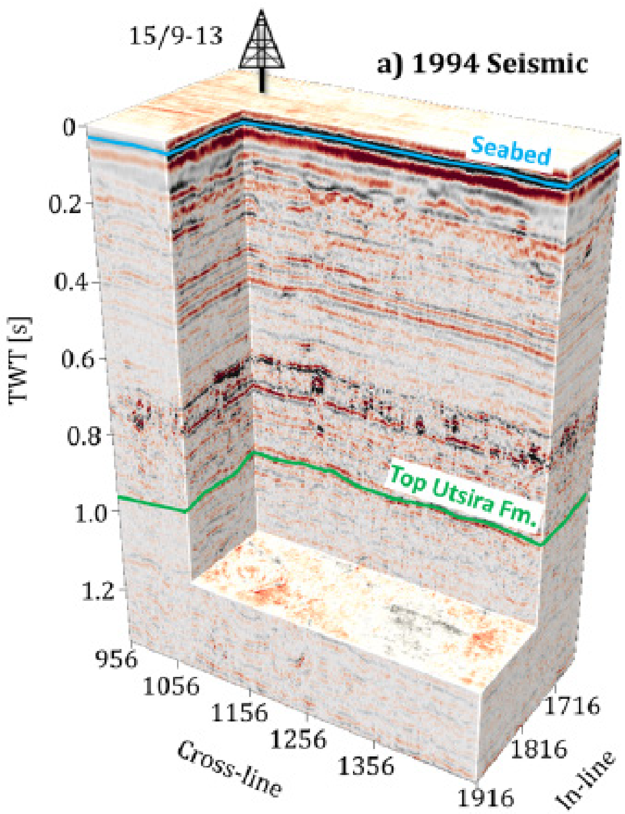
20 Philip Ringrose (2023) Personal communication.

21 Monastersky (2013) *Seabed scars raise questions over carbon-storage plan*, Nature; 504; 339.

gas emitted were natural methane leaks, with no CO_2 from Sleipner.[22] The CO_2 store remains intact.

Key takeaways: As the first large-scale example of geological CO_2 storage in Europe, the Sleipner project became a key reference for the technical and regulatory development of CO_2 storage in the region. It was used as a guide for the EU's 'Directive on geological storage of CO_2', which is the regulatory basis for how all EU states (as well as the UK, Norway, Switzerland) ensure CO_2 is stored safely and permanently. The project has operated successfully since 1996, as well as demonstrating several important techniques for detailed monitoring of the stored CO_2, including time-lapse seismic imaging and pressure monitoring. This allows the underground 'plume' of spreading CO_2 to be monitored in high resolution (**Figure 3**).

Figure 3. Seismic imaging of CO_2 storage Sleipner, showing the location and scale of the spreading CO_2 'plume' in 2001.[23]



22 Haszeldine S R et al. (2014) *Sleipner CO_2 securely stored deep beneath seabed, in spite of unexpected Hugin fracture discovery.* SCCS Working Paper WP-SCCS 2014-01.

23 Romero J (2023) *Seeing through the CO_2 plume: joint inversion-segmentation of the Sleipner 4D seismic dataset*, The Leading Edge, 42 (7); 457.

Melkøya LNG plant

The Snøhvit CCS project

Description: The Snøhvit CCS project is associated with the Melkøya plant in the far north of Norway, which produces liquified natural gas (LNG) that can be exported by ship. Natural gas is produced from the Snøhvit gas field offshore and transported in a pipeline to the Melkøya plant onshore. The gas contains about 5-8% CO_2 which needs to be removed to very low levels (a few parts per million) to meet the more demanding requirements of LNG. The separated CO_2 is transported back offshore by a 153-km pipeline for injection into a deep geological storage formation. Gas production began in August 2007 and CO_2 storage in April 2008. It can store up to 700,000 tonnes of CO_2 per year.[24]

CO_2 capture: The CO_2 is separated out using BASF's 'OASE White' solvent, of which the main ingredient is MDEA.

CO_2 storage: The CO_2 is injected into saline aquifers around 2.5 km below the seabed. It was originally stored in the Tubåen Formation from 2008 to 2011, before switching to the Stø Formation in 2011.
Cost and financing: No data is available on the project cost.

Motivation: Like Sleipner, Norway's CO_2 tax created an economic incentive to store the CO_2. However, the project also seems to have been conceived as a technological showcase, with the aim of demonstrating that oil and gas reserves in the region could be exploited in Norway's far north in a more environmentally sound way, and helping develop CCS at a time of growing interest in the technology by Norway and the companies involved. The Norwegian authorities made CCS a requirement of the development proceeding.

Technical performance: By the end of 2021, the project had stored almost 7 million tonnes of CO_2.[25] The change in storage sites after three years of operation was necessary because a gradual rise in pressure was observed, indicating that the CO_2 could not spread to as much of the available space as first thought. This was resolved by injecting the CO_2 into a different formation since 2011, which has responded

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24 Hansen et al. (2013) Snohvit. *The history of injecting and storing 1 Mt CO_2 in the fluvial Tubaen Fm*, Energy Procedia; 37; 3565. Heiskanen E (2006) *Case 24: Snohvit CO_2 capture and storage project.* EU Project Create Acceptance WP2. Eiken O et al. (2011) *Lessons learned from 14 years of CCS operations: Sleipner,* In Salah and Snøhvit, Energy Procedia; 4; 5541.

25 Equinor (2023) *Equinor's annual report for 2023.*

better. Annual CO_2 injection does not always reach the design capacity due to halts in production at the LNG plant. Most notably, a fire in 2020 led to the plant closing until 2022. CO_2 is only vented from the plant in exceptional circumstances, and requires an application for a permit.[26]

Key takeaways: Snøhvit is a successful example of carbon capture and storage for the purpose of CO_2 abatement. The early change in storage site demonstrates how future projects may have to be flexible to uncertainties in geology, and that alternative storage options can and should be planned for. The project is also notable for including transportation of CO_2 from an onshore facility to an offshore injection site, which is the model used by Norway's 'Northern Lights' CCS project (currently under construction).

Shute Creek Treating Facility
Source: ExxonMobil

Shute Creek

Description: The Shute Creek Treating Facility in Wyoming was constructed in the early 1980s to process natural gas from ExxonMobil's LaBarge field, which contains around 65% CO_2 (giving it the lowest methane percentage in a commercial field at the time). The plant separates out CO_2, helium and hydrogen sulphide from the gas. From 1986, up to 4.3 million tonnes per year of a pure CO_2 stream generated by the plant were sold for use in EOR. In 2010, this maximum capacity was increased to 7 million tonnes per year. From 2005, around 0.4 million tonnes per year of CO_2 have also been reinjected into the original gas field as part of a waste stream which mostly consists of hydrogen sulphide. ExxonMobil state that the combined 7.4 million tonnes amount to over 75% of the CO_2 from the LaBarge field – the rest is vented to the atmosphere.[27]

CO_2 capture: CO_2 and hydrogen sulphide are removed from the natural gas using the commercial Selexol™ process, first developed in the 1970s and widely used for natural gas processing and similar applications. The process produces around 9.6 million cubic metres of CO_2 per day in high purity streams (more than 95%), but a proportion of the gas is vented as part of more dilute waste streams. The plant's capacity to sell the high purity CO_2 for EOR is dictated by its capacity to compress CO_2 to pipeline pressures – the compression capacity was expanded in 2010.

CO_2 storage: Aside from the smaller acid gas waste stream stored in part of the LaBarge gas field,

26 Maidal T et al. *CO_2 underground storage for Snøhvit gas field development, Energy*; 29 (9-10); 1403.

27 Parker et al. (2011) *CO_2 management at ExxonMobil's LaBarge Field, Wyoming, USA*, Energy Procedia; 4; 5455.

the plant's CO_2 is sold to various EOR projects, in Rangely, Colorado and Balroil, Wyoming.

Cost and financing: The 2.7 million tonne expansion in 2010 is reported to have cost $86 million.[28]

Motivation: Potential income from CO_2 sales to oil producers is a bonus revenue stream for the facility, which generates large amounts of pure CO_2 as part of its normal operation. ExxonMobil apparently overestimated the demand for CO_2 for EOR in the area, with long term sales at only half the available volume until the late 2000s – ultimately due to low oil prices over this period, the remote location of the plant, and the lack of adequate CO_2 pipeline infrastructure. However, the Wyoming Oil and Gas Commission (a state regulator) put growing pressure on the facility to make more effort to market the CO_2 for EOR as a means of developing the state's oil resource. In the late 2000s, higher oil prices led to new EOR projects and more CO_2 pipelines, allowing the expansion of the CO_2 compression capacity at Shute Creek.

Technical performance: No reported issues, but transparent reporting is not required.

Key takeaways: The Shute Creek project has stored millions of tonnes of CO_2 which would otherwise have been released to the atmosphere. However, a significant portion of the CO_2 the plant captures is not stored, simply due to insufficient demand from local oil producers. In contrast to Norway, Wyoming has no regulations in place to prevent or disincentivise such releases.

Gorgon Facility
Source: Chevron Australia, https://australia.chevron.com/our-businesses/gorgon-project

Gorgon CO_2 injection project

Description: Chevron's Gorgon CO_2 injection project takes CO_2 from a liquefied natural gas production facility in Western Australia. Chevron first commenced natural gas production at the offshore Gorgon gas field in 2016, producing a gas stream with an average of 14% CO_2 content.[29] This gas is processed at an onshore facility on Barrow Island, where the CO_2 must be removed in order for the methane to be liquefied for export by ship. The CCS part of the project started in 2019, and was designed to inject between 3.3 and 4 million tonnes per year of CO_2 into a dedicated storage site beneath Barrow Island.[30]

CO_2 capture: The facility uses a commercial acid gas removal process for natural gas provided by BASF.
CO_2 storage: The CO_2 is injected to depths of around 2.3 km into a deep saline reservoir known as the Dupuy formation, which consists of sandstone rock.

