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The Carbon Capture Crux

Lessons Learned

Executive Summary

Carbon capture and storage (CCS) is a 50-year-old technology with variable results in capturing and storing carbon dioxide. Project developers have almost always reused the captured carbon for enhanced oil recovery (EOR), producing oil and gas and more emissions.

Carbon capture's role has been rejigged as a climate solution in recent years with its diverse applications being proposed to decarbonise fossil fuel plants and hard-to-abate sectors.

Some widely cited authorities are fuelling the debate on the role of this technology as a climate solution, including the International Energy Agency in both its Energy Technologies Perspectives[1] report and Net Zero by 2050 report.

This push has given a platform to polarising views on carbon capture utilisation and storage (CCUS) and carbon capture and storage (CCS): is it a greenwash to extend the life of fossil fuel assets[2] or a panacea to avert catastrophic climate change consequences?[3]

Is CCS/CCUS a greenwash to extend the life of fossil fuel assets or a panacea to avert catastrophic climate change consequences?

This report aims to shed light on the different applications and conceptualisations of CCUS/CCS, demystifying the technology's applications, concepts and categorisations. It explains the dichotomy between enhanced oil recovery and carbon capture within dedicated geological structures, and the difference between carbon capture and utilisation (CCU), CCUS and CCS. It uses a four-tiered structure to provide an overview of all carbon capture applications, which includes gas processing, power generation, industry application/production, and carbon dioxide removal technologies (CDR).

Finally, 13 flagship cases (10 in operation, two that have failed and one that has been suspended) comprising about 55% of the total nominal capture capacity

[1] IEA. Energy Technology Perspectives. September 2020.
[2] Crikey. Vested interests: fossil-fuel fans will use IPCC report to peddle carbon capture scam. 9 August 2021.
[3] Global CCS Institute. IPCC Report Reaffirms Carbon Capture and Storage as a Critical Technology for Mitigating Climate Change. 5 April 2022.

operating worldwide have been reviewed in detail. The projects are flagship in different senses, with each of them having unique aspects of importance.

Our sample is comprehensive, enough to learn lessons about the whole sector. IEEFA estimates that the studied cases have captured more than two-thirds of all anthropogenic carbon dioxide captured in history.

Appendix 1 summarises our case studies.

What We Found

Further extrapolated in our conclusion at the end of this report, we found:

- Failed/underperforming projects considerably outnumbered successful experiences.
- Successful CCUS exceptions mainly existed in the natural gas processing sector serving the fossil fuel industry, leading to further emissions.
- The elephant in the room of the application of CCS/CCUS in the natural gas processing sector: Scope 3 emissions are still not being accounted for.
- Captured carbon has mostly been used for enhanced oil recovery (EOR): enhancing oil production is not a climate solution.
- Using carbon capture as a greenlight to extend the life of fossil fuels power plants is a significant financial and technical risk: history confirms this.
- Some applications of CCS in industries where emissions are hard to abate (such as cement) could be studied as an interim partial solution with careful consideration.

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Section 1: Introduction to Carbon Capture and its Applications

Although carbon capture utilisation and storage (CCUS) technologies have been in use for half a century, they have gained more traction in recent years. This is especially true after widely cited energy authorities, such as the International Energy Agency (IEA), pushed them more in their portfolio of climate solutions.

The IEA's Energy Technologies Perspectives (ETP)[4] report, published in 2020, emphasises the role of CCUS and carbon capture and storage (CCS) in the clean energy transition.[5] The IEA's seminal Net Zero 2050 report, published in 2021,[6] had similar messaging. The two reports helped rejuvenate the argument for CCUS/CCS as a climate solution.

The Intergovernmental Panel on Climate Change (IPCC)'s six assessment reports provided a platform for polarising voices on CCUS/CCS, namely whether it is

[4] IEA. Energy Technology Perspectives. September 2020.
[5] IEA. CCUS in Clean Energy Transitions – Part of Energy Technology Perspectives. September 2020.
[6] IEA. Net Zero by 2050. May 2021.

greenwashing to extend the life of fossil fuel assets[7] or a panacea to avert catastrophic climate change consequences.[8] The nuance of the arguments likely depended on where interests lie, and truth on such a divisive topic is, of course, complex.

The vastly diverse application of CCUS/CCS often muddles the understanding of the technologies, particularly for uninitiated stakeholders who may mistakenly think of CCUS/CCS as a single subject.

The vastly diverse application of CCUS/CCS often muddles the understanding of the technologies.

CCUS/CCS is not a monolithic topic. Each CCUS/CCS application is largely running on separate tracks of maturity and cost projection. It covers various technologies and processes, contrasting environmental and social risks and opportunities, and differing mitigation potentials across multiple applications.

This report sheds light on different applications and conceptualisations of CCUS/CCS from a historical perspective and reviews most real-world flagship cases. It provides stakeholders, investors and policymakers with historical lessons from this technology. The report also tries to answer questions on whether CCUS/CCS is a climate solution in different contexts.

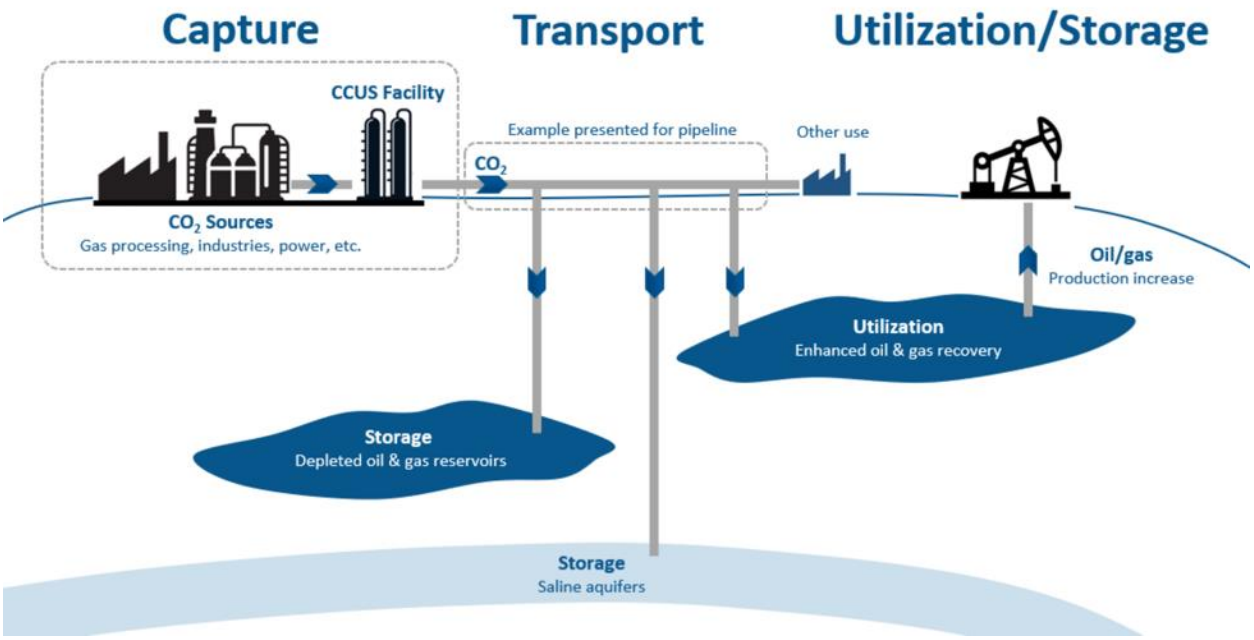
That the technology is in its infancy is not a realistic view. The climate change clock is ticking, and time is limited for trial and error. Stakeholders should take the experiences gained through half a century of utilising these technologies seriously in strategising future pathways for overcoming high emissions and climate change.

What are CCUS, CCS and CCU?

CCUS encompasses three distinct parts: capture, transport, and storage or utilisation, as depicted in Figure 1. Carbon dioxide (CO_2) captured from various stationary sources, such as chemical processes and power generation plants, is transported to sites and stored or utilised, mainly underground.

[7] Crikey. Vested interests: fossil-fuel fans will use IPCC report to peddle carbon capture scam. 9 August 2021.
[8] Global CCS Institute. IPCC Report Reaffirms Carbon Capture and Storage as a Critical Technology for Mitigating Climate Change. 5 April 2022.

Figure 1: CCUS Schematics



Source: IEEFA, Carbon Capture in the Southeast Asian Market Context. 2022.

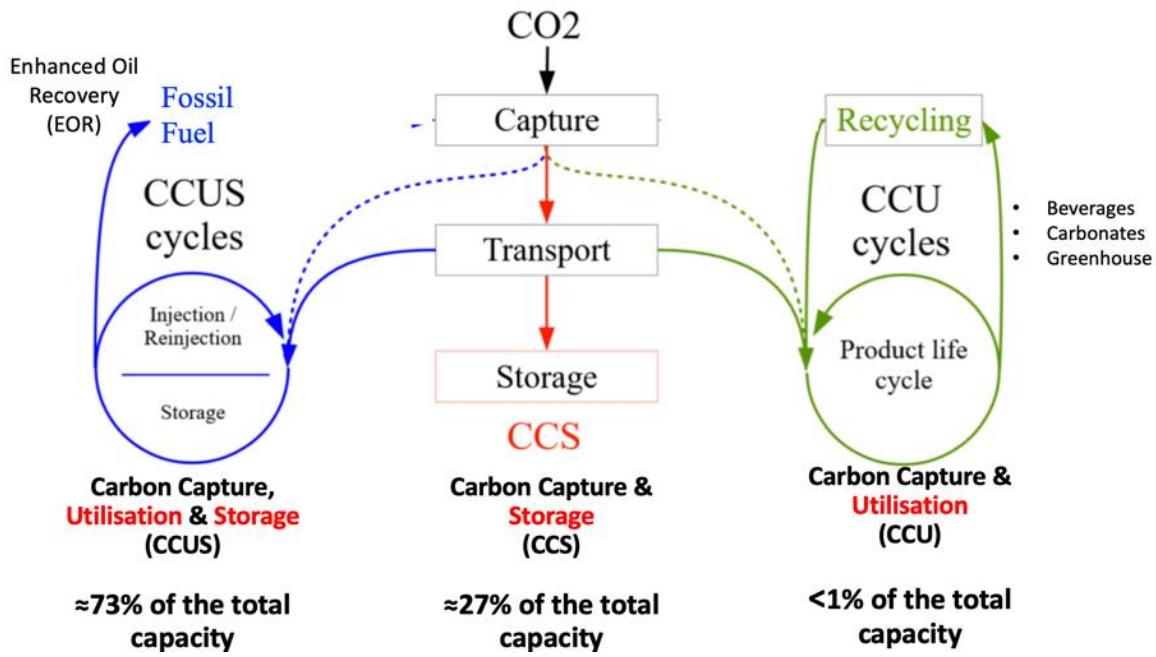
Often this CO_2 is sold as a commodity to oil and gas companies who use it to enhance their hydrocarbon production, hence the term enhanced oil recovery (EOR).[9] In this sense, carbon (C) is captured (C) and then utilised (U) by pumping it into the depleted oil and gas fields, pushing more oil and gas out of the wells and then stored (S) underground.

When CO_2 (C) is captured (C) and stored (S) underground in saline aquifers or other underground deposits and is not used for EOR, the process is called CCS.[10]

There is also a niche application of captured carbon (CC) for utilisation (U) and recycling into other valuable products, such as carbonates and beverages, and more recently products such as cement and plasterboard blocks.[11] This application is about capturing carbon and utilising it (CCU). However, compared to CCUS and CCS, the share of CCU is so far negligible (Figure 2).

[9] Global Carbon Capture Storage Institute (GCCSI). Global status of CCS 2021. 2021.
[10] From now on in this report, whenever the project is EOR, the term CCUS is used and if the project is not an EOR project and has a dedicated geological structure to store the carbon, the term CCS is used.
[11] Australian National University Reporter. Cementing the future of climate action. Winter 2021.

Figure 2: Conceptualisation of CCUS vs CCS vs CCU



Source: Sustainability Journal, MDPI, 2019.

Enhanced Oil Recovery: Injecting CO_2 to Emit CO_2

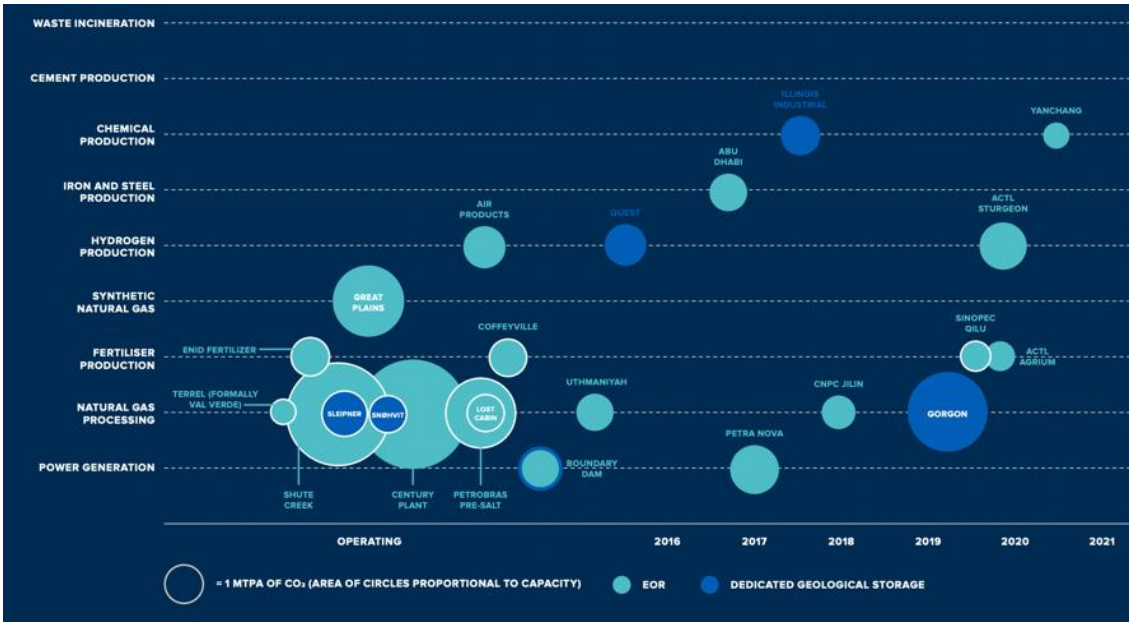
Historically, carbon capture applications have been dominated by enhanced oil recovery (EOR).

CCUS, or EOR with CO_2 (CO_2-EOR), is the largest industrial use of carbon dioxide. The basic idea is that oil and gas companies inject the pressurised CO_2 into existing oil and gas reservoirs to squeeze out more hydrocarbons.

Today, EOR is the only industrial use of CO_2 to have reached considerable scale—EOR projects use about 73% of the CO_2 captured each year globally in recent years.[12] The figure was higher in previous decades (see Section 2). Figure 3 shows the dominance of EOR in carbon capture project applications.

[12] Global CCS Institute. Global Status of CCS 2021. 2021, p. 63.

Figure 3: Dominance of Enhanced Oil Recovery in Carbon Capture Applications



Source: Global Status of CCS Report, Global CCS Institute, 2018.

EOR enhances the oil production rate from fields that have passed the maximum output rate. Therefore, oil producers can make money by revitalising oil fields with declining production rates.

However, EOR itself leads to CO_2 emissions both directly and indirectly. The direct impact is the emissions from the fuel used to compress and pump CO_2 deep into the ground. The indirect impact is the emissions from burning the hydrocarbons that could not have come out without EOR (so-called 'Scope 3 emissions'). When a car in the street or a jet plane uses EOR-induced oil, it still emits CO_2.

In sum, CO_2-EOR uses carbon dioxide to produce more oil rather than curbing its emissions. The additional oil produced this way either gets burned or used for industrial processes, both resulting in CO_2 emissions. Therefore, any claim that CO_2-EOR systems ultimately reduce CO_2 emissions by their nameplate capacity is an overstatement.[13]

About three-quarters of the CO_2 captured annually by multi-billion-dollar CCUS facilities, roughly 28 million tonnes (MT) out of 39MT total capture capacity, is

[13] Institute for Energy Economics and Financial Analysis (IEEFA). Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO_2 But Reaches the Goal Two Years Late. April 2021.

reinjected and sequestered in oil fields to push more oil out of the ground. This oil then gets refined, burnt and, at least partially, returned to the atmosphere.[14]

According to ExxonMobil, the company has stored 120MT of CO_2, 40% of the total anthropogenic CO_2 that humans have captured.[15] Therefore, the inference is that the total cumulative captured CO_2 figure is 300MT.

Looking at the total anthropogenic carbon that humans have captured during the last 50 years demonstrates that carbon capture technology has been serving the oil industry. IEEFA has estimated that the vast majority of the total 300MT of captured carbon throughout history found its use in EOR (~80–90%), and a small proportion of carbon capture projects (~10–20%) have stored carbon in dedicated geological structures, without using it for EOR.

Table 1: Share of CCUS vs CCS in Capturing Carbon; 50-years Cumulative and 2021[16]

Carbon Capture Type	Accumulated Captured CO_2 (Million Tonnes)	Share of Current 39MTPA Capture Capacity (%)
Enhanced Oil Recovery (EOR) - CCUS	>240 MT (80-90%)	~73%
Dedicated Geological Storage - CCS	<60 MT (10-20%)	~27%
Total	~300	100

Source: ExxonMobil, Global CCS Institute Report 2021, IEEFA, IEEFA Estimates.

[14] Several pieces of research discuss the emissions profile of CO_2-EOR systems through different lifecycle periods and boundaries. Some of them show that the CO_2-EOR could be emission-positive in some long-term situations and some discuss the CO_2-EOR as being carbon negative. Most research papers generally compare the emission profile of two types of oil: the conventionally produced oil and the CO_2-EOR-produced oil and conclude that the CO_2-EOR type produces relatively less emissions compared to the conventional one as CO_2-EOR stores some of the injected CO_2 in the ground. It is a true but misleading comparison. In fact, the emission comparison should be between a CCS plant with a dedicated geological structure to sequester CO_2 and a CO_2-EOR system (a CCS plant which serves the oil recovery where the captured CO_2 is injected into the ground to produce more oil). In this case, the CO_2-EOR system would produce more emissions considering the Scope 3 emissions when the oil is burnt plus the amount of CO_2 that comes out with the oil during the recovery process and potential fugitive emissions along the way of CO_2 transportation.

[15] ExxonMobil. Carbon Capture and Storage.

[16] For some of the projects the data on the capturing performance is not available publicly and their average designed capture capacity based on the Global CCS Institute annual reports have been used as a proxy to estimate the volume of captured carbon. Apart from the normal estimation error, the calculated figures are the best estimates based on the available data.

Demystifying Carbon Capture Applications

As opposed to being a monolithic subject, CCUS is an aggregate of technology applications across varying sectors, each sector largely running in its own development tracks and with its own drivers and maturity level. While similarities in technology may exist among different CCUS applications, they may involve different technicalities and approaches.

The four main domains for categorising carbon capture applications are:

1. Gas processing
2. Power generation
3. Industry application/production
4. Carbon dioxide removal (CDR) technologies

Gas processing has been the main CCS application globally. The extracted raw gas has a CO_2 content that needs removal to produce a marketable gas for distribution through pipelines or liquefied in LNG plants for export. Producing the primary usable product (i.e., natural gas) is not possible without separating CO_2. That is why the sector has used carbon capture technology for decades, not necessarily as a climate-friendly solution. On top of that, selling the captured CO_2,[17] mainly to oil producers for EOR, has enhanced the economic viability of gas development projects.

Power generation is a newer use case of CCS to decarbonise the power sector. It is known as post-combustion carbon capture as it aims to capture the CO_2 after burning the fuel. Pre- and post-combustion capture describes the stage of CO_2 capture, whether before or after burning the fuel. The strategic value lies in the ability to retrofit existing fossil-fuelled power plants with carbon capture facilities. This application has shown that it is not commercially advanced and raises several environmental concerns. As previously reported, CCS for power has also faced technical challenges in meeting performance targets. It is not cost competitive with renewables and storage as a climate change mitigation option for the power sector.[18, 19]

CCS is not cost competitive with renewables and storage as a climate change mitigation option for the power sector.

[17] Geological Storage of Carbon Dioxide (CO_2). 3 – Modelling the injectivity, migration and trapping of CO2 in carbon capture and storage (CCS). 2013.
[18] IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[19] Ahmed Abdulla, Ryan Hanna, Kristen R Schell, Oytun Babacan and David G Victor. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. Environmental Research Letters, Volume 16, Number 1. 29 December 2020.

Industrial applications of CCS are very diverse. Companies use it to capture carbon from ethanol, methanol, fertiliser, blue hydrogen and syngas production plants. Also, its application extends to hard-to-abate industries, such as steel and cement production. Carbon capture is an established business in some industrial applications, such as fertilisers and ethanol, while other applications are exploring it for technical and commercial competitiveness at scale.

The conclusion about whether carbon capture technologies could be part of the solution for the decarbonisation of industries is not that straightforward. Using carbon capture technologies needs careful research for each application in different industries and business environments. In some applications, with current high commodity prices, using green hydrogen is starting to look more attractive. It is worth studying carbon capture as an interim solution in a few others.

Carbon dioxide removal (CDR) technologies—bioenergy with carbon capture and storage (BECCS) and direct air carbon capture and storage (DACCS)—are not well advanced technically and commercially. Theoretically, these technologies could offer environmental and social usefulness by capturing carbon from the atmosphere, thus providing the option of negative emissions, should they prove cost-competitive and commercially robust technologies. However, the operating capacity of CDR is virtually zero[20] compared to the 39 million tonnes per annum (Mtpa) CCS industry.

