ASEAN

Neutral *(no change)*

Highlighted Companies

MISC Bhd
ADD, TP RM8.53, RM7.63 close

MISC is actively working towards the ownership of liquefied CO2 carriers to serve the transportation segment of the CCS value chain. MISC may also be involved in onboard-ship carbon capture and zero-emissions power generation.

Petronas Gas
HOLD, TP RM17.70, RM17.50 close

PetGas may leverage its long experience of handling gases to own and operate the CO2 terminals that Malaysia may construct by 2030F for the purposes of handling imported and domestic CO2 prior to injection into offshore reservoirs.

Yinson Holdings Bhd
ADD, TP RM3.26, RM2.33 close

Yinson has a 40% interest in Norway's Havstjerne CCS project, which by 2027F will provide shipping and CO2 injection services to emitters in Northern Europe for permanent sequestration in the Havstjerne storage site in the North Sea.

Summary Valuation Metrics

P/E (x)	Dec-25F	Dec-26F	Dec-27F
MISC Bhd	15.38	14.18	13.85
Petronas Gas	19.64	18.71	18.41
Yinson Holdings Bhd	11.65	8.02	7.22
P/BV (x)	**Dec-25F**	**Dec-26F**	**Dec-27F**
MISC Bhd	0.96	0.94	0.92
Petronas Gas	2.41	2.35	2.29
Yinson Holdings Bhd	0.68	0.55	0.55
Dividend Yield	**Dec-25F**	**Dec-26F**	**Dec-27F**
MISC Bhd	4.64%	4.64%	4.64%
Petronas Gas	3.91%	4.25%	4.32%
Yinson Holdings Bhd	2.50%	2.58%	2.58%

Analyst(s)

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Commodities - Overall

CCUS: Storage projects to take off in ASEAN

- CCUS projects have taken off in the US and Europe due to the governments' carrot-and-stick approach of tax credits, carbon pricing, and direct funding.
- Due to the absence of similar drivers, CCUS in SE Asia is focused on sour gas extraction, EOR/EGR, and projects to develop storage for foreign CO2.
- MISC and PetGas could benefit from such future business opportunities, while Yinson is operationalising a transport and injection solution in Norway.

SE Asia lacks the incentives or penalties for CCS adoption…

Proponents of carbon capture, utilisation and storage (CCUS) posit that it is an important component in the array of tools to reduce CO2 emissions, including as a means to extend the operating life of young fossil-fuel power plants and to decarbonise hard-to-abate industrial sectors like cement, and iron and steel. But this is where the theory clashes with the reality that CCUS is still too expensive to implement in power plants and industrial sectors. According to consultancy DNV, natural gas processing made up 85% of all CCUS projects, and 85% of CCUS projects utilise the CO2 for EOR/EGR in mid-2025. This is perfectly logical because CO2 separation is an essential process for the sale gas to meet contractual specifications, while EOR/EGR is the easiest way for the captured CO2 to be monetised. Globally, the US and Europe have historically led CCUS deployment, with the US providing the 'carrot' of 45Q tax credits while Europe uses a mix of 'carrots' and 'sticks'. The 'sticks' in Europe include the price of carbon (EU ETS and carbon taxes) as well as specific mandates for CO2 storage development, while 'carrots' include significant direct capex funding, and revenue and opex support for CCUS projects. In the Middle East, China, and SE Asia, the 'carrots and sticks' are largely missing or weak, hence governments via their NOCs and SOEs have taken the lead in driving CCUS projects, mainly for EOR/EGR and for sour gas processing although the latter comes at a heavy cost for oil companies like Petronas and PTTEP, in our view. We believe Hibiscus will passthrough the CCS costs at PM3 CAA to Petronas, hence neutral impact.

…but storage projects may drive the CCS business opportunities

In Malaysia, Indonesia and potentially Thailand, the storage of imported CO2 may emerge as a viable new business model, capitalising on plans by Japan, South Korea and/or Singapore to ship their CO2 captured from industrial sources for storage in SE Asia. This value chain will require the new LCO2 carriers, CO2 terminals at both the export and import ends, pipelines to transport the CO2 to offshore injection sites, as well as offshore injection assets. MISC is making plans to be the owner and operator of LCO2 ships, and may also be positioned to supply the offshore injection assets via MMHE. We believe that by 2030F, PetGas may own/operate the CO2 terminals in Malaysia, which may be contracted on a long-term basis to Petronas, which is the key driver of offshore storage assets in Malaysia. In Europe, Yinson has a 40% interest in Norway's Havstjerne CCS project, which targets to provide maritime solutions for the transport and injection of CO2 by 2027F. Bumi Armada is also pursuing opportunities in Europe for its Floating Storage Injection Unit (FSIU).

Figure 1: Future storage projects in Malaysia – Northern, Southern, Eastern Clusters

SOURCE: MINISTRY OF ECONOMY, MALAYSIA

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Figure 2: Sector comparisons table

Company	Bloomberg Ticker	Recom.	Price	Target Price	Market Cap (US$ m)	Core P/E (x)		3-year EPS CAGR (%)	P/BV (x)		Recurring ROE (%)			EV/EBITDA (x)		Dividend Yield (%)	
						CY25F	CY26F		CY25F	CY26F	CY25F	CY26F	CY27F	CY25F	CY26F	CY25F	CY26F
Hibiscus Petroleum Bhd	HIBI MK	Add	RM1.44	RM2.93	257	9.6	7.3	-18.1%	0.4	0.4	4.0%	5.4%	4.9%	2.1	1.8	5.9%	4.9%
Medco Energi Internasional	MEDC IJ	Add	Rp1,325	Rp1,380	1,997	17.0	11.6	-15.3%	0.9	0.9	5.5%	7.7%	9.3%	4.0	3.7	1.2%	1.7%
PTT	PTT TB	Add	THB30.75	THB37.50	27,059	10.0	9.8	7.3%	0.7	0.7	7.3%	7.5%	8.3%	5.3	5.1	6.5%	6.5%
PTT Exploration & Production	PTTEP TB	Add	THB106.50	THB128.00	13,135	6.9	6.9	-2.0%	0.7	0.7	10.7%	10.6%	11.1%	1.7	1.7	7.2%	8.0%
Average E&P group - under CGSI coverage						**9.0**	**8.7**	**1.9%**	**0.7**	**0.7**	**8.2%**	**8.5%**	**9.2%**	**4.1**	**3.8**	**6.3%**	**6.7%**
BP plc	BP/ LN	Not Rated	GBp454.20	n.a.	94,037	7.2	6.8	-1.1%	0.8	0.8	11.9%	12.2%	13.8%	2.3	2.4	9.6%	9.9%
Chevron	CVX US	Not Rated	US$151.13	n.a.	304,304	21.9	21.6	0.8%	1.8	1.9	8.0%	8.5%	11.3%	8.2	7.2	4.5%	4.8%
ConocoPhillips	COP US	Not Rated	US$88.69	n.a.	109,596	13.1	14.0	-0.8%	1.7	1.7	14.0%	12.0%	15.0%	5.0	5.3	3.6%	3.8%
Eni S.p.A.	ENI IM	Not Rated	€16.13	n.a.	58,865	8.4	7.8	7.0%	0.7	0.7	9.8%	9.5%	10.9%	3.2	3.3	8.7%	9.0%
Equinor	EQNR NO	Not Rated	NOK233.10	n.a.	58,884	8.3	8.0	-2.0%	1.4	1.3	15.5%	16.7%	16.5%	1.8	2.0	6.5%	6.8%
ExxonMobil	XOM US	Not Rated	US$115.92	n.a.	488,854	16.6	15.3	1.5%	1.9	1.8	11.5%	12.0%	14.4%	7.5	7.2	3.5%	3.6%
Shell	SHEL LN	Not Rated	GBp2,784	n.a.	211,763	6.8	6.3	-3.8%	0.7	0.7	10.4%	10.8%	11.7%	2.9	3.2	6.9%	7.1%
TotalEnergies	TTE FP	Not Rated	€56.80	n.a.	145,337	7.4	6.8	-3.8%	0.9	0.9	13.1%	12.9%	13.8%	3.5	3.7	7.7%	8.1%
Average E&P group - supermajors						**9.6**	**8.6**	**4.6%**	**1.2**	**1.2**	**13.1%**	**14.2%**	**15.2%**	**4.0**	**3.9**	**5.3%**	**5.6%**
CNOOC	883 HK	Not Rated	HK$18.52	n.a.	115,881	6.1	6.1	-2.8%	1.0	0.9	17.1%	15.6%	14.9%	2.8	2.8	7.3%	6.8%
Indian Oil Corp Ltd	IOCL IN	Not Rated	INR150.06	n.a.	24,594	21.1	10.2	-20.2%	1.1	1.0	2.2%	10.5%	10.5%	9.9	6.9	2.4%	3.8%
ONGC	ONGC IN	Not Rated	INR246.31	n.a.	35,963	7.1	7.4	-6.0%	0.9	0.8	8.6%	11.3%	11.6%	3.8	3.7	5.0%	4.9%
Petrobras	PBR US	Not Rated	US$12.01	n.a.	74,946	3.8	4.1	-15.2%	1.1	0.7	37.3%	21.0%	21.0%	2.4	2.4	13.9%	13.4%
Petrochina	857 HK	Not Rated	HK$7.21	n.a.	220,469	7.7	7.5	-3.7%	0.8	0.7	10.1%	9.8%	9.7%	3.1	3.1	6.6%	6.5%
PetroVietnam	PVS VN	Not Rated	VND34,200	n.a.	625	16.8	16.6	0.9%	1.2	1.1	7.0%	6.8%	7.6%	8.1	4.8	2.5%	2.5%
PTT	PTT TB	Add	THB30.75	THB37.50	27,059	10.0	9.8	7.3%	0.7	0.7	7.3%	7.5%	8.3%	5.3	5.1	6.5%	6.5%
PTT Exploration & Production	PTTEP TB	Add	THB106.50	THB128.00	13,135	6.9	6.9	-2.0%	0.7	0.7	10.7%	10.6%	11.1%	1.7	1.7	7.2%	8.0%
Saudi Aramco	ARAMCO AB	Not Rated	SAR24.11	n.a.	1,555,525	16.1	15.5	-0.6%	3.8	3.8	10.3%	24.4%	25.8%	7.3	7.2	5.5%	5.7%
Sinopec	386 HK	Not Rated	HK$4.34	n.a.	92,153	9.7	8.8	5.9%	0.6	0.6	6.0%	6.5%	6.9%	3.5	3.3	6.5%	7.2%
Average E&P group - NOCs						**13.1**	**12.7**	**-2.6%**	**2.1**	**2.0**	**10.1%**	**16.4%**	**17.1%**	**5.6**	**5.5**	**5.8%**	**6.0%**
Bumi Armada	BAB MK	Add	RM0.30	RM0.57	430	3.9	4.4	-19.1%	0.3	0.3	7.0%	6.1%	6.6%	2.7	1.7	0.0%	0.0%
Dialog Group Bhd	DLG MK	Add	RM1.84	RM2.33	2,512	21.6	18.0	8.2%	1.6	1.5	7.4%	8.7%	8.7%	14.3	12.6	1.9%	2.3%
Yinson Holdings Bhd	YNS MK	Add	RM2.34	RM3.26	1,655	17.9	9.6	1.0%	0.7	0.6	4.8%	8.6%	9.8%	8.5	7.7	2.5%	2.6%
Petronas Dagangan Bhd	PETD MK	Reduce	RM19.82	RM16.77	4,765	17.6	17.6	0.1%	3.3	3.3	18.7%	18.7%	18.7%	9.3	9.3	5.5%	5.5%
Hibiscus Petroleum Bhd	HIBI MK	Add	RM1.44	RM2.93	257	9.6	7.3	-18.1%	0.4	0.4	4.0%	5.4%	4.9%	2.1	1.8	5.9%	4.9%
Dayang Enterprise	DEHB MK	Add	RM1.60	RM2.10	448	9.7	9.7	-13.4%	1.0	0.9	10.0%	9.7%	9.9%	4.0	3.7	6.7%	6.7%
Wasco Bhd	WSC MK	Add	RM0.98	RM1.65	184	7.0	5.9	-9.7%	0.8	0.8	12.3%	13.4%	14.0%	2.8	2.0	4.3%	5.1%
Velesto Energy Berhad	VEB MK	Add	RM0.23	RM0.28	457	11.2	18.6	-22.9%	0.7	0.7	6.2%	3.9%	3.6%	3.6	4.4	10.9%	13.0%
MISC Bhd	MISC MK	Add	RM7.51	RM8.53	8,112	14.7	14.0	9.3%	0.9	0.9	6.5%	6.7%	6.7%	9.5	8.8	4.7%	4.7%
Average Malaysia O&G companies						**14.7**	**13.4**	**1.6%**	**1.1**	**1.0**	**7.5%**	**8.0%**	**8.2%**	**8.1**	**7.6**	**4.4%**	**4.6%**

DATA AS AT 28 NOV 2025
SOURCES: CGSI RESEARCH ESTIMATES, BLOOMBERG, COMPANY REPORTS
Note: Forecasts for Not Rated (NR) companies are Bloomberg consensus' estimates; Not Rated companies show reported net profit

Please see **Appendix 5** for other companies mentioned in this report.

CCUS: Storage projects to take off in ASEAN

(A) ABBREVIATIONS USED IN THIS REPORT

BECCS: Bioenergy with Carbon Capture and Storage
BESS: Battery energy storage systems
CBAM: Carbon Border Adjustment Mechanism
CCfD: Carbon Contracts for Difference
CCS: Carbon Capture and Storage (used interchangeably with CCUS)
CCU: Carbon Capture and Utilisation
CCUS: Carbon Capture, Utilisation and Storage (used interchangeably with CCS)
CDR: Carbon Dioxide Removal
CO2: Carbon dioxide
DAC: Direct Air Capture
DACCS: Direct Air Carbon Capture and Storage
EC: European Commission
EGR: Enhanced Gas Recovery
EOR: Enhanced Oil Recovery
ETS: Emissions Trading Scheme
EU: European Union
FOAK: First of a Kind
GCC: Gulf Cooperation Council
GCCSI: Global CCS Institute
GHG: Greenhouse gases
IEA: International Energy Agency
IEEFA: Institute for Energy Economics and Financial Analysis
IMO: International Maritime Organization
IRENA: International Renewable Energy Agency
JOGMEC: Japan Organization for Metals and Energy Security
LCO2: Liquefied CO2
LCOE: Levelised cost of electricity
METI: Ministry of Economy, Trade and Industry (of Japan)
MRV: Monitoring, Reporting and Verification
NEDO: New Energy and Industrial Technology Development Organization (of Japan)
NETR: National Energy Transition Roadmap (of Malaysia)
NOC: National oil company
PV: Photovoltaic solar panels
RAB: Regulated asset base
RE: Renewable energy
SAF: Sustainable Aviation Fuel
SOE: State-owned enterprise
T&S: Transport and storage (of CO2)
VCM: Voluntary Carbon Markets

Mt: Million tonnes
Mtpa: Million tonnes per annum
Gt: Giga tonnes (or 1,000 Mt)

(B) GLOBAL STATUS OF CCS

Global CCS Institute forecasts

The Global CCS Institute (GCCSI) published a report on 9 Oct 2025 detailing the CCS developments globally, and noted a significant increase in the number of number of capture facilities in the development pipeline.