Cost and financing: The CO_2 storage component of the project is reported to have cost AU$3.1 billion (USD$2 billion) to mid-2020, out of USD$54 billion for the entire gas production and processing facility.[31] The project is a joint venture co-owned by Chevron (47.3%), Shell (25%), Exxon (25%) and three Japanese utilities (each with a stake below 2%).[32] It received AU$60 million in funding from the Australian government's Low Emissions Technology Demonstration Fund.

28 ExxonMobil (2010) *ExxonMobil expands world's largest carbon capture plant in Wyoming.*

29 The facility is also fed by the Jansz Io field, which has only 1% CO_2 content.

30 Leamon G (2011) *Site selection – Gorgon carbon dioxide injection project.* Presentation at: CCS in CDM workshop, Abu Dhabi, 7-8 September 2011. Government of Western Australia (2024) *Gorgon carbon dioxide injection project.*

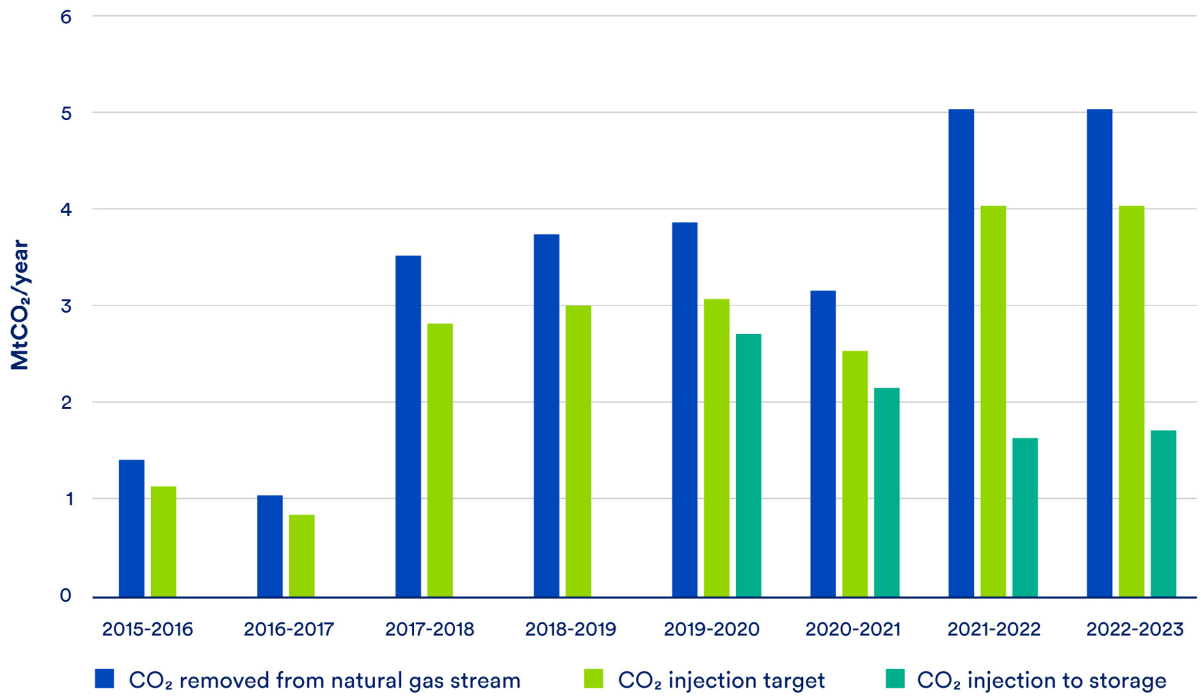
31 Milne P (2021) *Chevron's five years of Gorgon carbon storage failure could cost $230 million*, Sydney Morning Herald.

32 Blackridge Research and Consulting (2024) *All about Chevron Gorgon project in Australia.*

Motivation: The Western Australian state government made CO_2 storage a requirement for the new gas production facility to proceed, imposing a condition of storing at least 80% of the CO_2 produced over every rolling five-year operating period. In 2021, this requirement was changed to 100% of the CO2 over successive five-year periods.[33]

Technical performance: Storage of the separated CO_2 was originally meant to start at the same time as the gas production in 2016, but was delayed until August 2019. The delay was initially caused by final checks revealing that the system may allow water to condense in the CO_2 pipeline under some circumstances, which would cause corrosion. A water removal system was added prior to the CO_2 compressors, pushing back the start date. The facility reached its design injection capacity by February 2020, and stored 2.5 million tonnes by June 2020. However, it soon encountered problems with maintaining this rate of CO_2 injection. To prevent the pressure in the storage rock from increasing too much as CO_2 is injected, salty water (brine) has to be removed and re-injected into shallower rock formations. The sandstone formation targeted for CO_2 injection appears to have more unconsolidated (loosely bound) sand than expected, resulting in sand entering the brine stream and clogging up the wells where it is re-injected. Although equipment to remove these solids became operational in August 2021, Chevron concluded that it would not be possible to reach the design CO_2 injection rates without additional means of reducing the pressure in the storage reservoir. Another 2.26 million tonnes were stored in the financial year from June 2020 to June 2021, falling to 1.6 million tonnes in 2021/2022 and 1.71 million tonnes in 2022/23 as the issues with pressure in the reservoir persisted (**Figure 4**).[34] To enable the project to reach its design capacity, the company plans to add improved filtration systems to the existing water extraction wells, as well as drilling additional water extraction and injection wells.

Figure 4. Annual quantities of CO_2 removed from the natural gas produced at Gorgon and quantities injected for geological storage.[34]



33 Chevron (2023) *Gorgon gas development and Jansz feed gas pipeline ministerial statements 800, 965, 769, 1136 and 1198 compliance assessment report 2023.*

34 Chevron (various dates) *Gorgon gas development and Jansz feed gas pipeline Environmental Performance Reports 2019-2023.*

As of November 2023, Chevron reported having stored a total of 8.8 million tonnes since the project started. The first five years of operation of the natural gas plant – during most of which CO_2 storage had not yet started – led to a shortfall of 9.5 million tonnes of CO_2 against the regulatory requirement to store 80% of the CO_2 produced. To address this shortfall Chevron purchased 5.23 million tonnes of carbon offsets in 2022; these consist of Australian Carbon Credit Units (ACCUs) issued by the Australian government, Verified Emission Reductions (issued by the Gold Standard programme) and Verified Carbon Units (issued by the Verified Carbon Standard programme). These offsets are generated by projects such as renewable power, energy efficiency measures and ecosystem regeneration.[35] Chevron also invested AU$40 million in the Lower Carbon Grants Program – aimed at supporting local decarbonisation projects in Western Australia. Additional offsets will need to be purchased for the shortfall in the financial year 2023; however, from 2025 shortfalls will be addressed over fixed five-year periods.

Key takeaways: The ongoing problems faced by the Gorgon CCS project highlight that geological storage sites can face unexpected technical challenges. Companies and governments planning to use CO_2 storage for decarbonisation should mitigate this risk by ensuring site characterisation is rigorously carried out and by developing contingency plans with several possible storage options – particularly for storage at this scale. The project's use of greenhouse gas offsetting primarily through avoided emissions on voluntary carbon markets is a lower cost approach to mitigation which is unlikely to have as quantifiable a climate benefit as geological storage of the CO_2.[36] A more rigorous implementation of the regulatory requirement that Gorgon must use CCS as part of its 'licence to operate' would be to prevent the facility from producing additional geological CO_2 while the CO_2 storage is not functioning. Nevertheless, Gorgon represents an important step in improving our understanding of dedicated CO_2 storage technology at very large scales, and has prevented the emissions of nearly 9 million tonnes of CO_2.

Box 2: What is carbon capture rate?

CCS projects are often discussed in terms of the 'capture rate' they achieve, which generally refers to the amount of CO_2 they capture as a percentage of what they were intended to capture. However, this term is not strictly defined and can be used to mean different things by different commentators. The table below shows various ways in which capture rate is used and how useful they are in assessing project performance.

Most large-scale CCS projects announce a maximum or target quantity of CO_2 that they are able to capture and store over the course of a calendar year – usually in units of millions of tonnes. Some projects – if required to do so – also report on the actual quantity of CO_2 they store in each year of operation. Comparing these annual values might seem like a reasonable means of assessing the project's capture rate on its own terms, while also incorporating any shortcomings in the transport and storage of CO_2. However, there are several reasons why the actual quantity may fall short of the designed quantity, not all of which relate to the performance of the CCS process:

1. The emitting facility is not running as much as expected, due to unexpected downtime or reduced demand for its output (such as power, fuels, materials).
2. The operator chooses not to produce as much CO_2 as it could, for example, to reduce energy consumption or to match demand from CO_2 buyers.
3. The capture facility can't separate as much CO_2 from the gas it treats.
4. The capture or storage equipment was offline more than expected.
5. The capture or storage facility can't process as much exhaust gas or CO_2 as expected.

35 The price of ACCUs in 2022 averaged at less than $40 per tonne of carbon, which is significantly less than the cost of geological storage of CO_2 in most applications.