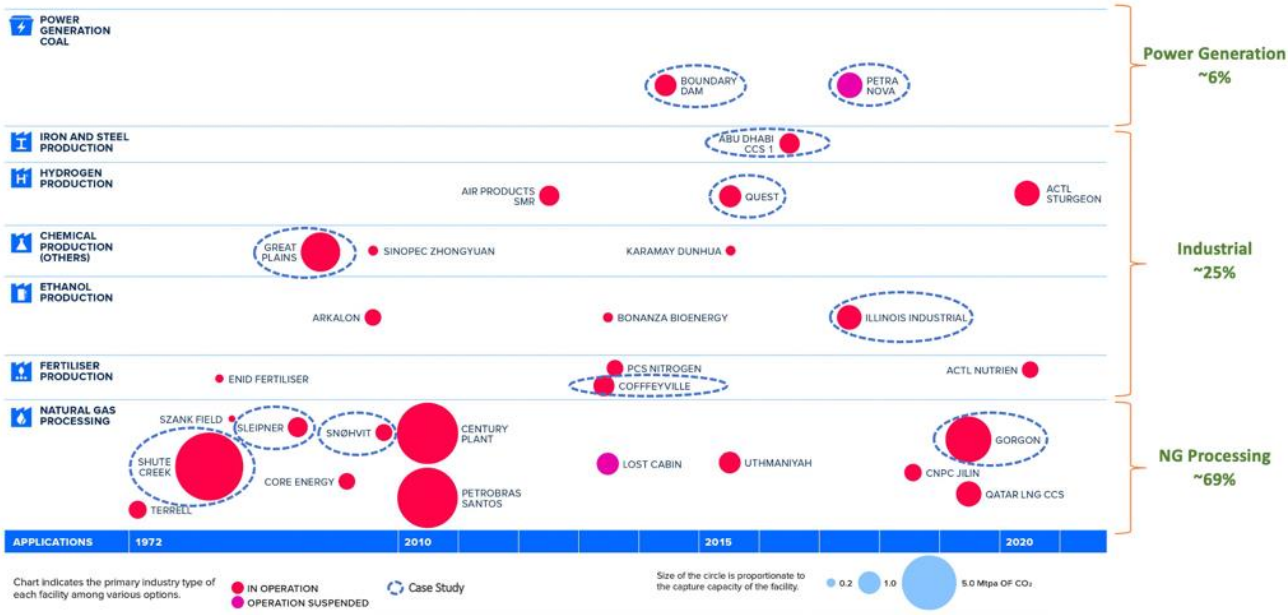
Thirteen Flagship Cases Reviewed

This report reviewed 13 operational large-scale CCS projects—including two flagship projects that failed and one that was mothballed—in terms of their history, economics and performance.[21]

As depicted in Figure 4, we fit sub-sectors identified by the Global CCS Institute into three of the four main categories of carbon capture applications. There is no category for CDR technologies in the figure as CDR is a nascent field and as noted above, the operational capacity of CDR is currently close to zero compared to the other technologies, with just one small project in Iceland.[22]

[20] For example, Orca, a direct air capture facility in Iceland that opened in September 2021, has the capacity to remove about 4000 tonnes of CO_2 a year—equivalent to the annual emissions of around 790 cars. Reuters. World's largest plant capturing carbon from air starts in Iceland. 14 September 2021.
[21] We include in our report two case studies, the Kemper Coal Gasification project and the In Salah CCS project—both of which failed—so they have not been depicted in Figure 4. Also, one of these 11 mentioned cases (Petra Nova) has been mothballed since mid-2020.
[22] Reuters. World's largest plant capturing carbon from air starts in Iceland. 14 September 2021.

Figure 4: Carbon Capture Case Studies



Source: Global CCS Institute 2021, IEEFA.

Natural gas processing dominates carbon capture projects with about 69% of total operational capacity worldwide. It is followed by industrial application, with about 25% of total capacity. Industrial applications with at least one operational CCS project include iron and steel, hydrogen, ethanol, fertiliser, and other chemical production. And a tiny proportion of about 6% is from the power generation sector. Considering the Petra Nova project shut down in 2020, the figure for power generation would be less than 3%.

In this report, we study five flagship projects in the *gas processing sector* to share the lessons from their technical performance and business processes. Four projects are operational, namely **Shute Creek** in the U.S., **Sleipner** and **Snøhvit** in Norway and **Gorgon** in Australia. The Norwegian cases are important as they have been among the few cases that could meet their designed capturing rate, mostly thanks to the unique regulatory/ business environment for Norway's oil and gas companies. Regarding their capture capacity, these four projects account for about half of the active CCS projects in the natural gas processing sector. Despite having some successful projects in this sector, several projects have underperformed their designed capture rate. We look at one such project, **In Salah** in Algeria.

Next we study three projects that have operated in the *power sector*: **Petra Nova** and **Kemper** in the U.S. and **Boundary Dam** in Canada. Petra Nova was mothballed indefinitely in 2020 and the Kemper coal gasification project failed. The report investigates the reasons. Petra Nova and Boundary Dam are the retrofits of two old coal power plants.

Finally, we have chosen five important projects to study for the *industrial applications* of carbon capture. We study these flagship cases in different sub-

sectors of the industry: the **Quest** project in the hydrogen production sub-sector; the **Great Plains CCUS** project in the chemical production sub-sector; the **Illinois Industrial CCS** project in the ethanol production sub-sector; **Coffeyville** in the fertiliser production sub-sector; and **Abu Dhabi CCUS** in hard-to-abate industries worldwide. These five projects account for about 65% of the current capacity of CCS/CCUS projects in industrial applications.

As this report analyses the carbon capture technology through a historical perspective and focuses on existing projects to derive lessons from failures and successes, it does not include any studies of CDR projects.

We cover all 13 flagship projects considering criteria such as their importance, availability of data, age, capacity and performance. Each project has had a unique aspect of importance, cumulatively accounting for around 55% of the total current operational capacity worldwide. Therefore, this sample is comprehensive enough to learn lessons about the whole sector.

IEEFA estimates that the studied cases have captured more than two-thirds of all 300MT of anthropogenic CO_2 in history.

Section 2. Carbon Capture Application in the Natural Gas Processing Sector

Gas processing has been the main CCS/CCUS application globally, with about 70% of current total operational capacity worldwide. Essentially for every 10 CCS/CCUS projects, seven projects are in the natural gas processing sector today.

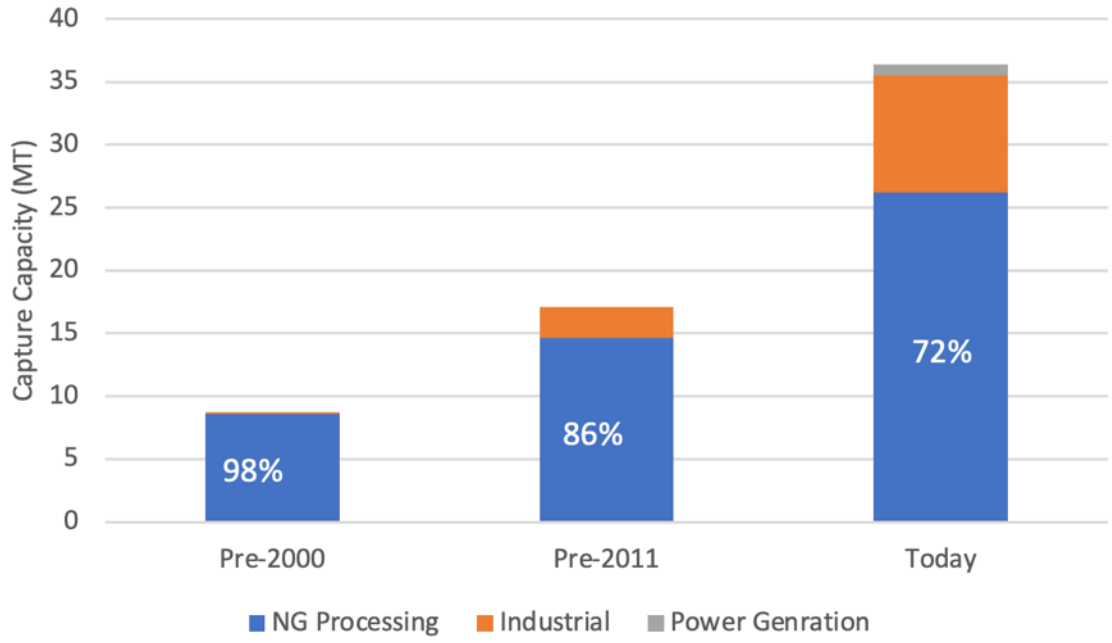
Looking back a decade, the figure was about 86% before 2011 and more than 98% pre-2000 (Figure 5). These figures demonstrate the historical dominance of natural gas processing as an application of carbon capture technology.

The key point about this application of CCS/CCUS is that producing the primary usable product (i.e., natural gas) is not possible without separating CO_2.

The extracted raw gas from any gas field has CO_2 content ranging from less than 3%[23] to 80%[24] in rare cases. This needs to be removed to produce a marketable gas for distribution through pipelines or liquefied in LNG plants for export. Therefore, capturing carbon was a part of the production process for oil and gas companies, regardless of the ultimate disposal or use of carbon dioxide (i.e., venting or using it for another purpose).

[23] IEEFA. Should Santos' Proposed Barossa Gas 'Backfill' for the Darwin LNG Facility Proceed to Development? March 2021.
[24] Energy Procedia. Worldwide development potential for sour gas. April 2011.

Figure 5: Historical Natural Gas Processing Share in CCS/CCUS Applications



Source: Global CCS Institute 2021,[25] IEEFA.

From a historical perspective, climate concerns did not figure in CCUS/CCS projects commissioned before the mid-1990s. In fact, the narrative around CCUS/CCS projects before the global community started to take climate change risks more seriously (i.e., since the Kyoto protocol of 1997) was more about economics than the environment. The only thing is that since the 1970s, oil and gas companies have decided to derive value from a CO_2 by-product, which used to be vented.

The reason was that in the 1970s and early 1980s, a massive supply shortage in the oil market—due to Iran's revolution and its consequent war with Iraq—pushed oil prices up dramatically. Oil companies, on the other hand, were seeking to increase the dropped production rate from their depleting oil wells in the U.S. Pumping CO_2 into the depleted wells to enhance the oil recovery was a promising solution.

Abundant captured CO_2 from the natural gas processing plants was among the most important driving forces behind developing CO_2-EOR technologies. Shute Creek Treating Facility in the U.S., the largest CCUS/CCS facility (7Mtpa) in the world, belongs to this era.

[25] Excluding suspended Lost cabin and Petra Nova Projects.

The economic narrative of using CO_2 for EOR gradually started to change in the 1990s towards an environmental one that sees carbon capture as a climate solution. The Sleipner project, commissioned in 1996, was the first carbon capture project with a dedicated geological structure (CCS), and the ultimate destination of captured CO_2 was a saline formation. Furthermore, it was the first project capturing CO_2 and not using it for EOR.

Due to the regulatory and business environment in Norway, Sleipner has been among the most successful projects of its kind, followed by another Norwegian project, Snøhvit, commissioned in 2007.

With the changing narrative, some authorities started to regulate oil and gas developments conditional on having a CCS facility to capture and sequester the CO_2 emissions of the field. The failed Gorgon project in Australia is an example.

Case Studies

In this section, we review Shute Creek, Sleipner, Snøhvit, and Gorgon in terms of their performance, history and economics.

Shute Creek

The Largest and the Third Oldest CCUS Project in the World

Shute Creek was commissioned in 1986 by ExxonMobil near the LaBarge field in southwest Wyoming, U.S. Gas from the field comprises just 21% methane (regarded as the marketable gas) and 65% CO_2—as such, it is considered among the highest CO_2 and lowest thermal energy content commercially produced gas in the world.

For Shute Creek's business model to work, considering revenue streams from selling products other than methane was inevitable. There was abundant CO_2 from LaBarge and, at the time of commissioning, nearby fields in Colorado and Wyoming were thirsty for CO_2 for enhanced oil recovery (EOR). Carbon capture was integral to the business model's cash generation.

Oil prices were high when the project was conceived in the early 1980s. After the project was commissioned, the tacit assumptions of long-term high oil prices and of oil producers' ongoing inflated demands for CO_2 for EOR were proved in error with two decades of a bearish oil market with low prices.

Shute Creek became a "Sell or Vent" project.

Shute Creek became a "Sell or Vent" project. It could either sell the CO_2 to third parties or vent the CO_2 when prices were low and EOR was uneconomic. The excess CO_2 that could not be sold for EOR has been vented over the years.

As part of the Shute Creek Treating Facility, the carbon capture plant originally captured about 4.3Mtpa.[26] In 2008, the Oil and Gas Conservation Commission questioned Exxon's effort to market the CO_2 and examined possible changes to the permit to vent. Exxon started an expansion project, completed in 2010, that delivered 50% more capture capacity (6–7Mtpa).[27]

With a nominal capacity of about 7Mtpa, Shute Creek is the world's largest CCS facility.[28]

[26] ZeroCO2.no. Shute Creek.
[27] Massachusetts Institute of Technology. LaBarge Fact Sheet: Carbon Dioxide Capture and Storage Project.
[28] Global CCS Institute. Global Status of CCS 2020. 2020.

The plant has captured more anthropogenic CO_2 than any other carbon capture project in the world[29] but it belongs to an era in which there was little public discussion about climate change and little climate-friendly motivation behind commissioning such projects.

Economics and Performance

The original cost for the whole Shute Creek Treating Facility, including the capturing facility, was US$170 million. In 2010 an extra US$86 million was provided to expand the carbon capture facility from 4.3Mtpa to 7Mtpa.[30]

In February 2022, ExxonMobil made the final investment decision to expand its carbon capture at La Barge by 1.2Mtpa at an estimated cost of $400m. It is expected that the expansion will be operational by 2025.[31]

The gas composition entering Shute Creek is 65% CO_2, 21% methane, 7% nitrogen, 5% hydrogen sulphide (H_2S) and 0.6% helium. The Shute Creek Treating Facility separates CO_2, methane and helium for sale. Concentrated acid gas stream, which includes 40% CO_2, is also injected into a carefully selected section of the same reservoir removing and storing approximately 0.4MT of CO_2 per year that is not sold for EOR.

The facility was not planned to have a dedicated geological structure for CO_2 storage, accounting for its "Sell or Vent" status. Were there a customer to buy the CO_2, it would be captured, compressed and transported. With fewer customers in the time of low oil prices, the excess captured CO_2 would be vented.

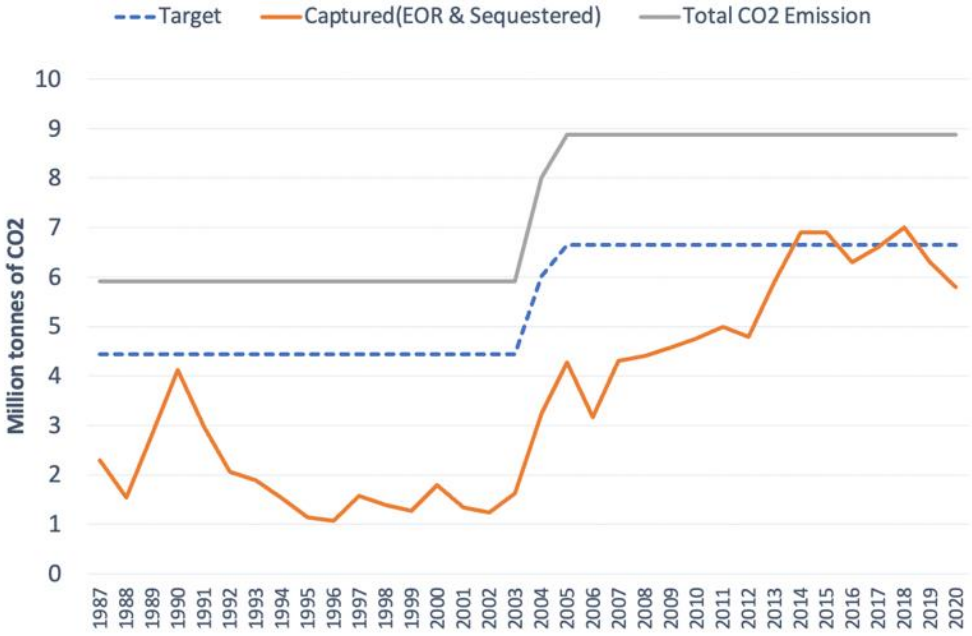
In the first 17 years of weak oil prices, from the beginning of the project to 2003, the plant rarely captured and sold more than 2Mtpa. Since then, soaring oil prices enabled Shute Creek to sell more of its CO_2 for EOR, volumes increasing until 2014 in step with historically high oil prices. From 2014 to 2020, despite oil prices starting to fall, ExxonMobil still managed to sell a high volume of CO_2 for EOR.[32]

Figure 6 summarises the performance of the Shute Creek CCUS plant over its 35-year lifetime. Despite its improved performance over recent years, the plant has reached its capturing capacity target (about 75% of total CO_2 emissions) in only a few of those years. At all other times, the plant has fallen short, mostly by a wide margin.

On average, the Shute Creek CCUS facility has fallen short of its capacity by about 36% over its lifetime, translating to approximately 66MT of CO_2 released into the atmosphere. Essentially, just half of CO_2 emissions captured and the other half vented.

[29] Global CCS Institute. Global Status of CCS 2021. 2021.
[30] IEEFA. Carbon Capture to Serve Enhanced Oil Recovery: Overpromise and Underperformance. March 2022.
[31] Exxon Mobil. ExxonMobil to expand carbon capture and storage at LaBarge, Wyoming, facility. 25 February 2022.
[32] ExxonMobil. Energy and Carbon Summary. 2021, 2020, 2019.

Figure 6: Capturing Performance Trend of the Shute Creek CCUS Plant (1987–2020)



Source: IEEFA Estimates, ExxonMobil Energy and Carbon Summary Reports 2019, 2020, 2021. -- Energy Procedia.

Figure 7 provides a lifetime performance snapshot of the Shute Creek CCUS plant.

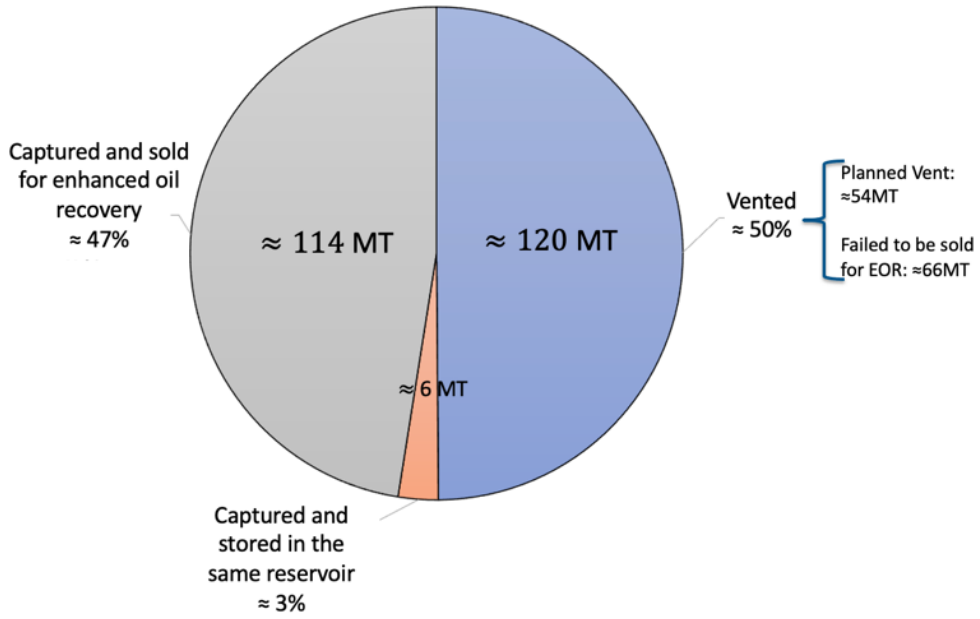
To the end of 2020, IEEFA estimates the treating facility on its own directly produced 240MT of CO_2, of which about 47% (114MT) was captured and used to recover oil (EOR).

Over its lifetime, about 3% of total CO_2 emissions has been sequestered in the same geological formation from which the feeding gas is extracted. The remaining 50% of the CO_2 content of the Shute Creek gas, estimated at about 120MT, has been vented. These numbers suggest that the CCUS plant has reduced the gas at the Shute Creek field only from extremely high CO_2 content (65%) to very high (33%).

To put it into perspective, that figure of 120MT is greater than the combined national emissions of Norway, Sweden and Finland in 2018, according to the World Bank.[33]

[33] The World Bank. CO_2 emissions(kt) – Norway, Sweden, Finland.

Figure 7: Shute Creek CCUS Lifetime CO_2 Capture Performance



Source: IEEFA Estimates, ExxonMobil Energy and Carbon Summary Reports 2019, 2020, 2021. – Energy Procedia.

Sleipner and Snøhvit: Norwegian Successful Experiences

Sleipner

Sleipner CO_2 Storage Project, commissioned in 1996 and located in the Central North Sea between the UK and Norway, was the world's first commercial carbon capture project with a dedicated geological structure for CO_2 sequestration.[34] It was also the world's first demonstration of CCS technology for a deep saline storage reservoir and the first large-scale CCS project to become operational in Europe.[35] To date, it has been among the world's most successful (if not the most successful) carbon capture projects, reaching its target capacity throughout many years of operation with no evidence of leakage or harmful CO_2 movement in the formation.

The natural gas produced from the Sleipner West field contains 4–9% CO_2, so needing to be reduced to less than 2.5% to produce marketable gas. The additional proportion of the CO_2 content of the extracted gas from the field is captured and pumped back to the Utsira geological storage, a 200–250 metres thick massive sandstone formation. The

[34] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[35] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.

estimated storage capacity is 600 billion tonnes of CO_2. Studies have shown that there is no leakage of the CO_2 from this formation into other horizons.[36]

The main motivation for adding this extra step in the hydrocarbon processing facility there—instead of venting the gas—was the Norwegian CO_2 tax introduced in 1991.

The capturing and injection capacity of the project is between 0.85Mtpa[37] and 1Mtpa[38] as cited by different sources.[39, 40] The project stakeholders are Equinor as the operator (~58.3%), ExxonMobil (~17.2%), LOTOS Exploration and Production Norge (15%) and KUFPEC (~9.4%).[41]

The experience from Sleipner was effective in designing and implementing different regulatory frameworks for carbon storage around the world. For example, it was used as a guide for the EU Directive on geological storage of carbon dioxide (adopted by the European Parliament in 2009). Amendments to the London Protocol and the Convention for the Protection of the Marine Environment of the North-East Atlantic (or OSPAR Convention) to allow for CO_2 storage in offshore geological formations also used the Sleipner project as a benchmark.[42]

Snøhvit

Snøhvit is a liquefied natural gas (LNG) development in the Barents Sea off northern Norway, commissioned in 2007. The extracted gas contains 5–8% CO_2 by volume, which is solidified into dry ice under the pressure and temperature conditions of liquefying natural gas and therefore must be removed before the gas is processed into LNG.