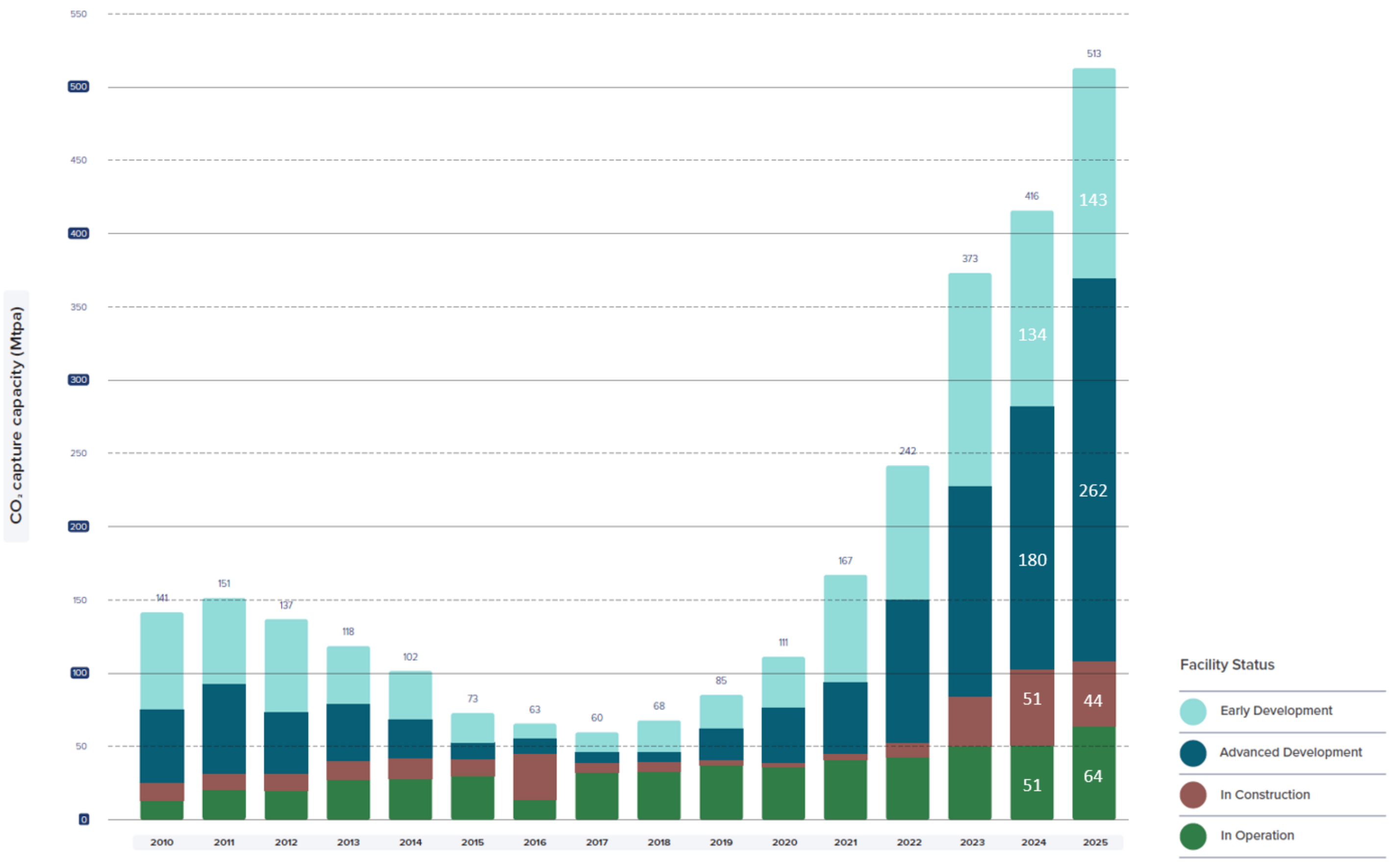
The pipeline as at 28 Jul 2025 stood at:

- 44 Mtpa under construction;
- 262 Mtpa in advanced development (from 180 Mtpa in 2024); and
- 143 Mtpa in early development (from 134 Mtpa in 2024).

The operational CO2 capture capacity:

- As at 28 Jul 2025 was **64 Mtpa**
- And GCCSI projects this to increase to **337 Mtpa by 2030F**, representing a CAGR of almost 40%.
- Assuming all projects are eventually operationalised, capture capacity will ultimately rise to **513 Mtpa**, based on the current pipeline.

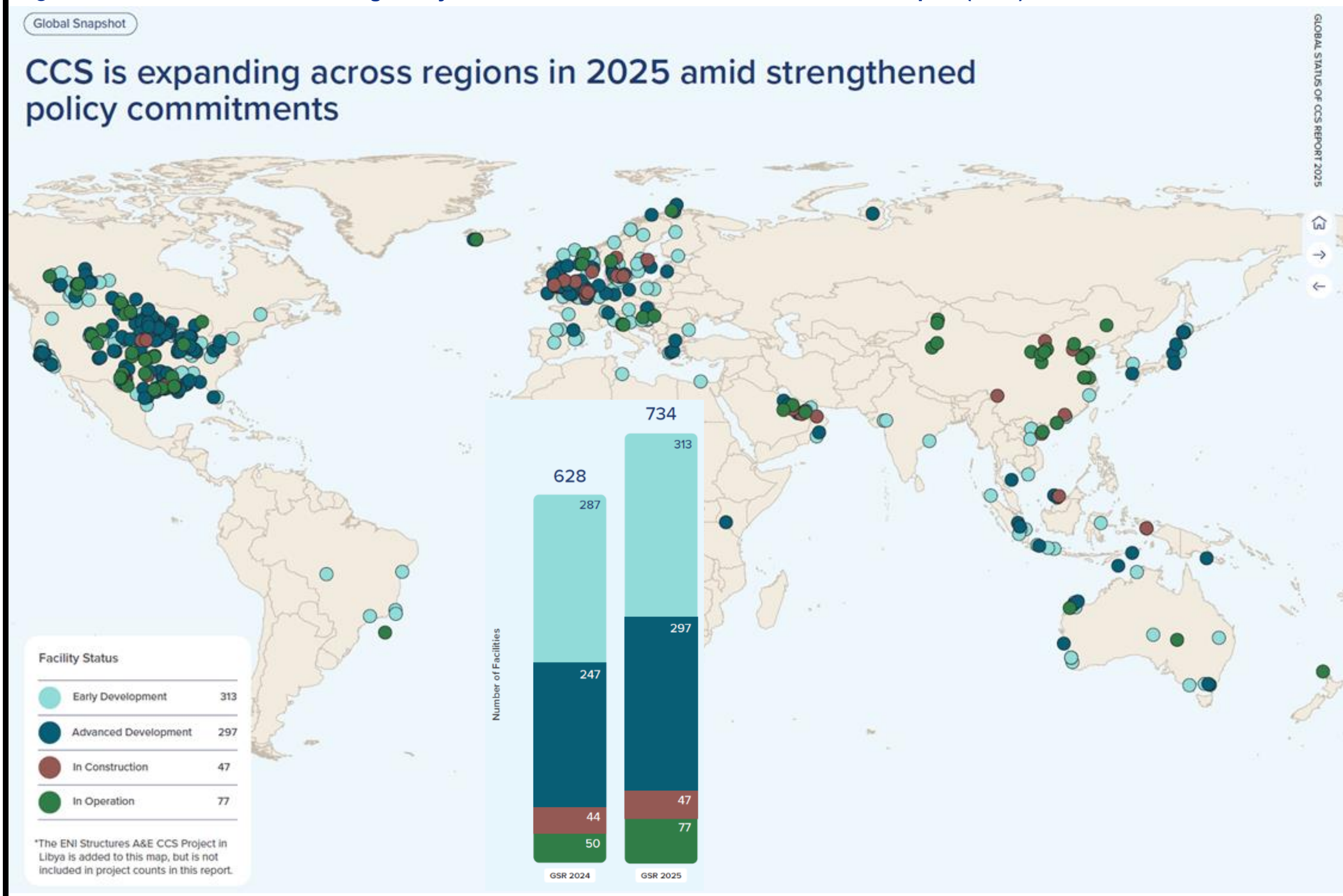
Figure 3: CO2 capture capacity of commercial CCS facility pipeline since 2010



SOURCE: GLOBAL CCS INSTITUTE, 2025

The number of CCS facilities in operation, construction, advanced development and early development has also increased, from 628 facilities last year to 734 facilities as at 28 Jul 2025, according to GCCSI.

Figure 4: Number of CCS facilities globally increased between GCCSI's Global Status Report (GSR) 2024 and GSR 2025



SOURCE: GLOBAL CCS INSTITUTE, 2025

Natural gas processing has the most number of projects currently in operation. However, the strongest growth trajectories are for CO2 transport/storage, CCS for ethanol/biomass fermentation plants, and for the hydrogen/ammonia/fertiliser value chain, based on GCCSI data. GCCSI noted that 'first of a kind' (FOAK) CCS developments at commercial scale include cement and concrete production (including in China and Norway), and natural gas-fired power generation (esp. for North American Artificial Intelligence data centres). Meanwhile, DACCS and BECCS projects are being supported by Voluntary Carbon Markets (VCM).

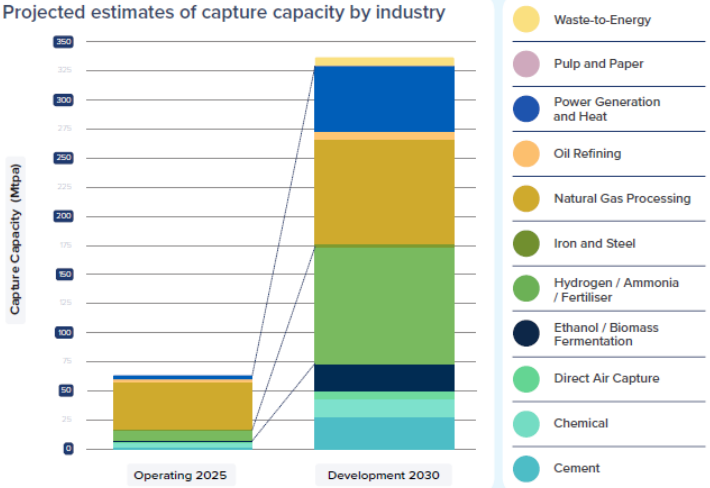
Figure 5: Total number of CCS facilities as at Jul 2025, by industry and stage of development

SOURCE: GLOBAL CCS INSTITUTE, 2025

As noted previously, GCCSI forecasts CO2 capture capacity to rise exponentially from 64 Mtpa in 2025 to 337 Mtpa in 2030F.

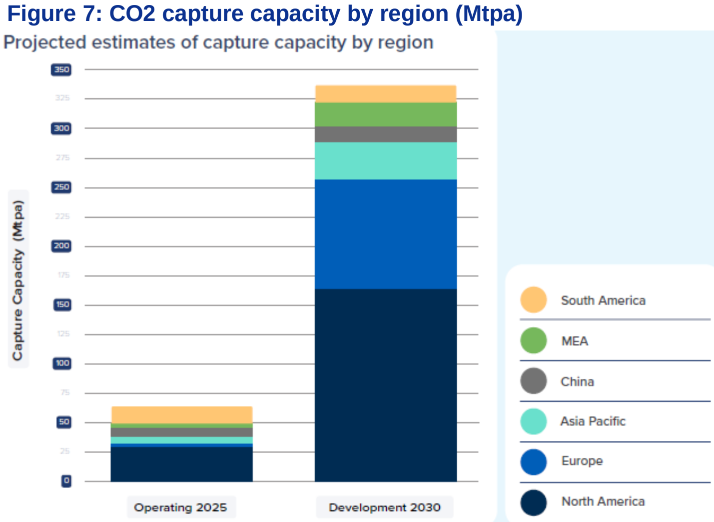
- By industry, natural gas processing is the dominant CO2 capture application in 2025. By 2030F, applications in the hydrogen/ammonia/fertiliser and power generation sectors could also become large.
- Geographically, the US is currently dominating CCUS developments globally and may continue to lead in 2030F. But Europe could significantly increase its CO2 capture from 3 Mtpa (2025) to >90 Mtpa (2030F). The US and Europe will likely continue dominating the CCUS industry in 2030F, according to GCCSI.

Figure 6: CO2 capture capacity by industry (Mtpa)



SOURCE: GLOBAL CCS INSTITUTE, 2025

Figure 7: CO2 capture capacity by region (Mtpa)



SOURCE: GLOBAL CCS INSTITUTE, 2025

DNV analysis and forecasts

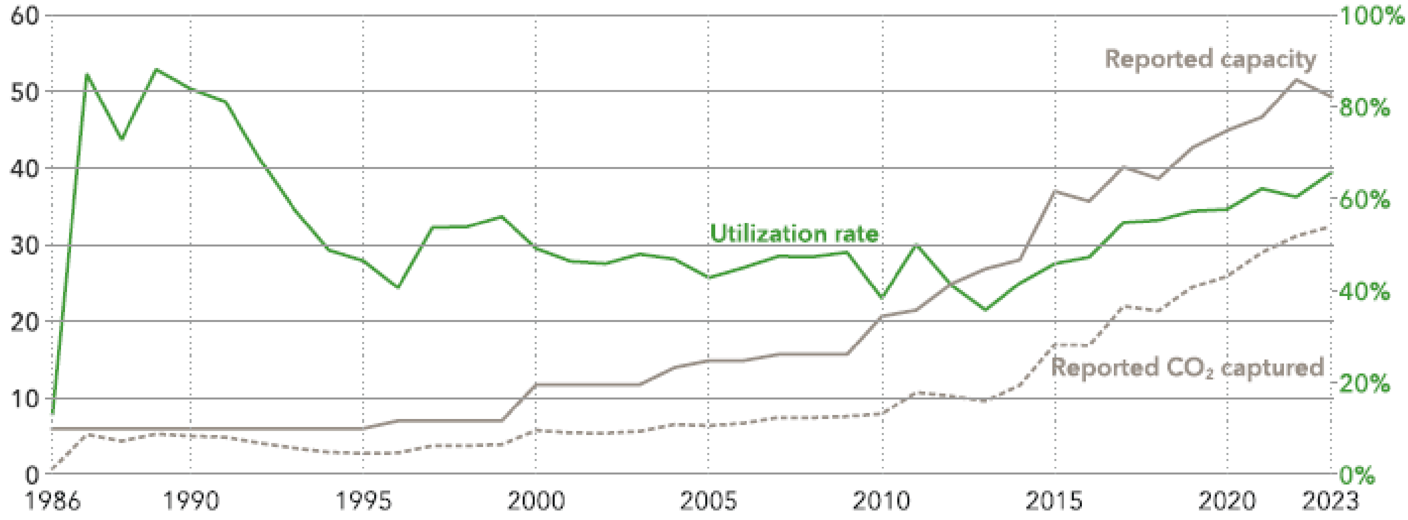
Historically, gas processing has dominated the CCS sector, comprising around 85% of installed capacity globally, according to DNV, a consultancy and shipping classification society (a report from the IEA in 2023 noted that 65% of operational CCS capacity was related to natural gas processing). CO2 removal from raw natural gas streams is essential because the sale gas (gas that is sold to users) typically cannot contain more than 3 mol% of CO2 to prevent pipeline corrosion and to maintain high heating values. As a result, CO2 capture in natural gas processing facilities is essential to monetising the sale gas. However, in the past 25 years, other sectors have also deployed CCS, mainly in power and industrial processes, according to DNV.

Of the total CO2 capture capacity, around 85% captures CO2 for EOR, according to DNV. This is because EOR/EGR provides the economic use for the captured CO2, which is injected into oil and gas reservoirs to enhance production, with c.99% of the injected CO2 typically permanently stored in the reservoirs.

Based on DNV's analysis, the average utilisation rate of CO2 capture facilities was 53% in 1986-2023, and increased to around 60% in 2018-2023. Excluding gas processing projects, the utilisation rate drops to 50% in 2018-2023, as several projects have had issues with equipment that resulted in unexpected downtime or maintenance, leading to lower-than-expected capture rates or higher-than-expected amine degradation rates (amine is a chemical solvent to absorb CO2, but degrades in effectiveness over time).