36 Cullenwald et al. (2023) *Carbon offsets are incompatible with the Paris Agreement,* One Earth; 6 (9); 1085.

Table 1. The different ways in which the term 'capture rate' is used

Definition	Comments	Example
The percentage of CO_2 the capture equipment separates from the exhaust gas it receives.	Sometimes known as capture efficiency, this measures how well the capture equipment works when it's operating, but doesn't account for periods when the equipment is offline. CCS projects often report a target for this value, which is typically 80-95%.	The Boundary Dam CCS project separates on average around 90% of the CO_2 from the gas it treats.
The percentage of CO_2 the capture equipment separates as a proportion of all CO_2 produced by the targeted exhaust stream.	This accounts for any periods when CO_2 is emitted due to capture equipment being offline. It is the best way to assess the performance of the capture project.[37]	The Boundary Dam CCS project is often not able to process all the exhaust gas it was designed for, and has also been offline more than expected for maintenance and upgrades.
The percentage of CO_2 the capture equipment separates as a proportion of all CO_2 produced by the target source.	This penalises capture projects that were not designed to deal with all the gases produced by a single polluting source. This can be due to diverse factors including available funding or technical challenges. It should not be used to assess project performance, but may provide important context for how easily a given application of CCS could be used to approach zero emissions.	The Brevik CCS project in Norway is designed to process 50% of the exhaust gases from a cement kiln. This is determined by the waste heat energy available from the cement plant. Treating all the gas is technically possible, but would require additional energy costs.
The percentage of CO_2 the facility captures as a proportion of all CO_2 produced by the industrial site.	This penalises capture projects located in larger industrial sites with several sources of emissions. This is not usually informative, as the other sources would typically require separate capture equipment.	The Illinois Industrial CCS project is designed to take all the CO_2 from the fermentation of corn sugars to ethanol at ADM's Decatur plant. However, the whole industrial site produces several million tonnes of other CO_2 emissions, largely associated with fossil fuel combustion for heat and power.

37 Some projects also account for an expected amount of downtime for the capture equipment.

The first two factors are unrelated to the CCS project, but may make a significant contribution to perceived shortfalls in CO_2 stored over the course of a year. This is particularly the case for projects that were motivated by commercial factors such as enhanced oil recovery, rather than those driven by climate-targeted incentives. Factors 3 to 5 are related to the reliability and performance of the capture or storage equipment, and are therefore useful for assessing how well a technology is working. Unfortunately, very few CCS projects provide a record of their operations to this level of detail, so it can be difficult to accurately assess the extent to which any perceived shortfalls should be attributed to the CCS technologies.

Hydrogen and ammonia production for petrochemicals and fertilisers

Other industries where the separation of CO_2 is already routinely carried out as part of the commercial process include fertiliser and petrochemicals; in both cases this CO_2 capture relates to the production of hydrogen. In a process called steam methane reforming, natural gas is first converted to a mixture of carbon monoxide and hydrogen known as 'syngas'. The carbon monoxide is usually reacted with steam to produce CO_2 and more hydrogen. The useful hydrogen is then separated out using various processes, leaving CO_2 as a by-product.

In fertiliser plants, the hydrogen is immediately converted to ammonia, which is the key precursor for most fertilisers. Many fertiliser plants react the hydrogen with some of the separated CO_2 to form urea (a form of nitrogen fertiliser), which re-releases the CO_2 when it is used in agriculture. Steam methane reforming is also an integral process in most oil refineries, where the hydrogen is used to remove sulphur and other impurities, as well as converting heavier oils to more valuable molecules. Together, these two industries each account for around half of the world's hydrogen production – a process that collectively emits around 830 million tonnes of CO_2 each year.[38]

How much additional purification is required for the CO_2 to be stored depends on the exact design of the hydrogen plant. In order to protect the catalysts used in ammonia synthesis, all ammonia plants already separate out the CO_2, so there are hundreds of examples of this 'CO_2 capture' process worldwide. These usually employ chemical solvents such as the MDEA process from BASF. Older steam methane reformers for oil refineries also used to selectively remove CO_2 in a similar way; however, modern units use a different process in which the discarded CO_2 stream still contains carbon monoxide, hydrogen, and other gases. These plants produce very pure hydrogen, but the CO_2 requires some further separation. This additional 'CO_2 capture' step is the target of the project case studies we see in industrial hydrogen production.

However, the CO_2 from this 'process stream' represents only around 60% of the total emissions from the reformer, with another 40% associated with the combustion of fuel (usually natural gas or other hydrocarbon gases) to heat the process. Although it is more costly to capture this less-concentrated CO_2, there are many commercial fertiliser plants where capture from the combustion process is also carried out, usually in order to produce more CO_2 for urea synthesis. The largest of these capture 450 tonnes of CO_2 per day (~150,000 tonnes per year).[39]

Many new plans to equip hydrogen production with carbon capture have selected an alternative technology known as autothermal reforming, in which the CO_2 is produced in one stream and can be more easily separated in one process step.

38 IEA (2019) *The future of hydrogen.*

39 Hirata et al. (2014) *Current status of MHI CO2 capture plant technology, 500 tpd CCS demonstration of test results and reliable technologies applied to coal fired flue gas*, Energy Procedia; 63; 6120.

Quest

The Quest Carbon Capture and Storage project

Description: The Quest project is an initiative led by Shell to capture and store at least 1 million tonnes of CO_2 per year from hydrogen production at the Scotford Upgrader plant in Alberta, Canada. The hydrogen is used for 'upgrading' of bitumen produced by Alberta's oil sands operations; essentially converting heavier oils to lighter oils. Steam methane reformers are used to produce the hydrogen from natural gas, as well as from some of the waste gases produced by other processes at the plant. The reformers also produce a separate stream of CO_2 from the fuel combusted to provide heat, and the wider facility includes a gas-fired power plant to provide it with electricity and steam.[40,41]

Quest is designed to capture 80% of the CO_2 in the syngas produced by the three reformers, and the 1 million tonne target is based on the assumption they will run for 90% of the year. The project's total design capacity of 1.2 million tonnes is based on continuous operation. The project started storing CO_2 in August 2015.

CO_2 capture: The steam methane reformer produces syngas – a mix of carbon monoxide and hydrogen – which then undergoes a conversion to CO_2 and hydrogen. CO_2 is then removed from this gas using Shell's ADIP-X process, which uses the monoethyldiamine (MDEA) solvent. This was an existing technology that had to be redesigned to meet the requirements of the plant.

CO_2 storage: The CO_2 is transported around 64 km by pipeline and injected into a saline aquifer in the Basal Cambrian Sands, over 2 km below the surface.

Cost and financing: Quest cost CA$790 million to build and has operating costs estimated at CA$30-35 million per year.41 It received CA$6.3 million from Alberta's 'Alberta Innovates' fund and CA$745 from the province's CCS Fund, of which 40% of goes towards the first ten years of operation. The project also received a grant of CA$120 million from the federal government towards pre-construction development (Natural Resources Canada).[40]

Motivation: The project was driven by the favourable funding environment created by the Alberta government and Shell's strategic interest in developing CCS, as well as a specific interest in improving the greenhouse gas emissions of oil sand production, which is significantly worse than conventional production. In addition to the grant

40 IEAGHG (2019) *The Shell Quest carbon capture and storage project.*

41 Alberta Department of Energy (various dates) *Quest annual summary reports.* Available at: https://open.alberta.ca/publications.

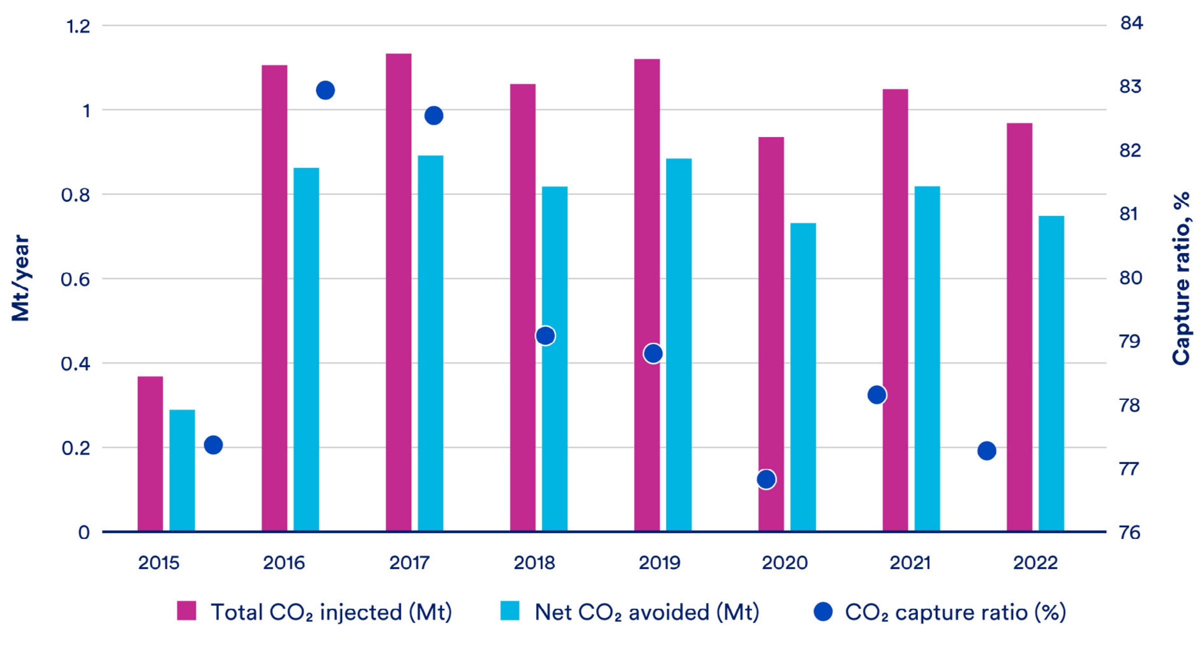
funding from the provincial and federal governments, Quest benefits from the generation of offset credits under Alberta's 'Technology Innovation and Emissions Reduction (TIER) Regulation'. Owing to its status as a 'first of a kind' project in the province, the project received two offset credits for every tonne of CO_2 avoided by carbon capture and storage, starting at a posted credit value of CA$15/tonne in 2015 and reaching CA$50 per tonne in 2022.[42] This credit doubling was set to expire in 2025 or earlier if the project's revenue ever exceeds its costs (this has reportedly occurred since the 2022 project summary). Following Canada's federal 'Greenhouse Gas Pollution Pricing Act' in 2022, the value of credits in the TIER system must – at a minimum – follow a trajectory to CA$170/tonne of CO_2 in 2030, by increasing in CA$15 annual increments.[43]

Technical performance: Performance data for Quest is made available in annual summary reports to the Alberta government. The facility has consistently captured and stored close to the 80% targeted, with an average capture rate of 79% over the period 2015-2021 for which data is available (**Figure 5**).