As the Norwegian government mandated CCS as a condition to approve Snøhvit's licence, Equinor, the operator of the project, proceeded on a carbon capture project to avoid venting the separated CO_2 from the field. Instead of venting, after the unprocessed raw natural gas stream is transported 143km to shore into the Hammerfest LNG plant in the far north of the country to be liquefied, the removed CO_2 is pumped back to the Snøhvit field offshore through a separate pipeline, to be injected in the geological reservoir 2600 metres beneath the seabed. The company says "a shale cap which lies above the sandstone will seal the reservoir and ensure that the CO_2 stays underground without leaking to the surface".[43]

The LNG project consists of nine wells, eight for production and one for injecting CO_2. The removal process at the LNG plant is designed to capture 0.7Mtpa of CO_2 at full

[36] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[37] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.
[38] Sintef. Sleipner partnership releases CO_2 storage data. 12 June 2019.
[39] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[40] Ola Eiken. Twenty years of monitoring CO_2 injection at Sleipner. In Thomas L. Davis, Martin Landrø, Malcolm Wilson (Eds). Geophysics and Geosequestration. Cambridge University Press. 9 May 2019.
[41] Equinor. Sleipner partnership releases CO_2 storage data. 12 June 2019.
[42] Institution of Civil Engineers. Sleipner carbon capture and storage project. 3 February 2017.
[43] Equinor. Carbon storage started on Snøhvit. 23 April 2008.

capacity. Injection of CO_2 started in April 2008, a year after the gas plant started production.[44] In early 2010, It was announced that it had discovered that there was less storage capacity than expected at the Snøhvit injection site.[45]

A fire in September 2020 at the Hammerfest LNG plant led to it being shut down for more than 18 months.[46] It has resumed operation recently and is preparing to produce LNG again.[47]

Economics and Performance

Stringent emission regulations were the key drivers behind these Norwegian CCS projects.

Carbon Dioxide Tax

The key drivers that enabled these two projects to proceed were the CO_2 tax and climate quota obligation, introduced by the Norwegian government in 1991 and 2005, respectively.

Stringent emission regulations were the key drivers behind these Norwegian CCS projects.

Norway was one of the first countries in the world to impose a CO_2 tax, legislated in the Act on Tax on CO_2 Emissions in Petroleum Activities on the Continental Shelf. This requires companies to pay a CO_2 tax on the combustion of gas, oil, and diesel in petroleum activities in the designated offshore area, as well as on CO_2 or natural gas emissions.[48]

For 2022, the tax rate is NOK 1.65 per standard cubic metre of gas or per litre of oil or condensate. For combustion of natural gas, this is equivalent to NOK 705 per tonne of CO_2. For emissions of natural gas, the tax rate is NOK 1066 per standard cubic metre.[49]

The government in its new climate plan for 2021–2030 has announced that the total CO_2 price of emissions will increase in line with the increase in the tax on non-ETS (Emissions Trading System) emissions subject to an emissions tax, so the total CO_2 price in 2030 will be about NOK 2000/tonne measured in fixed 2020 NOK—almost three times the current price.[50]

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[44] Global CCS Institute. Global Status of CCS: Special Report. Introduction to Industrial Carbon Capture and Storage. June 2016.
[45] Massachusetts Institute of Technology. Snohvit Fact Sheet: Carbon Dioxide Capture and Storage Project.
[46] Reuters. Norway LNG plant restart faces new delay in blow to Europe's gas supply. 31 January 2022.
[47] Offshore Engineer. Norway's Hammerfest LNG Plant Resumes Operation After 20-month Outage. 27 May 2022.
[48] Norwegian Petroleum. Emission to Air. Updated August 2021.
[49] Norwegian Petroleum. The Government's Revenues. Updated May 2022.
[50] Ministry of Climate and Environment. Norway's comprehensive climate action plan. 1 August 2021.

Quota Obligation

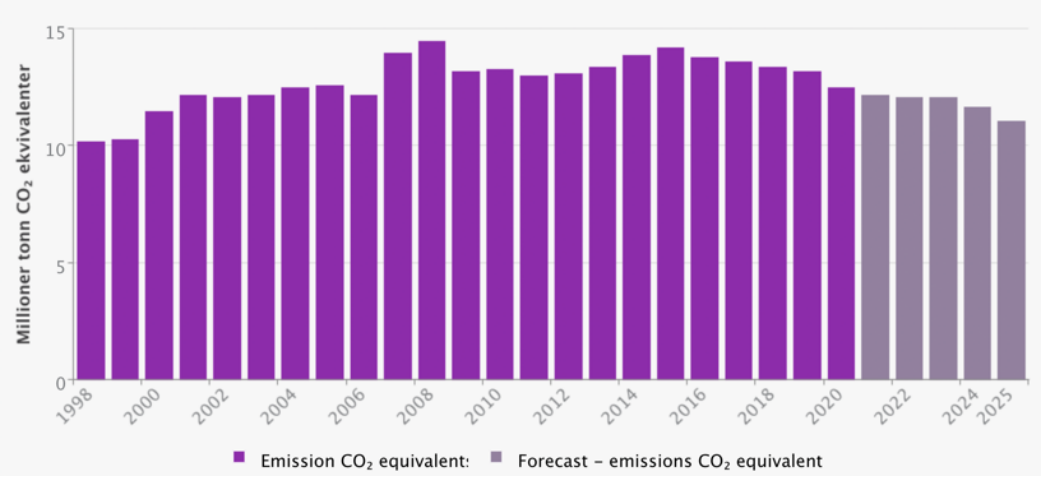
The Climate Quota Act, enacted in 2005, connects Norway to the EU's quota system for greenhouse gas emissions, and the country joined the European Emission Trading System in 2008. Norwegian companies are subject to the same quota obligations as those in the EU. The system is currently in its fourth period, which runs until 2030.[51]

The EU quota system establishes a maximum level of total emissions. This ceiling is reduced on an annual basis to ensure that the system contributes to the system's set emission target when the relevant quota period expires. Quotas are either auctioned or allocated free. In recent years, the CO_2 price in the EU quota system has been increasing, putting a greater burden on polluters.

The combination of the CO_2 tax and quota obligation means that the companies on the continental shelf are facing an extremely high price per tonne for emitting CO_2. The figure is significantly higher than the tax most companies in other sectors must pay in Norway and massively higher than the obligations on similar oil and gas companies in other countries with fossil-based economies.

With these instruments in place, emissions from the Norwegian petroleum sector have been virtually stable during the past decade (Figure 8) with relatively stable oil and gas production (Figure 9). Under the effect of coming, more stringent regulations, emissions are expected to decrease. The Norwegian Ministry of the Environment has described CO_2 taxes as the most important tool for reducing emissions.[52]

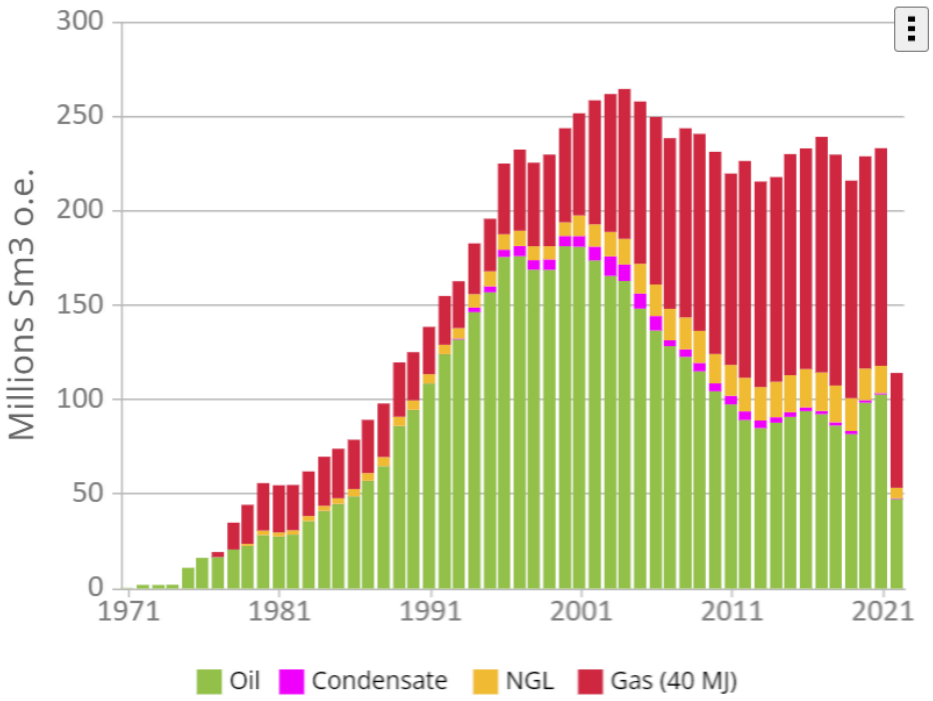
Figure 8: Emissions of Greenhouse Gases from the Norwegian Petroleum Sector



Source: Norwegian Petroleum, Emissions to Air.

[51] European Commission. EU action against climate change. EU emissions trading — an open system promoting global innovation. 2007.
[52] Norwegian Ministry of the Environment. Norway`s Fifth National Communication under the Framework Convention on Climate Change. Status report as of December 2009.

Figure 9: Norwegian Petroleum Production



Source: Norwegian Petroleum Directorate.

CCS Was Financially Viable for Norwegian Cases

The regulatory framework that was the main motivation for these CCS projects in turn made them economic and pushed the oil and gas industry to adopt CCS in extraction facilities.

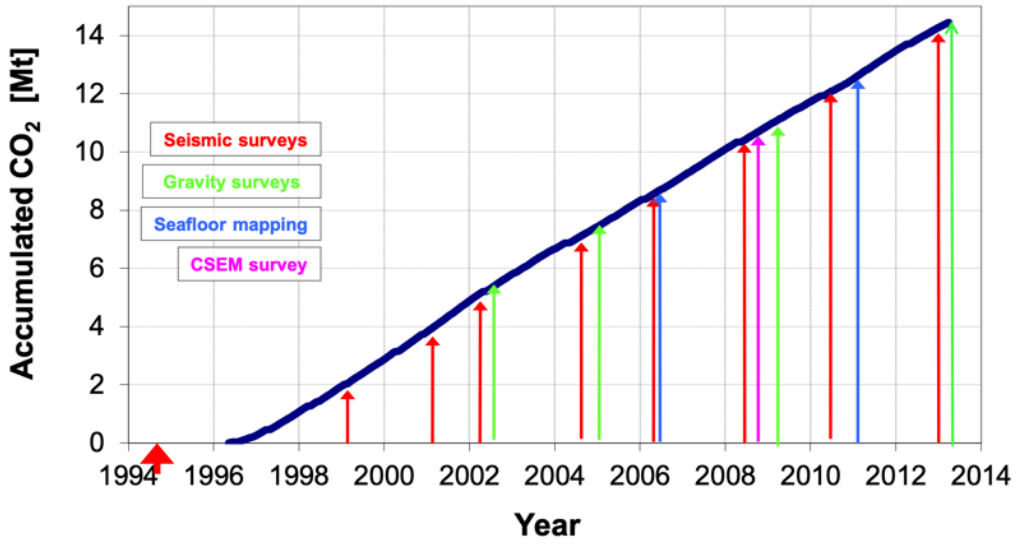
When the Sleipner CCS project was commissioned in 1996, five years after the Norwegian government introduced the carbon tax, the levy on natural gas processing in the North Sea petroleum extraction sector was US$49 per tonne of CO_2.[53] Had the operators vented, for example, 1MTof CO_2 in that first year, the tax bill would have been US$49 million. On the other hand, the additional investments to compress and inject the removed CO_2 amounted to about US$100 million in 1996).[54] Injecting CO_2 was estimated to cost about $17 per tonne.[55] Considering injection averaged about 0.9Mtpa, the partner companies could have recovered the capital cost and operating injection cost of the project in the first few years of the project.

[53] Annegrete Bruvoll og Bodil Merethe Larsen. Greenhouse gas emissions in Norway: Do carbon taxes work? Statistics Norway, Research Department. Discussion Papers No. 337. December 2002.
[54] Olav Skalmeraas. Vice President CCS, Statoil. Sleipner carbon capture and storage project. In ICE Group. 3 February 2017.
[55] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.

The same 'carrot and stick' measures applied to the Snøhvit project, with millions of dollars saved in avoiding the carbon tax while complying with stringent emission regulations.

The Sleipner CCS project has operated consistently near its capturing capacity. Figure 10 shows the project's capturing performance up to 2014. It demonstrates the steady performance of the carbon capture facility.

Figure 10: Sleipner CCS Injection and Monitoring History (1994–2014)



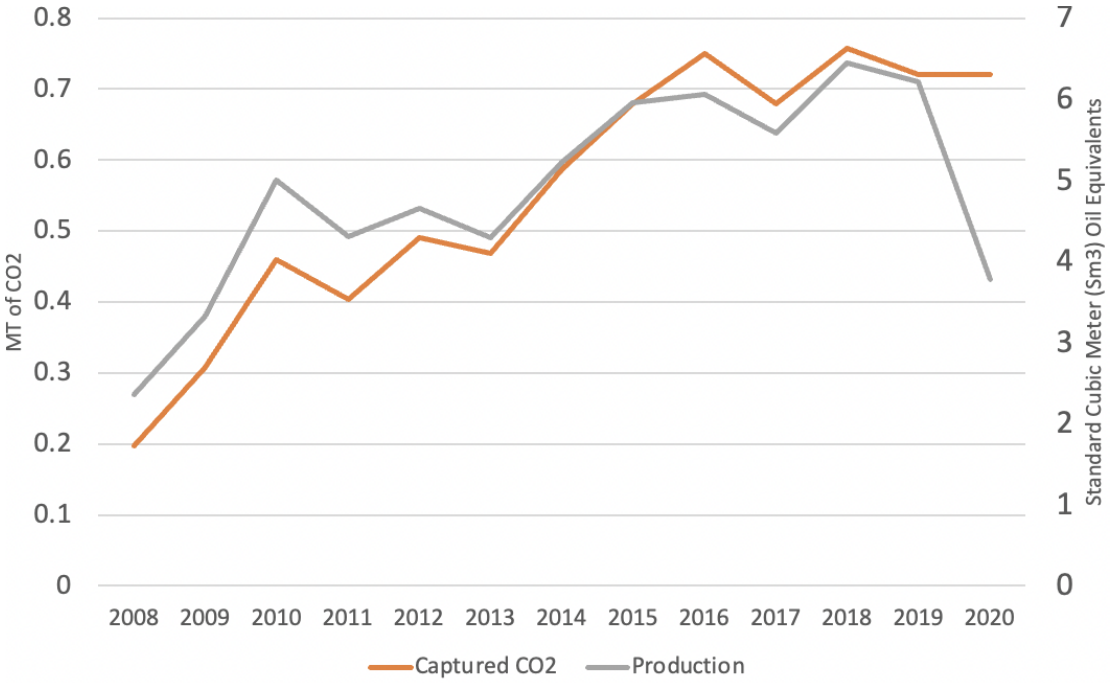
Source: Statoil, The Sleipner CCS Experience, 2014.

Snøhvit's capturing rate has been increasing since its commissioning in 2008, surpassing its capture target of 0.7Mtpa in recent years. Figure 11 shows the capture performance of the project. The reason that Snøhvit had been capturing less than its 0.7MT nominal capacity in the early years of the project was not due to its underperformance. This is evident from the gas production level of the project from which Snøhvit CO_2 is sourced (second axis of Figure 11). The correlation between the production and capturing rates confirms the steady performance of the carbon capture facility with its nominal capacity in recent years, where the production of the field stands at its maximum as well (Figure 11).

Since commissioning in 2008, Snøhvit has captured more than 7MT of CO_2, averaging 0.55–0.6MT annually.[56]

[56] Olav Skalmeraas. Sleipner carbon capture and storage project. 3 February 2017.

Figure 11: Snøhvit Project: Production vs Captured CO_2



Source: Norwegian Petroleum, Snøhvit. Environmental Science and Technology Letters, 2022.

Figure 12, based on Equinor's 2021 sustainability report, demonstrates the total CO_2 captured and stored per year by the projects it operates. Cumulative capacity of Snøhvit and Sleipner is depicted as the orange line in the graph. Other than in the past two years, there is a consistent trend in capturing carbon.

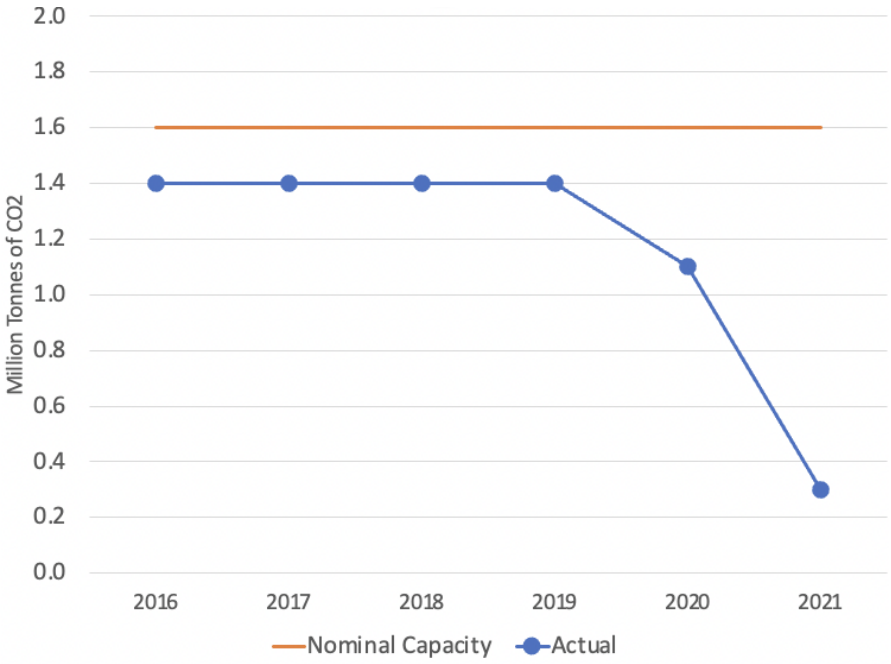
The drop in capturing rate in 2020 and 2021 was due to the fire in September 2020[57] in the Hammerfest LNG plant, which fed CO_2 back to Snøhvit. The low capture for those years is not related to the CCS plant underperformance.

Moreover, Sleipner field's production has been in its late tail phase[58] throughout the last decade, otherwise the capture figures of the two projects would be at their 1.6MT nominal capacity.

In the past two decades, several research efforts on these two projects have reported no leakage or harmful movement of stored CO_2 in the reservoirs.[59, 60]

[57] Upstream. Hammerfest LNG plant to restart next week after shutdown extended by six days. 16 May 2022.
[58] Norwegian Petroleum. SLEIPNER ØST. Website accessed August 2022.
[59] Andy Chadwick, Rob Arts, Ola Eiken, Paul Williamson and Gareth Williams. Geophysical monitoring of the CO_2 plume at Sleipner, North Sea: An outline review. 2006.
[60] Andy Chadwick, Benjamin Marchant, and Gareth Williams. CO_2 storage monitoring: leakage detection and measurement in subsurface volumes from 3D seismic data at Sleipner. 2014.

Figure 12: Snøhvit and Sleipner Projects: Carbon Capture Performance (2016–2021)



Source: Equinor Sustainability Report, 2021.

Gorgon

World's Largest CCS Project

The Gorgon LNG project on Barrow Island off the Pilbara coast of Western Australia is the world's largest such projects, with export capacity of 15.6MT of LNG and provides the state with up to 300 terajoules (TJ) of domestic gas daily.[61]

The plant was planned to be equipped and simultaneously started with the world's largest carbon capture project with dedicated geological structure in 2016.[62]

It has a nominal maximum capacity of 4Mtpa accounting for 40% of the capacity of all CCS projects with dedicated geological storage operating around the globe.[63] The Gorgon CCS project was initially planned to capture and inject underground more than

[61] WA Department of Mines, Industry Regulation and Safety. Gorgon Carbon Dioxide injection project. Website accessed August 2022.
[62] Massachusetts Institute of Technology. Gorgon Fact Sheet: Carbon Dioxide Capture and Storage Project.
[63] Global CCS Institute. Global Status of CCS 2021. 2020.

100 million tonnes of CO_2 over its life. This was supposed to reduce Gorgon's greenhouse gas emissions by about 40%.[64]

The CCS project was meant to start operations concurrently with the LNG plant in March 2016, though several technical problems meant CCS injection did not start until August 2019. As a result, the facility completely missed its targets for the first three and a half years.

The Gorgon Project is a joint venture between the Australian subsidiaries of Chevron, the operator (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and JERA (0.417%).[65]

Economics and Performance

The Gorgon CCS project started with great fanfare, both as Australia's largest project and as the world's largest CCS project with a dedicated geological structure. It received $60 million from the Australian government as part of the Low Emissions Technology Demonstration Fund.[66]

The $3.1 billion Gorgon plant produced its first LNG cargo in March 2016[67] but the first CO_2 injection from its CCS facility[68] did not occur until three and a half years later. Start-up checks in late 2017 found leaking, corroded valves and excess water in the pipeline between the LNG plant and the injection wells, a potential cause of corrosion.[69]

Technical problems did not end there. In January 2021, it was reported[70] that the WA Department of Mines, Industry Regulation and Safety had ordered Gorgon to reduce the volume of carbon captured by the project, due to structural issues. Essentially, sand was blocking the well that reinjects water underground, compromising the crucial pressure management system.