Figure 8: Reported capacity, reported CO2 captured and utilisation rates of operational carbon capture projects globally

Units: $MtCO_2/yr$ (left axis), Percentages (right axis)



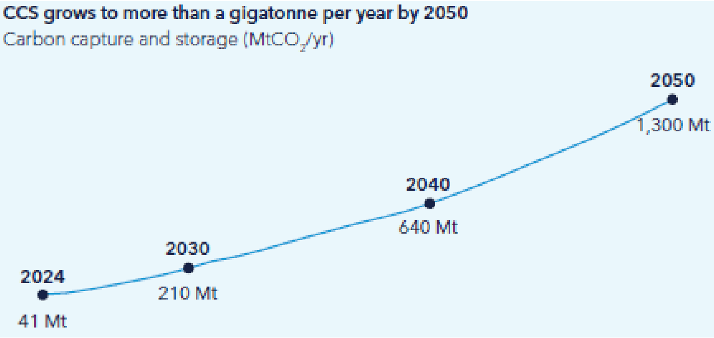
Note: 30 operational carbon capture projects globally. Data source: DNV (2025)

SOURCE: DNV, 2025

DNV projects that:

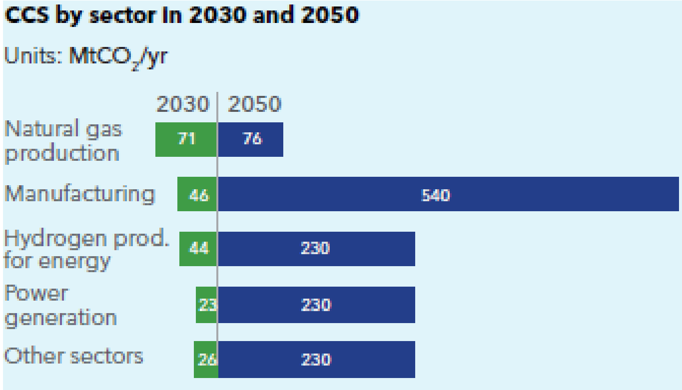
- North America and Europe will drive the uptake of CCS capacity up to 2030F, in line with GCCSI's expectations; and that
- Natural gas processing will remain the main application until 2030F;
- After 2030F, CCS in the hard-to-decarbonise manufacturing sector may take off, due to DNV's expectations for falling technology costs and rising carbon prices. For example, cement and chemicals in Europe, hydrogen and ammonia in the Middle East, coal-fired power plants in China could see significant CCS uptake.

Figure 9: Actual CO2 captured and stored to rise to 1,300 Mtpa in 2050F



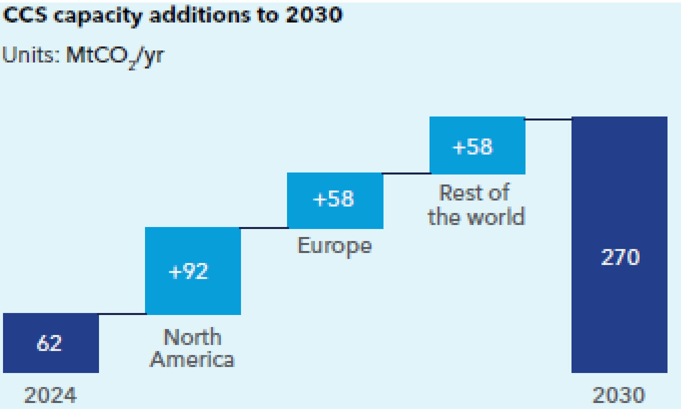
SOURCE: DNV, 2025

Figure 10: CCS applications by sector in 2030F and 2050F



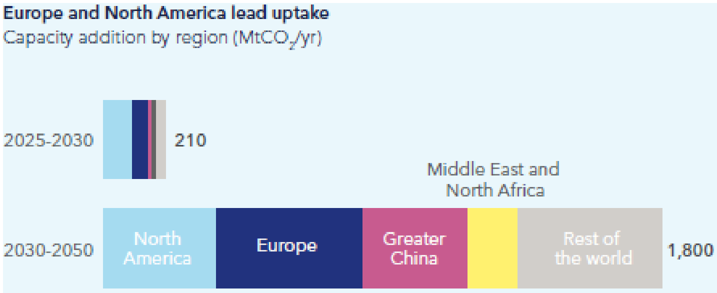
SOURCE: DNV, 2025

Figure 11: CCS capacity additions to 2030F



SOURCE: DNV, 2025

Figure 12: Europe and North America to continue leading global CCS applications



SOURCE: DNV, 2025

According to DNV, the reasons for North American dominance in CCS projects in the short term include:

- Deep experience and knowledge base in implementing carbon capture, transport, and storage;
- Lower project costs due to time in the CCS market, and decades-long existence of established pipeline infrastructure;
- Carbon capture for EOR provides a source of revenues that can reduce the business risk of adopting capture technologies;
- Government support via tax credits in the US, and Canadian governmental support for CCS; and
- Clear laws and regulations with regards to transport and storage of CO2 (both in saline aquifers and depleted oil and gas wells).

In Europe, the primary driver for CCS adoption is the continent's carbon neutrality target, its ambitious decarbonisation agenda, and EU carbon price.

In the Middle East, trade to Europe is the main motivator for CCS, given EU's Carbon Border Adjustment Mechanism (CBAM) rules from 1 Jan 2026F. Adopting CCS for natural gas processing, methane-based hydrogen production, and ammonia production will keep exports to the EU open to Middle East oil and gas producers.

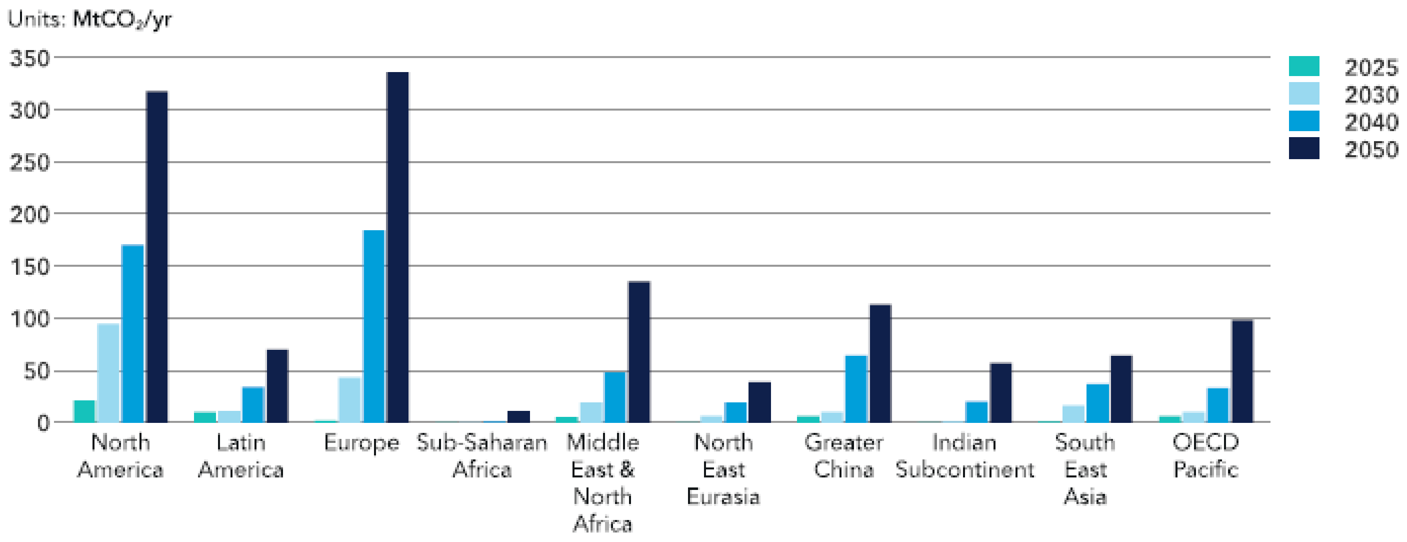
China's dual carbon goals, to reach peak emissions by 2030F and carbon neutrality by 2060F, plus the expansion of its Emissions Trading System (ETS) to include cement, steel, and aluminium in 2025 are drivers of CCS deployment in the power and industrial sectors.

Various countries have also committed to developing CO2 capture and storage capacity by 2030F, according to DNV. These include:

- US: 110 Mtpa
- EU: 50 Mtpa
- Brazil: 45 Mtpa
- UK: 20-30 Mtpa
- Australia: 25 Mtpa
- Malaysia: 15 Mtpa

Separately, oil majors ExxonMobil, Shell, BP, Chevron, and Aramco have also announced individual CCS targets ranging from 10-30 Mtpa by 2030F, according to DNV.

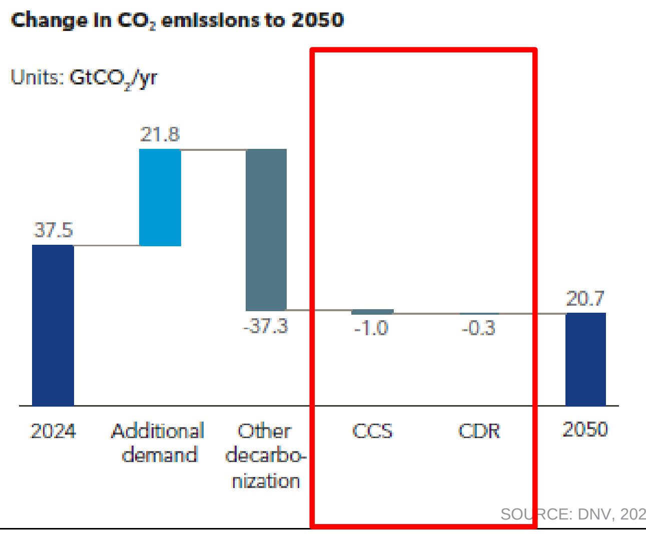
Figure 13: Regional uptake of CCS



SOURCE: DNV, 2025

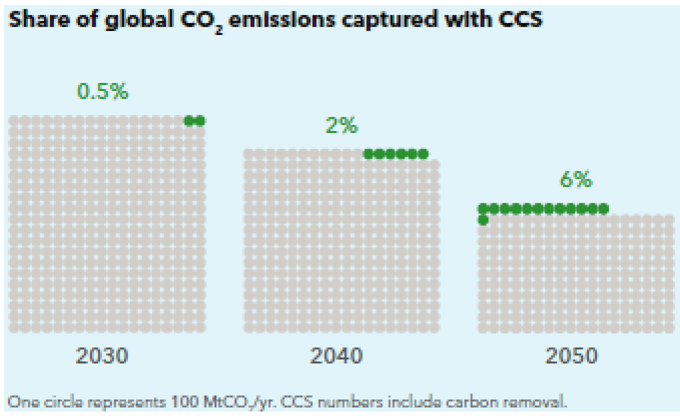
Despite expectations of growing CCS deployments globally, DNV projects 'only' 1,300 Mtpa CO2 will be captured in 2050F, representing just 6% of estimated global emissions in 2050F, and only one-sixth of the total CCS needed to reach DNV's Pathway to Net Zero Emissions by that year. DNV believes that 'other decarbonisation' methods, such as adopting renewable energy, will contribute much more significantly (i.e. 37,300 Mtpa) to global decarbonisation by 2050F.

Figure 14: CCS and CDR projects may only contribute 1.3 Gtpa of CO2 removals by 2050F



SOURCE: DNV, 2025

Figure 15: DNV estimates that only 6% of global CO2 emissions will be captured by CCS by 2050F



SOURCE: DNV, 2025

(C) CCUS KEY SUCCESS FACTORS

There are several key ingredients that need to be present for CCUS projects to take off, in our analysis. These include:

(a) Government policy support
(b) Government funding support
(c) Legal/regulatory frameworks and support
(d) Government mandates
(e) Carbon pricing
(f) Technological innovation
(g) Clear business case
(h) NOC/SOE initiatives to spearhead projects
(i) Public trust and acceptance

(a) Government policy support

The presence of national and supranational environmental targets can play an important role to encourage CCS adoption. For instance:

- The EU has a legally-binding target to achieve climate neutrality by 2050F and to cut GHG emissions by at least 55% by 2030F.
- Malaysia aims to achieve net-zero emissions by 2050F, reduce GHG emission intensity against GDP by 45% by 2030F vs 2005.
- China aims to reach peak carbon emissions by 2030F and carbon neutrality by 2060F.
- Gulf Cooperation Council (GCC) countries target net zero emissions by 2050F or 2060F.

In the **EU**, the Industrial Carbon Management Strategy (released in Feb 2024) aims for 50 Mtpa CO2 injection and storage capacity by 2030F, and 450 Mtpa by 2050F. Meanwhile, the EU Clean Industrial Deal (released in Feb 2025) is providing policy support for industries like steel, metals, and chemicals to decarbonise their processes, via measures such as affordable and clean energy access, encouraging public procurement for low-carbon products, targeted financing, and a focus on circularity and raw material supply chains.

Canada's 2030 Emissions Reduction Plan (released in 2022) focuses on CCS and CDR in energy and industry, while Canada's Carbon Management Strategy targets around 16 Mtpa of CO2 injection and storage by 2030F.

Malaysia's National Energy Transition Roadmap (NETR; issued in 2023) listed CCUS as one of the six energy transition levers to achieve Malaysia's environmental goals. Malaysia plans to develop three CCS hubs with 15 Mtpa capacity by 2030F, while another three CCS hubs may be developed by 2050F to raise cumulative storage capacity to 40-80 Mtpa.

China's Long Term Low GHG Emissions Development Strategy (issued 2021) recognises CCS for fossil energy decarbonisation, supports large-scale CCS demonstration, and industrial applications of CCS. By 31 Dec 2025F, China's national ETS will expand to cover 60% of national emissions including steel, cement, and aluminium smelting industries, adding about 3 GtCO2 emissions to the market (in addition to about 5 GtCO2 from power), according to DNV.

Japan's Act on Carbon Dioxide Storage Business (issued 2024) introduces a licensing system for CCS activities, targeting 13 Mtpa by 2030F and 240 Mtpa by 2050F.

Certain countries have CO_2 capture targets. For example, the GCC capture targets are as follows:

- **UAE** targets CCS capacity of 43.5 Mtpa by 2030F (current capacity is 1 Mtpa).
- **Saudi Arabia** targets 44 Mtpa by 2035F (current capacity is 1.3 Mtpa).
- **QatarEnergy** targets CCS capacity of 11 Mtpa by 2035F (current capacity is 2.2 Mtpa).

Meanwhile, the **UK** aims to capture and store 20-30 Mtpa of CO_2 by 2030F, and aims to have at least 5 Mtpa of CDR by 2030F.

(b) Government funding support

Government funding support can come in four different ways, and examples of each are illustrated below.

1. **Direct capital grant or subsidy**
    - Monies collected from the EU ETS is funnelled back to CCS developments via the **EU Innovation Fund**, which will provide up to 60% project funding for regular grants and up to 100% for competitive auction bids, according to the EU. The Havstjerne CCS project is slated to receive €225m over several project milestones.
    - The EU's **Connecting Europe Facility** (available from Nov 2023) offers co-funding rates of 50-75% for supported Projects of Common Interest (PCI) such as cross-border CO_2 network projects that also benefit from fast-tracked permitting. Netherland's Porthos CCS project received €108.5m funding from EU's Connecting Europe Facility.
    - Norway's government funded US$2bn (c.70%) of the capex of the Longship and Northern Lights CCS project, paid to both the capturing entity and the infrastructure provider.
    - Denmark's government provided US$41m in funding to the Greensand CCS and Bifrost CCS projects.
    - In Oct 2024, the UK government announced a total of £21.7bn in funding to support the UK's first two CCUS clusters ('Track-1') over a 25-year period. This funding is primarily split between the HyNet North West CCS project and the East Coast Cluster CCS project. The 'Track-2' transport and storage solutions – Viking and Acorn – will likely also receive substantial UK government funding.
    - The US Inflation Reduction Act allocated US$6bn for the demonstration and deployment of low-carbon industrial production technologies through grants, loans, and guarantees (2022 to 2026F).
    - Canada's US$5.9bn Strategic Innovation Fund - Net Zero Accelerator aids large industrial emitters in adopting clean technology.
    - Japan's Ministry of Economy, Trade and Industry (METI) has a Green Innovation Fund that will support emissions reduction capex in iron and steel, chemicals, paper and cement over 10 years from 2021.