Combined with consistent operation of the hydrogen unit, this has meant that the volume stored annually has usually been above the 1 million tonnes per year minimum target, except for in 2020 and 2022, when it fell to 0.94 and 0.97 million tonnes respectively. To calculate the net amount of CO_2 avoided by the project in each year, any emissions from powering the process itself are deducted, which average at 0.24 million tonnes per year. The annual reports also detail any technical issues that led to reduced capture rates, which typically include scheduled maintenance and various rapidly resolved equipment faults such as power trips or faulty valves. As of May 2024, Quest had stored 9 million tonnes of CO_2.[44]

Key takeaways: Quest has implemented an existing CO_2 separation process at a larger scale than previously realised, and was also the third project globally to store CO_2 at large scale in a saline reservoir – solely for the purposes of emissions reduction. Overall, it has been a technical success, despite falling marginally short of its capture rate targets in some years.

Figure 5. Quest CCS project performance over time[45]



42 Government of Alberta (2010) *Alberta inks deal for Shell Quest CCS project.*

43 Lexology (2023) *Amending the TIER regulation.*

44 Tucker O (2024) *The Quest CCS project. Presentation to: Zero Emissions Platform Technology Committee.*

45 Quest (2023) *Quest annual summary report 2022.*

Valero Oil Refinery in Port Arthur
Source: Valero, https://www.valero.com/about/locations/port-arthur-refinery

Air Products hydrogen production facility in Port Arthur

Description: Industrial gas company Air Products operates two steam methane reformers in Valero's Port Arthur oil refinery on Texas's Gulf Coast. These supply over 200 million cubic feet per day of hydrogen to refineries in the wider area. Capture of at least 90% of the CO_2 from the first unit began in December 2012, and from the second unit in March 2013. Assuming continuous operation of the plant, approximately 1 million U.S. tons (0.925 metric tonnes) can be captured annually.[46,47]

CO_2 capture: CO_2 is separated from the reformer process stream using a proprietary Air Products process based on vacuum swing adsorption. The CO_2 is selectively absorbed onto a solid material, then a vacuum is applied to release pure CO_2. This relatively unusual process was used instead of solvents as it has no need for steam to drive the process, and was assessed to be lower cost. A similar concept was first used by Air Products at a hydrogen plant in Pennsylvania, to produce CO_2 for sale, where it has operated continuously since 1986. The CO_2 is also dried and compressed.

CO_2 storage: A 21-km connector pipeline was constructed to take the CO_2 to an existing long-distance CO_2 pipeline on the Gulf Coast (Denbury's 'Green Pipeline'). The CO_2 is then transported up to 150 km and used for enhanced oil recovery in the West Hastings oil field. This field was subject to a monitoring and verification procedure to account for the quantity of CO_2 stored.

Cost and financing: The total cost of the project was $431 million, with a U.S. Department of Energy grant contributing $284 million.[46]

Motivation: The project was driven by the alignment of the DOE funding programme for industrial carbon capture and storage (under the American Recovery and Resilience Act) with Air Products' strategic

46 IEAGHG (2018) *The carbon capture project at Air Products' Port Arthur hydrogen production facility.*

47 Busse A et al. (2018) *Demonstration of Carbon Capture and Sequestration of steam methane reforming process gas used for large-scale hydrogen production,* Final report to the Department of Energy.

company goals. These included the opportunity to demonstrate the decarbonisation potential of the company's growing industrial gas business, as well as the large-scale viability of their new CO_2 capture technology.

Technical performance: The terms of the DOE grant required the project to operate for a demonstration period concluding in September 2017, when a final report was issued. This reported no major issues with the plant and plans to remain in operation 'for at least the next few years'. As of 2024, the plant continues to operate. In May 2013, the plant conducted a 'capacity test' by demonstrating its maximum CO_2 capture capability over 24 hours. During this test it produced 4-5% more CO_2 than the design capture rate. In June 2016 the plant announced it had captured over 3 million tonnes of CO_2. However, it does not appear to routinely report the volumes it captures and store. The hydrogen plants are expected to run fairly continuously, but can occasionally turn down due to reduced hydrogen demand.

To confirm permanent storage of the CO_2, the project was required to demonstrate adequate monitoring, verification and accounting activities to the Department of Energy. The steps normally taken by the enhanced oil recovery operator (Denbury Onshore) were considered sufficient, but were supplemented by additional monitoring work by the University of Texas at Austin and Dallas.

Key takeaways: The project primarily demonstrated the use of the vacuum swing adsorption system for separation of large volumes of CO_2 from steam methane reformers. It met its performance requirements during the three-year demonstration period required by the U.S. DOE, but has made very little data publicly available since 2017, as it operates as a commercial provider of CO_2 to EOR.

Alberta Carbon Trunk Line
Source: Alberta Carbon Trunk Line

The Alberta Carbon Trunkline Project

Description: The Alberta Carbon Trunkline in Canada is a 240 km-long CO_2 pipeline that carries CO_2 from a fertiliser plant (Nutrien Redwater) and a refinery (NWR Sturgeon) to a depleted oil reservoir for use in enhanced oil recovery. The project started operation in 2020, and can receive up to 1.3 million tonnes of CO_2 annually from NWR Sturgeon and up to around 0.2 million tonnes from Nutrien Redwater (increased to 0.3 million tonnes in 2023). Other sources of emissions are expected to connect to the pipeline in the future, which is able to accommodate up to 14.6 million tonnes per year. The project is a partnership between Enhance Energy, which owns and operates the oil field, Wolf Carbon Solutions, which owns and operates the pipeline, and NWR.

CO_2 capture: The fertiliser plant produces a stream of CO_2 mixed with water, which is removed by dehydration equipment before the dry CO_2 is compressed and fed to the pipeline. The refinery uses the commercial Rectisol capture process to separate dry CO_2 from a syn gas mixture produced by the 'gasification' of heavy oils found in tar sands. Developed by Linde, the Rectisol process dissolves CO_2 in cold methanol and is widely used in the production of hydrogen, ammonia, methanol, carbon monoxide and other chemicals.

CO_2 storage: CO_2 is shipped 240 km to Enhance Energy's Clive Field, where it is injected into a depleted hydrocarbon reservoir approximately 2 km below the surface and utilized for enhanced oil recovery. The CO_2 is permanently stored, as any CO_2 returning to the surface with the oil is reinjected (known as a 'closed loop').

Cost and financing: The full project cost approximately CA$1.2 billion. It received CA$63.2 million in a grant from the federal government (through Natural Resources Canada) and over the course of operations it will receive up to CA$495 million in funding from the Alberta government. The project also annually reports a total cost per tonne of CO_2 captured and stored (including all operational and capital costs), which was quoted as CA$102 per tonne in 2022.[48] Aside from the government grant, the economic viability of the project is supported by the revenues from hydrocarbon production from enhanced oil recovery and the generation of carbon credits under Alberta's TIER regulation for large emitters.

Motivation: Enhance and NWR teamed up in 2008 with the aim of giving multiple industries in the area access to CO_2 transport and storage infrastructure. The storage of industrial CO_2 in Alberta is incentivised by the generation of carbon credits under the province's greenhouse gas compliance regulations, while emissions abatement at fuel production facilities is additionally incentivised by the federal government's Clean Fuels Regulation.

Technical Performance: The project provides annual summaries of operational performance and any issues encountered and annual quantities stored are also recorded by Enhance Energy and Alberta Carbon Registries.[48,49] Reporting from 2021 to 2022 shows that both CO_2 sources have sent slightly less than the maximum capacity each year, averaging a combined 1.15 million tonnes annually. However, this is due to the production processes at both sites experiencing more time offline, and therefore producing less CO_2 for capture. Over the first two full years of operation, the CO_2 capture equipment at the refinery has been available 97% of the time, while the CO_2 dehydration and compressor used at the fertiliser plant recorded over 99% availability. As of May 2024, Enhance Energy report having stored 5.1 Mt of CO_2 emissions since the start of the operations.[50]

Key takeaways: The CO_2 capture technologies at the fertiliser plant and refinery are already widely used in their respective industries. The Alberta Carbon Trunkline primarily demonstrates that it is technically and commercially viable to build large-scale, shared pipelines for CO_2. The enhanced oil recovery operation is subject to an additional monitoring, measurement and verification programme to ensure that all the CO_2 is permanently stored.

48 Enhance Energy Inc., Wolf Carbon Solutions, and North West Redwater Partnership (2021-2023) *Knowledge sharing reports.*

49 Alberta Carbon Registries (2024) *Enhance Energy CO_2-EOR project at Clive Field.* Available at: https://alberta.csaregistries.ca/GHGR_Listing/AEOR_ListingDetail.aspx?ProjectId=157

50 Enhance Energy (2024) https://enhanceenergy.com/

Bioethanol

Bioethanol is typically made by fermenting types of biomass containing sugars or starch, such as cereal grains or sugar cane. The resulting ethanol can be used as an alternative to fossil-based transport fuels. Global bioethanol production is dominated by the U.S. (largely from corn) and Brazil (largely from sugarcane). The gas produced by bioethanol fermentation consists entirely of CO_2 and water, so 'carbon capture' at these sites requires only the addition of a water removal (dehydration) step and CO_2 compression. These processes are well-established technologies, but still represent an investment for the plant. There are also separate emissions associated with providing heat and power to the process and related production lines – often provided by fossil fuels. Given there are no 'carbon tax' penalties or restrictions on emitting non-fossil, biological CO_2, there has rarely been an incentive to avoid these emissions. However, direct incentives for CCS projects and low-carbon fuel production, are beginning to drive projects in this industry in the U.S., as well as growing interest in storing biological CO_2 as a form of 'carbon dioxide removal'.