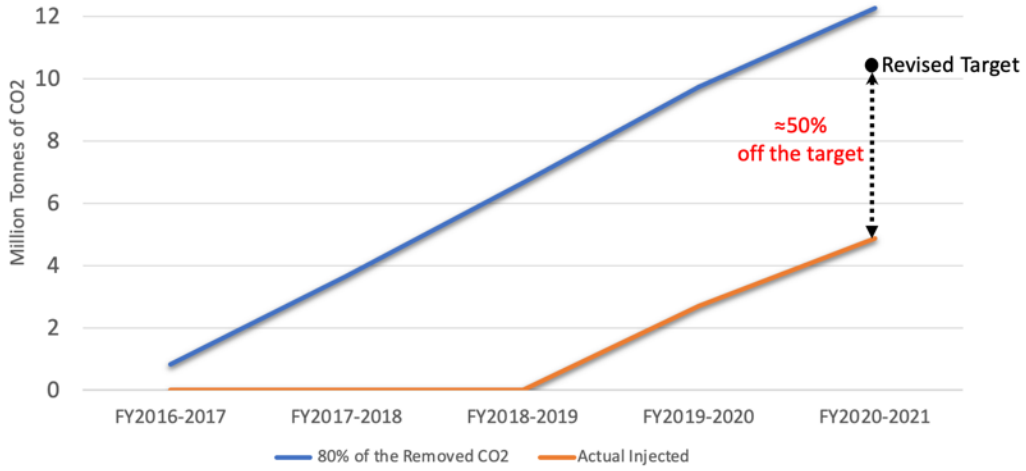
A closer look at Gorgon's CCS target and results demonstrates the project's considerable underperformance in the first five years. Calculated on a five-year rolling average commencing on 18 July 2016, Chevron committed to ensure that at least 80% of reservoir CO_2 removed during processing at the gas treatment plant, that would otherwise be vented to the atmosphere, would be injected underground.[71] On this

[64] Chevron. Gorgon Gas Development and Jansz Feed Gas Pipeline Five-year Environmental Performance Report 2015–2020. October 2020, p. 4.
[65] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[66] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[67] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[68] Financial Times. Monster problem; Gorgon project is a test case for carbon capture. 26 July 2021.
[69] The West Australian. Carbon hiccup for Chevron with 5 million-tonne greenhouse gas problem at Gorgon LNG plant. 19 December 2017.
[70] Boiling Cold. Chevron's Gorgon emissions to rise after sand clogs $3.1bn CO_2 injection system. 12 January 2021.
[71] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 45.

basis, the Gorgon CCS plant should have captured at least 12.3MT of the removed CO_2 in its five years of operation.

The environmental performance reports show that the plant had injected only 4.9MT by July 2021. The shortfall from the five-year target is claimed to be 5.23MT CO_2.[72] Putting all this together, it can be inferred that the Gorgon CCS project's revised target for the first five-year period was about 10.1MT and it failed to meet this target by about 50% (Figure 13 shows the cumulative trend of Gorgon's sequestered CO_2 versus the cumulative target trend).[73]

Figure 13: Gorgon CCS Plant's Performance (Cumulative Trend, 2016–2021)



Source: Gorgon Environmental Performance Reports 2015–2020 & 2021

In the Gorgon 2021 environmental performance report, Chevron cited planned and unplanned maintenance among other causes for the underperformance of the plant.[74]

Gorgon's technical troubles and ongoing "unplanned" maintenance after five years illustrate some of the inherent and unique risks of CCS, despite the technology's decades of operation.

Gorgon has recently agreed to acquire and surrender credible greenhouse gas offsets recognised by the West Australian government to offset its target shortfall of 5.23MT of CO_2. Estimates of what this may cost Gorgon vary from US$100 million to US$184 million.

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[72] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 45.
[73] In its latest environmental performance report published in November 2021, four months after the first five-year period ended, Chevron stated that 5.5MT had been injected in the five years of the project's lifetime.
[74] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 44.

The project is expected to run for 40–45 years, after which there will be a closure period of 15 years. Post-closure, liability will be handed over to the WA government.

The project also has failed to reach its five-year rolling average (ending July 2022) target.[75]

Other Big CCS/CCUS Project Failures in the Natural Gas Processing Sector

Apart from the operating projects, several projects in this sector have failed or been suspended due to technical issues and/or environmental concerns. A case in point is the In Salah project in Algeria.

In Salah

The In Salah project in Algeria was a CCS project with a total cost of US$2.7 billion. Equinor (Previously Statoil) was the operator, and the announced capture capacity was 1–1.2Mtpa.[76]

Injection started in 2004 and was suspended in 2011 due to concerns about the integrity of the seal. Nevertheless, the project successfully stored 3.8MT of CO_2 in the Krechba Formation during its lifetime.[77]

Analysis of the reservoir, seismic and geo-mechanical data from 2010 led to the decision to suspend CO_2 injection in June 2011. Concerns about possible vertical leakage into the caprock led to an intensified R&D program to understand the geo-mechanical response to CO_2 injection at this site.[78]

Lost Cabin is another example of a project in which CO_2 injection was suspended in 2018. It was a CCUS project (CO_2-EOR) with a capacity of 0.9Mtpa started in 2013 in Fremont County, Wyoming, U.S. ConocoPhillips and Denbury were the companies involved in the project.[79]

Just after five years of operation, in 2018, a fire occurred at the Lost Cabin Gas Plant in Wyoming, resulting in the shutdown of the plant's CCUS facility. There was an expectation that operations would restart by the end of 2020 with a lower capture

[75] The Guardian. Gas giant Chevron falls further behind on carbon capture targets for Gorgon gasfield. 16 July 2022.
[76] In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.
[77] In Salah Fact Sheet. Carbon Dioxide Capture and Storage Project.
[78] In Salah Fact Sheet. Carbon Dioxide Capture and Storage Project.
[79] Lost Cabin Fact Sheet. Commercial EOR using Anthropogenic Carbon Dioxide.

rate of 0.7Mtpa.[80] But it did not happen, and the latest Global CCS Institute report, published in late 2021, still labels the project as suspended.[81]

Enhanced Oil Recovery Business Dominates Natural Gas Processing Sector

Natural gas processing has been the main CCS/CCUS application historically, with about 70% of current total operational capacity worldwide. The first CCUS project, Terrel, established in 1972, was in the U.S.

Developing such projects was not about environmental or climate concerns in the 1970s. Separating CO_2 from extracted raw gas is essential to producing marketable and flammable natural gas. It was/is a technical must.

Further, during the energy crisis in the 1970s and 1980s, the interest in capturing the separated CO_2 and selling it to oil companies to enhance the rate of their oil production started to increase. It was a win-win deal for both gas producers who could increase their revenue by selling a previously vented CO_2 to oil companies and for the oil companies who could revitalise their ageing depleted oil wells and get more oil out of them to sell in those eras of the bullish oil market. Hence, economics was the second incentive behind developing such projects in that era.

This is evident in the share of carbon capture projects servicing EOR activities (CCUS) compared to the carbon capture projects with dedicated geological storage for sequestering the carbon without using it for EOR(CCS). Nevertheless, more than 73% of operational projects in the natural gas processing sector remain dedicated to EOR projects.

More than 73% of operational projects in the natural gas processing sector remain dedicated to EOR projects.

And as EOR is about producing more oil and gas, encouraging investment in these fossil fuels negates the very initial claimed emission reduction goal for carbon capture technology.

Scope 3 Emissions—the Elephant in the Room

Gas processing CCS/CCUS covers a tiny proportion of the value chain emissions compared to CCS/CCUS in other sectors.

As gas processing CCUS is largely about 'capturing excess CO_2', it is obvious that CCUS in the sector is *not* about reducing Scope 3 emissions from the final

[80] Global CCS Institute. Global Status of CCS 2020.
[81] Global CCS Institute. Global Status of CCS 2021.

combustion/use of gas. Rather it is about minimising production-related Scope 1 emissions from gas with excessive CO_2 content. This is in contrast to most other CCUS applications in the industrial and power sector, which aim to minimise the emissions coming from the end consumption of fossil fuels, whether by combustion or as feedstock materials.[82]

Therefore, giving the green light to new oil and gas projects just because of CCS/CCUS promises attached to those projects is not climate friendly.

Even if the CCS/CCUS facilities work at their capacity (which was not the case historically, barring some exceptions), such projects could only manage a minor proportion of the value chain emissions they themselves produce by adding CCS/CCUS.

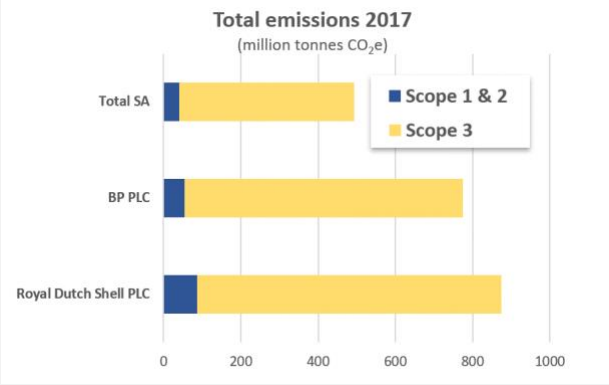
The gas burnt at the end of the value chain produces the biggest chunk of emissions, which CCU/CCUS proposals do not address.

Scope 1, 2 and 3 Emissions

Value chain emission of different products is categorized into three different scopes, as outlined by the Green House Gas (GHG) Protocol Corporate Standard.

Scope 1 emissions constitutes emissions from sources owned or controlled by the producer company. Scope 2 represents indirect emissions from purchased energy inputs such as electricity or heat which are not generated directly by the company. Scope 3 represents all other emissions in the value chain, including those located in the upstream (input) and downstream (output) part of the company's process.

Specific for companies involved in energy *extraction*, it is important to note that the end product emissions (Scope 3) constitute a much greater portion of the overall (Up to 90%). Below chart further illustrates the typical emission scopes for oil & gas companies.



Source: Trucost, S&P Global Market Intelligence.

[82] IEEFA. Carbon capture in the Southeast Asian market context: sorting out the myths and realities in cost-sensitive markets. April 2022.

Lessons Learned

In general, due to its association with EOR and historic capture rate issues,[83, 84] carbon capture in the natural gas processing sector has minimal environmental and social credibility as a decarbonisation option.

The most obvious point is that there is no more room for a new EOR project (CCUS) as it contradicts net-zero goals and emission reduction activities. In contrast, EOR has been the central part of the carbon capture application in this sector and others historically.

A new EOR project (CCUS) contradicts net-zero goals and emission reduction activities.

What about capturing and storing carbon without using it for oil production (CCS)?

As clearly stated in the seminal IEA's Net Zero 2050 report,[85] there should be no new oil and gas field developments if the world wants to reach net zero by 2050 and avert the catastrophic consequences of climate change. Therefore, any new oil and gas development should not get a green light, with or without CCS.

Even if a CCS project could capture a majority of the oil and gas facilities' emissions (which most projects show is unlikely), it could only capture 10–15% of the value chain emissions of oil and gas produced by those fleets (i.e., Scope 1 and 2 emissions). Roughly 80–90% of the emissions are Scope 3 emissions,[86] and CCS projects cannot do anything about that.

The niche remainder of existing gas processing units are not 'new' and would be operating through the next one or two decades until renewables, green hydrogen and battery technologies take up the whole energy system. They might provide cases to think about, but there are still risks associated with these.

There is no confidence that the proposed CCS projects could meet their designed capture rates. Except for a few successful cases in a unique regulatory environment, such as Norway, with high carbon taxes and stringent environmental regulations, the history of carbon capture technology is full of failed or underperformed projects. This report has studied some of the biggest ones.

There is also no room to bet billions of dollars on projects that could not meet expectations. Instead, there are proven, cost-effective, and established investment alternatives to battle climate change, such as solar and wind energy.

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[83] Robertson and Mousavian. IEEFA. Carbon Capture to Serve Enhanced Oil Recovery: Overpromise and Underperformance. March 2022, pp. 18–20.
[84] IEEFA. Gorgon Carbon Capture and Storage: The Sting in the Tail. April 2022.
[85] IEA. Net Zero by 2050. May 2021.
[86] Robertson and Mousavian. IEEFA. Santos 2022 climate change report. 1 April 2022.

The other problem with CCS projects is the availability of suitable geological storage locations nearby the projects to make the finance of CCS work.

Monitoring is another challenge—the trapped CO_2 underground needs monitoring for centuries to ensure it does not come back to the atmosphere. Leakages and fugitive emissions in the long term are serious risks. It is impossible to guarantee that the stored CO_2 will stay underground and not leak into the atmosphere. There are several real-world examples of failure in keeping gas underground. The best example is the California Aliso Canyon gas leak in 2015, the worst man-made greenhouse gas disaster in U.S. history when 97,000MT of methane leaked into the atmosphere.[87] The other one is the In Salah project in Algeria, which was a CCS project with a total cost of US$2.7 billion.[88] Injection started in 2004 and was suspended in 2011 due to concerns about the integrity of the seal and suspicious movements of the trapped CO_2 under the ground.

It is impossible to guarantee that the stored CO_2 will stay underground and not leak into the atmosphere.

There will always be a risk of such disasters for any CCS project. The IPCC's Carbon Dioxide Capture and Storage Special Report stated:

> *"CO_2 storage is not necessarily permanent. Physical leakage from storage reservoirs is possible via (1) gradual and long-term release or (2) sudden release of CO_2 caused by disruption of the reservoir."*[89]

The other challenge is liability. The question of who will be responsible for long-term monitoring of the geological structure is crucial. Large oil and gas companies mainly benefiting from the gas developments must be liable for any failure/leakage and monitoring costs of CCS projects, specifically if they get subsidies, grants and tax credits for capturing the carbon.

The most recent example of the liability challenge is the Gorgon CCS project discussed earlier. The expected project life is 40–45 years, after which there will be a closure period of 15 years. Post closure, the Western Australian government,[90] essentially taxpayers, take over the project's liability.

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[87] The Washington Post. California gas leak was the worst man-made greenhouse-gas disaster in U.S. history, study says. February 2016.
[88] Massachusetts Institute of Technology. In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.
[89] Intergovernmental Panel on Climate Change. Carbon Dioxide Capture and Storage Report. 2005.
[90] WA Department of Mines, Industry Regulation and Safety. Gorgon Carbon Dioxide injection project.

Section 3: Carbon Capture Application in the Power Sector

As one of the highest emitting sectors, the power sector (electricity and heat production) had the largest increase in CO_2 emissions by sector in 2021. This accounted for 46% of the global increase in emissions in 2021. CO_2 emissions from the sector neared 14.6 gigatonnes (GT), their highest ever level.[91]

Power plants inherently emit large volumes of CO_2.

Power plants inherently emit large volumes of CO_2. For example, a 1 gigawatt (GW) coal plant could emit 5–7MT of CO_2 annually.[92]

The most recent proposed application for CCS/CCUS is retrofitting existing, and usually old,

[91] IEA. Global Energy Review: CO_2 Emissions in 2021. March 2022.
[92] Global Energy Monitor. Estimating carbon dioxide emissions from coal plants. Accessed on 3 February 2022.

fossil-based power plants with carbon capture technology to reduce their staggering emissions.

CCUS for the power sector is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream, as evidenced by the string of historical issues in retrofitting CCUS into power plants with several failed projects and cost blowouts. In contrast to gas processing and certain industrial processes that could generate exhaust gas with 40–90% CO_2 composition, coal plants emit gases that typically only contain 10–14% CO_2, while gas power plants generate 4–5% CO_2.[93] Small in concentration but large in terms of absolute volume globally.

Over the years, IEEFA has published a comprehensive body of knowledge in assessing the economics and viability of CCS/CCUS projects,[94] particularly its application in the power sector. Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity delivered to consumers.[95] Under normal operation, power plants already consume a portion of the power they generate for self-use. CCS/CCUS impose additional energy penalties into the mix, typically by drawing steam or power to operate the capture process.

This also means that more fossil fuels will need burning to generate the same amount of electricity in a non-CCUS power plant. Decades of technological progress have been devoted to increasing coal power plant efficiency from the sub-38% of subcritical plants to the ~45% of Ultra Super Critical (USC) plants. A loss of 8–12% poses a substantial barrier for many CCS/CCUS applications.[96]

To be able to compete in the electricity market context, the high cost of CCS/CCUS projects will need compensation—by selling the captured CO_2, receiving government incentives, or charging a premium price to consumers. However, these pathways are not guaranteed and also could lead to financial instability for the project or environmental externalities in the case of using CO_2 for EOR.

Selling captured CO_2 for EOR contradicts the very goal of capturing carbon.

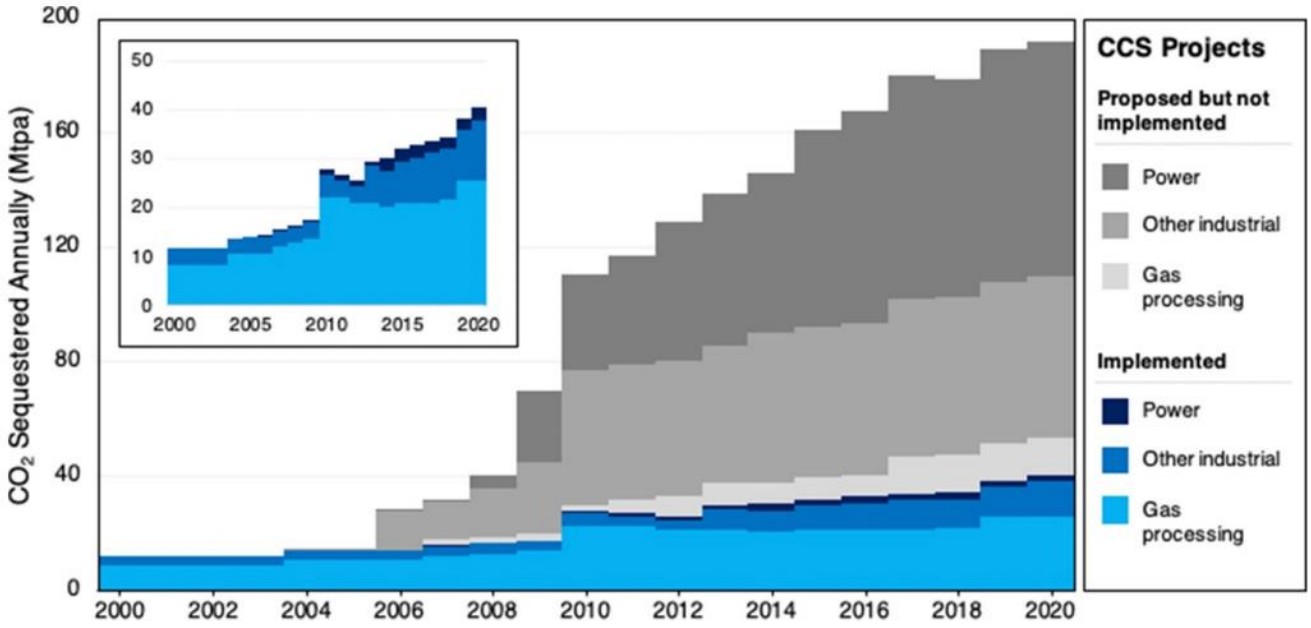
Government incentives could flow into fast-growing, efficient, and clean, renewable energy technologies and battery and storage sectors. Selling captured CO_2 for EOR contradicts the very goal of capturing carbon as it leads to producing fossil fuels. Moreover, considering the EOR business as a cash-generating business for power

[93] IPCC. Carbon capture utilization and storage. 2005. Energy Procedia. Comparison of solvents for post-combustion capture of CO_2 by chemical absorption. 2009.
[94] IEEFA. Carbon Capture and Storage.
[95] Energy consumption can be in the form of drawing steam from the power plant to heat solvent-based CCUS process.
[96] IEEFA. Carbon capture in the Southeast Asian market context: sorting out the myths and realities in cost-sensitive markets. April 2022.

plant owners is a flawed assumption. EOR activities highly correlate with oil prices, and the demand for CO_2 would be as volatile as oil prices. IEEFA has elaborated on this issue in previous research.[97]

Apart from the financial side, carbon capture has shown a track record of technical failures since 2000. Close to 90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early.[98] Figure 14 reflects the results of recent research by academic institutions and universities in Canada and the U.S. It depicts the failure of carbon capture technology in the power sector.

Figure 14: Global Implemented Annual CCS/CCUS Projects By Sectors



Source: Abdulla et al, 20201, Environmental Research Letters.

Globally, there is only one operating power generation CCUS, which is located at the Boundary Dam plant in Canada. A second CCUS plant, Petra Nova in the U.S., was operational between 2017 and 2020 and later reported to be "shut down indefinitely" after only four years.[99] Both of these plants have been studied in this report, and important lessons were elicited.

It might be the case that there are more proposals for CCUS projects in the power sector, especially as the narrative is becoming attractive in Southeast Asian countries with relatively young fossil power plant fleets. However, the historical lessons clearly suggest that no more greenfield coal or gas powerplants should be

[97] Robertson and Mousavian. IEEFA. Shute Creek – world's largest carbon capture facility sells CO2 for oil production, but vents unsold. March 2022.
[98] IOP Publishing. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. 29 December 2020.
[99] Reuters. Problems plagued US CO_2 capture project before shutdown: document. 7 August 2020. Yahoo Finance. Power plant linked to idled US carbon capture project will shut down indefinitely – NRG. 30 January 2021.

greenlit just because of an embedded CCS facility in its design plans. Also, in the case of CCUS proposals for existing and ageing power plants, to prevent them from getting stranded, investors should know that these projects will likely face financial and technical difficulties that will put them in trouble. The era of fossil-based power plants is over, and renewable technologies plus storage capabilities are the future solutions serving net-zero goals.

Case Studies

In this section, only two carbon capture projects ever operationalised in the power sector have been studied. As the power sector has a track record of failures in utilising carbon capture technologies to curb emissions, the Kemper coal gasification power plant, one of the biggest failures that led to the most expensive power plant ever built, has also been studied.

Petra Nova

The Only Post-combustion Project in the U.S. Was Shut Down After Four Years

There have been only two post-combustion CCS plants commissioned to date. The Petra Nova project was the second and the only one operationalised in the U.S. It was designed to reduce carbon emissions from a power plant southwest of Houston, Texas. Project partners NRG Energy and JX Nippon Oil retrofitted one the boilers at the W. A. Parish Generating Station—with post-combustion carbon capture treatment technology to manage exhaust emissions.

The 45-year-old powerplant has a total capacity of 3.7GW and the CCS was fitted in January 2017 to a boiler in its Unit 8 with 240 megawatts (MW) capacity.[100]

Citing low oil prices during the COVID-19 pandemic, the plant was shut down in May 2020,[101] a common issue with CO_2-EOR projects that are typically very sensitive to oil price volatility.

The amine-based absorption technology, developed by Japanese technology giants Mitsubishi and Kansai Electric Power[102] removes CO_2 from the exhaust gas through a basic absorber-stripper system, then compresses it into liquid. The captured CO_2 was piped 130km away to the sandstone Frio Formation of the West Ranch oil field and after being used to increase the rate of oil recovery, was stored at a depth of about 1500 metres.