2. **Revenue or opex support**
    - CCfD are available in the UK, Netherlands, Denmark and France (10-15 years contracts) to compensate industrial capture facilities for differences between levelised cost of capture vs. prevailing ETS/carbon tax rates.
    - Norway's government will provide opex funding of Longship and Northern Lights CCS (paid to capturing entity and infra provider) for the first 10 years.
    - Canada committed US$7bn to CCfD and had proposed draft regulations to cap and reduce emissions from upstream oil and gas facilities by 35% below 2019 levels by 2030F.
    - In the US, the 45Q tax credit is paid to capturing entities to offset the cost of capture. US provides a large carrot in the form of the 45Q tax credit in

the US Inflation Reduction Act (2022), and further enhanced by the 'One Big Beautiful Bill Act' (2025). The 45Q tax credit is claimable by the emitter for 12 years from the date the carbon capture equipment is placed in service. The US Treasury estimated a 10-year 45Q cost of US$43.4bn between 1 Oct 2025 and 30 Sep 2034F.

- Australia's Safeguard Transformation Stream offers grants covering up to 50% of eligible expenses, with US$380m allocated from 2023 to 2027F to support decarbonisation investments in trade-exposed facilities.

3. Preferential government loan

- China offers low-cost funding via the People's Bank of China's Carbon Emission Reduction Facility.
- The state-owned Japan Organization for Metals and Energy Security (JOGMEC) JOGMEC is providing subsidies and support through equity investments and debt guarantees for nine priority CO2 storage projects (20 Mtpa of CO2), five for domestic and four for overseas storage, for commissioning by 2030F.
- South Korea is channelling around US$320bn (Won452tr) in support or policy loans for climate initiatives through to 2030F, according to DNV.

4. Government equity investment

- The Dutch government announced a €639m investment in the Aramis CCS project after TotalEnergies and Shell scaled back their funding.

Figure 16: CCS projects in Europe

Project Greensand is Denmark's leading CCS project (FID Dec 2024), located in the Danish North Sea. Led by a consortium of 23 partners, including INEOS Energy, Harbour Energy, and Nordsøfonden (the state subsurface company), its goal is to store captured CO2 in depleted oil and gas fields within the Siri fairway, transported via ship 200 km offshore Denmark. kilometers off Denmark's west coast. The project plans to store 0.4 Mtpa of CO2 from 2026F and 8 Mtpa by 2030F.

Bifrost CCS is a large-scale CCS project in the Danish North Sea which will repurpose existing O&G infrastructure to store up to 3 Mtpa of CO2 initially, with the potential to scale up to 16 Mtpa. This project is a cornerstone of Denmark's goal to become a European hub for carbon storage. Key partners include TotalEnergies (operator), CarbonVault (representing Schwenk), Nordsøfonden, Noreco, and Ørsted.

Norway's Longship project is a full-scale CCS initiative, encompassing the entire process of capturing, transporting, and storing CO2 from various industrial sources. Northern Lights is part of the Longship project specifically responsible for the transportation of liquefied CO2 by ship and its permanent storage under the seabed in the North Sea. The current Phase 1 CO2 injection capacity is 1.5 Mtpa and Phase 2 will see the capacity expanded to 5 Mtpa by 2028F.

The Porthos project aims to capture CO2 from industrial facilities in the Port of Rotterdam, transport it via a 30 km pipeline to a platform in the North Sea for injection into depleted gas fields in the North Sea. Once operational in 2026F, the project is designed to store 2.5 Mtpa of CO_2 over a 15-year period, for a total of 37 Mt.

SOURCES: CGSI RESEARCH, HARBOUR ENERGY, ORSTED, LONGSHIP, PORT OF ROTTERDAM

Figure 17: CCS projects in the UK

The Northern Endurance Partnership (NEP) is a JV between bp, Equinor, and TotalEnergies developing CCS infrastructure in the UK to transport and store up to 4 Mtpa of CO2 initially via a 145 km offshore pipeline into the Endurance saline aquifer in the North Sea from industrial clusters on the UK East Coast Cluster; the latter industries includes Net Zero Teesside Power and H2Teesside.

The Hynet North West CCS project is led by Eni and a consortium to capture CO2 from industrial clusters across the North West of England and North Wales. From c.2027F, the pipeline transport system will have an initial capacity of 4.5 Mtpa, to be expanded to 10 Mtpa after 2030F. The pipeline will transport CO2 to be injected in depleted offshore gas reservoirs in Liverpool Bay.

Viking and Acorn aim to transport and store up to 18 Mtpa of captured CO2 from industrial clusters in the North Sea.

The Viking project is in the Humber region of northeast England and will transport emissions from the Immingham area and store CO2 in depleted gas fields in the North Sea. Viking is led mainly by bp and Harbour Energy.

The Acorn project is in Scotland and reuses existing oil and gas pipelines to transport CO2 and will store CO2 in sandstone rock in the North Sea. Acorn is spearheaded by a JV including Storegga, Shell, Harbour Energy, and North Sea Midstream Partners.

SOURCES: CGSI RESEARCH, NORTHERN ENDURANCE PARTNERSHIP, ENI, BP, HARBOUR ENERGY

In SE Asia, there is limited government funding support for CCS projects, in our view.

- Malaysia has tax incentives for CCS from 2023 to 2027F. Malaysia has also launched a US$480m (RM2bn) National Energy Transition Facility (NETF) initial seed fund to finance marginally bankable energy transition projects, such as EV charging, hydrogen and CCUS technologies.
- In Thailand, natural gas separation plants and petrochemical plants that use CCUS eligible for an 8-year corporate income tax exemption; tax incentives are being considered for the PTTEP Arthit CCS project.
- Indonesia may offer tax allowances and exemptions in the future for CCS projects.

(c) Legal/regulatory frameworks and support

To facilitate CCUS projects, legal frameworks are required to regulate capture, transport and storage infrastructure and service provision, to determine provisions for liability of CO2 leakage from storage, etc.

In SE Asia, there has been notable regulatory developments, with Indonesia as the first mover.

- Indonesia's Minister of Energy and Mineral Resources (MEMR) Regulation No. 2 of 2023 regulates CCS/CCUS activities within oil and gas PSC Working Areas (WA).
- Indonesia's Presidential Regulation (PR) No. 14 of 2024 regulates all WAs, and Carbon Storage Licence Areas (WIPK) which are applicable for all CCS operators. PR 14/2024 allows up to 30% of a storage site's capacity to be used for CO2 imported from overseas.
- Indonesia's MEMR 16/2024 grant storage operation permits for up to 30 years, with a potential 20-year extension.
- Malaysia has passed the federal-level Carbon Capture Utilisation and Storage Act 2025 (CCUS Act 2025), and the CCUS (Offshore Permit and Licensing) Regulations 2025 with a minimum 10-year liability for CO2 leakage. However, many other details have yet to be finalised.
- Sarawak has enacted its own Land (Carbon Storage) Rules 2022, with minimum 20-year liability for CO2 leakage.
- Thailand is in the process of amending the Petroleum Act to regulate carbon storage activities, according to an article by legal firm Baker McKenzie in 2023.

In 'partial chain' business models, private entities are involved in different parts of the CCUS value chain, and government intervention may be required to disentangle a 'chicken-and-egg' conundrum.

- For example, emitters need transport and storage options before they are ready to invest in capture, while infrastructure investors that provide transport and storage services require certainty on future demand and CO2 volumes before they are ready to invest. Government support and coordination are likely essential to mitigate such cross-chain risks, according to GCCSI.
- Meanwhile, in the UK, the government has implemented the regulated asset base model (RAB) to ensure adequate returns to the multi-user transport and storage facilities.

To facilitate cross-border CO2 transport and storage, countries also need to ratify the London Protocol.

- Malaysia, Indonesia and Thailand have not ratified the London Protocol.
- Australia and South Korea have ratified the 2009 amendment to the London Protocol that allows for the transboundary shipping of CO2 for storage in sub-seabed geological formations.
- Japan is in the process of ratifying the 2009 amendment to the London Protocol.

(d) Government mandates

Government mandates can catalyse and push CCS developments forward. For instance:

- The **EU's Net-Zero Industry Act** mandates that oil and gas producers must develop a minimum of 50 Mtpa CO2 injection and storage capacity by 2030F.
- **Australia's Safeguard Mechanism** requires large emitters to reduce emissions by 4.9% p.a. from 2023 to 2030F, generating Safeguard Mechanism credit for improvements below the baseline which can be sold for additional revenue.

(e) Carbon pricing

The presence of carbon pricing at sufficiently-high levels can internalise the costs of pollution and motivate emitters to invest in CCUS.

Carbon taxes have been introduced in Europe, including Sweden, Finland, Norway, Switzerland, Ireland, UK, Denmark, Austria, Germany, etc. Norway's carbon tax was the critical factor supporting for Equinor's Sleipner CCS project in 1996 and Equinor's Snohvit CCS project in 2008, according to global think-tank Institute for Energy Economics and Financial Analysis (IEEFA).

In Europe, the **EU ETS** and the **UK ETS** are in force. The EU will also introduce the CBAM on Scope 1 and Scope 2 emissions from 1 Jan 2026F on imports of cement, iron and steel, aluminium, fertilisers, electricity and hydrogen; this will force exporters of those commodities to the EU to pay for the embedded emissions at the same rate as the price of the EU ETS. New products to be phased into the **CBAM** from 2027-2030F.

Meanwhile, **China's national ETS** which was introduced in 2021, was expanded from Mar 2025 to cover 60% of national emissions including steel, cement, and aluminium smelting industries, adding about 3 GtCO2 emissions to the market (in addition to about 5 GtCO2 from power), according to DNV.

Malaysia is planning to introduce a carbon tax in 2026F, potentially at an indicative price of c.US$3.60/tCO2 (or RM15/tCO2), according to various press reports.

(f) Technological innovation

Technological innovation to reduce the cost of capture, transport and storage can strengthen the business case for investment. Over time, CCS capture costs have been trending lower, and China has been at the forefront of cost reduction successes. This is explained further in Section D: CCUS Economics.

(g) Clear business case

A clear business case for CCS will accelerate adoption. According to DNV, of the total capture capacity in 2025, around 85% captures CO2 for EOR/EGR. The captured CO2 is sold to upstream oil and gas companies for EOR/EGR activity, and the price of CO2 is higher when oil and gas prices are high.

The business case for CCS may also arise when the cost of CCS is lower than the carbon tax or ETS price, or when there is a CCfD mechanism to ensure that the levelised cost of CCS is at least on par with the carbon price.

The provision of CO2 storage as a service to local or foreign emitters to generate storage revenues can also be a viable business case. Malaysia is planning the development of three storage hubs by 2030F to store 15 Mtpa. Another three storage hubs with a cumulative 40-80 Mtpa of capacity is planned by 2050F.

(h) NOC/SOE initiatives to spearhead projects

In the Middle East, national oil companies (NOC) like Saudi Aramco, Abu Dhabi National Oil Company (ADNOC), QatarEnergy, and Oman LNG often spearhead CCS projects in the absence of carbon pricing signals. Similarly, in SE Asia, NOCs like Petronas and PTTEP are taking the lead on CCS projects.

In China, state-owned enterprises like China National Offshore Oil Corporation (CNOOC), China National Petroleum Corporation (CNPC), China Energy Investment Corporation (CHN Energy), Huaneng Power International, etc. are taking the initiative to invest in CCS.

(i) Public trust and acceptance

If project safety, and social and economic benefits from CCUS projects can be demonstrated, public trust and acceptance will smoothen the process to implement such projects.

In DNV's 2025 'Energy Transition Outlook: CCS to 2050' report, two examples were used to illustrate the importance of public engagement:

- "Initiated in 2007, a pioneering project in Barendrecht, the Netherlands, aimed to capture CO2 from a nearby refinery and store it onshore in depleted gas fields. Residents and politicians were worried about perceived risks, including CO2 leaks, long-term environmental impacts, and the potential depreciation of property values. Residents felt the responses to these concerns were inadequate, and changes to the regulatory approval process further exacerbated opposition. The project was eventually cancelled in Nov 2010."
- "In 2021, the Heartland Greenway 2,000 km pipeline project was set to span five states in the US Midwest. The project planned to transport up to 15 Mtpa of CO2, captured from ethanol plants, for underground storage in Illinois. Local communities expressed strong resistance, citing concerns over land rights and environmental impacts. Due to strong community opposition, state officials in South Dakota and Iowa rejected the necessary permits. The combined impact of community-driven opposition and regulatory hurdles resulted in the project's cancellation in Oct 2023."

Malaysia lacks strong drivers for CCUS advancement

In our view, the incentives for CCUS are largely missing in Malaysia, and hence, development may be slow and limited, in our view.

On the other hand, we think that viable business cases may be present for:

- The development of offshore CO2 storage hubs to cater to the export of CO2 captured from industrial sources in Japan, South Korea and/or Singapore; and
- The development of sour gas reserves via the capture and permanent sequestration of CO2 (natural gas processing).

(a) Government policy support

Malaysia has aspirational emissions targets, namely:

- To reduce carbon intensity against GDP by 45% by 2030F compared to the 2005 baseline;
- To achieve a 32% reduction in GHG emissions for the energy sector by 2050F compared to the 2019 baseline via the NETR; and
- Net zero emissions by 2050F.

In the NETR, CCUS is included as one of the six energy transition levers to achieve Malaysia's environmental goals.

However, Malaysia has no explicit carbon capture targets.

(b) Government funding support

Malaysia has tax incentives for CCS from 2023 to 2027F, but they are not by themselves sufficient to spur CCS activities, we think.

Malaysia has also launched a US$480m (RM2bn) National Energy Transition Facility (NETF) initial seed fund to finance marginally bankable energy transition projects, such as EV charging, hydrogen and CCUS technologies, but this amount is limited and spread across many energy transition projects.

(c) Legal/regulatory frameworks and support

Malaysia has passed the federal-level CCUS Act 2025 and the CCUS (Offshore Permit and Licensing) Regulations 2025. However, many details have yet to be finalised.

Sarawak has enacted its own Land (Carbon Storage) Rules 2022, but the regulatory split with Peninsular Malaysia and Labuan could complicate matters.

Sabah has not enacted any CCUS law.

Malaysia has not ratified the London Convention that is required to facilitate the cross-border shipping of CO_2.

(d) Mandates

Malaysia has broad policy targets for emissions, but no enforceable mandates for carbon capture.

(e) Carbon pricing

Malaysia is planning to introduce a carbon tax in 2026F, but the carbon tax rate is likely to be too low to stimulate adoption of CCS projects (indicative price of US$3.60/t$CO_2$ or RM15/tCO_2 according to The Edge).

(f) Technological innovation

Cost of CCS adoption remains too high in industrial, hard-to-abate sectors, in our view. The contrast to the proposed low carbon price of US$3.60/t$CO_2$ is too wide, and we think CCS adoption in sectors outside of natural gas processing will be delayed as a result.

(g) Clear business case

Development of storage hubs in Malaysia geared towards storage of foreign-origin CO_2 may go ahead as it may be economically viable, we think. Malaysia has ongoing negotiations with emitters in Japan, South Korea and/or Singapore to store their captured CO_2 into subsea reservoirs in Malaysia, and this may proceed if Japanese and South Korean industrial emitters are willing to pay for the costs.

(h) NOC/SOE initiatives to spearhead projects

Petronas and other Petroleum Arrangement Contractors (PAC) are spearheading CCS projects, but at this point, this appears to be largely limited to the development of sour gas reserves e.g. at the Kasawari field (Sarawak), at the PM3 CAA block (Malaysia-Vietnam Commercial Arrangement Area), the BIGST fields (offshore Terengganu), and the Lang Lebah field (offshore Sarawak), etc.