Archer Daniels Midland Plant
Source: Jackie Anderson, ADM

Illinois Industrial Carbon Capture and Storage Project

Description: Commissioned in 2017, the Illinois Industrial CCS project is designed to capture up to 1 million tonnes annually from bioethanol production at Archer Daniels Midland's (ADM) Decatur plant. The project followed on from the smaller Illinois Basin Decatur Project, that captured 1000 tonnes of CO_2 per day from the same site, and ultimately stored one million tonnes of CO_2 over three years (2011-2014).

The larger capture project was designed to add an additional capacity of 2000 tonnes per day from one set of ethanol fermenters. The Decatur site is a very large agricultural industry site, with several other emission sources including on-site fossil fuel power generation.

CO_2 capture: Bioethanol fermentation at the plant produces a high purity CO_2 stream that contains less than 3% water. The CO_2 is dehydrated using a commercial tri-ethylene glycol absorption process and compressed to around 100 bar.

CO_2 storage: The CO_2 is transported by pipeline for 1 mile and injected into the Mt Simon Sandstone formation, around 1.9 km below the surface.

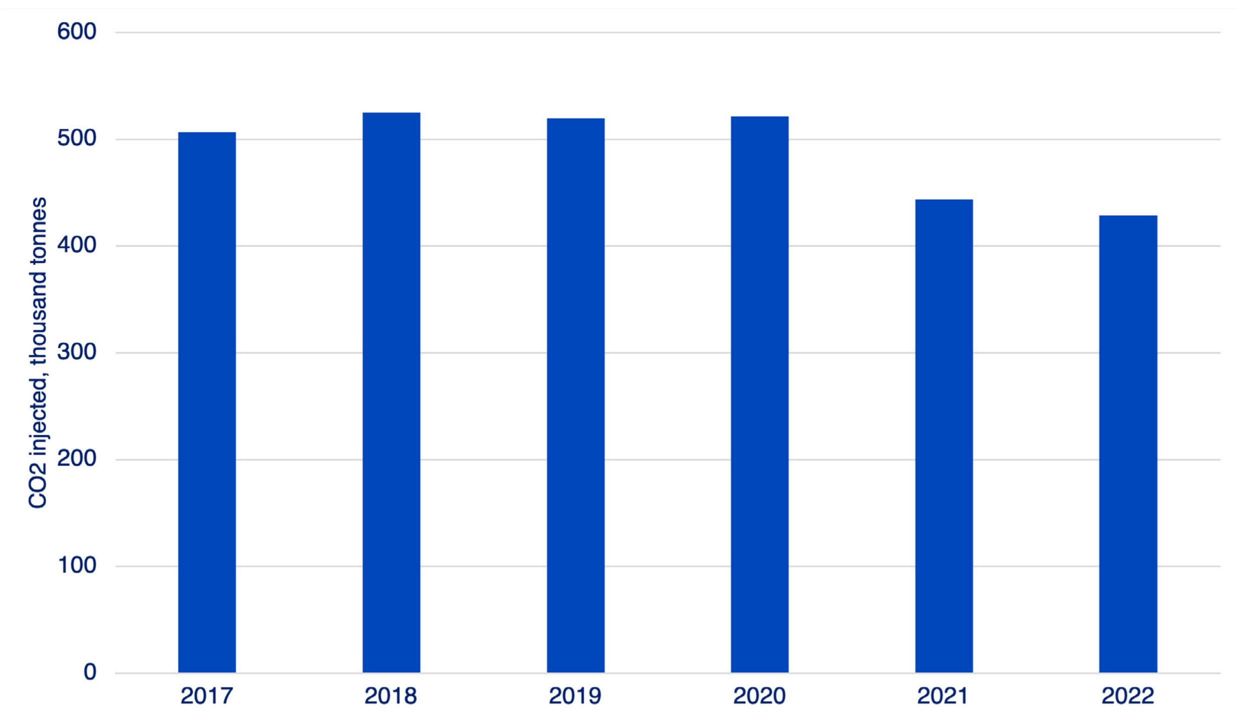
Cost and financing: The project cost $207 million and was supported by a DOE grant of $141 million.

Motivation: The project was a public-private partnership between Archer Daniels Midland and the U.S. DOE, supported by funding from the American Recovery and Reinvestment Act (ARRA). It aimed to advance CO_2 storage research while also receiving a tax credit for CO_2 storage known as '45Q'. Introduced in 2008, the credit originally awarded $22 per ton of CO_2 stored in a saline aquifer (it was increased in 2018, and then again in 2022).

Technical performance: Data from the Environmental Protection Agency (EPA) shows that the project has stored around 520 thousand tonnes annually, falling to 444 thousand tonnes in 2021 (**Figure 6**).[51] The plant attributes this dip to reduced demand for ethanol as a result of the Covid pandemic, and preliminary 2023 data indicates a record injection level. According to ADM, the consistent operation at levels well below the stated design capacity for CO_2 storage (1 million tonnes per year) is generally associated with ethanol production below the plant's maximum capability.[52] However, the facility has also encountered some technical challenges that have had an impact on injection rates. Particularly when operating at lower ethanol production rates, too much ethanol or water can remain in the CO_2 stream, preventing it from being taken to compression and storage. It was also discovered that some lubricants in the compressor were entering the CO_2 and ultimately clogging parts of the injection well. This issue was resolved by a chemical cleaning of the injection well. Finally, there were minor equipment issues typical of chemical plants, including maintenance associated with freezing weather.

Key takeaways: The Decatur Project and the Illinois Industrial CCS project are the first projects to carry out the large-scale storage of CO_2 in a saline

Figure 6. Volumes of CO_2 injected annually at the Illinois Industrial CCS project[50]



51 Environmental Protection Agency (2024) *Facility level greenhouse gas emissions data*, Archer Daniels Midland Co., Decatur, IL. Available at: https://ghgdata.epa.gov/ghgp/service/facilityDetail/2019

52 ADM (2024) personal communication.

reservoir in the U.S., and among the first globally. Both projects have therefore provided valuable experience with dedicated CO_2 storage in these formations, including measurement, monitoring, and verification technologies. CO_2 injection rates below the design rate are partly linked to lower-than-expected ethanol production, as well as technical issues encountered under certain operating conditions, which the project continues to address. The plant has a greater commercial incentive to optimise the functioning of its ethanol production process than to maximise the CO_2 it stores.

Power generation

Coal-fired power plants are some of the largest single sources of CO_2 in the world, and the sector as a whole emits nearly a quarter of global CO_2 emissions. Many researchers and governments therefore considered these facilities to be an early priority for the use of carbon capture and storage as a climate technology, and several large-scale projects were planned by power companies in Europe and North America in the late 2000s and early 2010s.

Unlike the existing use of carbon capture in natural gas processing and petrochemicals, separating large quantities of CO_2 from power plant exhaust (known as flue gases) has no commercial purpose and was first seriously considered as an emissions mitigation option in the 1990s. Coal flue gas contains about 10-15% CO_2 and is at ambient pressure, so it takes more energy and larger equipment to separate the CO_2 than for natural gas or syngas. It also contains contaminants such as particulates and oxides of sulphur and nitrogen; in most regions, these already need to be largely removed to meet air quality standards, but many carbon capture processes can require the gas to undergo some further treatment. Despite these challenges, commercial processes for CO_2 capture from fossil fuel combustion predate interest in the technology for climate reasons.

Demand for CO_2 from sectors, including the food and beverage industry, drove the development of many CO_2 capture plants on small-scale industrial combustion processes from the early 1980s, such as coal, gas and oil-fired boilers and furnaces, gas engines, and gas turbines.[53] These range in scale from around 100,000 to 500,000 tonnes of CO_2 per year, and separate CO_2 from gas mixtures of very similar composition to full-scale power plants.

Using these existing CO_2 separation technologies or modified variants, many trials on coal power plant flue gas were carried out during the 1990s and 2000s, with the aim of eventually capturing CO_2 from a whole power generating unit – this would require capturing at least 1 million tonnes per year.[54]

As coal power plants have become subject to phase-out targets in Europe and Canada, and less economically competitive in the U.S., interest in some countries has shifted to gas power plants on the basis that they are likely to remain integral to the stable operation of the power grid. Gas power plant flue gas is more dilute in CO_2 than coal flue gas, at around 3-4%, but the technologies considered are very similar to those used for coal, and have also been tested or used commercially at smaller scales. The flue gas also has many fewer contaminants, but does contain higher levels of oxygen that can require removal.

Interest in using carbon capture on coal power remains in the U.S., China, and India, where the large coal power fleets are expected to remain for several decades in some form (particularly in Asia). Several Chinese power companies have stated an ambition to equip a large coal power plant with carbon capture and storage in the next few years.[55]

53 Table developed by CATF in preparing Comments of CATF & NRDC in Response to Proposed Rule: Emissions Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emissions Guidelines Implementing Regulations; Revision to New Source Review Program, Docket ID No. EPA-HQ-OAR-2017-0355-24266 (Oct. 31, 2018), https://www.regulations.gov/comment/EPA-HQ-OAR-2017-0355-24266

54 Gas and coal-fired power plants usually consist of several generating units, consisting either of a coal boiler of gas combustion turbine, as well as a steam turbine. Each unit typically has its own distinct flue gases which are usually addressed separately by carbon capture projects.

55 Lockwood (2021) *CCUS becoming a commercial reality in China?* Modern Power Systems, 26 May 2021.

Boundary Dam
Source: SaskPower, https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project

Boundary Dam Carbon Capture Project

Description: Boundary Dam is a coal-fired power plant in Saskatchewan, Canada, owned by the provincial utility SaskPower and currently comprises four separate generating units, all built in the 1970s.[56] Unit 3 was upgraded with a refurbished boiler and a new turbine, a process to remove sulfur oxides from the flue gas, and a carbon capture system designed to capture up to 90% of its emissions, or 3200 tonnes per day. The modernised unit has a net output of 150 MW, which is reduced to around 115 MW when the carbon capture is operating. Carbon capture and storage commenced in October 2014.