As with most CCS projects in North America, generating cash from selling CO_2 for EOR was one of the main incentives for launching this project.

[100] U.S. Department of Energy, Petra Nova – W.A. Parish Project.
[101] NRG. Petra Nova Status Update, August 2020.
[102] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project.

To meet the Clean Coal Power Initiative requirements of the U.S. Department of Energy (DOE), the Texas Bureau of Economic Geology established a scheme for monitoring CO_2 injection and movement beneath the rock structures.

Economics and Performance

Installing the Petra Nova carbon emissions reduction system cost about US$1 billion. Known funding sources were US$190 million provided by the DOE in the form of grants and appropriation, US$250 million by Japanese banks as a loan and US$300 million invested by NRG Energy and JX Nippon Oil.[103]

The main enabler in its business model was the revenue from selling captured CO_2 to the adjacent oil field. This project was expected to run for at least 20 years to enhance the rate of oil production in the West Ranch field from less than 1000 barrels per day to more than 15,000 per day. When the project was first proposed, oil prices were very high (US$100 per barrel) and the very optimistic and unrealistic assumption, given the global transition away from fossil fuels, was that the price would not drop. In 2017, the oil price was about US$50 per barrel and there was a net loss from oil production at the field.[104]

On 1 May 2020, NRG shut down Petra Nova, citing low oil prices during the COVID-19 pandemic.[105, 106] The plant had also reportedly suffered frequent outages and missed its carbon sequestration goal by 17% over its short three years life.

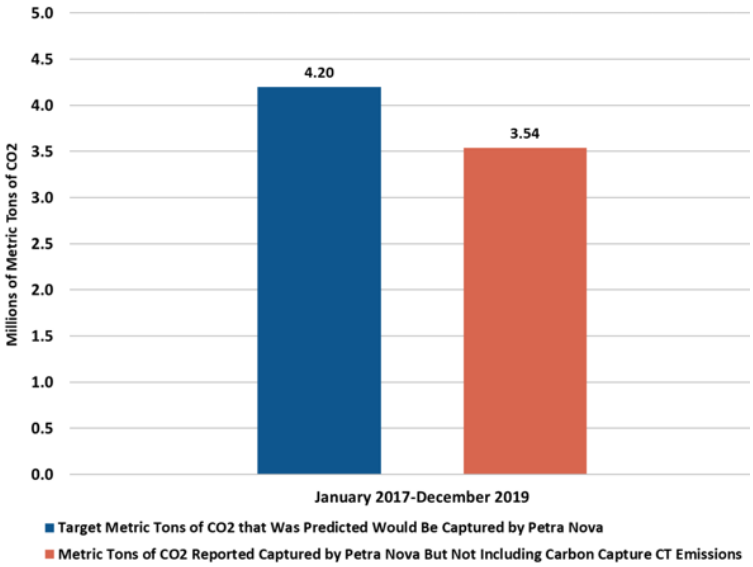
Petra Nova had reportedly suffered frequent outages and missed its carbon sequestration goal by 17%.

The plant was originally expected to capture at least 1.4 million metric tons of CO_2 annually (33% of carbon emission from unit 8 of the powerplant), or a total of 4.2 million metric tons from 2017 to 2019.[107, 108] However, as Figure 15 shows, the project fell well short of that goal during its first three years of operation. IEEFA estimated that the shortfall of 662,000 fewer tonnes in CO_2 captured would have cost investors about US$23 million. It was supposed to recover investment costs via.

[103] Forbes. Ambitious Texas Carbon Capture Project Turns Rocky For NRG At $50 Oil. January 2017.
[104] Forbes. Ambitious Texas Carbon Capture Project Turns Rocky For NRG At $50 Oil. January 2017.
[105] NRG. Petra Nova Status Update. August 2020.
[106] Reuters, Problems plagued U.S. CO_2 capture project before shutdown: document. August 2020.
[107] U.S. Energy Information Administration (EIA). Petra Nova is one of two carbon capture and sequestration power plants in the world. October 2017.
[108] U.S. Department of Energy, Office of Scientific and Technical Information (OSTI). W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project, Final Public Design Report. February 2017.

If the 20-year prospective lifetime of the plant is considered,[109] the cost to investors would have been at least US$150 million.[110]

Figure 15: Projected vs Actual Amount of CO_2 Captured by Petra Nova CCS Plant



Source: U.S. Department of Energy, NRG, Inc.

Moreover, the net amount of CO_2 reduction by Petra Nova would be less than the cited 3.54MT as the plant's built-in gas turbine had emitted about 1.1MT of CO_2 by May 2020.

The Petra Nova CCS project met neither the investors' financial expectations nor the specified CO_2 capture, the pre-assumed high-capacity factor of the power plant or the expected EOR rates. Over the past four years, according to company financial reports, NRG recorded three separate impairment charges related to the plant and to Petra Nova Parish Holdings, the subsidiary that operates the facility. The impairments have totalled US$310 million.

Paradoxically, these projects needed the power plant to produce more CO_2 to sell to oil companies and make money. So, they need an unrealistically high capacity factor to run and generate electricity. While research shows the capacity factor for fossil-based power plant is declining around the world.[111]

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[109] Considering the full 20 years of operation for the plant is not a plausible assumption as it is highly correlated with oil price fluctuations, which practically shut down the plant just after three years. As the future unfolds a business model heavily reliant on a highly volatile oil price would not seem to be prosperous.

[110] Dennis Wamsted, David Schlissel. IEEFA. Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign. August 2020.

[111] Bruce Robertson, Milad Mousavian. IEEFA. Australia's Gas-fired Recovery Under Scrutiny Inaccurate Assumptions Behind Fossil Fuel Power Plants' Capacity Factor Leads to Financial Overvaluations. June 2021.

Based on the IEA Clean Coal centre report on CCS project costs published in 2020, the levelised cost of capturing CO_2 in Petra Nova was about $60–$70 per tonne. The real levelised cost would be much higher, however, as this study assumes an unrealistically high capacity factor of 85% for the plant.[112] Historical operation data shows the capacity factor of the plant to be about 63%.[113] The financial viability of similar projects, when sensitivity of cash flow is added to oil price fluctuations, must be questioned.

The validity of such projects, which use CO_2 to produce yet more fossil fuel, also must be challenged.

Boundary Dam

The Only Post-combustion CCS Plant in the World

The Boundary Dam Integrated Carbon Capture and Storage project was retrofitted to the lignite-fired Unit 3 of the 50-year-old Boundary Dam power plant in Saskatchewan, Canada. It was recognised as the first coal-fired power plant to use post-consumption CCS technology.[114]

Commissioned in October 2014, it is now the only operating coal-fired power plant in the world that captures CO_2. This project was re-sized from an earlier plan to build a 300MW clean coal facility, shelved by the previous provincial government because of its escalating cost (from US$1.5 billion to US$3.8 billion).

This smaller-scale project was initiated after the Canadian government gave the province C$240 million. It could capture CO_2 using post-consumption amine technology but also was equipped with facilities to capture sulphur dioxide and nitrogen oxides.[115]

Economics and Performance

The original estimated construction cost of the Boundary Dam project was US$1.3 billion but the ultimate figure was US$1.5 billion. Of the original estimate, US$800 million was for the CCS process, with the balance for retrofit costs.

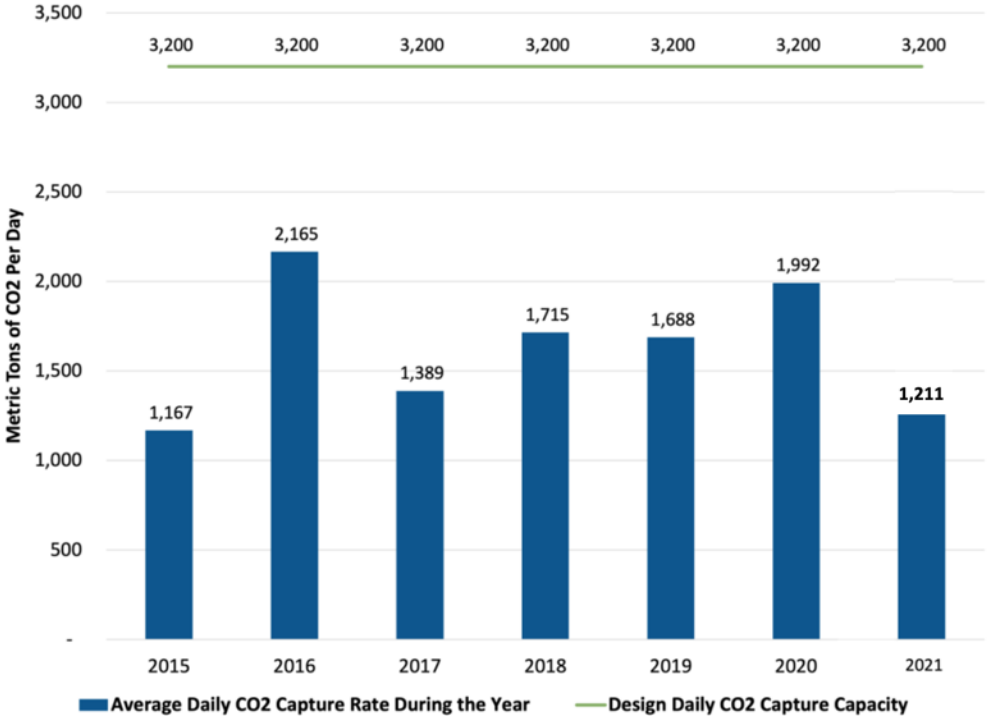
Besides selling electricity, the main revenue stream came from the contract with Cenovus Energy of Calgary, which were supposed to purchase the majority volume of 1Mtpa of captured CO_2 for EOR projects operated by Cenovus near the Weyburn oil field. While a majority of the 1Mtpa of CO_2 captured from Boundary Dam Unit 3 is expected to be sold for EOR operations at the Weyburn oil field, Aquistore provides a

[112] International Centre for Sustainable Carbon, Carbon Capture Utilisation and Storage – Status Barriers and Potential, CCC/304. July 2020.
[113] David Schlissel, IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[114] The Globe and Mail, Energy and Resources. SaskPower unveils world's first carbon capture coal plant. October 2014.
[115] IEAGHG. Integrated Carbon Capture and Storage Project at Saskpower's Boundary Dam Power Station. August 2015.

facility for "buffer" storage against EOR sales fluctuations.[116] Cenovus also set up injection wells and built a 60km-plus pipeline connecting the Weyburn EOR project to Boundary Dam.[117]

The initial goal of the project was capturing about 1 million metric tons of CO_2 each year or 3200 tonnes daily. However, the plant has captured an average of slightly more than 615,000 metric tons annually. Data published by SaskPower, the operator of the project, suggests that the Boundary Dam 3's average CO_2 capture rate to date is about 50%, not the targeted 90%.[118] It has barely achieved the latter figure on any single day and has never done so over any extended period.[119] Despite SaskPower's announcement regarding improvements and upgrading facilities during plant outages, as Figure 16 shows, the plant still falls well short of the original daily goal.[120]

Figure 16: Projected vs Actual Boundary Dam CO_2 Daily Capture Rate



Source: SaskPower's Monthly Boundary Dam Status Updates

[116] Global CCS Institute. Aquistore: CO2 Storage at the World's First Integrated CCS Project – Project Summary Report. 2015.
[117] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.
[118] SaskPower. BD3 Status Update: March 2021.
[119] IEEFA. Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO_2 But Reaches the Goal Two Years Late. April 2021.
[120] SSRN. SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability. March 2021.

Consequently, it took until March 2021 for Boundary Dam 3 to capture 4 million metric tons of CO_2, a yield that should have been met more than two years earlier, in October 2018.

SaskPower had counted on sales of CO_2 at US$19 (C$25) a tonne for Cenovus Energy's Enhanced Oil Recovery project. Without such sales, SaskPower's income was down. And without the expected CO_2 volume, Cenovus Energy collected US$9 million (C$12 million) in payments under the penalty provisions in its CO_2 supply contract.[121] SaskPower also became embroiled in two separate legal disputes with contractors over payments.[122]

The levelised cost of capturing CO_2 in Boundary Dam 3 has been calculated at about $100–$120 per tonne. As with Petra Nova, the underlying assumption for this calculation is that the plant operates at 85% capacity factor—which does not match SaskPower's monthly operating reports. The $100–$120 figure could be considered as the lowest cost of capturing carbon for the lower bound of Boundary Dam 3's carbon capturing cost.[123]

This project, though still operating, is struggling to meet the pre-specified targets.

Kemper Coal Gasification CCS Plant

A Failure and the Most Expensive Power Plant Ever Built

Gas and electric utility Southern Company's Kemper facility was supposed to be a flagship "clean coal" project. Initially proposed in 2008, the greenfield project near Meridian, Mississippi, U.S., was pegged to cost less than US$3 billion and to be running in 2014. It did not unfold as envisioned. Not only was it delayed for more than three years and cost more than US$7 billion, but the company also cancelled the integrated gasification combined cycle (IGCC) and carbon capture portions of the project.

Kemper was designed as a first-of-a-kind plant with a system that produced gasified coal to be burned in a modified combined cycle gas power plant and a carbon capture system that would pull the CO_2 from the gasified coal pre-combustion.[124]

The gasification process and associated emissions controls were expected to produce marketable quantities of ammonia and sulphuric acid as well as the captured CO_2, which was slated for use in EOR.[125] The main argument in favour of the project was that the CO_2 capture would bring the plant's emissions down to levels comparable with conventional combined-cycle gas-fired generators.

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[121] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology, Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.
[122] RenewEconomy. The fallout from SaskPower's Boundary Dam CCS debacle. November 2015.
[123] IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[124] IEEFA. Holy Grail of Carbon Capture Continues to Elude Coal Industry. November 2018.
[125] U.S. Department of Energy. Southern Company – Kemper County, Mississippi.

Essentially, the Kemper gasification process turned the relatively straightforward operation of burning coal to boil the water, running the steam turbine and producing electricity into a complicated chemical process that strips gas from coal to be used in a combined cycle gas turbine (CCGT) accompanied by a steam boiler/generator that uses the heat created through the chemical syngas production for electricity production.[126] These complicated steps were essentially added to use the lignite coal extracted from the Mississippi mine, which has 4 billion tonnes of reserves. Lignite or so-called 'brown coal' is considered the most harmful type of coal for human health as its heat value relative to the amount of CO_2 and sulphur it releases is lower than all other grades of coal.[127]

Economics and Performance

Running Kemper's commercial scale on-site equipment, including coal gasification and carbon capture, was expected to consume 30% of the plant's 830MW gross output. A typical natural gas-fired plant consumes just 3–4% of its gross output to run internal equipment. The conventional combined-cycle gas units at Kemper came online in late 2013.[128]

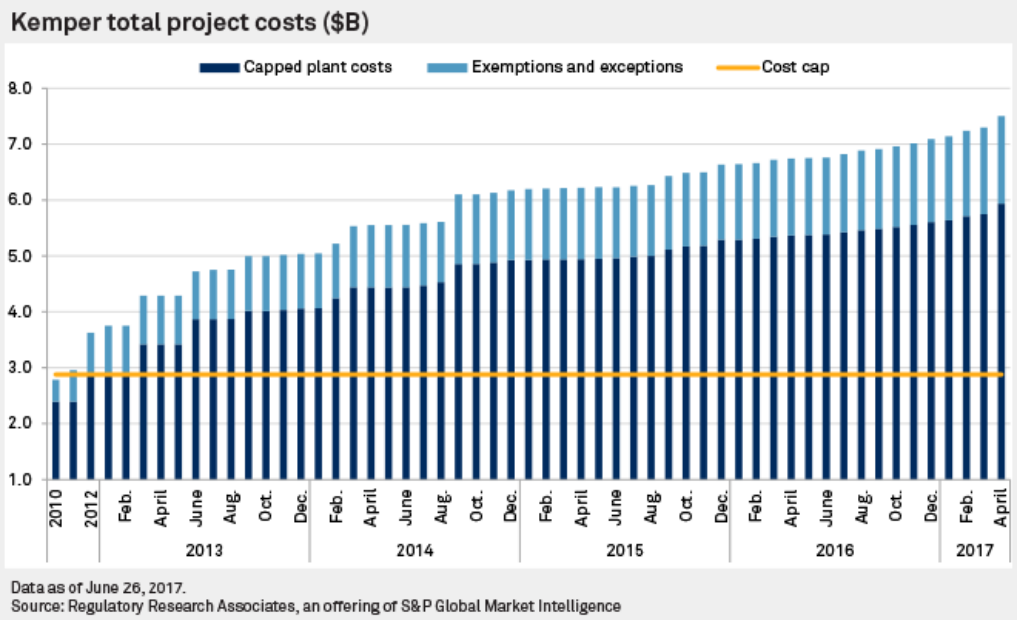
The Kemper project was approved in 2010 by the Mississippi Public Service Commission. Southern Company estimated the US$2.9 billion project would be in operation by the end of 2014. There was no reasonable estimate of either the cost or the commissioning date. Some consultants warned about cost underestimation at the time.[129]

Costs steadily increased as construction proceeded, as shown in Figure 17, and its commercial in-service date was repeatedly delayed. The "cost cap" represents that adopted by the Mississippi Public Service Commission, based on Southern Company's original cost estimate.[130]

Kemper began producing electricity in mid-2014 as a CCGT, burning natural gas, but problems with the operation of its unproven gasification systems—which were to have come online that same year—further added to costs and delays. These led to a 250% increase in the cost of the project, to US$7.5 billion.

[126] IEEE Spectrum. The Three Factors That Doomed Kemper County IGCC. June 2017.
[127] Heal. Lignite coal – health effects and recommendations from the health sector. December 2018.
[128] IEEFA. Holy Grail of Carbon Capture Continues to Elude Coal Industry. November 2018.
[129] Mississippi Public Service Commission. Direct Testimony of David A. Schlissel on Behalf of the Sierra Club. December 2009.
[130] IEEFA. Costly and Unreliable, Two Multibillion-Dollar American Coal-Gasification Experiments Prove the Case Against Such Projects. September 2017.

Figure 17: Kemper IGCC Project's Increasing Cost (US$)



Source: SNL Financial, a unit of S&P Global Market Intelligence.

These technical and financial failures led to the Mississippi Public Service Commission calling for burning coal to cease and for gas to be used in CCGT. The commission said Kemper's gasification technology would not be used or useful in serving Mississippi customers. It found the technology had not operated reliably and was not likely do so in the near future.[131]

The Kemper "clean coal" journey ended in 2017 with the failed coal gasification idea. Southern Company was left with the then most expensive power plant ever built.[132]

Lessons Learned

Using CCS/CCUS in the power sector is the latest application of the technology, which has been gaining traction recently.

Despite generous funding and numerous incentives to push the technology in this sector (such as the 45Q Tax Credit in the U.S.[133]), it has shown a disappointing track record of failures, with a majority of the proposed CCS/CCUS capacity failing at the implementation stage or getting suspended early. Looking at the historical trajectory, technical issues have been one of the most prominent barriers. A lot of projects failed to operate at their theoretically designed capturing rates. As a result,

[131] Southern Company. Southern Company and Mississippi Power announce suspension of gasification operations at Kemper. June 2017.
[132] Bloomberg. Coal's Best Hope Rising with Costliest U.S. Power Plant. April 2014.
[133] Global CCS Institute. 45Q: The "Most Progressive CCS-Specific Incentive Globally" Is Now Open for Business. 24 March 2021.

the 90% emission reduction target generally claimed by the industry has been unreachable in practice.

There has not been any operational project that could meet its capture target so far. Petra Nova, marketed as a flagship breakthrough in this area, underperformed by 17% in four years of its operation before being mothballed indefinitely in 2020. Boundary Dam 3, the only active carbon capture project in the power sector worldwide, has captured less than its pre-specified target by a wide margin (about 50%).

The 90% emission reduction target generally claimed by the industry has been unreachable in practice.

CCS/CCUS for the power sector is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream, as evidenced in the string of historical issues in retrofitting carbon capture technologies into power plants with several failed projects and cost blowouts.

The financial side of the CCS/CCUS business in the power sector is also problematic. Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity that can go to consumers. It imposes additional energy penalties into the mix, typically by drawing steam or power to operate the capture process.

In a competitive electricity market, the high cost of CCS/CCUS will lead to financial instability for the project or environmental externalities in the case of using CO_2 for EOR.

The investment cost for such complex facilities is also staggering. This is evident in the case of the Kemper coal gasification plant that left investors with the most expensive power plant ever built at US$7.5 billion.

All in all, the technology should not be marketed as a quick fix for power sector emissions and make policymakers feel relieved about the world-saving technology just around the corner. It has not worked financially or technically. Instead, we should address the root of the problem, which is fossil-based energy production. Embedding carbon capture technologies in the proposed plan for building power plants and promoting such new fossil-based fleets in emerging economies such as Southeast Asia would have a deteriorating effect on climate in the long term.

Proven, cost-effective and climate-friendly alternatives reduce the dependency on fossil fuels and the risk of ending up with billions of dollars of stranded assets.

Section 4: Carbon Capture Application in Industry

The application of carbon capture in heavy industries and chemical production is diverse and complex.

It is not a monolithic subject: each application has its own specifications and considerations. It covers various technologies and processes, contrasting risks and opportunities, and differing mitigation potentials across multiple applications. Some domains in this sector need greater exploration, such as CCU, which is about utilising and recycling captured carbon into other valuable products such as cement and plasterboard blocks.[134]

In this section, we categorise the industrial application of carbon capture technologies into three categories:

1. Hydrogen production
2. Chemical production
3. Hard-to-abate industries

[134] Australian National University Reporter. Cementing future climate action. 2021.

Hydrogen Production

Hydrogen could play an important role in decarbonising industries, but what colour of hydrogen?

Different colours are used to differentiate hydrogen production methods. Grey hydrogen production utilises natural gas using steam reformation. It is an energy-intensive process that emits a lot of carbon dioxide. Blue hydrogen, often touted as a clean energy alternative, is essentially the same as grey hydrogen. The difference is that carbon dioxide emissions are captured during production using carbon capture technologies. And green hydrogen is made by electrolysing water into hydrogen and oxygen with renewable energy.

Green hydrogen is the real climate-friendly solution.

History shows that capturing more than 90% of emissions from industrial processes is very unlikely. Hence, betting on blue hydrogen is not a promising solution and only keeps the fossil fuel status quo. Instead, green hydrogen, with its rapidly plunging cost, would be the clean alternative in industries that run or plan to run on hydrogen.