(i) Public trust and acceptance

We do not expect the general Malaysian public to perceive CCS as unsafe, as Malaysia's storage hubs are all offshore.

On the other hand, we think that public acceptance of CCS mandates and high carbon prices may be difficult to secure, as passthrough of CCS costs could raise cost of living and negatively impact living standards among a price-sensitive population.

(D) CCUS ECONOMICS

The business case for CCUS

Value proposition of CCUS includes:

- Avoidance of carbon taxes or avoidance of payment for carbon allowances;
- Sale of captured CO2 to upstream companies for use in EOR/EGR and other utilisation options; and
- Creation of low-carbon products which may command a price premium.

CCUS is economically viable and makes business sense if:

- The full-chain cost of decarbonisation is less than the carbon taxes or cost of carbon allowances.
- The full-chain cost is less than the benefits arising from CO2 utilisation, such as with EOR/EGR.
- The full-chain cost can be recouped via the price premium on low-carbon products.

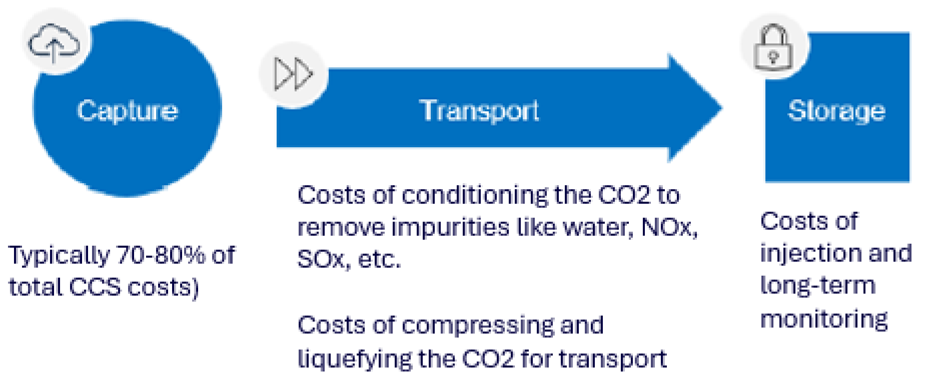
If CCUS does not make sense economically, governments may need to step in with

- Capital grants
- Opex subsidies
- Revenue support
- Tax grants
- Preferential loans
- Direct equity investment
- Implement CCS initiatives via state-owned companies, or via public-private partnerships

CCS value chain costs

The CCS value chain comprises of three main activities: Capture, Transport and Storage. The costs of capture typically make up 70-80% of total CCS costs, according to The Oxford Institute for Energy Studies.

Figure 18: The CCS value chain



SOURCE: THE OXFORD INSTITUTE FOR ENERGY STUDIES, 2024

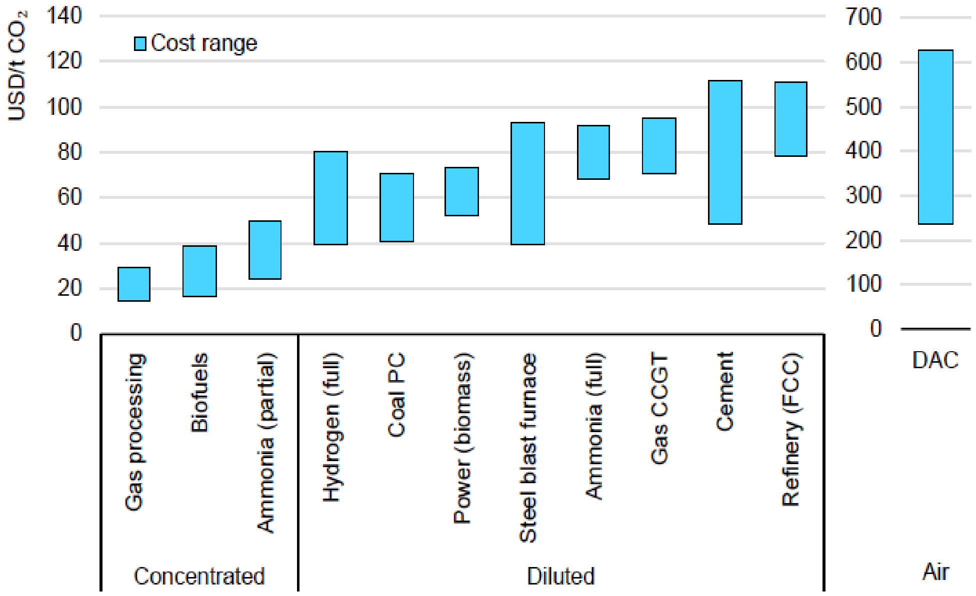
Levelised CO2 capture costs

Capture costs of CO2 depend on the factors below.

1. Higher CO2 concentrations will usually result in lower costs of capture (COC).
    - In bioethanol production, the COC can be as low as **US$30-36/tCO2**, according to DNV, as the gas stream entering the capture plant is >90 mol% CO2;
    - Natural gas processing, ammonia production have high CO2 concentrations of >98 mol% CO2.
    - Power plants, iron and steel and cement plants have lower CO2 concentrations of 3-10 mol% CO2 for gas-fired power plants, and 12-15 mol% CO2 for coal-fired power plants. As a result, COC can be **US$60-120/tCO2** from power generation applications, according to DNV.
    - DAC costs are the highest at **US$200-600/tCO2** (according to IEA, 2023), as CO2 concentration in atmosphere is only 0.043 mol%.
2. Flue gas streams with higher CO2 partial pressure within the inlet stream to the capture plant are easier to extract the CO2, and hence cheaper to capture.
3. Scale of the capture facility. Natural gas-fired power plant COC decreases from US$120 to US$75/tCO2 if the capture capacity increases from 70 ktpa to 606 ktpa, according to DNV.
4. Different capture technologies have different capture costs.
5. When reaching very high CO2 capture percentages (near 100%), the cost of capture per unit of CO2 increases.
6. The amount of energy required will also determine the capture costs. According to DNV, chemical solvent-based capture (e.g. amine solvents) will use significant thermal energy in the regeneration of the solvent in the CO2 desorber, whilst cryogenic and membrane processes are more likely to use electrical energy in the compression and expansion process for cooling the flue gas streams. The cost of cooling systems also play a role.
7. The necessity for and cost of flue gas pretreatment to remove contaminants such as NOx (nitrous oxide) and SOx (sulfur oxide) will also determine the COC. These contaminants need to be removed, in order to slow down the degradation of the amine solvent.
8. Building a greenfield plant with CCS will have lower costs of construction, vs. retrofitting brownfield plants which may be complex as it requires working around existing equipment, according to DNV.

The chart and table below shows the IEA's estimates in 2023 of the levelised cost of CO2 capture in various applications, excluding any transport and storage costs. They differ from DNV's estimates as likely different assumptions were used, we believe. For instance, DNV estimated 2025 CO2 capture costs at US$60-120/tCO2 for power generation applications, but the IEA estimated 2023 CO2 capture costs at US$41-71/tCO2 for coal-fired power plants and at US$71-95/tCO2 for combined-cycle gas turbines.

Figure 19: Levelised cost of CO2 capture in various applications (IEA, 2023)



Levelised cost of capture (US$/tCO2)	Low	High
Concentrated CO2 streams		
Gas processing	15	29
Biofuels	16	39
Ammonia (partial)	24	50
Diluted CO2 streams		
Hydrogen (full)	40	80
Coal (pulverised coal)	41	71
Power (biomass)	52	73
Steel blast furnace	40	93
Ammonia (full)	68	92
Gas CCGT	71	95
Cement	48	112
Refinery (FCC)	79	111
Carbon dioxide removal (CDR)		
DAC	235	626

SOURCE: IEA, 2023

Notes: BF = blast furnace; CCGT = combined cycle gas turbine; FCC = fluid catalytic cracker; NGP = natural gas processing; PC = pulverised combustion. Cost of electricity: USD 32-116/MWh; cost of fuel (USD/GJ): 4-14 (natural gas), 2-7 (coal), 7-9 (biomass); plant financial lifetime (years): 40 (coal and biomass thermal plants), 35 (gas CCGT), 25 (all other plants); discount rate: 8%; capacity factor: 85% (power plants), 95% (all other plants); capture rates: 60% (partial hydrogen, ammonia), 90% (all), 93% (hydrogen, ammonia). No carbon price. Capture rates are for the overall plant (power, hydrogen, cement), or for the flue gas when a specific unit is specified (steel blast furnace, refinery fluid catalytic cracker). For hydrogen, DAC, fuel transformation and industry applications, heat is assumed to be provided by a natural gas-fuelled auxiliary boiler, and electricity from the grid.

GCCSI has its own estimates for CO2 capture costs, published in 2025 as follows:

- US$50-60/tCO2 capture costs for some of the latest coal-fired power plant CCS projects.
- US$80-90/tCO2 capture costs for some of the latest natural gas-fired power plant CCS projects.

The high and low ranges reflect uncertainties over certain cost estimates.

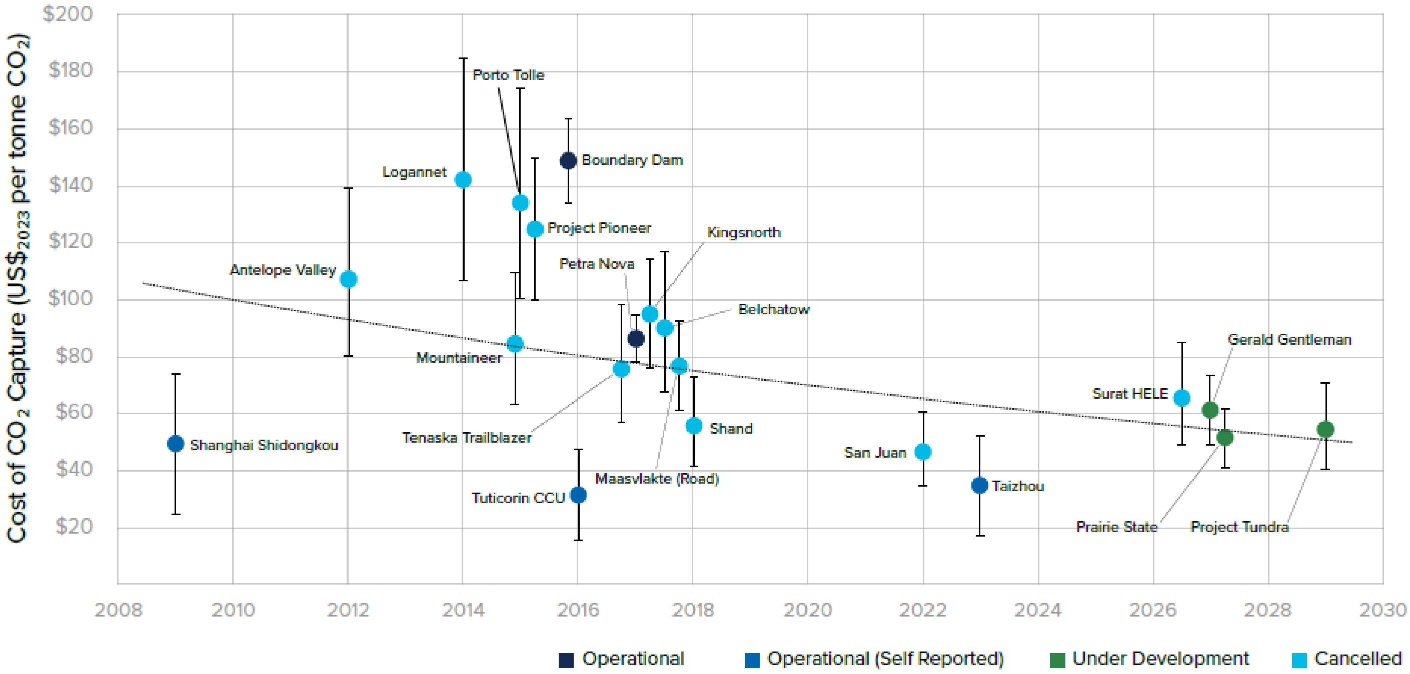
Natural-gas fired power plants have a higher cost of CO2 capture compared to coal-fired power plants. This is because the concentration of CO2 in the flue gas is higher for coal-fired power plants:

- 12-15 mol% CO2 for coal-fired power plants
- 3-10 mol% CO2 for gas-fired power plants

Capture costs of US$30-40/tCO2 would represent some of the lowest-cost coal-fired power plant CCS capture projects, typically in China.

- CHN Energy's coal-fired Jiangsu Taizhou Power Plant commenced the 0.5 Mtpa CO2 capture facility in 2023 (Taizhou CCS) at a capture cost of US$35/tCO2, according to Xinhua News Agency.
- Huaneng Longdong Energy Base's 1.5 Mtpa CCS project at its coal-fired power plant in Gansu Province, China commenced operations in 2025 at a capture cost of US$30/tCO2, according to GCCSI. This power plant is part of the China Huaneng Group.

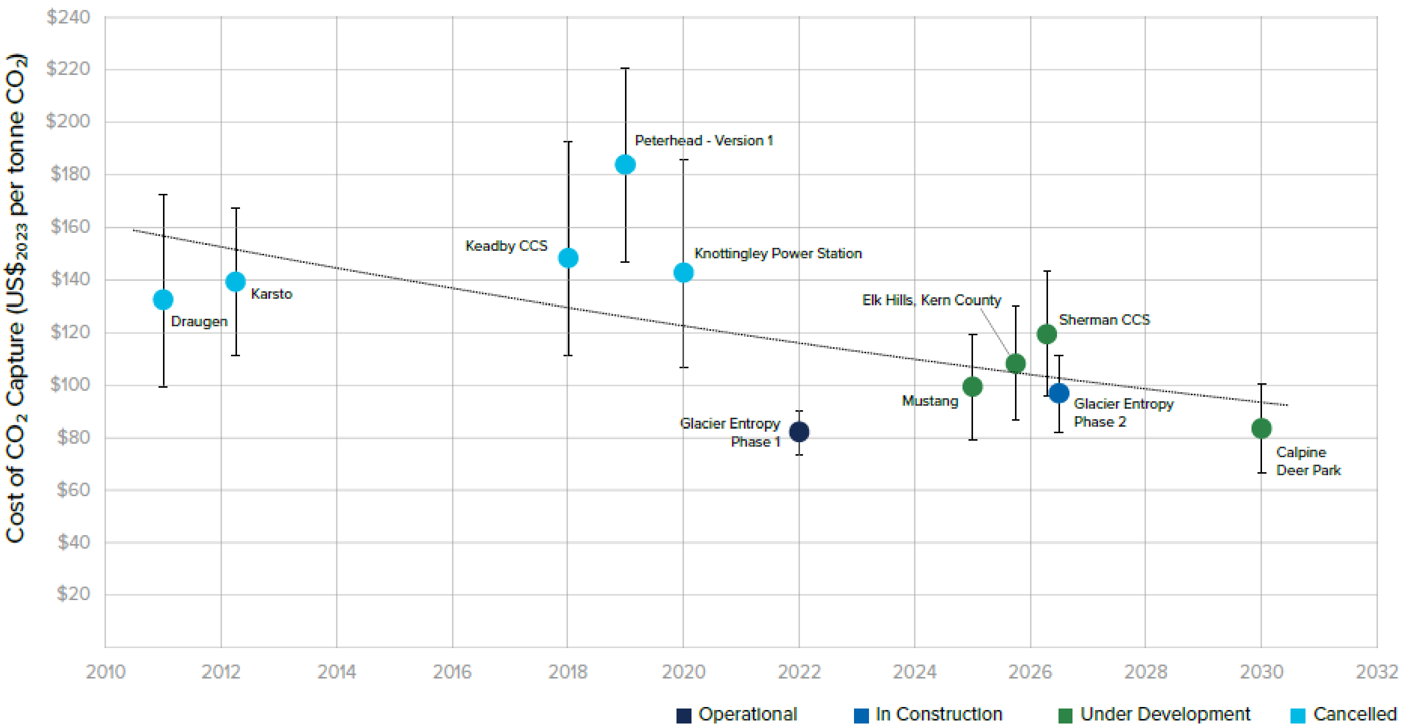
Figure 20: CO2 capture costs from coal combustion sources (GCCSI, 2025)



SOURCE: GLOBAL CCS INSTITUTE, 2025

Notes: Capture fraction is 90% of CO2 across the absorber. Plant uses the solvent monoethanolamine (MEA) to capture CO2 from the flue gas, due to significant number of commercial applications. Inlet flue gas contains 13.7 mol% CO2 at a temperature of 55°C and pressure of 5 kPa. Cost of CO2 capture is calculated, not cost of CO2 avoided due to scarcity of information on CCS plant operation emissions. Cost of CO2 capture includes capex and opex costs, with capex costs distributed over the full lifetime operation of the plant using a certain capital recovery factor (CRF).