CO_2 capture: The CO_2 is separated using an amine-based solvent developed by Shell Cansolv (a Canadian technology acquired by Shell in 2008). The chemical reacts with the flue gas CO_2 in a large absorber tower, and is regenerated to release CO_2 using steam extracted from the power plant. The process had first been tested at much smaller scales in the UK (50 tonnes of CO_2 per day) and South Africa (170 tonnes per day).

CO_2 storage: Most of the CO_2 is sold for use in enhanced oil recovery at the Weyburn oil field and is transported there via a 70-km long pipeline. Any CO_2 that is not required by the oil field is stored in a deep saline reservoir (3.4 km below the surface) as part of a research project known as Aquistore.

Cost and financing: The total cost of the project came to CA$1.47 billion. However, 30% of this cost was associated with the new boiler and turbine, roughly 20% on other emissions controls, and around 50% related to the carbon capture process. Unlike many coal plants, Boundary Dam did not have equipment to remove sulphur oxides from the flue gas (desulphurisation), which added to the total cost. The project received CA$240 million as a grant from the federal government. Expected income from the sale of CO_2 to EOR, as well as sulphuric acid and fly ash by-products were also integral to the business case. A ten-year contract for CO_2 offtake was agreed with oil field operator Cenovus in 2014 (now Whitecap Resources).

Motivation: When the project was first conceived, a new federal regulation imposing a maximum carbon intensity on older power plants was anticipated, which was expected to make Saskatchewan's coal power plants unviable in the long term. While also investing in wind power for the province, SaskPower required a long-term source of reliable back-up power, and regarded new gas power as economically risky, given its reliance on volatile gas prices.[57] The chosen alternative was to use CCS to decarbonise some of the existing coal units, which burn the low-cost, locally mined 'lignite' coal. The economic viability of this option was further boosted by the grant from the federal government and the income of CO_2 sales to the oil field operator. The anticipated regulation came into effect in 2015, requiring older power plants to emit no more than 420 tonnes of CO_2 per GWh generated – impossible for a coal plant without carbon capture. In 2018, this was extended to apply to all power plants, regardless of age, from 2030. In addition, a federal carbon price was imposed in 2019, reaching CA$80 in 2024 and intended to rise to CA$170 in 2030.

56 Two older units from 1959 were closed in 2013 and 2014.

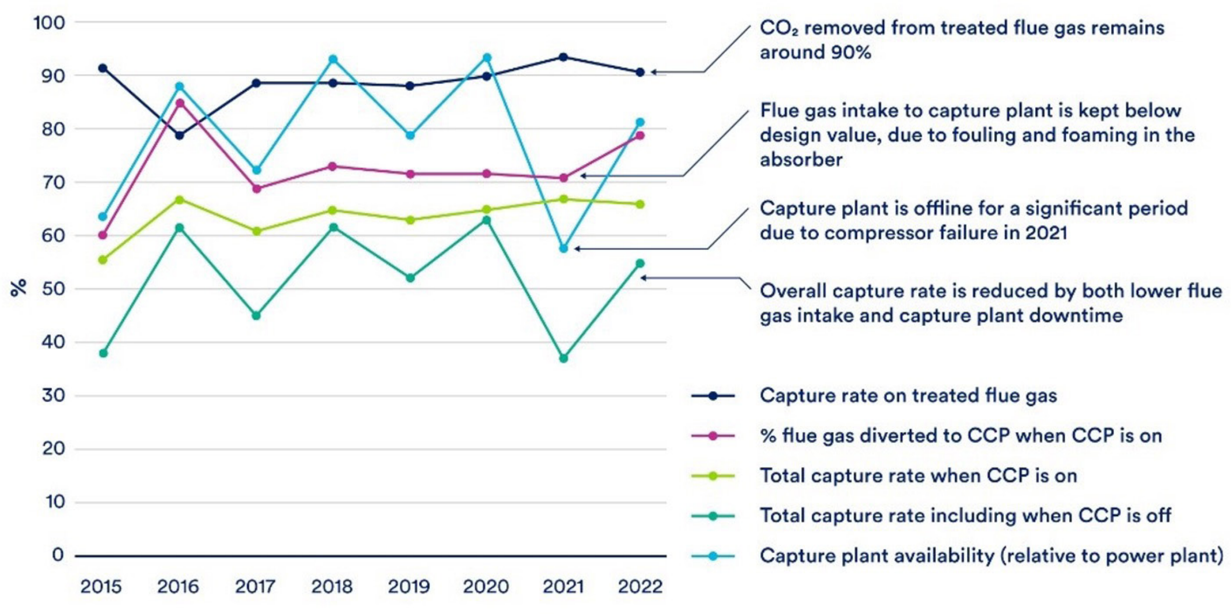
57 With North American gas prices plummeting following the shale gas revolution in the U.S. from 2011, this motivation lost weight over time.

Technical performance: As of May 2024, the Boundary Dam 3 CCS project has captured and stored over 6 million tonnes of CO_2, but has experienced several technical challenges since starting in 2014. Regular performance reporting provides insight into which factors are responsible for shortfalls (see **Box 2**) and how multiple issues have been successfully overcome (**Figure 5**).[58,59] Most of the problems during the first three years of operation were related to ash particulates from the power plant entering the system, leading to clogging and scaling of multiple pieces of equipment. This was a particular challenge at Boundary Dam due to the large quantity of fine ash produced by the local coal, and its use of relatively low-performance particulate removal systems. To deal with ash-related problems, SaskPower made modifications to the facility during shutdowns in 2015 and 2017, including installation of water spray systems to washout the unwanted particulates and additional 'redundant' equipment that allowed the plant to continue running while equipment is cleaned. Other issues addressed included cleaning of the solvent, which was degrading more than expected, and replacing a leaky solvent storage tank.

Aside from the planned shutdown in 2017, the facility operated with relatively good reliability from 2016 to 2020, and reached 94% availability in 2020. However, the total CO_2 captured still averaged only around 60% during this period, primarily due to consistently less flue gas being sent to the capture plant than planned – less than 75% of the total gas flow in most years (**Figure 7**). This is generally a result of fouling and scaling of equipment limiting the amount of gas that can be drawn into the system and properly processed. While the early issues with ash contamination were mostly addressed, more recent problems relate to biological growth in the absorber, as well as solvent 'foaming'. These problems are being addressed using chemical cleaning and 'anti-foaming' agents, and flue gas intake increased in 2022, but they have not been fully resolved.

However, Figure 7 also highlights that the capture plant consistently captures around 90% of the CO_2 in the flue gas it receives; in other words, the chemical process is working as intended. More detailed data shows the plant often captures well over 90% of the CO_2 it receives over a given hour, and has averaged over 95% in the past two years.[59]

Figure 7. The performance of the CO_2 capture plant (CCP) at Boundary Dam 3 from 2016 to 2022[59]



58 Giannaris et al. (2021) *SaskPower's Boundary Dam Unit 3 carbon capture facility – the journey to achieving reliability*, Proceedings of the 15th Greenhouse Gas Control Technologies Conference; Pradoo P et al. (2022) *Improving the operating availability of the Boundary Dam Unit 3 carbon capture facility*, Proceedings of the 16th Greenhouse Gas Control Technologies Conference.

59 Jacobs B et al. (2022) *Reducing the CO_2 emission intensity of Boundary Dam Unit 3 through optimization of operating parameters of the power plant and carbon capture facilities*, Proceedings of the 16th Greenhouse Gas Control Technologies Conference.

Major shutdowns occurred in 2021 and 2022 due to failures of the CO_2 compressor, which were attributed to manufacturing defects; these were resolved with replacement parts. More recent data shows that the capture plant has been operational 85% of the time in 2023, and over 92% in the first half of 2024.[60] The facility captured a record quantity of CO_2 over a 12-month period from July 2023 to June 2024 (882,273 tones), indicating that operational and design improvements are taking effect.[60]

Shortfalls in CO_2 captured relative to the design maximum are also partly attributable to the plant operators choosing to run less CO_2 capture, either to maximise power output or because there is less demand from the oil field. The economic incentive to maximise CO_2 capture is becoming more significant as Canada's carbon price increases.

Key takeaways: Although the capture facility at Boundary Dam has experienced multiple technical challenges, they are typical of a first-ever demonstration of a new technology at full scale – particularly those involving chemical processes. There were some failings in the original plant design, particularly relating to inadequate flue gas cleaning and lack of equipment redundancy. The major issues faced by the project early on were all successfully addressed, and future plants will be better able to pre-empt these problems from the design stage. Rare failures of otherwise well-established commercial technologies – in particular, the CO_2 compressor – are of limited relevance to the general technical readiness of CO_2 capture technology, and should be more rapidly addressed as supply chains develop. As the power plant faces higher carbon prices, it is increasingly incentivised to adjust its output to a level that the capture plant is able to deal with – showing that, with the right policy tools, CO_2 capture technology is just one aspect of what's needed to cut emissions.

Petra Nova Facility

60 SaskPower (2024) BD3 status updates.

Petra Nova

Description: Petra Nova is a carbon capture and storage project at NRG's WA Parish coal and gas power plant in Texas – a large site including four coal-fired units built between 1977 and 1982. Carbon capture and storage was applied to around 40% of the flue gas emitted by the 615 MW Unit 8, usually expressed as 'equivalent' to a 240 MW plant, and amounting to a maximum of 1.4 million tonnes of CO_2 captured per year. The project began operating in 2017, but in September 2020 the capture plant stopped operating, citing the poor economics of oil production during the Covid-19 pandemic which harmed the business case centred on enhanced oil recovery. In 2023, JX Nippon purchased NRG's 50% stake in the project, with the intention of using the facility to gain further technical experience with carbon capture. It was restarted in September 2023.[61]

CO_2 capture: The CO_2 is captured using an amine-based solvent produced by Mitsubishi Heavy Industries. This process had previously been installed at 11 smaller commercial sites, mainly on the combustion flue gas produced by ammonia plants, as well as being tested on a coal plant from 2011.[39] The process is similar to the one used at Boundary Dam, but the flue gas required less additional cleaning, having already been treated for sulphur oxides. The steam used to regenerate the solvent is produced by a small, purpose-built gas-fired turbine.