Chemical production mainly comprises the production of fertilisers, ethanol, methanol and syngas. We analyse the CCS application in each sub-sector by reviewing a project in each area. Results are mixed, with most projects underperforming by a considerable margin and few others presenting a relatively better performance. As hydrogen has an important role in many processes in different sub-sectors, pro-fossil fuel groups have pushed blue hydrogen. However, wherever hydrogen is applicable technically, green hydrogen would be the solution due to the financial and imminent cost-efficiency.

CCS/CCUS should not be an excuse to greenwash and encourage the establishment of new fossil-based fleets in different industries.

The final area of focus in the industrial application of carbon capture technology is the steel and cement industry, so-called hard-to-abate industries. These two industries constitute 13–14% of the total greenhouse gas emissions worldwide and are critical to decarbonising.[135] The only active CCUS project in this sector is in Abu Dhabi, United Arab Emirates. Although no official data on the performance or finance of the project are available, we reviewed this project based on different accessed sources that were publicly available. The steel sector is in the early years of utilising this technology. Studies could be done on probable projects. However, as the carbon capture technology in different sectors has not reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time we are left with does not seem to be a sustainable solution.

Instead, alternative methods of steel production, such as scrap steel recycling, emit about 80% less CO_2 per tonne of crude steel than other forms of steel production

[135] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.

used today. Green hydrogen leading to the production of "green steel"[136] also looks to be a more promising method to follow.

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. Carbon capture technologies seem useful in this industry if they aren't used as an excuse to postpone other methods now under investigation to reinvent the processes and make cement production green.

All in all, compared to the natural gas processing and power sectors, there are few sub-sectors in the industrial application where carbon capture could be considered as an interim option for decarbonisation while the research and development studies being done in parallel reach readiness and maturity levels to be commercialised. Even in these sub-sectors, such as cement, rigorous environmental and technical conditions need to be satisfied.

Blue hydrogen is not "clean" hydrogen.

Hydrogen could play an important role in decarbonising some energy-thirsty industries, whether for sectors that are hard to electrify or to address seasonal energy storages.

Some companies use CCS to promote the expansion of hydrogen made from natural gas. This type of hydrogen is typically labelled blue hydrogen as opposed to green hydrogen, which is produced with renewable energy.

Blue hydrogen is emissions intensive.

Blue hydrogen is an emissions-intensive process, even with CCS. It is also currently uncompetitive with its green cousin as global gas prices soar. Recent research from Cornell and Stanford Universities found that:

> *"Considering both the uncaptured carbon dioxide and the large emissions of unburned, so-called 'fugitive' methane emissions inherent in using natural gas, the carbon footprint to create blue hydrogen is more than 20% greater than burning either natural gas or coal directly for heat, or about 60% greater than using diesel oil for heat."*[137]

Researchers at the Australian National University came to similar conclusions in a recent scientific paper published in January 2022.

> *"We find that emissions from gas or coal-based hydrogen production systems could be substantial even with CCS, and the cost of CCS is higher than often assumed."*[138]

[136] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.
[137] Cornell Chronicle. Touted as clean, "blue" hydrogen may be worse than gas. August 2021.
[138] Science Direct. Clean Hydrogen? Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen. January 2022.

Blue hydrogen is uneconomic in the face of high gas prices.

In addition, blue hydrogen seems to be no longer economic in the near future compared to green hydrogen. The gas market is global and very volatile. Prices can quickly fluctuate due to geopolitical issues, weather disruptions, supply and/or demand variations, etc. Blue hydrogen project economics are tied to this volatility. Expected production costs published only a year ago are significantly higher today, raising questions about continued policy support for the blue hydrogen technology. Unlike gas, renewables can be more regionally or locally located and are free from annual fuel cost dependency.

Green hydrogen projects can capitalise on this advantage and offer an alternative route to hydrogen production that generates near-zero emissions at a cost that could become cheaper than blue hydrogen no later than 2030. Although where possible, direct renewables use should be the alternative instead of producing green hydrogen.

Blue hydrogen's sensitivity to volatility in the gas market is alarming.[139] During 2021–2022, European gas prices have risen fivefold to more than €100/MWh, radically changing the cost dynamics for blue hydrogen. However, even with gas at €80/MWh, asset management company Alliance Bernstein has estimated blue hydrogen exceeds €6/kg.[140]

Blue hydrogen's sensitivity to volatility in the gas market is alarming.

Electrolyser costs are also falling fast. According to BloombergNEF's global head of strategy, Kobad Bhavnagri, green hydrogen's unit costs will be lower than US$2/kg by 2030 worldwide and US$1/kg by 2050.[141] Tenfold reduction in the cost of electrolysers and cheap renewable energy presents a "serious problem" for investments in blue hydrogen and will force gas companies to "think again", according to Bhavnagri.

[139] IEEFA. Russia sanctions and gas price crisis reveal danger of investing in "blue" hydrogen. May 2022.
[140] Reuters. Hydrogens civil war reveals its winner. 31 March 2022.
[141] Recharge News. 'White elephants' | Green hydrogen will be cheaper than blue H2 in all parts of world by 2030, says BNEF. 17 May 2022.

IEEFA has done extensive work on why blue hydrogen is not a climate solution from a technical, financial and environmental perspective.[142, 143, 144, 145, 146]

Case Studies

This section studies the following five important carbon capture projects in industrial applications: the Quest project is the project that has captured CO_2 more than any other CCS/CCUS project in the hydrogen production sub-sector; the Great Plains CCUS project is the largest and the oldest project in the chemical production (others) sub-sector producing Syngas; the Illinois Industrial CCS(IL-CCS), the largest and latest project commissioned in the ethanol production sub-sector; Coffeyville, the largest application of CCUS in the fertiliser production sub-sector; and Abu Dhabi CCUS is the only CCUS project operationalised in hard-to-abate industries worldwide.

These five projects account for about 65% of the current capacity of CCS/CCUS projects in industrial applications. IEEFA estimates that these five projects have captured 70–80% of all CO_2 captured by the industrial application of CCS/CCUS projects worldwide so far.

Quest CCS Project

The Athabasca Oil Sands Project, a joint venture between Shell Canada (60%), Chevron (20%) and Marathon Oil Sands L.P. (20%), proposed the development work in 2011 on a CCS project to help manage CO_2 from the Scotford Upgrader. This facility, near Fort Saskatchewan in Alberta, Canada, upgrades the extracted oil from the oil sands for refineries nearby. Shell started construction in September 2012 after receiving approval from Alberta's Energy Resources Conservation Board. The CCS plant was commissioned in August 2015 and reached commercial operation in Q4 of 2015.[147, 148]

Canadian Natural Resources Limited (CNRL) gained majority ownership of Quest in March 2017 as part of its C$12.7 billion acquisition of Shell's oil sands operations.[149] As of 2020, the Quest project ownership was 70% CNRL, 20% Chevron and 10% Shell.

[142] IEEFA. Blue Hydrogen Has Weak Case When It Comes to Emission Reductions. February 2022.
[143] IEEFA. Blue Hydrogen Has Extremely Limited Future in U.S. Energy Market. February 2022.
[144] IEEFA. Costs of Blue Hydrogen Production Too High Without Fiscal Life Support. February 2022.
[145] IEEFA. Reality Check on CO2 Emissions Capture at Hydrogen-From-Gas Plants. February 2022.
[146] IEEFA. Russia sanctions and gas price crisis reveal danger of investing in "blue" hydrogen. May 2022.
[147] Hydrocarbon Technology. Quest Carbon Capture and Storage Project, Alberta.
[148] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Quest Fact Sheet: Carbon Dioxide Capture and Storage Project.
[149] Financial Post. Shell mulls more carbon capture projects in Alberta as Quest hits 5 million tonne milestone. 10 July 2020.

The Quest project targeted the capture of up to 1.2Mtpa (a proposed 27MT over the project life) of CO_2 from the Scotford Upgrader and aimed to permanently store it deep underground, reducing 35% of the CO_2 of the upgrader.[150, 151] The carbon dioxide is captured from the Scotford steam methane reformer units, which produce hydrogen for upgrading bitumen. The CO_2 is then transported about 65km by underground pipeline to an injection location near the Scotford Upgrader and stored at 2300 metres in a geological formation.[152] The project's engineering, procurement and construction was managed by Fluor Canada.[153]

The project delivered 1Mtpa in the first five years of operation,[154] on the way to an estimated 10.8MT for the first decade of operation. The storage capacity of the field has been reported at 27MT and the project life has been estimated at about 25 years.

Economics and Performance

Construction of the Quest project cost C$790 million and the total capital cost over 2009–2015 was C$1395 million. Of this, more than 40% (C$573 million) was funded by the Canadian and Alberta governments. A double CO_2 credit was also agreed, using a C$30/t[155] price to give the project C$60/t CO_2 reduction credits (and additional government funding of C$26/t). It adds C$1985 million of estimated project receipts from the Alberta and Canada governments until the end of the project's life.

On this basis, the total estimated government subsidies over the project's life is C$2.56 billion or C$95/t.[156]

[150] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Quest Fact Sheet: Carbon Dioxide Capture and Storage Project.
[151] Global CCS Institute. Global Status of CCS 2020.
[152] Shell. Quest CCS Facility Captures and Stores Five Million Tonnes of Co2 Ahead of Fifth Anniversary. 9 July 2020.
[153] Fluor. Shell Quest Carbon Capture and Storage.
[154] Shell. Quest CCS Facility Captures and Stores Five Million Tonnes of Co2 Ahead of Fifth Anniversary. 9 July 2020.
[155] C$ per tonne of CO_2
[156] Quest Carbon Capture and Storage Project. Annual Summary Report – Alberta Department of Energy: 2017. March 2018.

Table 2: Financial Information of the Quest Carbon Capture and Storage Project

C$m	2009 Capex	2010 Capex	2011 Capex	2012 Capex	2013 Capex	2014 Capex	2015 Capex	2016 Opex	2017 Opex	2018-2025 Opex	2027-2040 Opex Etimated
Alberta Innovates	3	2	1								
Government of Canada				108			12				
Alberta Government				130	115	53	149	30	30	239	400
CO2 reduction credits *								3	36	466	781
Total Government Funding	3	2	1	238	115	53	161	33	66	704	1,182
Cummulative government funding	3	5	6	244	359	412	573	606	673	1,377	2,558
Cummulative government funding share	0.2%	0.4%	0.5%	17.5%	25.8%	29.6%	41.1%	43.2%	45.4%	62.5%	
Cummulative Capital Cost Implied	1,611	1,260	1,268	1,396	1,393	1,393	1,395	1,403	1,481	2,203	
CO2 stored (Mt) - actual or estimate							0.4	1.1	1.1	9.1	15.3
Cummulative CO2 stored (Mt)							0.4	1.5	2.6	11.7	27.0

* Double credits are received, valued at C$30/t * 2 = C$60/t

Total Capital Cost	1,395	C$m
Government subsidies	573	C$m
Cummulative government funding share	41.1%	

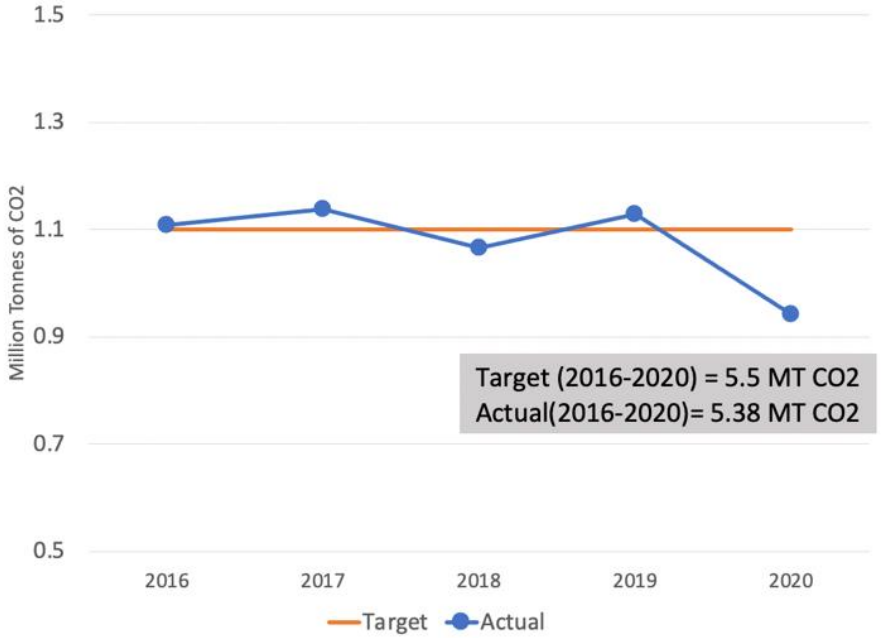
	2015-2025	2015-2040	
Capital Cost Total Subsidy	573	573	C$m
Operating Cost Total Subsidy	803	1,985	C$m
Total Subsdy	1,377	2,558	C$m
Expected CO2 captured	5.8	27.0	Mt
Subsidy per tonne	237	95	C$/t

Source: Shell Canada Energy, 2017 Annual Report

In terms of performance, Quest almost hit its yearly targets. The CCS plant was supposed to capture at least 1Mtpa and up to 1.2Mtpa. Taking the average of 1.1Mtpa as the target capture rate, to the end of 2020 it should have captured 5.5MT of CO_2. Based on the company's disclosures, the actual captured amount was 5.38MT; almost equal.

Figure 18 illustrates yearly amount captured and injected by the plant (orange line) versus the project's target (blue line). As depicted in the graph, the Quest plant largely performed at the targeted level until 2019. In 2020, the 15% drop in the injection rate reflects underperformance during the pandemic. However, the plant almost reached the overall pre-defined target after five years of operation.

Figure 18: Target vs Actual Capture Rate of Quest CCS Plant (2016–2020)



Source: Quest Annual Status Reports, IEEFA Analysis

The Real Amount of CO_2 "Avoided" Is Lower than What Was Just Captured

Limiting analysis to the cumulative amount of CO_2 captured by the plant is an incomplete conclusion about the performance of CCS plants as capturing operations produce additional CO_2 emissions.

The amount of CO_2 captured is not the net amount of CO_2 prevented from being emitted into the atmosphere. Any operation of the plant—such as absorbance, dehydration, compression, transport and injection—needs energy, the source of which is fossil fuel. That fuel and the fossil-based electricity used in each step produce CO_2 emission.

According to the Quest annual data, in the five years depicted in Figure 18 above, 1.16MT of CO_2 were emitted through the whole carbon capture and sequestration process (i.e., capture, transport and storage). So more than 21% of the 5.38MT of captured CO_2 was offset by the emitted CO_2.

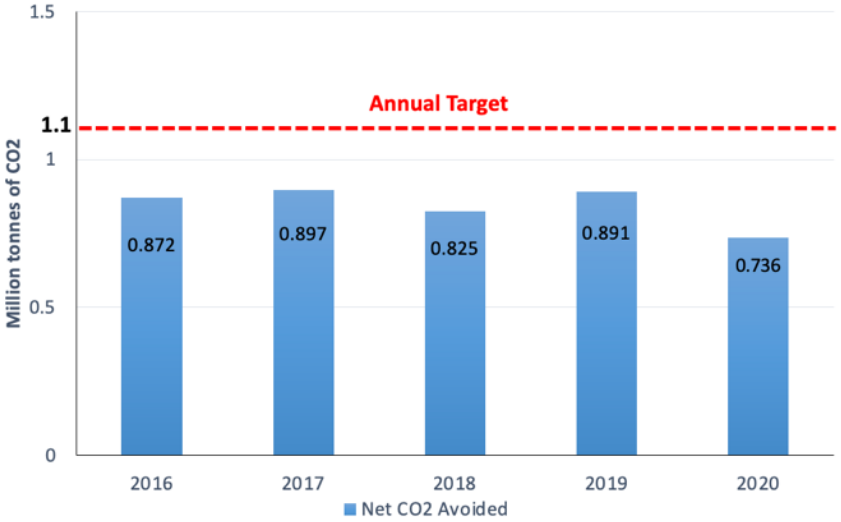
On this calculation, the net avoided CO_2 in the project's first five years was 4.22MT not 5.38MT. A similar calculation applies to each CCS plant that sources energy from fossil fuels. The 'net avoided CO_2' criterion reflects the real impact of CCS projects from an emissions reduction perspective.

Figure 19 compares the yearly amount of avoided CO_2 from the Scotford Upgrader with the target amount. For the Quest CCS operation, the net avoided amount did not exceed 0.9MT in any year, or only about 32% of the yearly CO_2 emission of the Upgrader and CCS plant together.

Extrapolating this trend and considering approximately 0.24MT of CO_2 emitted each year in capture, transport and storage indicate the CCS operation on its own would emit 6MT of CO_2 during the project's lifetime.

Accordingly, to the end of the project's life, the total amount of avoided CO_2 would be about 21MT instead of 27MT. Further, the government's subsidy per tonne of avoided CO_2 turns out to be C$120, considerably higher but more realistic than the C$95 figure.

Figure 19: Net CO_2 Avoided vs CO_2 Yearly Capture Target (2016–2020) – Includes Emissions from the CCS Operations



Source: Quest Annual Status Reports, IEEFA Analysis

Chemical Production (Ethanol, Fertiliser, Syngas etc.)

Chemical production could be the most convoluted application area for carbon capture technologies. This is because of the diversity of chemical products produced in this sector and of the technologies can be applied. It includes but is not limited to nitrogen-based fertilisers, such as ammonia and urea ammonium nitrate, ethanol and biofuel products, methanol, and reformed and synthetic gas. For many of the processes, blue hydrogen has been proposed. However, wherever hydrogen is applicable technically, green hydrogen would be the solution, not blue, due to the financial and emission reasons discussed earlier. For example, for nitrogen-based fertilisers, which need hydrogen to produce the final product, any type of coal gasification or petroleum coke gasification to produce hydrogen and then capture the released CO_2 with CCS facilities should not be greenlit. Instead, green hydrogen should be considered a climate-friendly alternative.

If there is no alternative to current processes in each of these applications, then carbon capture could be considered if:

- it does not promote EOR
- it does not extend or is used as an excuse to extend the life of any type of fossil asset
- a safe storage location is identified, and a long-term monitoring plan and compensation mechanism in case of failure are developed
- liability of the projects is not handed over to the taxpayers.

In the following section, three of the biggest CCS/CCUS projects ever built in each sub-sector of chemical production have been reviewed. All of these projects are located in the U.S.: the Great Plains Synfuels Plant producing syngas from lignite coal gasification, which is planned to be redeveloped into a blue hydrogen project; the Illinois Industrial Carbon Capture and Storage, the largest project of its kind tied with biofuel production; and finally, the Coffeyville Gasification Plant, the biggest CCUS project in the fertiliser production sector.

Great Plains Synfuels Plant

The Great Plains Synfuels Plant (GPSP) in Beulah, North Dakota, is a coal gasification plant that has produced synthetic natural gas (SNG) from lignite coal since 1984.

Coal gasification is a highly emitting process and lignite, also known as brown coal, used in this plant is considered the most harmful type of coal for human health due to the large amount of CO2 and sulphur it releases in combustion.[157]

Hence, the motivation behind such a heavily polluting project could be simply the abundance of cheap feedstock in the U.S. The National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE) estimates that about 200 years' worth of consumption remains in the U.S.[158]

Operated by the Dakota Gasification Company's (DGC), the GPSP is the only coal-to-SNG gasification plant in operation in the U.S. Annually, the plant consumes about 6MT of coal to produce 54 billion standard cubic feet of SNG as well as some chemical by-products.[159] The SNG (95% methane) is piped to the Northern Border Pipeline, which transports gas from Canada, Montana, and North Dakota to the Ventura, Iowa area, where it connects with numerous pipelines that supply the eastern U.S.

[157] Heal. Lignite coal – health effects and recommendations from the health sector. December 2018.
[158] National Energy Technology Library, U.S. Department of Energy. Hydrogen & Synthetic Natural Gas from Coal.
[159] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.

After 16 years of operation and venting millions of tonnes of CO2, capturing and selling of CO2 to the nearby oil producers started in October 2000. The CO2 is pumped via an onshore 315km pipeline for EOR in two carbonate fields, the Cenovus Energy-owned Weyburn field (with demand rate of 6500 tonnes per day) and Apache company-owned Midale field (with demand rate of 1200 tonnes per day).[160]

CO_2 Leakage Case

Following claims of leakage from the Weyburn site in January 2011, operator Cenovus and the International Performance Assessment Centre for Geologic Storage of CO_2 (IPAC-CO_2) launched investigations. The "leaking" gas was discovered to be naturally occurring biogenic CO_2, originating from biological processes in the soil, rather than injected CO_2. The 2012 report discovered no potential CO_2 pathways from pipelines or other infrastructure.[161]

Economics and Performance

GPSP was commissioned by American Natural Resources company (ANR). However, as it was not easy to secure financing for such a huge project, ANR formed a partnership with several other natural gas utility companies which became known as the Great Plains Gasification Associates (GPGA). This allowed the U.S. DOE to back funding for the plant.[162]

The plant was built in response to the energy crisis of the 1970s.[163] Total cost for design and construction was roughly U$2 billion of which a $1.5 billion loan was guaranteed by the DOE.[164] Construction began in 1981.[165]

In addition, the CO_2 monitoring and storage project in Weyburn and Midale fields was conducted between 2000 and 2011 (at an estimated cost of U$70 million).[166] And the cost of pipeline was US$100 million.[167]

According to the DOE's NETL, the separated CO_2 was emitted into the atmosphere for the first 16 years of the project's lifetime due to lack of demand. In October 2000, the operator started capturing and selling CO_2 to oil companies for EOR in the nearby fields. The capacity at the beginning of the project was reported to be about 105 million standard cubic feet per day (~2Mtpa) or 60% of total CO_2 produced by the plant.[168] This

[160] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[161] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[162] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.
[163] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[164] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[165] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.
[166] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.
[167] School of GeoSciences, University of Edinburg. Great Plains Synfuels Plant: Project Details.
[168] National Energy Technology Library, U.S. Department of Energy. Weyburn Project. n

capacity increased to about 3Mtpa in 2006 by installing the third CO_2 compressor to meet the needs of Apache Canada Ltd for EOR. Up to 2007, CO_2 sales exceeded 11MT.[169]

For the first six years of operation the carbon capture facility averaged 1.8–1.9Mtpa, very close to its nominal capture capacity.