Figure 21: CO2 capture costs from natural-gas fired power plants (GCCSI, 2025)



SOURCE: GLOBAL CCS INSTITUTE, 2025

Levelised CO2 transport costs

CO2 transport costs largely depend on whether the CO2 is transport by sea or by pipeline. The discussion below is based on information extracted from reports by the IEA, DNV and GCCSI.

Pipeline transport is more cost effective for large volumes (several Mtpa) of CO2 over short-to-medium distances (up to a few hundred kilometres). Pipeline transport benefits from economies of scale when mass flow rates increase, particularly in the CO2 dense phase with higher fluid density, when more CO2 can be transported efficiently.

Transport by **sea** via liquefied CO2 (LCO2) carriers will generally be more expensive than via pipeline, as shipping requires additional equipment such as liquefaction, liquid buffer storage, as well as higher energy consumption.

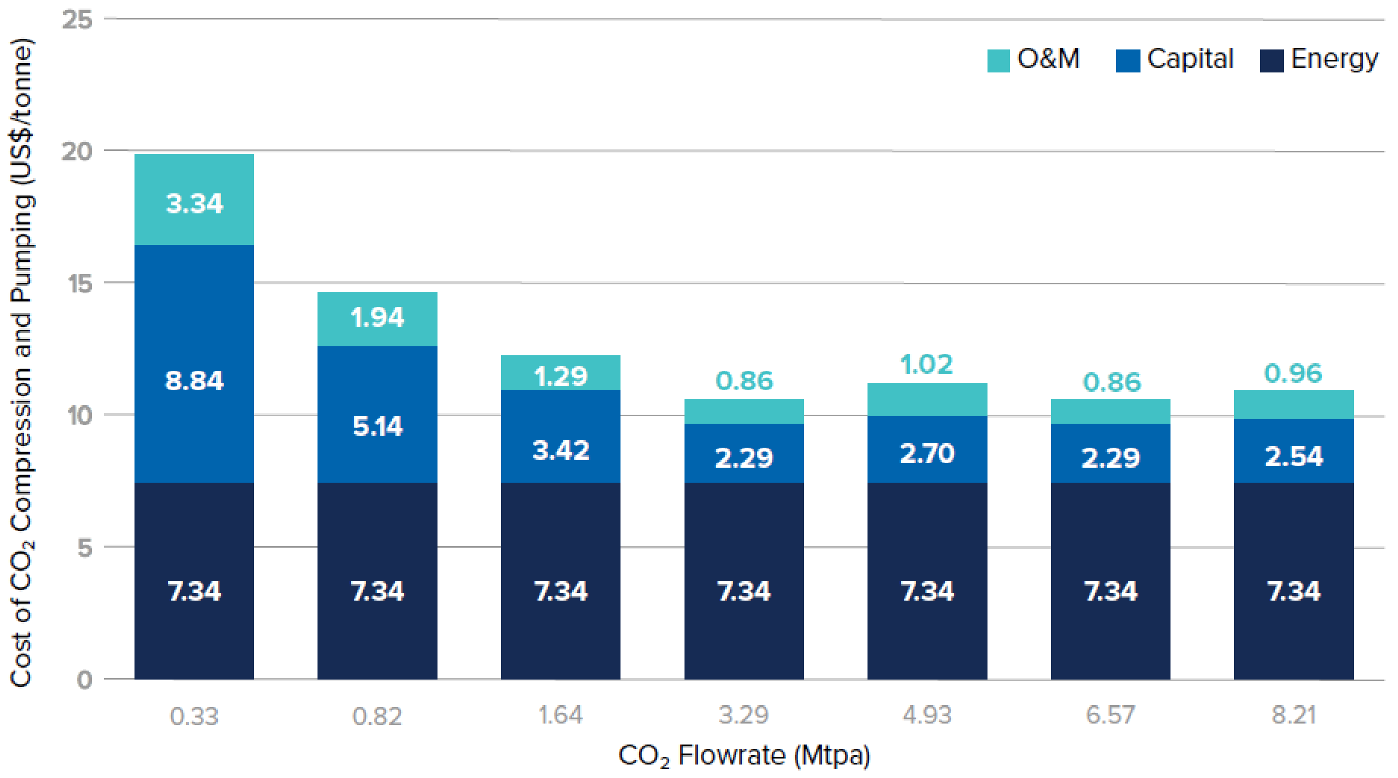
However, liquid CO2 shipping is more cost efficient than pipeline for longer distances, geographically dispersed emitters, and lower CO2 volumes.

According to DNV, reasonable costs for compression and pipeline transport may range from **US$6-28/tCO2**, while transport by ship, train, and truck tend to entail somewhat higher costs.

GCCSI provides more detailed cost estimates for both 1) compression and pumping costs; and 2) pipeline costs.

GCCSI estimates costs of **US$10-11/tCO2** for **CO2 compression and pumping** for pipeline transport operations, at the minimum, based on CO2 flowrates above 3 Mtpa.

Figure 22: CO2 compression and pumping costs (for pipeline transport) (GCCSI, 2025)



SOURCE: GLOBAL CCS INSTITUTE, 2025

According to GCCSI, CO2 transport in the gas phase is more expensive than for the dense phase. Therefore, there is strong preference for dense-phase transport in CO2 pipelines globally, particularly over longer distances.

The US Department of Energy explains that CO2 dense phase is a supercritical or high-pressure state where it has both liquid-like density and gas-like viscosity, making it ideal for pipeline transport because it can be transported in much larger quantities with lower energy loss per unit of CO2 than in the gas phase. In contrast, CO2 in its gaseous phase is a less dense, lower-pressure state that requires more energy to move the same volume.

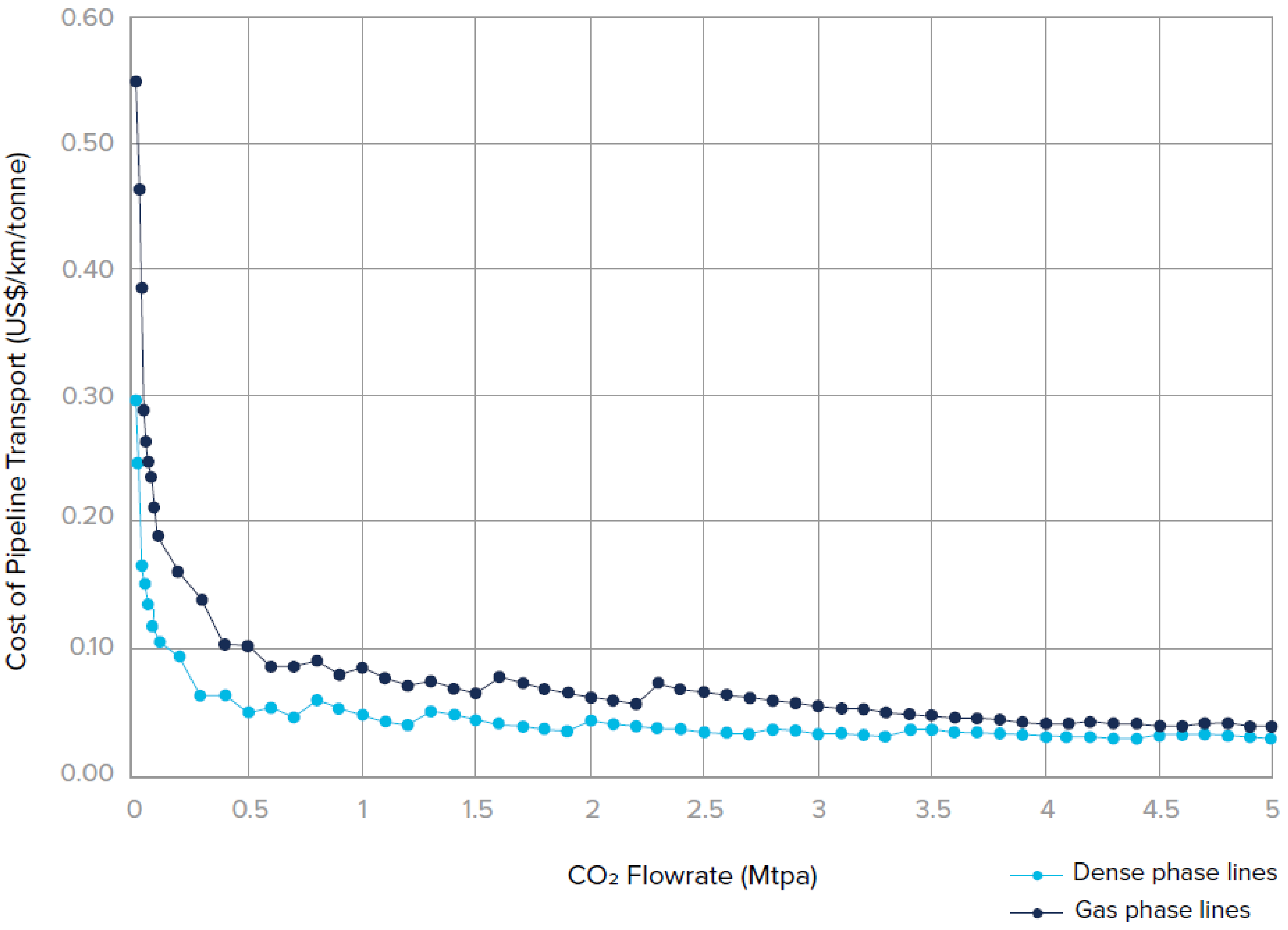
Meanwhile, **pipeline costs** are dependent on the volume of CO2 transported and the distances travelled. Most economies of scale are reached once CO2 flows exceed 1 Mtpa.

Based on GCCSI data (see below), for CO2 dense-phase pipeline transport, assuming pipeline cost of US$0.05/km/tCO2, the pipeline cost works out to be **US$5/tCO2 for every 100km distance**.

Hence, for every 100km pipeline distance:

- CO2 compression and pumping: US$10-11/tCO2; and
- Pipeline cost: US$5/tCO2
- Total: US$15-16/tCO2

Figure 23: CO2 pipeline transport costs (GCCSI, 2025)



SOURCE: GLOBAL CCS INSTITUTE, 2025

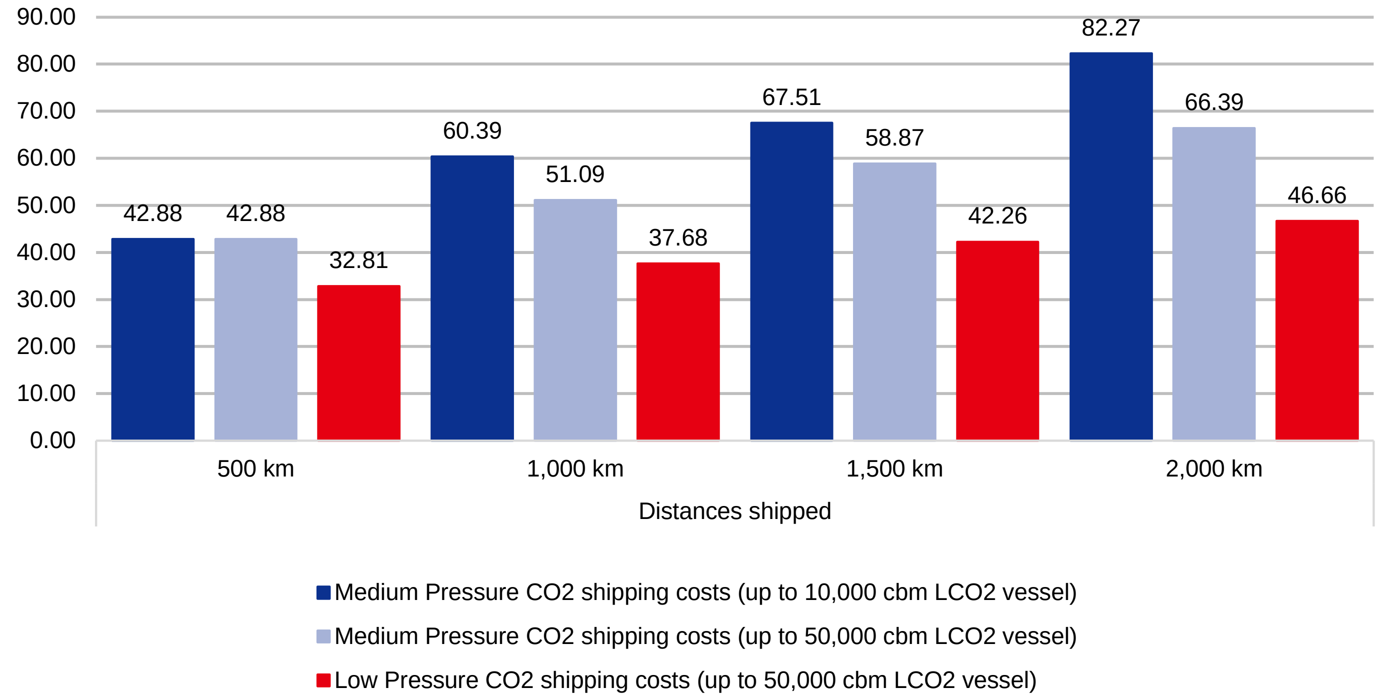
Shipping costs will require a separate calculation. For 500-1,000km shipping distances, low-pressure vessels with 50,000 cbm of CO_2 capacity deliver costs at **US$33-38/t$CO_2$**.

LCO_2 shipping costs fall if the ships have a larger capacity, due to economies of scale.

According to GCCSI, unit shipping costs on low-pressure LCO_2 vessels are lower than on medium-pressure vessels.

- Low-pressure vessels allow for larger tank volumes and higher cargo capacities, making them more suitable for industrial-scale CO_2 transport by ship.
- The higher capital costs for medium-pressure ships reflect the higher complexity and material requirements for ships operating at medium pressure, which typically require more robust containment systems to handle the elevated pressures.
- Medium-pressure ships have a lower energy requirement per tonne of CO_2 compared to low pressure ships. This is because low pressure ships require the CO_2 to be cooled down to lower temperatures in order to achieve liquefaction. However, the high capital costs and the challenges in maintaining CO_2 in a pressurised state over longer distances make medium-pressure ships less economically viable.

Figure 24: Costs of shipping LCO2 (GCCSI, 2025)



SOURCE: GLOBAL CCS INSTITUTE, 2025

Levelised CO2 storage costs

The main factor determining storage costs is:

- Whether the storage is onshore or offshore (with offshore costs being higher); and
- Whether it is a depleted oil and gas field or saline aquifer (with depleted fields being lower cost).