CO_2 storage: The capture CO_2 was sent to the West Ranch Oil Field for use in enhanced oil recovery.

Cost and financing: The project cost $1 billion, of which $300 million was spent on work on the oil field and pipeline and $637 million on the capture plant site. It was a 50:50 joint venture between power company NRG and Japanese oil and gas company JX Nippon, which each contributed $300 million in equity.[62] The project also received $167 million as a U.S. Department of Energy Grant for carbon capture and storage demonstration, with the remaining costs financed through loans from Japanese lenders aiming to support Japanese technology exports.

Motivation: The early economic viability of Petra Nova was bolstered by the inclusion of the oil field operations within the project scope. Rather than selling CO_2 to a separate oil field operator, it directly receives income from the sale of the oil produced. However, this also made it more sensitive to the falling oil prices that led to its closure – it was conceived at a time when oil prices were around $100 per barrel. The project was also motivated by Japanese interest in promoting carbon capture technologies for export, and U.S. government interest in developing carbon capture and storage.

Technical performance: As part of the DOE funding requirements, the project was required to submit a detailed report of its first three years of operation, from 2017 to 2019.[63] Over these three years, the project captured 83% of the planned volume of CO_2, but with a steady increase from 72% in 2017 to 95% in 2019 (**Figure 8**). Only a portion of this shortfall is attributable to issues with the capture plant, with other factors including issues at the oil field, the coal power plant, and the gas generator providing the steam. As at Boundary Dam, the CO_2 capture process itself worked well when operating – removing 92.4% of the CO2 from the flue gas it received over the three years. The CO_2 capture shortfall was therefore due to equipment shutdowns, with the capture unit held responsible for 28% of these. Availability of the capture unit steadily improved over the three years, reaching 92% in 2019. Surprisingly, the gas plant used to power the process was responsible for a further 24% of outages, but these occurred mainly in the first year and were soon resolved with replacement parts.

Outages at the capture plant were due to various issues including leaking heat exchangers and scaling of equipment caused by contaminants carried into the system. Unlike Boundary Dam, these contaminants were carried over from the limestone-based desulphurisation system used by WA Parish (and most coal power plants); this problem was partly mitigated by introducing a blocking wall in the flue gas ducting. The leaking heat exchangers were replaced in 2017 and parts of the CO_2 compressor – which also struggled with scaling by contaminants – were replaced in 2018. However, the replacement parts were not able to match the design performance under some operating conditions, such as in hot weather and when the power plant was operating at low output. The project's report indicates that the budget did not allow for some major components to have back-up systems, which would have helped with reliability.

Key takeaways: The Petra Nova project provided vital experience with operating CO_2 capture from a power plant at a large scale, which has been used to optimise and adapt MHI's technology for even larger scales and other applications. Partly based on the project learnings, MHI state that they have optimised the process to enable a 30% reduction in capital cost, mainly by using more compact, modular

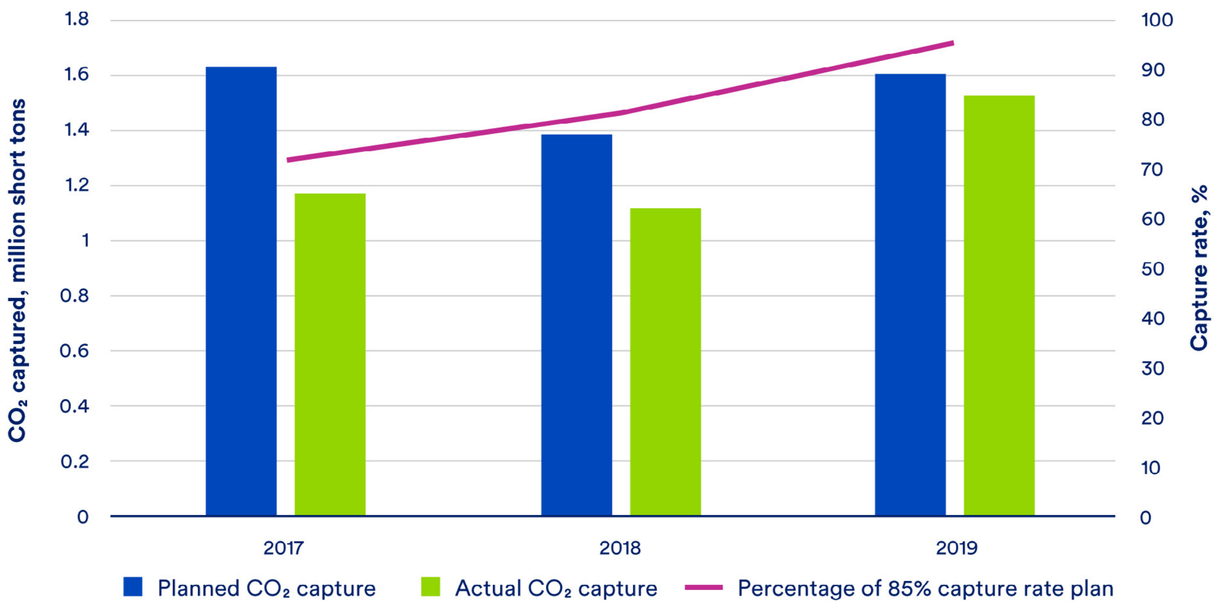
61 Reuters (2023) *Carbon capture project back at Texas coal plant after 3-year shutdown.*

62 McMahon T (2016) *Petra Nova carbon capture and sequestration project construction update.* Presentation at: Energy, Utility, and Environment Conference 2016.

63 DOE (2020) W.A. *Parish post-combustion CO_2 capture and sequestration demonstration project.* Final scientific/technical report.

Figure 8. CO_2 capture performance over Petra Nova's first three years of operation.

Note: the planned CO_2 capture is lower in 2018 due to planned maintenance time on the capture unit.[63]



equipment.[64] As at Boundary Dam, downtime experienced by the project has mostly been related to the need to replace underperforming or poorly designed components, and performance noticeably improved as a result of modifications made over the course of the project. Again, preventing too many gas contaminants from entering the process seems to be a key challenge, but can also be addressed through equipment modifications and backup for key processes.

Kemper County IGCC

Description: Developed by power utility Southern Company, the Kemper County project in Mississippi was intended to be a new 582 MW power plant based on 'integrated gasification combined cycle' (IGCC) technology. Coal is first converted or 'gasified' to carbon monoxide and hydrogen, before most of the carbon monoxide is converted to CO_2 which is separated out for storage. The hydrogen and some remaining carbon monoxide is used to fuel a gas turbine and generate power. Following a costly construction delay of over three years, the plant started operating (without CO_2 capture) in 2016 but experienced technical problems with the coal gasification process.[65] As a result of the ongoing costs and falling U.S. gas prices, the State regulator ordered the coal-based process to be halted in 2017. Southern Company now run the turbines on natural gas, without carbon capture. If fully operational, the plant would have captured and stored up to 3 million tonnes of CO_2 annually.

CO_2 capture: Separating CO_2 from gasified coal is easier than it is from normal power plant flue gas, as the CO_2 is at higher concentration and pressure. The commercial solvent 'Selexol' – which has been widely used for this application since the 1960s – was to be used at Kemper to separate 65% of the CO_2 in the gas stream.

CO_2 storage: The CO_2 was to be sold to an oil field operator for use in enhanced oil recovery.

Cost and financing: The project is reported to ultimately have cost up to $7.8 billion, although this includes elements external to the power plant, including creation of a new coal mine. Costs within the power plant project were reported as $5.2 billion.

64 Susaki M (2021) Presentation at: 'CO_2 capture, utilization, and storage (CCUS) briefing.'

65 DOE (2019) *Kemper County IGCC final project report.*

A breakdown of costs within the plant process is not publicly available, but the Selexol CO_2 capture process is estimated to cost around $80 million at this scale.[66] The project received a grant of $430 million from the U.S. Department of Energy for demonstrating carbon capture and storage. The cost overrun and delays have been partly attributed to construction on the plant starting before the design was completed.[67]

Motivation: Southern Company wanted to exploit the significant cheap, local coal (lignite) resource in Mississippi, while demonstrating the new coal gasification technology they had developed. The ability to access the U.S. DOE funds for CCS demonstration was also a key enabling factor.

Technical performance: First developed in the 1990s, IGCC power plants are a relatively well-understood but little-used form of power generation from coal, with only around 12 plants ever having been built (most of which have since been decommissioned). However, the coal gasification technology used at Kemper County was a new process developed by KBR and Southern Company, that had previously only been trialled at a much smaller scale. All the problems experienced during operation of the plant related to this process, rather than the Selexol CO_2 capture process, which is a well-established commercial technology for separating CO_2 from syngas. The capture process was tested over around 20 days and consistently achieved the 65% capture rate targeted.[65] However, the heat resistant lining of the coal gasifier was poorly installed and not suited to the wet coal that was eventually used, causing it to flake off. There were also leaks in the water tubes used to cool the gasifier. Nevertheless, Southern Company maintain that these issues had been resolved or were being resolved with replacement parts, citing the falling gas price as the main reason for the failure of the coal-based concept.

Key takeaways: The project has little bearing on the development of CO_2 capture technology for applications where it is most likely to be used. The capture process worked as designed and problems with the plant were related to scaling up a relatively new coal gasification technology. Since Kemper, there has been a general decline in interest in IGCC as a coal power generation technology, although two large units were since commissioned in Japan and have operated successfully (without CO_2 capture).