No detailed data and information have been found regarding the plant's annual capture performance. Based on cumulative figures from the MIT CCS database[170] and National Petroleum Council report,[171] it had captured and transported nearly 38MT of CO_2 for geological sequestration up to 2020. Factoring in the capacity expansion to 3Mtpa in 2006, the total amount CO_2 captured and sold for EOR until 2020 was 27MT.

The average annual capture rate for the 14 years post-expansion has remained ~1.9 Mtpa, or about 1MT lower than the maximum capture capacity for these years.

The first hypothesis is that this underperformance could be due to lower gas production in the main synthetic gas production plant. Should this be the case, the CCS plant would not be underperforming. On the other hand, the alternative hypothesis is that CCS plant underperformance, technical problems or lack of demand from oil companies would result in the uncaptured CO_2 being vented into the air.

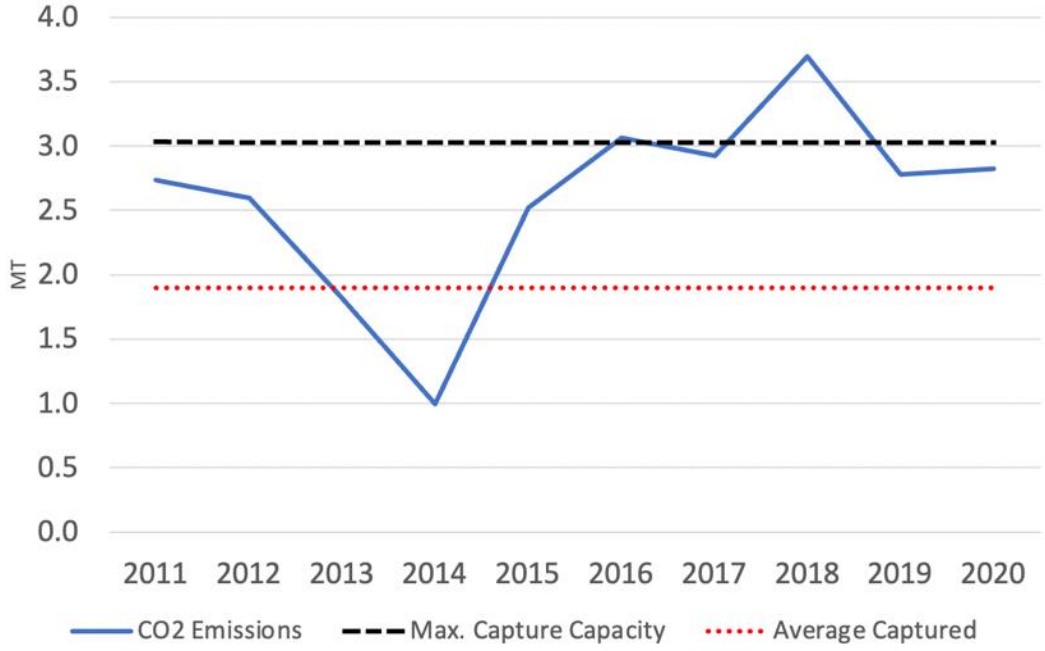
Looking at the U.S. Environmental Protection Agency (EPA) data of the plant's CO_2 emissions for the period 2011–2020 confirms the underperformance hypothesis.

Figure 20 shows the CO_2 emissions from the synthetic gas (syngas) production process (blue line), maximum capture capacity of the plant (black dotted line) and the average yearly captured CO_2 of the plant (red dotted line).

It essentially shows that during this decade the amount of CO_2 produced by the plant was higher than the average 2MT capture rate (2014 excepted). The CCS facility had the capacity to capture all of the CO_2 produced by the syngas process (but for 2018, when CO_2 production exceeded the maximum 3MT capturing capacity).

[169] National Energy Technology Library, U.S. Department of Energy. Weyburn Project.
[170] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[171] National Petroleum Council. Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage. Appendix C – CCUS Project Summaries. December 2019 (last updated 12 March 2021).

Figure 20: Great Plains Synfuels Plant CO2 Emissions vs Capture Performance (2011–2020)



Source: National Energy Technology Laboratory (NETL), Department of Energy. U.S. Global CCS Institute. 2021. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program (GHGRP). IEEFA

The cumulative tallies for CO_2 captured and produced during 2011–2020 show that the CCS plant underperforms by about 25%. During the decade, it captured about 19MT of CO_2 to be sold for producing more oil and vented another 6–7MT. (Figure 21).

It is important to note that the overall figure for emitted CO_2 should be considerably higher as the above figures exclude the emissions from the CCS facility operations, potential leaks through pipelines and fixtures and the CO_2 emitted in reinjecting at the EOR point.

An Imminent Blue Hydrogen Redevelopment for Plant

In 2021, Bakken Energy and Mitsubishi Power Americas announced plans to purchase GPSP from Dakota Gasification Co., which is financially in trouble. The deal was expected to be finalised by April 2022.[172] It is part of a plan to create a hydrogen hub in Dakota.[173] It has been labelled "clean" hydrogen. However, the hub will focus on the production of blue hydrogen, derived from natural gas with CO_2 emissions captured, and sequestered underground or used for EOR. The hydrogen will come

[172] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[173] AP. Companies aim to build 'clean hydrogen' hub in North Dakota. 3 June 2021.

from natural gas produced in North Dakota's oil fields or from gas from the Dakota Gasification plant, or a mix of both.

The hub is not a green hydrogen project as it is essentially producing gasified hydrogen and capturing its CO_2 by-product. Blue hydrogen is neither a climate-friendly solution or an economically sound choice compared to green hydrogen, as discussed earlier.

Illinois Industrial Carbon Capture and Storage (IL-CCS)

In 2011, Archer Daniels Midland (ADM), one of the world's largest agribusiness companies, started the Decatur carbon capture project with partners. As part of the U.S. DOE's Regional Carbon Sequestration Partnerships initiative, and with funding from the DOE, it started as a research and development project in industrial CCS, in Illinois.

Having passed pre-specified targets for capturing carbon and showing no CO_2 leakage, the project moved ahead to the design and implementation phases and captured and stored 1MT of CO_2 from 2011 to 2014.[174]

With the successful completion of the Decatur demonstration project, ADM and corporate partner Schlumberger Carbon Services continued on to the larger- scale Illinois Industrial Carbon Capture and Storage (IL-CCS) plant with a 1Mtpa capturing and storing capacity. Started in 2017, as the world's first large-scale CCS project from a biofuel source, it relied on the Mount Simon Sandstone saline formation as its dedicated geological structure to store the captured carbon. The CO_2 not being used for EOR was to be stored more than 2000 metres underground.[175]

The gas from the ADM biofuel plant is a >99% pure CO_2 stream that is a by-product of fuel-grade ethanol production via anaerobic fermentation of corn stover (harvest remnants).[176]

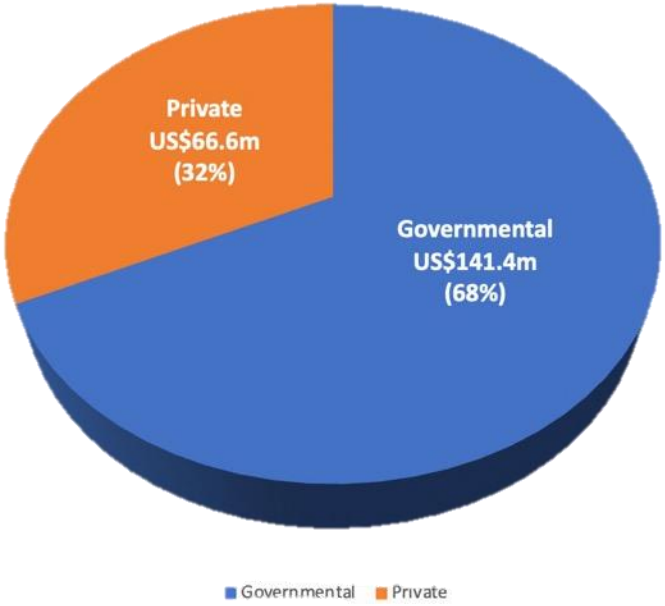
Economics and Performance

Following the success of the Decatur project, backed by about US$106 million in federal funding and US$21 million from the corporate partners, site characterisation and permitting of IL-CCS was finished in 2014 and the project started to capture and inject CO_2 in 2017.

[174] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.
[175] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.
[176] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.

The cost of the project was US$208 million, of which US$141.4 million came via the DOE's CCS grants. Essentially, the project was 68% government funded (Figure 21).[177, 178, 179]

Figure 21: IL-CCS Finance Portfolio



Source: U.S. Spending.gov.

Looking at total CO_2 emissions of the ADM biofuel plant, the figure is four to five times higher than the designed capture target of 1Mtpa. On average, the plant has emitted 4.5MT of CO_2 annually. In the best-case scenario, if the CCS facility could capture at its theoretical capacity, it would contain only 22% of the plant's CO_2 emissions. This illustrates how technically and economically challenging it is to reach capture rates of >80% that are usually claimed for CCS facilities. The technical difficulty is evident in the quote by engineering consultancy WSP, advisor to ADM for a carbon reduction feasibility study in 2020:

> *"The ability to capture stack emissions and sequester them is likely 10 years out, due to the technology and energy needed to separate and process the stack gas sufficiently to inject the CO_2 in the sequestration well."*[180]

Moving from theory to practice, the reality is even starker. EPA data illustrate that the CCS facility has been performing at about half of its designed capacity since the beginning of the project (Figure 22).

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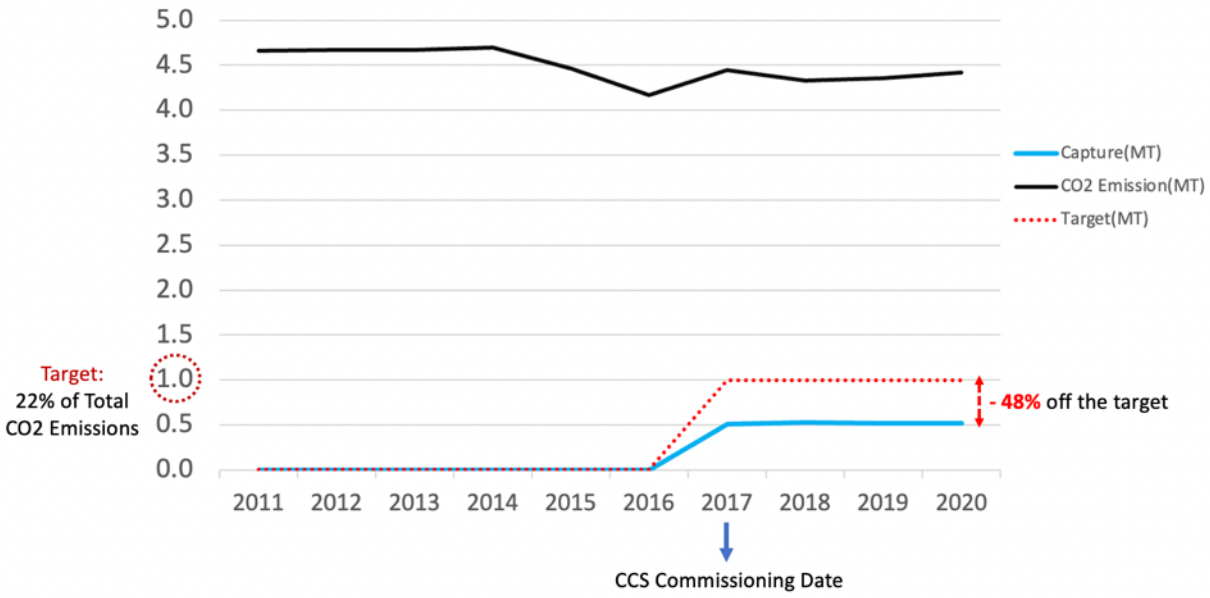
[177] Midwest Center for Investigative Reporting. Despite hundreds of millions in tax dollars, ADM's carbon capture program still hasn't met promised goals. 19 November 2020.
[178] USASpending.gov.
[179] AIChE Academy. Successful Demonstration of Illinois Industrial Carbon Capture and Storage in a Saline Reservoir. 2018.
[180] Archer Daniels Midlands. Carbon Reduction Feasibility Study. 30 March 2020.

The facility is underperforming by 48% to the end of 2020,[181] meaning that it could capture and sequester only up to 12% of the total CO_2 emissions of the ADM biofuel plant. The emission problem is still there and, essentially, the US$200m-plus CCS retrofit could not solve that.

Figure 22: CO_2 Emissions vs Capture Performance of the IL-CCS Plant (2011–2020)



Source: Global CCS Institute. 2021. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program (GHGRP).

Coffeyville Resources Nitrogen Fertilizers Plant

Coffeyville Resources Nitrogen Fertilizers Plant incorporated in 2003[182] in Kansas, U.S., produces ammonia and urea ammonium nitrate (UAN) fertilisers. It gasifies petroleum coke to produce hydrogen, from which it synthesises ammonia and UAN fertilisers. An oxygen separation plant provides oxygen for the gasifiers, as well as nitrogen needed downstream for reaction with hydrogen to produce ammonia. Syngas is cleaned in a dual-stage acid gas removal process, delivering Hydrogen sulfide (H_2S) and CO_2 in separate streams.

A proportion of the separated CO_2 is used to produce UAN but most of the gas was vented in the first decade of the plant's operation.

[181] The data was accessible through until end of 2020.
[182] Bloomberg. Coffeyville Resources Nitrogen Fertilizers.

The plant produces about 5% of total UAN demand in the U.S. and is close to extensive fertiliser markets in the Midwest, lowering the distribution costs of its products.

In 2011, subsidiaries of Chaparral Energy and CVR Energy (the owner and operator of the Coffeyville plant) reached a purchase and sale agreement to capture CO_2 from the plant, which Chaparral needed for EOR operations in north-eastern Oklahoma. The plant started to capture CO_2 in June 2013. Under the agreement, the majority of the plant's CO_2 was planned to be captured by Chaparral, which constructed a CO_2 compression facility at the plant site and installed about 110km of pipeline to deliver it to its North Burbank Unit in Osage County in Oklahoma.[183]

Economics and Performance

Blue Source, LLC, a carbon-reduction advisory company, initiated the idea of capturing greenhouse gas from the fertiliser plant and injecting it into ageing petroleum fields to boost oil output. With Chaparral Energy and CVR Energy, it planned and executed the CCS retrofitting and construction of the pipeline. The project was estimated to cost between US$50 million and US$$80 million.[184] The project was finished, and injection started in 2013.[185]

U.S. EPA data for total CO_2 produced by the fertiliser plant is shown in Figure 23 (orange line). However, as a step in the UAN production process, part of the CO_2 produced during the acid gas removal process is then used in production of UAN. Hence, the net emitted CO_2 is lower than the total CO_2 produced. Based on industry averages[186] and scattered data publicly available on the facility's UAN production figures,[187] the average CO_2 produced (excluding the amount used in UAN production) is an estimate (blue line).

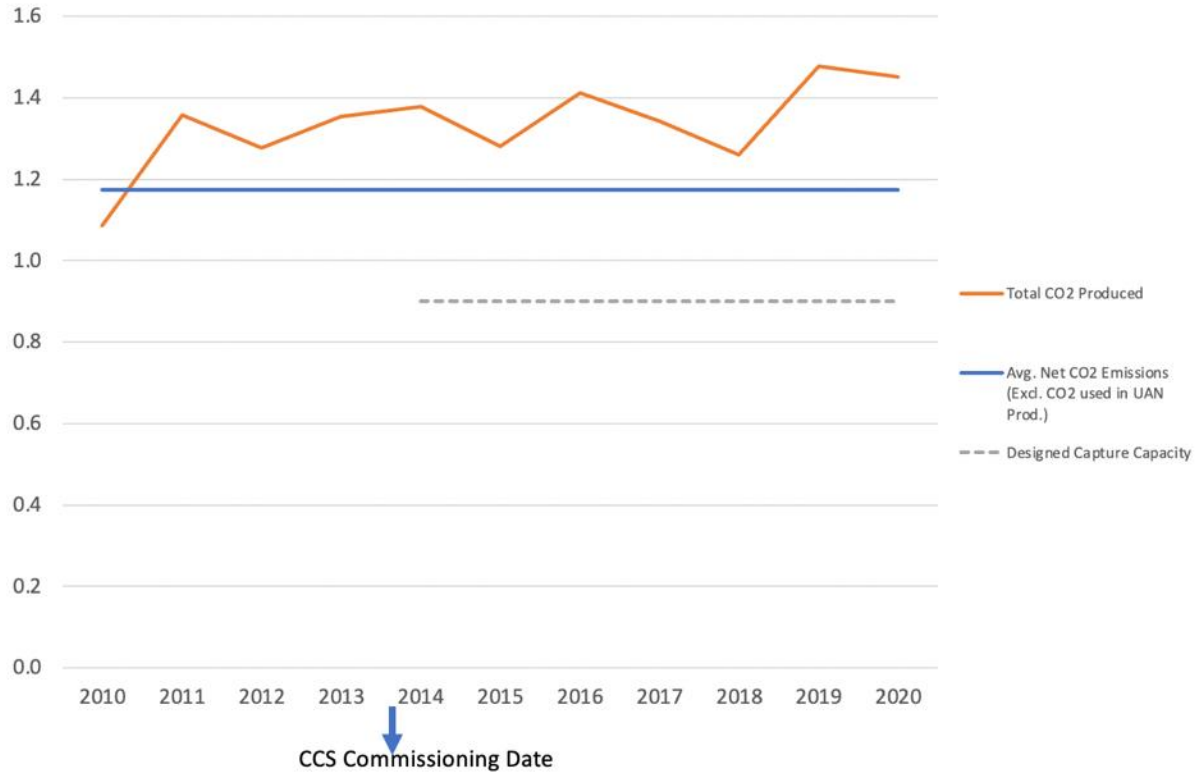
No public data has been found on the yearly capture performance of the plant over its whole lifetime. For illustration, the maximum capture capacity of the plant (Figure 23, grey dotted line) accounts for up to 80% of its CO_2 emissions. Some research shows that the plant could have overperformed during 2017–2019 by about 16%, which is an acceptable result.[188] However, the question remains as to whether the plant has achieved maximum capacity each and every year since 2013, given very few CCS/CCUS projects have done so historically. Also, it is notwithstanding that captured CO_2, when used for EOR, at least partly negates the original figure of reduced carbon.

As most of the CO_2 created in these plants assist in the production of hydrogen to be used in fertiliser production, replacing green hydrogen with current processes of producing syngas hydrogen from petroleum coke seems to be more efficient and climate friendly than the technically challenging and extremely expensive carbon

[183] National Energy Technology Library, U.S. Department of Energy. Coffeyville Resources Nitrogen Fertiliser Plant.
[184] Reuters. Blue Source to capture Kansas CO2, up oil output. 21 August 2007.
[185] ZeroCO2.no. Coffeyville Gasification Plant.
[186] International Fertiliser Society. The Carbon Footprint of Fertiliser Production: Regional Reference Values. 2019.
[187] National Energy Technology Library, U.S. Department of Energy. Coffeyville Resources Nitrogen Fertiliser Plant.
[188] ACS Publications. An Estimate of the Amount of Geological CO2 Storage over the Period of 1996–2020. 19 July 2022.

capture solutions. Considering the falling cost of green hydrogen and recent astronomical gas prices, it would soon also be a more economical option compared to blue hydrogen.

Figure 23: Coffeyville CCS CO_2 Emissions vs Maximum Capturing Capacity (2010–2020)



Source: MIT. CCS database. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program(GHGRP). International Fertilizer Society(IFS), 2018.

Hard-to-abate Industries (Steel and Cement)

Source of ~14% of Global CO_2 Emissions

Steel and cement are named hard-to-abate industries as it is technically and financially difficult to completely electrify them using renewable energy. Yet, according to Imperial College London, cement and steel production contribute to 6.5% (2.3 billion tonnes) and 7% (2.6 billion tonnes) of global CO_2 emissions, respectively.[189] That is partly owing to the large quantities of use of these materials: concrete is the second-most-consumed product on the planet, after clean water. It is also due to their carbon-intensive manufacturing: the chemical reactions and the burning of fossil fuels to deliver the extreme temperatures required all release CO_2.

[189] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.

Carbon capture has been discussed recently as one of the solutions contributing to decarbonising these heavy polluting industries.

There is only one operating CCUS plant in the steel sector and no commercialised CCS plant in the cement industry.

There is no public data on the performance and finance of the only operating CCUS project in Abu Dhabi, United Arab Emirates. Hence, there is not much to learn from the history of the application of CCS/CCUS in this industry. However, the technical failures of CCS/CCUS in other sectors are alarming. This is important as the time to reach net zero targets is very limited, and there is little room for trial and error. Nevertheless, there is a lot of research and development going on to decarbonise these two industries with different options[190, 191] and CCS/CCUS has been considered as one of the alternatives.

There is only one operating CCUS plant in the steel sector.

Steel

There are three main steel production processes.

1. The most widespread is the integrated blast furnace and basic oxygen furnace process (BF-BOF), in which iron oxide is reduced to iron inside the blast furnace with coke (derived from coking coal) as a reducing agent. The product of the blast furnace, carbon-rich pig iron, is then processed into steel in a basic oxygen furnace, where oxygen is blown through the molten pig iron to reduce its carbon content. In 2020, global crude steel production totalled 1.88 billion tonnes, and of this, 73% came via the BF-BOF process.[192]

2. A second primary steelmaking pathway is to produce direct-reduced iron (DRI), which is then further processed into steel in an electric arc furnace (EAF). DRI is produced by directly reducing iron ore without melting, usually using a mixture of carbon monoxide and hydrogen derived from natural gas. Although, these can also come from gasified coal. This method provides the final steel product with around 36% less CO_2 emissions.[193]

[190] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.
[191] IEEFA. Green steelmaking will need technology and mining advances. 1 July 2022.
[192] World Steel Association. World Steel in Figures 2021 now available. 3 June 2021.
[193] IEEFA. Iron Ore Quality a Potential Headwind to Green Steelmaking. 28 June 2022.

DRI does not use coking coal. An increasing number of steel companies are seeking to develop technology that uses 100% hydrogen in the DRI-EAF process—potentially zero-carbon green hydrogen, produced via renewable energy-powered electrolysis.[194] And due to the reasons discussed earlier, green hydrogen is the fuel for heavy industries' future. Any type of coal gasification/methane reformation to produce hydrogen and then capturing its carbon with CCS/CCUS—that is, blue hydrogen—does not seem to be a climate saviour or cost-efficient option.