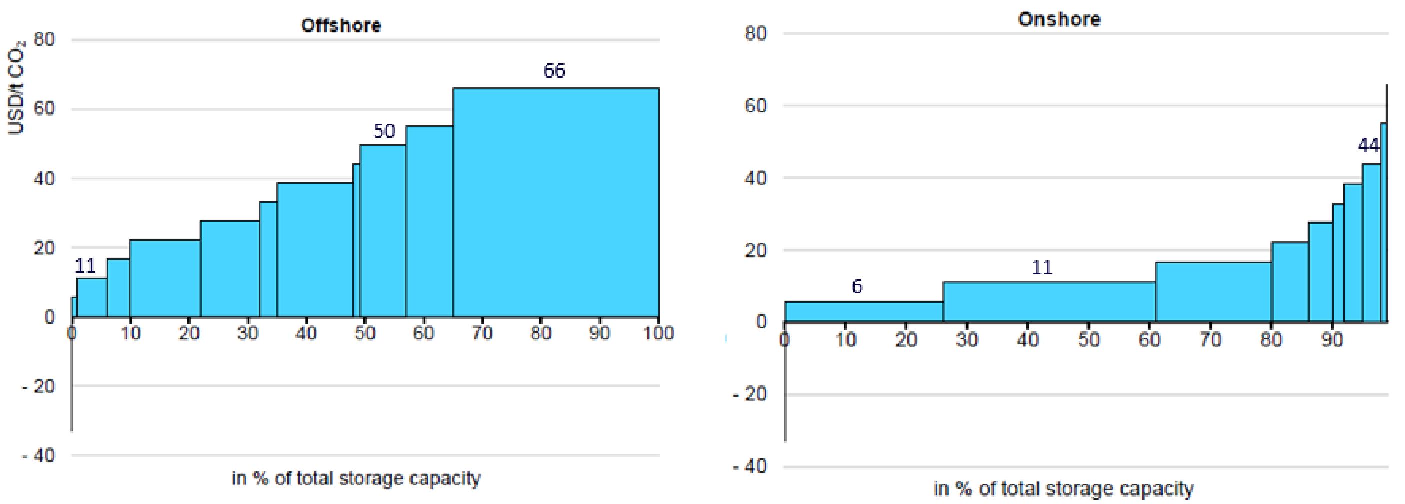
In Europe, DNV estimates:

- Cost range of **US$5-35/tCO2** for storage in saline aquifers,
- Lower cost range of **US$3-15/tCO2** for storage in depleted oil and gas fields due to decreased characterisation costs and potential to re-use infrastructure.
- Offshore storage carries 1.5-3x higher costs than onshore storage. Offshore storage is more common in Europe, while onshore storage is more common in the US.

The IEA estimated storage costs in 2023, with:

- Offshore storage cost range of **US$11-66/tCO2**;
- Onshore storage cost range of **US$6-44/tCO2**.

Figure 25: CO2 storage costs (IEA, 2023)



SOURCE: IEA, 2023

Transport and storage tariffs

When a third party operates transport and storage networks, the tariffs charged to the emitters are higher than the cost of the transport and storage facilities themselves, according to DNV.

DNV estimated that transport and storage tariffs globally averaged around **US$74/tCO2** in 2022. This figure will vary between projects within Europe due to higher costs associated with CO2 shipping, offshore storage, gas-phase pipelines, and transport through urbanised areas.

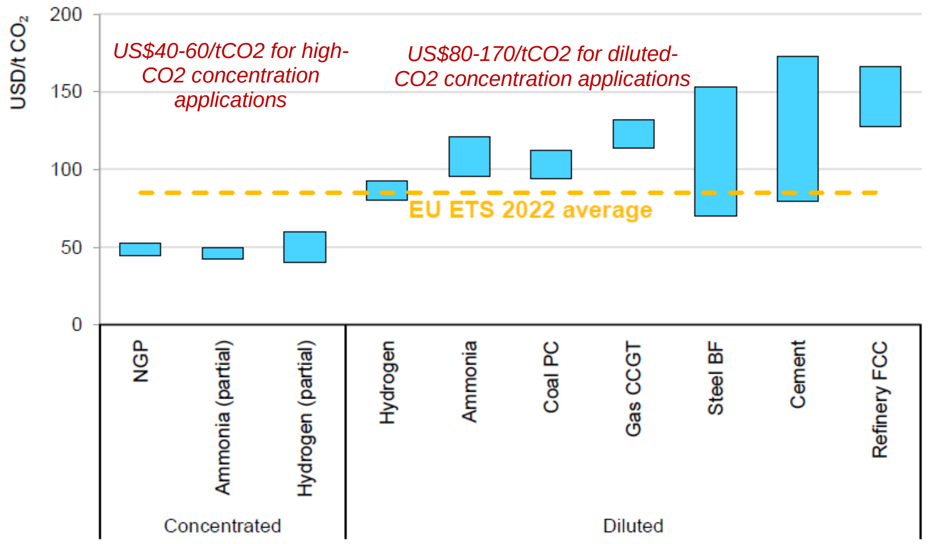
Full chain costs

The full capture, transport and storage cost can be as low as **US$30/tCO2** for gas processing and onshore storage (e.g. Moomba CCS project, Australia), but rise to **US$100-300/tCO2** for capturing CO2 with lower concentrations when including shipping costs, according to DNV.

The IEA estimated in 2023 that the levelised full-chain cost of CO2 avoided ranges were:

- **US$40-60/tCO2** for high-CO2 concentration applications such as natural gas processing (NGP), ammonia production (with partial, 60% capture rates), and hydrogen production (with partial, 60% capture rates).
- **US$80-170/tCO2** for low-CO2 concentration applications such as hydrogen and ammonia production with 93% capture rates, coal pulverised combustion power plants, gas combined cycle gas turbine power plants, steel blast furnace, cement and refinery fluidised catalytic crackers.

Figure 26: Levelised full-chain cost of CO2 avoided in various applications (IEA, 2023)



SOURCE: IEA, 2023

Notes: BF = blast furnace; CCGT = combined cycle gas turbine; FCC = fluid catalytic cracker; NGP = natural gas processing; PC = pulverised combustion. Cost of electricity: USD 32-116/MWh; cost of fuel (USD/GJ): 4-14 (natural gas), 2-7 (coal), 7-9 (biomass); plant financial lifetime (years): 40 (coal and biomass thermal plants), 35 (gas CCGT), 25 (all other plants); discount rate: 8%; capacity factor: 85% (power plants), 95% (all other plants); capture rates: 60% (partial hydrogen, ammonia), 90% (all), 93% (hydrogen, ammonia); CO2 transport and storage: USD 30/t CO2. No carbon price. Capture rates are for the overall plant (power, hydrogen, cement), or for the flue gas when a specific unit is specified (steel blast furnace, refinery fluid catalytic cracker). For hydrogen, DAC, fuel transformation and industry applications, heat is assumed to be provided by a natural gas-fuelled auxiliary boiler, and electricity from the grid.

Notes:

1. *The cost of CO2 avoided is higher than the cost of CO2 captured, as the CO2 avoided is a lower value than the CO2 captured. This is because the capture process also consumes energy and releases emissions; these emissions are netted off against the volume of CO2 captured to derive the volume of CO2 avoided.*
2. *Levelised costs take into account both the capital and opex costs of the CO2 capture facility, compression and/or liquefaction, plus the transport and storage costs. The levelised capital cost is the annualised capex cost allocated over the expected operating life of the capture facility using the 'capital recovery factor' method, which factors-in the applicable discount rate.*

CCS for high-CO2 concentration applications are economically viable

Costs of CO2 avoided are relatively low for NGP, ammonia, hydrogen and ethanol production due to the high CO2 concentration streams of c.98 mol%, and because CO2 capture is an inherent part of the production process.

With the EU ETS price exceeding the costs of CO2 avoided, these applications are economically viable.

CCS cost for sectors with diluted CO2 streams higher than EU ETS price

Based on the chart above, the levelised cost of CO2 avoided for many sectors with many diluted CO2 streams was higher the average EU ETS price of US$84/tCO2 in 2022, and higher than the EU ETS price of US$92/tCO2 (€79; EECXM1 SONA Index) as at 21 Oct 2025.

As a result, CCS applications in sectors with diluted CO2 streams will need to be supported by other measures, such as direct government capex and opex subsidies, CCfDs, etc.

CCS cost for sectors with diluted CO2 streams higher than the US's 45Q tax credit, but may be viable when accompanied by EOR revenues

The current US 45Q tax credit of US$85/tCO2 is also below the levelised cost of CO2 avoided for many sectors with diluted CO2 streams.

However, when the US 45Q tax credit of US$85/tCO2 is combined with EOR revenues, some CCS applications may become viable.

US upstream E&P companies typically pay US$30/tCO2 for EOR when oil prices are around US$70/bbl (IEA, 2023). For reference, WTI crude traded at below US$60/bbl in early-Nov 2025.

CCS for industrial applications: DNV's projects falling cost trajectory, but to remain expensive even in 2050F

Mirroring IEA's 2023 study, DNV's Jun 2025 report noted that the total cost of CCS remains high, often exceeding US$100/tCO2 avoided, particularly for industrial applications in cement, steel, and pulp and paper. Costs at oil refineries can rise well above US$200/tCO2 avoided.

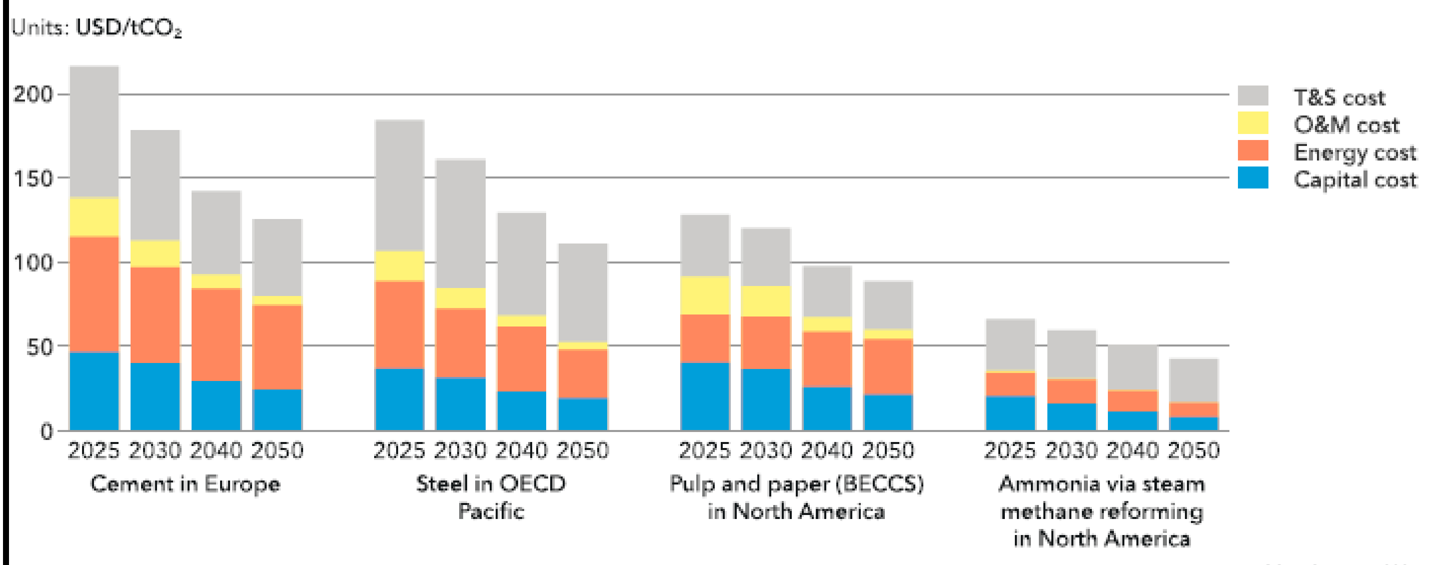
DNV notes that CCS costs vary significantly by region, largely driven by differences in energy prices and transport and storage (T&S) methods and cost components. For example, T&S in the US is cheaper due to established pipeline infrastructure and where storage is mainly onshore. T&S in Europe is more expensive due to the predominance of offshore storage.

In terms of the cost trajectory:

- DNV anticipates an average cost reduction of around 14% by 2030F, and c.40% by 2050F, driven mainly by declining capital costs for capture technologies and lower T&S costs as infrastructure matures and economies of scale are realised.
- DNV forecasts that CCS capital costs have a learning rate of 13%, while O&M costs have a learning rate of 15%. This is the percentage decrease in the cost per unit each time installed capacity doubles.

Despite DNV's forecasts of cost reductions, it still expects the cost of CO2 avoided in applications such as cement (Europe) and steel (Japan, South Korea) to remain above US$100/tCO2 in 2050F. Carbon prices will have to rise above these costs in order to incentivise adoption of CCS in these industries, we believe, or these applications will have to be subsidised by governments.

Figure 27: Levelised full-chain cost of CO2 avoided for selected industrial applications and regions



SOURCE: DNV, 2025

CCS for fossil-fuel power plants: potentially costly to implement

According to an IEEFA study in 2022, it noted that the viability of CCS at power plants in SE Asia may be questionable due to the following factors:

1. Markets and consumers in SE Asia are cost sensitive, and if independent power producers have to sell electricity at fixed tariff, they may not be able to passthrough the cost of CCS.
2. Power plants have diluted CO2 flue gas streams (3-10 mol% CO2 for gas-fired power plants; 12-15 mol% CO2 for coal-fired power plants), which make CO2 capture more expensive.
3. CCS processes can consume 20-30% of the power generated by the plant.
4. Power plant flue gas contain a lot of pollutants like NOx and SOx, requiring extensive flue gas pre-treatment, which adds to capex and opex. CCS also requires substantial cooling water usage.
5. Fossil-fuel plants will CCS may eventually be outcompeted by RE and BESS applications which are seeing rapid fall in costs, potentially rendering the CCS facility obsolete ahead of the end of its useful life.

The total costs for CCS for a coal-fired power plant are:

- **US$71-120/tCO2** for pipeline transport to onshore storage; and
- **US$94-164/tCO2** for shipping transport to offshore storage.

This is based on CCS cost estimates published by GCCSI and IEA.

Pipeline transport to onshore storage (US$71-120/tCO2), comprise:

- US$50-60/tCO2: capture costs for coal-fired power plant
- US$10-11/tCO2: CO2 compression and pumping costs for pipeline transport operations
- US$5/tCO2: CO2 dense-phase onshore pipeline transport over 100km
- US$6-44/tCO2: Storage costs in onshore depleted oil and gas fields

Shipping transport to offshore storage (US$94-164/tCO2), comprise:

- US$50-60/tCO2: capture costs for coal-fired power plant
- US$33-38/tCO2: shipping costs, including liquefaction, intermediate storage, conditioning, loading and unloading, for 500-1,000km shipping distances on low-pressure vessels
- US$11-66/tCO2: storage costs in offshore depleted oil and gas fields

Note that CCS costs for gas-fired power plants are higher at US$80-90/tCO2, while the use of independent T&S service providers under the partial chain model will almost certainly result in higher T&S costs. Transport and storage tariffs globally averaged US$74/tCO2 in 2022, according to DNV.

CCS in the manufacture low-carbon products: market demand may not support the price premium

One way of monetising CCS is to produce low-carbon products and sell those products at a premium to products produced about CO2 emissions abatement.

However, IEA's 2023 report noted that CCS can increase production costs by various percentages on steel, ammonia and cement, relative to unabated processes:

- Steel production costs can increase 10-20% (using natural gas-based direct reduced iron or electric arc furnace routes);
- Ammonia production costs can increase 10-20% (using steam methane reforming); while
- Cement production costs can increase 60-130% (using cement kilns).