Bellingham Power Plant
Source: NextEra Energy

66 Mohammed I Y et al. (2014) *Comparison of Selexol™ and Rectisol™ technologies in an integrated gasification combined cycle (IGCC) plant for clean energy production.*

67 Bade G (2014) Coal gasification: *American coal power's last, best chance*, Utility Dive (17 Dec 2014).

Bellingham

Description: Bellingham is a 320 MW gas-fired power plant in Massachusetts. From 1991 to 2005, it operated a CO_2 capture process on a portion of the plant's flue gases, equivalent to around 40 MW, and capturing 320-350 tonnes of CO_2 per day. The CO_2 was sold for use in the food industry.[68]

CO_2 capture: The CO_2 was separated using Fluor's Econamine FG PlusSM, an amine-based solvent process. The process was developed for recovering CO_2 from flue gases by Dow Chemical in the early 1980s, and purchased by Fluor in 1989.

CO_2 storage: The CO_2 was not stored, but used in the food industry and ultimately re-released to the atmosphere.

Cost and financing: There is no data available on the cost of the CO_2 capture facility at Bellingham.

Motivation: The project was motivated by the high demand for food-grade CO_2 in the 1990s. this later declined as natural gas prices increased in the early 2000s.

Technical performance: Performance data is not available for this plant.

Key takeaways: Bellingham remains the largest example of CO_2 capture operating on gas-fired power plant flue gases. As one of the earliest instances of large-scale CO_2 capture from combustion flue gases of any kind, it is regarded as having kickstarted the development of bespoke amine solvents for CO_2 capture for this application. While not conceived or operated for climate benefit, the project demonstrates that large-scale capture of CO_2 from this kind of source is technically possible, even in a commercial context.

Steel

New steel can be produced either from iron ore, or from the smelting of steel scrap. Although recycle rates are high (>85%), demand for new steel is such that the iron ore route (known as 'primary steel') still meets around 70% of global production. Around 90% of new steel production from iron ore uses coal-fired blast furnaces, which are very carbon intensive and have therefore been heavily researched as a target for carbon capture and storage. Another way of producing steel from iron ore is to make 'direct reduced iron' (DRI), which uses furnaces fired with natural gas and is therefore only used in a few countries with access to low-cost natural gas. DRI steel currently represents around 10% of global steel production.
Carbon capture and storage has been trialled on blast furnace exhaust gases at the scale of around four thousand tonnes per year for research purposes, but has not yet been applied to a full-scale plant.

Capturing CO_2 from DRI plants is more straight-forward, as the process is somewhat similar to methane reforming for hydrogen production.
In fact, one of the two major DRI technologies available (Tenova's Energiron) already incorporates CO_2 separation as a means of enhancing plant performance. There are several examples of these plants worldwide where the by-product CO_2 is sold to the food and beverage industry or other uses. The more widely used Midrex technology has also begun offering this option more recently.[69] As for steam methane reforming, there is another source of CO_2 emissions from the gas combustion used to heat the reactor. Tenova's literature indicates that around 60% of the CO_2 emissions from the DRI can be avoided by the integrated CO_2 separation process. However, this represents a smaller fraction of total emissions from the overall steel-making process, of which around 50-70% can be from power generation.

Al Reyadah Emirates Steel

Description: The Emirates Steel plant in Abu Dhabi consists of two direct reduced iron (DRI) units constructed in 2007 and 2011, which produce around 4.2 million tonnes of steel annually. In 2016, 'Al Reyadah' or the Abu Dhabi Carbon Capture company was set up to develop and commercialise carbon capture and storage, identifying the steel plant as an ideal place to demonstrate the technologies.

Storage of CO_2 from the steel plant commenced in November 2016, with the capacity to capture and store 800 thousand tonnes per year.

CO_2 capture: CO_2 separation using monoethanolamine (MEA) was already an integral process in the HYL Energiron DRI technology used by the plant. The CO_2 is then dehydrated and compressed at the 'Al Reyadah' facility.

CO_2 storage: The CO2 is taken by Abu Dhabi National Oil Corporation (ADNOC) and transported 70 km for use in enhanced oil recovery.

Cost and financing: Information on the project costs is not publicly available. The cost of CO_2 from the process has been estimated at $30/t; at this price, enhanced oil recovery is profitable, although still

68 U.S. DOE (ND) *Carbon capture opportunities for natural gas-fired power systems.*

69 Midrex (ND) Carbon capture and use. https://www.midrex.com/carbon-capture-use/

Al Reyadah
Source: U.S. Department of Energy, https://fossil.energy.gov/archives/cslf/Projects/AlReyadah.html

more expensive than conventional oil production in Abu Dhabi.

Motivation: The project was a result of Abu Dhabi's strategic goal of developing carbon capture and storage through the creation of Al Reyadah, while also developing an enhanced oil recovery as a route to boost oil production. EOR was first trialled at small scale in the emirate in 2009.

Technical performance: The project does not make CO_2 capture and storage performance data publicly available. The plant can produce 4.2 million tonnes of steel per year, comprising two units producing 2 million tonnes of steel each, and one smaller 0.2 million tonne 'micro-module' (not treated with CCS). Tenova's literature on the Energiron process suggests that direct emissions from each of the larger units should typically be around 770 thousand tonnes of CO_2, of which up to 60% (462 thousand tonnes) is treated by the CO_2 separation process.[70] This would suggest that the 400 thousand tonnes captured and stored by the Al Reyadah project represents capture of 87% from the processed gases. However, with no imperative to maximise the storage of CO_2 from the unit, it is likely that the process is optimised according to the requirements of the steel production facility and the CO_2 demand of the oil field.

Key takeaways: The Al Reyadah project demonstrates the integration of several established CO_2 technologies. There are several other large Energiron plants already producing pure streams of CO_2, and the use of CO_2 in enhanced oil recovery is also well established, although had not previously been employed at such a scale in the United Arab Emirates. However, it represented a significant step for the Gulf region in gaining experience with CO_2 processing and transport, and raised the profile of the technology as an industrial decarbonisation option.

Cement

The cement industry is an important target for the application of carbon capture and storage technology, as it contributes around 7% of global CO_2 emissions and currently has no other options available for complete decarbonisation. Cement is made by heating natural minerals (limestone, clay, silica) in cement kilns to temperatures of up to 1450°C. Around a third to 40% of the CO_2 released by these plants comes from fossil fuel combustion to reach these high temperatures, but the majority is associated with the release of CO_2 from limestone (calcium carbonate). Switching to clean fuels would therefore only partially address the industry's

70 Duarte et al. (2010) *Achieving carbon free emissions via the Energiron DR process*; Tenova HYL (2015) HYL News, Dec 2015.

71 Brevik P (2022) Brevik CCS. Presentation to Visit from Danish delegation. Available here.

Brevik cement plant
Source: Heidelberg Materials, https://www.brevikccs.com/en

massive emissions problem. Despite the clear role for carbon capture and storage in decarbonising this sector, full-scale CO_2 capture from cement plants has not yet been demonstrated, but the first example is currently under construction at the Brevik cement plant in Norway. The Brevik project plans to capture around 50% of the flue gas from the cement kiln, amounting to 400,000 tonnes of CO_2 per year.[71] This capture rate is determined by the availability of waste heat in the plant, which can be used to power the capture process and minimise the need for additional energy.

Cement flue gas is generally higher in CO_2 concentration than coal power plant flue gases (at least 15%), but very similar technologies have been developed and tested for this application. There are now several other plans for full-scale carbon capture and storage on cement plants in Europe and North America, using a range of different technologies.

71 Brevik P (2022) Brevik CCS. Presentation to Visit from Danish delegation. Available here.

SECTION 3

Conclusions

Building full-scale versions of climate technologies – sometimes known as 'commercial projects' – is a vital step towards more widespread adoption, and a step which most well-established technologies have had to go through, including offshore wind, nuclear, and air pollution controls for power plants. To be truly useful, new technologies need to become mundane, with standardised processes that can be mass fabricated and represent low-risk investments. At this point a technology is often referred to as 'commercialised', even though its commercial viability may depend entirely on environmental and climate policies and regulations.

Carbon capture and storage is an umbrella term for a diverse range of techniques for handling CO_2 and permanently preventing it from reaching the atmosphere. Certain types of carbon capture and storage have already reached commercial status, but unsurprisingly only in applications where there is an economic value for the technology. As such, they mostly do not operate to maximise their benefit to the climate. On the other hand, applications where there is a climate imperative to develop carbon capture and storage technologies (cement, steel, petrochemicals, gas power, direct air capture) have often seen little or no testing at large scales. These applications rely on policy and/or regulations to make such trials financially viable.

Examining the carbon capture and storage project track record therefore provides a mixed picture, with some well-established technologies operating for commercial gain and others designed to test the capabilities of new technologies at large scales. It is normal and even valuable for the true demonstration projects (such as Boundary Dam, Petra Nova, or Quest) to encounter technical issues and identify solutions. Fortunately, the issues encountered by these front-runners have been found to be surmountable – often requiring straight-forward practical fixes such as minor redesign of components, more rigorous cleaning of processed gas, or greater system redundancy to allow operation to continue while maintenance is carried out. The next iteration of each of these technologies should operate more efficiently, economically, and reliably, and the following iteration should perform still better.

Ultimately, the climate science tells us that we need to make CO_2 capture and storage technologies work at very large scales – not just to cut emissions at the necessary speed, but for the inevitable task of removing CO_2 from the atmosphere. The successful projects we have today are sufficient to tell us that these technologies are able to meet this need. However, we also have a clearer idea that not every project attempted will work perfectly – some may face unexpected challenges, be poorly executed, or have weak incentives to perform. In the face of the climate imperative, the response to imperfect projects should be to redouble efforts to ensure that more projects are successful. This will require a combination of technical innovation and policies that ensure projects are designed and operated to maximise climate benefit. As such policies are now beginning to be implemented in several jurisdictions, including the U.S, Canada, and Europe, a new wave of large-scale CCS projects is emerging that can be expected to uphold a high standard of climate performance, and will be more usefully assessed in those terms.[72]

72 CATF (2024) CCS project maps: https://www.catf.us/ccsmapglobal/