3. As an alternative to primary steel manufacture, recycling scrap steel is an option with around 80% lower CO_2 emissions.[195] Also called secondary steelmaking, this technology does not require iron ore or coking coal. An electric arc furnace is charged with steel scrap, which is melted to form new steel. Renewable energy can power EAFs, reducing carbon emissions for the scrap EAF process to almost zero. Although there are limitations on the volume of available scrap and some quality issues, even a little increase in this type of production instead of BF-BOF would be a gamechanger.

Although there is a long way to go in the steel sector, green hydrogen seems to be a more promising pathway than CCS. As discussed, it will be a cost-effective option in the next few years.

The steel sector is in the early years of utilising this technology. Studies could be done on probable projects. But, as carbon capture technology in different sectors has not reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time we are left with does not seem a sustainable solution.

Green hydrogen seems to be a more promising pathway than CCS.

Instead, alternatives such as scrap steel recycling or green hydrogen leading to the production of "green steel"[196] looks a more promising path to follow.

Cement

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. The process is known as calcination when crushed limestone is heated and releases calcium oxide (CaO) and CO_2.[197]

$$CaCO_3 + heat \rightarrow CaO + CO_2$$

[194] IEEFA. Iron Ore Quality a Potential Headwind to Green Steelmaking. 28 June 2022.
[195] IEEFA. The facts about steelmaking: Steelmakers seeking Green Steel. 2022.
[196] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.
[197] University of Mosul. Calcination of Limestone.

The heat for the process and the chemical reaction itself produce CO_2.

Second only to water, concrete is the most consumed material in the world.[198] Considering these two facts, it is one of the most challenging industries to decarbonise.

Carbon capture technologies seem to be useful in this industry if they are not used as an excuse to postpone other methods now under investigation to reinvent processes and make cement production green.

For example, one of the recent innovations in this sector is using the captured carbon in other industries to produce cement and plasterboard blocks.[199] These processes are worth being funded and studied.

Abu Dhabi CCUS Plant (Al Reyadah)

The First and Only CCUS Plant in the Steel Sector

The Abu Dhabi CCUS plant, commissioned in 2016 in Mussafah, Abu Dhabi, United Arab Emirates, is the only commercial-scale CCUS facility in the world that captures CO_2 from the flue gas of a steel production facility. The final application of the captured CO_2 is EOR in the Abu Dhabi National Oil Company's (ADNOC) nearby oil fields.[200]

The main objectives of the project were reducing the carbon footprint of the United Arab Emirates, implementing EOR in subsurface oil reservoirs, and freeing up natural gas that would have been used for oil field pressure maintenance.[201] From the emissions perspective, such objectives seem incompatible with climate targets, as the CO_2 is used to increase oil production and free up other emission-intensive fossil fuels.

Economics and Performance

The project cost was US$122 million,[202] and it was developed by Abu Dhabi carbon capture company Al Reyadah, a joint venture between ADNOC and clean energy company Masdar,[203] with respective stakes initially of 51% and 49%. ADNOC bought out Masdar's share in January 2018.[204]

[198] Engineering Failure Analysis. Cement and concrete as an engineering material: An historic appraisal and case study analysis. 2014.
[199] Australian National University Reporter. Cementing future climate action. 2021.
[200] The University of Edinburgh. School of Geoscience. Al Reyadah: Project Details.
[201] Carbon Sequestration Leadership Forum. Al Reyadah Carbon Capture, Use, and Storage (CCUS) Project. May 2017.
[202] The National News, Business. Abu Dhabi starts up world's first commercial steel carbon capture project. 5 November 2016.
[203] Power Engineering International. MENA's first CCUS project now operational. 6 January 2017.
[204] The University of Edinburgh. School of Geoscience. Al Reyadah: Project Details. 2022.

The project includes capturing, compressing and dehydrating the CO_2 and then conveying it via a 43km underground pipeline for EOR injection to ADNOC's North East Bab (NEB) (Al Rumaitha) and Bab onshore oilfields.

The project was set to capture and transport 800,000 tonnes per year of CO_2 and, tentatively, was part of an overall master plan to create a CO_2 network and hub for managing future CO_2 supply and injection requirements in the United Arab Emirates.[205]

Technically, the plant is the largest CO_2 project of any type in the Persian Gulf region,[206] the Middle East's first commercial-scale CO_2 capture plant and the project with the world's highest pressure (240 bar) CO_2 transfer pipeline at the time of commissioning. ADNOC has announced plans to expand the capacity of this program by more than 500%, aiming for 5MT of CO_2 annually by 2030.[207]

Phase 2 of the project, set for commissioning in 2025,[208] aims to capture 1.9 to 2.3Mtpa CO_2 from its gas processing plant for EOR in the same reservoir. At the same time, the company plans to increase production to 5 million barrels of oil equivalent (boe) daily in 2030.[209]

The CO_2 to be captured by CCS plant(s) would have a considerable contribution to expanding that production, raising the question yet again: Is using CCS for EOR really reducing emissions?

Lessons Learned

Steel and cement are responsible for 13–14% of total global emissions, and the demand for these two materials is increasing. Therefore, decarbonising these two crucial industries is necessary if the world wants to reach net-zero emissions by 2050. CCUS/CCS has been proposed as one of the pathways for pursuing the decarbonisation of these two industries.

The application of CCUS/CCS in the steel and cement sector is a relatively new area with only one ~6-year-old operating project in Abu Dhabi with no publicly published data on its performance. Essentially, there is not much to learn from the application of CCS/CCUS in these two industries. However, based on limited knowledge of the technology trajectory in other applications with common processes as these industries, as well as other solutions being developed and researched in parallel, future CCS/CCUS application in the steel and cement industry could be projected to some extent.

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[205] Carbon Sequestration Leadership Forum. Al Reyadah Carbon Capture, Use, and Storage (CCUS) Project. May 2017.
[206] Global CCS Institute. Building Momentum for CCS in the Gulf Region and Around the Globe. 2020.
[207] Hydrocarbon Processing. ADNOC announces expansion of carbon capture program. February 2020.
[208] International Association of the Oil and Gas Producers. Global CCUS Projects. 2021.
[209] Drilling Contractor, Increased hydrocarbon production, sustainability programs go hand in hand to create a resilient upstream. 27 April 2021.

Green hydrogen or recycling scrap steel should be prioritised in the steel sector over CCUS/CCS to capture carbon from gasification, reformation, or burning fossil fuels.

In the cement sector, however, as CO_2 is the by-product of the fundamental chemical reaction of producing cement, CCUS/CCS projects could be considered cautiously. Other innovative methods should be pursued to reinvent the whole process toward green and zero-emissions cement.[210] For example, one recent innovation in this sector is using the captured carbon in other industries to produce cement and plasterboard blocks.[211] Cambridge University researchers have proposed zero-emissions cement.[212] Both innovations are worth exploring.

Meanwhile, carbon capture could be used as long as the captured carbon is not used for EOR. CCUS/CCS also should be used only if the technical performance reaches close to nominal capture capacities, in contrast with general trends throughout history. Also, it could be considered an interim option as long as it does not distract financial flows from fundamental and innovative solutions to reinventing the cement production process.

[210] UK FIRES. Cambridge engineers invent world's first zero emissions cement. 4 May 2022.
[211] Australian National University Reporter. Cementing future climate action. 2021.
[212] UK FIRES. Cambridge engineers invent world's first zero emissions cement. 4 May 2022.

Conclusion

Failed/Underperforming Projects Considerably Outnumbered Successful Experiences

The immediate inference from the projects reviewed is that the number of failures and the underperformance of these projects with carbon capture technology has outnumbered the successful projects considerably. Ten of the 13 flagship projects reviewed, comprising 90% of the total capture capacity in our sample, have failed or are underperforming mostly by large margins.

While a limited sample, predominantly focusing on projects in operation, additional research[213] looking (from a different angle) at the number of failures of all of the proposed/initiated projects since 2000 conveys, in essence, a similar message. Further, recently published research by the Imperial College London[214] on the capture performance of operating projects since 1996 confirms the underperformance of most projects against their designed/claimed capture capacity.

Successful CCUS Exceptions Mainly Existed in the Natural Gas Processing Sector Serving the Fossil Fuel Industry, Leading to Further Emissions

The natural gas processing sector historically dominates the application of carbon capture technology. Extracted raw gas has a carbon dioxide (CO_2) content that needs removal to produce a marketable (methane) gas for distribution through pipelines to customers or liquefied in LNG plants for export.

Producing the primary usable product (i.e., natural (methane) gas) is impossible without separating CO_2. This explains why the sector has been using carbon capture technology for decades, not necessarily as a climate-friendly solution, but as an inevitability to produce the fossil-fuel natural gas. On top of that, selling the captured CO_2 primarily to oil producers for enhanced oil recovery improves the economic viability of gas development projects. Sleipner and Snøhvit have two of the most successful among the few successful projects in the history of carbon capture being used in this sector.

The IEA's Net Zero by 2050 report, one of the seminal energy transition roadmap documents worldwide, has explicitly expressed alarm about the danger of developing any new oil and gas projects globally. It emphasised not developing any new oil and gas projects if the world wants to reach net zero by 2050.

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[213] IOP Publishing. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. 29 December 2020.
[214] ACS Publications. An Estimate of the Amount of Geological CO2 Storage over the Period of 1996–2020. 19 July 2022.

The Elephant in the Room of the Application of CCS/CCUS in the Natural Gas Processing Sector: Scope 3 Emissions Are Still Not Being Accounted for

Gas processing CCS/CCUS covers a tiny proportion of the value chain of emissions compared to CCS/CCUS in other sectors. As gas processing CCUS is largely about 'capturing excess CO_2', it is obvious that CCUS in the sector is not about reducing Scope 3 emissions from the final combustion/use of gas. Rather, it is about minimising production-related Scope 1 emissions from gas with excessive CO_2 content. This is in contrast to most other CCUS applications in the industrial and power sector, which aim to minimise the emissions coming from the end consumption of fossil fuels.

As such, giving the green light to new oil and gas projects just because of CCUS/CCS promises attached to those projects is not climate friendly. Even if the CCS/CCUS facilities work at their capacity (which has not been the case historically, barring some exceptions), such projects could only manage a minor proportion of the value chain emissions of themselves by adding CCS/CCUS.

The gas burnt at the end of the value chain produces the most significant chunk of emissions.

The gas burnt at the end of the value chain produces the most significant chunk of emissions, which CCU/CCUS proposals do not address.

Captured Carbon Has Mostly Been Used for Enhanced Oil Recovery (EOR): Enhancing Oil Production Is Not a Climate Solution

Today, EOR is the only industrial use of CO_2 to have reached a considerable scale. In recent years, EOR projects have used about 73% of the CO_2 captured globally each year. This figure was greater in previous decades.

EOR enhances the oil production rate from fields that have passed the maximum output rate. The basic idea is that oil and gas companies inject the pressurised CO_2 into existing oil and gas reservoirs to squeeze out more hydrocarbons. Oil producers can make money by revitalising oil fields with declining production rates.

EOR itself leads to CO_2 emissions. CO_2-EOR uses carbon dioxide to produce more oil rather than curbing its emissions. The additional oil produced this way either is burned or used for industrial processes, both resulting in CO_2 emissions. Therefore, any claim that CO_2-EOR systems ultimately reduce CO_2 emissions by their nameplate capacity is an overstatement.

About three-quarters of the CO_2 captured annually by multi-billion-dollar CCUS facilities, roughly 28MT out of 39MT total capture capacity, is reinjected and sequestered into oil fields to push more oil out of the ground. This oil then gets refined, burnt and, at least partially, returned to the atmosphere.

IEEFA has estimated that the vast majority of the total captured carbon throughout history found its use in EOR (~80–90%), and a small proportion of carbon capture projects (~10–20%) have stored carbon in dedicated geological structures, without using it for EOR.

Relatively speaking, carbon capture and storage with dedicated geological structures (CCS) is better than CCUS, which is essentially EOR. Any carbon capture project with the final goal of enhancing oil production would not be a climate solution, regardless of whether the carbon capture facility could reach its capture capacity.

Using Carbon Capture as a Greenlight to Extend the Life of Fossil Fuels Power Plants Is a Financial and Technical Risk: History Confirms this

CCS/CCUS for the power sector, one of the most recent proposed applications of carbon capture technology, is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream. This is evident by the string of historical issues in retrofitting CCS/CCUS into power plants with several failed projects and cost blowouts. In contrast to gas processing and certain industrial processes that could generate exhaust gas with 40–90% CO_2 composition, coal plants emit gases that typically only contain 10–14% CO_2, while gas power plants generate 4–5% CO_2. While this may seem small in concentration, it is large in terms of absolute volume globally.

Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity delivered to the consumers. This also means that more fossil fuels will need to keep burning to generate the same amount of electricity in a non-CCUS power plant.

Capturing CO_2 consumes a lot of energy.

To compete in a competitive electricity market context, the high cost of CCS/CCUS will need compensation by selling the captured CO_2, receiving government incentives, or charging a premium price to consumers. However, these pathways are not guaranteed and could also lead to financial instability for the project or environmental externalities, especially in the case of using CO_2 for EOR. Government

incentives should instead flow into fast-growing, efficient, and clean renewable energy technologies and the battery and storage sectors.

Further, apart from the financial argument, carbon capture has shown a track record of technical failures since 2000. Close to 90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early.

Some Applications of CCS in Industries Where Emissions Are Hard to Abate (Such as, Cement) Could be Studied as an Interim Partial Solution with Careful Consideration

Industrial applications of CCS are very diverse. Carbon capture is an established business in some industrial applications, such as fertilisers and ethanol, while other applications are exploring it for technical and commercial competitiveness at scale.

The conclusion about whether carbon capture technologies could be part of the solution for the decarbonisation of industries is not that straightforward. Using carbon capture technologies needs careful research for each application in different industries and business environments. In some applications, with the current high commodity prices, using green hydrogen is a better way to go rather than blue hydrogen.

History shows that capturing 90% (or more) of emissions from industrial processes is very unlikely. Hence, betting on blue hydrogen is not a promising solution and only keeps the fossil fuel status quo. Instead, green hydrogen, with its rapidly plunging cost, would be the clean alternative in industries that run or plan to run on hydrogen.

It is, however, worth studying carbon capture as an interim solution in some sectors, such as cement.

This report studies five flagship cases in different sub-sectors that account for about 65% of the total existing industrial carbon capture capacity. Chemical production mainly comprises the production of fertilisers, ethanol, methanol, and syngas. We analyse the CCS application in each sub-sector by reviewing a project in each area. The results are mixed, with most projects underperforming by a considerable margin and few others presenting a relatively better performance. As hydrogen has an important role in many processes in different sub-sectors, pro-fossil fuel groups have pushed for blue hydrogen. However, wherever hydrogen is applicable technically, green hydrogen would be the better solution due to the financial and imminent cost-efficiency.

The final area of focus in the industrial application of carbon capture technology is the steel and cement industry, so-called hard-to-abate industries. Steel and cement are responsible for 13–14% of total global emissions, and the demand for these two materials is increasing. Therefore, decarbonising these two crucial industries is necessary if the world aims to reach net-zero emissions by 2050.

The steel sector is in the early years of utilising carbon capture technology. Studies could be done on probable projects. However, as carbon capture technology in different sectors has *not* reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time before needing to reach net zero by 2050 does *not* seem to be a sustainable solution. Instead, alternative methods of steel production such as scrap steel recycling emit about 80% less CO_2 per tonne of crude steel than other forms of steel production used today, and green hydrogen leading to the production of "green steel"[215] looks like a more promising method to follow.

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. Carbon capture technologies seem useful in this industry if they aren't used as an excuse to postpone other methods now under investigation to reinvent the processes and make cement production 'green'.

In all of these industrial applications, CCS/CCUS could be studied if:

- it does not promote EOR
- it does not extend or is used as an excuse to extend the life of any type of fossil asset
- a safe storage location is identified, and a long-term monitoring plan and compensation mechanism in case of failure are developed
- the liability of the projects is not handed over to the taxpayers.

Lessons Learned: Insights for the Way Forward

The natural gas processing and power sector, where carbon capture technologies would extend the life of fossil fuel assets (even if its use could overcome historical technical and financial issues), is not in line with net zero goals.

There are a few sub-sectors for industrial application, however, where carbon capture could be considered an interim option for decarbonisation if it doesn't distract the research and development studies being done in parallel to reinvent the production process. Even in such sub-sectors, such as cement, the technical prosperity of the technology is uncertain. Considering the climate clock is ticking, rigorous environmental and technical conditions need to be satisfied if these few applications are to be greenlit.

The application of CCUS/CCS in the steel and cement sector is a relatively new area with only one ~6-year-old operating project in Abu Dhabi with no publicly published data on its performance. Essentially, there is not much to learn from the application of CCS/CCUS in these two industries. However, based on limited knowledge of the technology trajectory in other applications but with common processes as in these industries, as well as other solutions being developed and

[215] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.

researched in parallel, future CCS/CCUS applications in the steel and cement industry could be projected to some extent.

Green hydrogen or recycling scrap steel should be prioritised in the steel sector over CCUS/CCS to capture carbon from gasification, reformation, or burning fossil fuels.

In the cement sector, as CO_2 is the by-product of the fundamental chemical reaction of producing cement, CCUS/CCS projects could be considered cautiously. Other innovative methods should be pursued to reinvent the whole process toward green cement. Meanwhile, carbon capture could be used as long as the captured carbon is not used for EOR. CCUS/CCS should only be used if the technical performance reaches close to nominal capture capacities, contrasting with general trends of its application throughout history. Also, it could be considered an interim option as long as it does not divert financial flows from fundamental and innovative solutions reinventing the cement production process.

For other industrial applications, wherever hydrogen is applicable technically, green hydrogen seems to be the way to go due to the financial and imminent cost-efficiency.

Appendix 1

Project	Flagship Aspect	Year Capturing Started	Type	Country	Size[216] (Mtpa)	Sector	Performance Against Designed Capture Rate[217]	Comment
Abu Dhabi	The first and only CCS plant in the steel sub-sector	2016	Enhanced oil recovery (CCUS	UAE	0.8	Industrial (hard-to-abate sector)	No data has been published publicly	The project is 100% government owned
Boundary Dam	The only project operating in the power sector worldwide	2014	Mostly enhanced oil recovery (CCUS)	Canada	1	Power sector	Under-performing by about 50%	A 50-year-old coal power plant retrofitted with the carbon capture facility
Coffeyville	The largest project operating in the fertiliser production sub-sector	2013	Enhanced oil recovery (CCUS	U.S.	0.9	Industrial (chemical production)	No public data was found on the lifetime performance. Only some research shows that the plant over-performed during 2017–2019 by about 16%.	The CO_2 was vented until the year 2013, then some agreements with nearby oil companies were finalised to sell the CO_2
Gorgon	Largest and one of the more recent CCS projects in the world	2019	Dedicated geological structure (CCS)	Australia	4	Gas processing sector	Under-performing by about 50%	Started after 3.5 years delay with a track record of technical failures. Compensating under-performance will cost up to US$184 million.
Great Plains	The largest carbon capture project in all sectors other than natural gas processing	2000	Enhanced oil recovery (CCUS)	U.S.	3	Industrial (chemical production)	Lifetime under-performance of 20–30%	The project started capturing CO_2 16 years after the syngas plant was commissioned. In 2022, it has been planned to be redeveloped into a blue hydrogen project.
Illinois Industrial Carbon Capture and Storage (IL-CCS)	The largest and the latest project commissioned in the ethanol production sub-sector	2017	Dedicated geological structure (CCS)	U.S.	1	Industrial (chemical production)	Under-performing by about 45–50%	The project was 68% government funded. It has only captured about 12% of the yearly total CO_2 emissions of the biofuel plant so far
In Salah	One of the largest operating CCS projects of our time	2004	Dedicated geological structure (CCS)	Algeria	1.1	Gas processing sector	Failed after seven years of operation	Started in 2004. Concerns about possible vertical leakage into the caprock led to investigations, and finally, the project was suspended in 2011

[216] There are different sizes for some projects in different sources. In those cases, the average size has been considered.
[217] For some of the projects, scattered data from different sources has been complied to calculate the performance. An estimated interval is provided for the performance.

Kemper	It was planned to be a first-of-a-kind plant, capturing CO_2 from producing gasified coal, and using gas in the modified gas power plant to produce electricity	2014 (without Carbon Capture)	Enhanced oil recovery (CCUS)	U.S.	3	Power sector	Failed to be started	Technical problems led to a 250% increase in the previously estimated cost of the project from U$3b to US$7.5 billion. The carbon capture idea was cancelled in 2017. It was the most expensive power plant ever built.
Petra Nova	The only project in the power sector in the U.S.	2017	Enhanced oil recovery (CCUS)	U.S.	1.4	Power sector	Under-performed by 17% in four years of its operation and then shut down.	It was mothballed indefinitely in 2020 citing low oil prices during the COVID-19 pandemic
Quest	One of the operating projects in the hydrogen production sub-sector operating at its design capacity	2015	Dedicated geological structure (CCS)	Canada	1.1	Industrial (hydrogen production)	Performing close to the capture capacity	The project got off the ground thanks to huge government funding estimated at C$95 per tonne of CO_2 captured until the end of the project's lifetime. It captures 35% of the CO_2 emissions of the oil upgrader.
Shute Creek	Largest and one of the oldest carbon capture projects in the world	1986	Enhanced oil recovery (CCUS)	U.S.	7	Gas processing sector	Lifetime under-performance of 36%	It is estimated that the lifetime under-performance of the project against its capturing capacity is approximately equivalent to the combined emissions from Sweden and Denmark in 2019
Sleipner	First commercial carbon capture project with a dedicated geological structure worldwide	1996	Dedicated geological structure (CCS)	Norway	0.9	Gas processing sector	Performing close to the capture capacity	It is among a few successful cases located in Norway. An exceptionally high carbon tax and stringent regulatory environment linked to the ETS are among the drivers. The gas project is in its tail of production lifetime.
Snøhvit	One of the two successful Norwegian carbon capture projects	2007	Dedicated geological structure (CCS)	Norway	0.7	Gas processing sector	Performing close to the capture capacity	It is one of the successful cases which is located in Norway. An exceptionally high carbon tax and stringent regulatory environment linked to the ETS are among the drivers.

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The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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