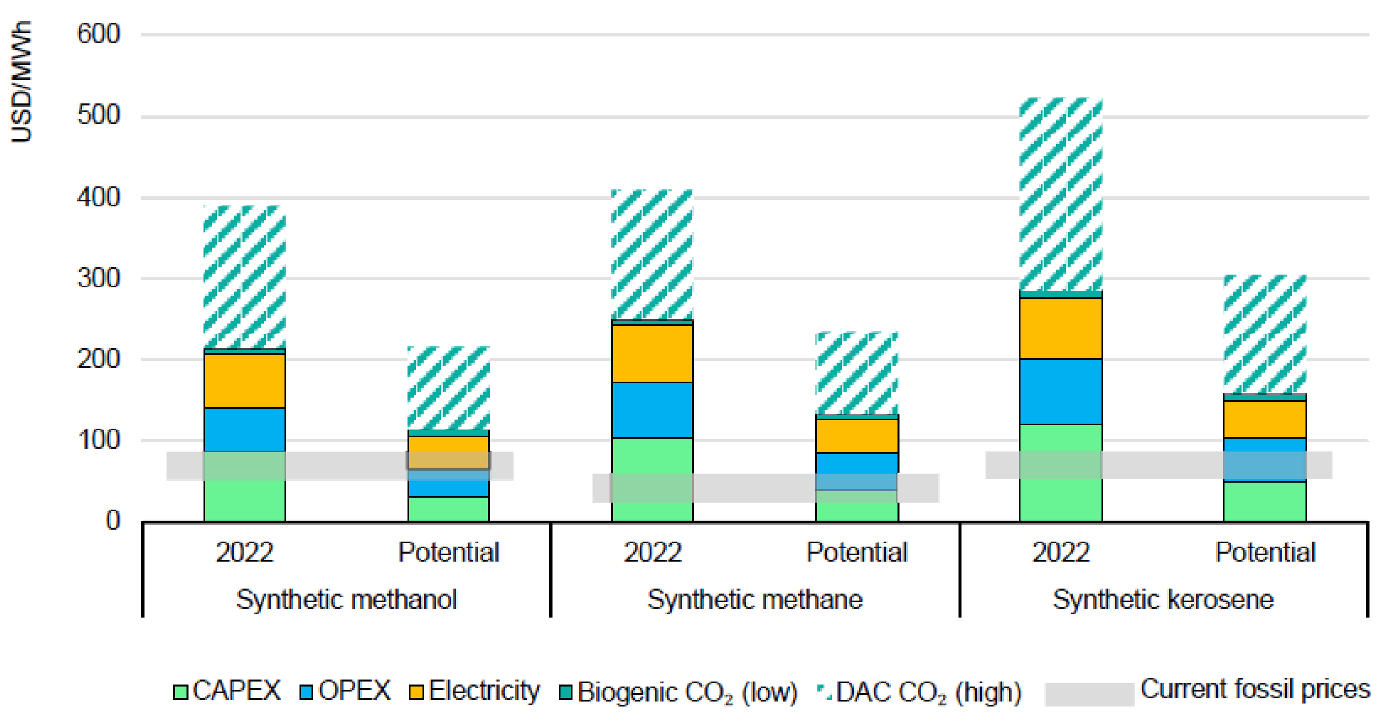
The 2022 production cost of synthetic fuels was also much higher than prevailing market prices* of those fuels in 2023, according to IEA:

- Synthetic methanol levelised production cost of US$215/MWh (vs. c.US$70/MWh market price)
- Synthetic methane levelised production cost of US$250/MWh (vs. US$40/MWh market price)
- Synthetic kerosene levelised production cost of US$290/MWh (vs. US$75/MWh market price)

** Assumes US$30/tCO2 for CO2 captured from biofuel plants*

As such, we believe that the demand for more expensive low-carbon products and synthetic fuels is likely negligible, unless there are regulatory mandates for their use.

Figure 28: Levelised cost of CO2-based fuel production



SOURCE: IEA, 2023

Notes: CAPEX = capital expenditure; OPEX= operational expenditure. CO2 feedstock cost 2022: lower bound: US$30/tCO2 (assumed cost of capture for a biofuel plant); upper bound: US$720/tCO2 (cost of capture for a DAC plant). CO2 feedstock cost potential: lower bound: US$30/tCO2 (assumed cost of capture on a biofuel plant); upper bound: US$430/tCO2 (assumed cost of capture for a DAC plant in 2030).

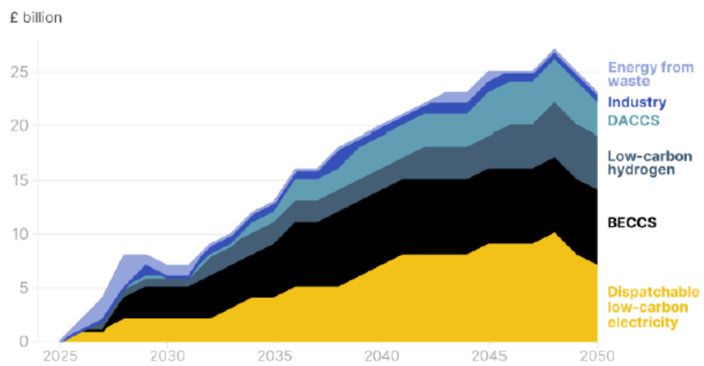
Cost passthrough to consumers in the UK

According to UK's Climate Change Committee (as quoted in an IEEFA report in Jul 2025), the total UK CCS investment over the next 25 years will need to be about £408bn in order to meet the UK's CCS targets.

IEEFA believes that implementing CCS initiatives in the UK will be very expensive for the consumer, as environmental levies that support the roll-out of renewable energy and to make CCfD payments for CCS operators will be 75% financed through additional electricity bill charges, when electricity prices in the UK are already high.

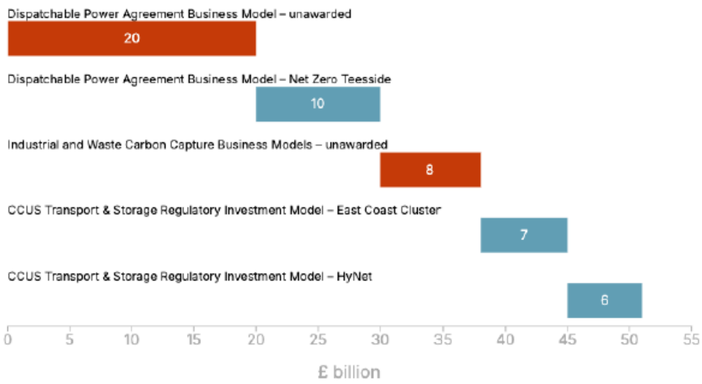
These environmental levies are required because that there is little economic incentive for polluters to install CCS facilities as ETS prices are too low; hence, over £50bn of subsidies have been earmarked to support CCS projects, according to IEEFA.

Figure 29: Additional CCS investment requirements by sector (UK)



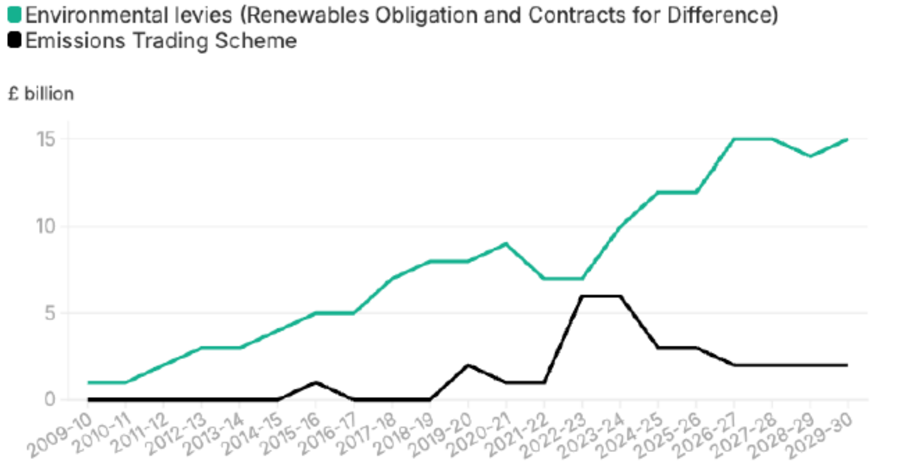
SOURCE: IEEFA, 2025

Figure 30: More than £50bn in UK CCS subsidies are required



SOURCE: IEEFA, 2025

Figure 31: Historical and forecast UK environmental levies and ETS revenues



SOURCE: IEEFA, 2025

Potential cost passthrough to consumers in Malaysia

CGSI utilities analyst Dharmini Thuraisingam estimates that electricity tariffs in Peninsular Malaysia will rise by 23%, if all CO_2 emissions from the power sector are captured, if all CO_2 costs of capture are fully passed to consumers, and assuming cost of capture at US$30/t$CO_2$. This is based on the low cost incurred by the Huaneng Longdong coal-fired power plant in China.

Huaneng Longdong achieved a very low cost of CO_2 capture of US$30/t$CO_2$ with a capacity of 1.5 Mtpa. Around 0.5 Mtpa of CO_2 captured is sold for EOR purposes while 1 Mtpa is stored in onshore geological storage.

The full-chain CCS cost of power plants in Malaysia should be higher, as Malaysia will use offshore storage sites at Kertih, Kuantan and Bintulu.

If full-chain capture, transport and storage CCS costs in Malaysia are at US$90/t$CO_2$, electricity tariffs could rise by 70% if all CCS costs are passed through.

Also, implementing CCS for subcritical coal-fired power plants will be more expensive than for supercritical plants, as the former will require more extensive flue gas pre-treatment to remove pollutants like NOx, SOx and particulate matter, as these can degrade the performance and lifespan of the CO_2 capture solvents, according to IEEFA.

Figure 32: Impact assessment on Peninsular Malaysia power sector

			Notes
a	2024 total electricity generated in Peninsular Malaysia (GWh)	141,800	
b	Grid emissions factor (Gg CO2e/GWh)	0.78	One gigagram = 1,000 tonnes
c = a x b	**Implied CO2 emissions by the power sector (m tonnes)**	**111**	
d	Cost of CO2 capture (US$/tCO2)	30	For the Huaneng Longdong coal-fired power plant; cost of CO2 capture below Rmb220/tCO2, according to Global CCS Institute.
e = c x d	Annual cost for CO2 capture (US$ m)	3,318	
f	Exchange rate (RM:US$1)	4.20	
g = e x f	Annual cost for CO2 capture (RM m)	13,936	
h	2024 total power consumption base (GWh)	130,800	
i = g / h	**Implied cost of CO2 capture (sen/kwh)**	**10.7**	
j	Existing base tariff (sen/kwh)	45.4	
k = i + j	**New TNB tariff assuming full CO2 capture cost passthrough (sen/kWh)**	**56.1**	
k / j -1	Increase (%)	23%	

SOURCES: CGSI RESEARCH; TENAGA NASIONAL BHD; SURUHANJAYA TENAGA; GLOBAL CCS INSTITUTE, 2025

(E) CHALLENGES AND RISKS FOR CCUS

The main risks for CCUS projects revolve around technical risks, economic risks, political and legal risks, and cross chain risks. Below we list down the litany of risks.

Technical risks

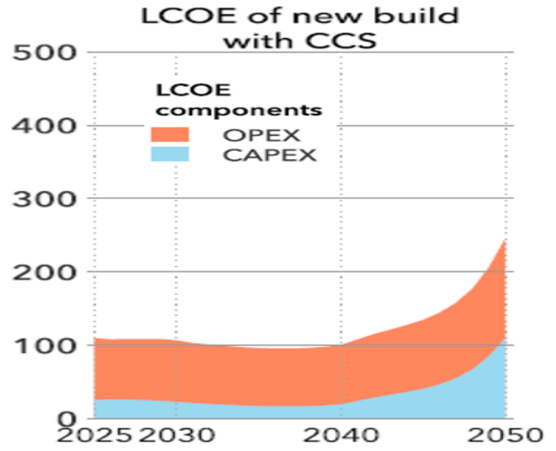
- CCS technologies have high design complexity and a high need for customisation, which presents obstacles to technological advancement, according to a report published by Canada's International Institute for Sustainable Development (IISD) in 2023. The high design complexity involves "multiple interactions between the components, which makes technological innovation more difficult, leading to a highly iterative process with high risk of bottlenecks and dead ends," according to the report.
- CCS capture projects that involve First-of-a-Kind (FOAK) capture technologies may result in lower-than-expected capture rates.
- Current capture technologies may suffer obsolescence, once new technologies are made available.
- The transportation and storage of CO2 may result in leaks across the physical network, which may result in negative environmental and safety effects.

Economic risks

- FOAK capture technologies entail capex and opex uncertainties, and actual costs may come in at the higher end of estimates.
- CCS has relatively low historical experience rates, according to IISD, due to the high degree of customisation required. Experience rates indicate the percentage reduction in real unit costs for each doubling of the cumulative installed capacity. Experience rates between 1976 and 2015 for CCS with natural gas combined cycle power plant ranged between 2% and 7%, compared to the median experience rate for solar photovoltaic (PV) modules at 23%, according to IISD. Given that renewable energy (RE) has much higher experience rates, IISD believes that fossil fuel power plants will eventually be outcompeted when compared against unit cost reduction in the RE space. The International Renewable Energy Agency (IRENA) released a report in Jul 2025 stating that 91% of new RE projects commissioned in 2014 were more cost-effective than new fossil fuel alternatives, with "solar PV 41% cheaper on average than the lowest-cost fossil fuel alternatives, while onshore wind projects were 53% cheaper" due to the significant cost reduction in solar PV panels and battery energy storage systems (BESS). This potentially makes the RE-BESS combo a more economically-viable energy investment than fossil fuel power plants with CCS.
- Meanwhile, GCCSI noted that the levelised cost of electricity (LCOE, per MWh) of fossil-fuel power plants may rise over time if capacity utilisation of thermal power plants declines with greater adoption of RE; this may render the entire plant uneconomic, including any investments in capture infrastructure.
- The viability of CCS projects for EOR will depend on the price of oil. For example, the Petra Nova coal-fired power plant CCS project in Texas, US opened in 2017 but ceased operations in 2020 due to low oil prices during Covid-19.
- CCS projects may be costly and damage IRRs if not supported by CCfDs, or governmental capex/opex subsidies, or tax credits.
- In partial chain CCS business models, providers of common-user transport and storage facilities may face demand uncertainties if there is insufficient supply of CO2 from emitters due to delays in capture projects. Meanwhile, independent storage providers typically have to incur costs to monitor storage sites for leakage for at least 20 years after storage site closure despite not earning additional revenues.

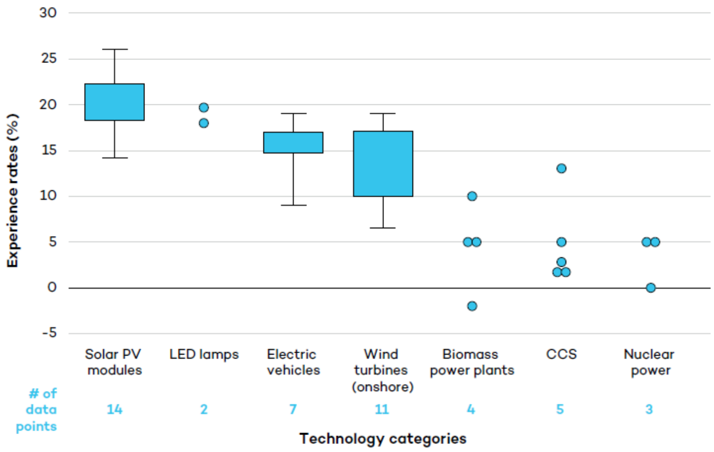
- Liabilities resulting from CO2 leakages may be onerous. Even after independent storage providers hand over responsibility of the CO2 storage sites to the respective national governments, any leakage arising from events, omissions or negligence arising prior to the handover may result in liabilities accruing to the storage providers, in our view.

Figure 33: LCOE for coal-fired power plants in China



SOURCE: GLOBAL CCS INSTITUTE, 2025

Figure 34: Experience rates for various technologies globally



SOURCE: INTERNATIONAL INSTITUTE FOR SUSTAINABLE DEVELOPMENT (IISD), 2020

Political and legal risks

- The second US Trump administration has dismantled some of the Biden administration's environmental and decarbonisation support measures; if these measures are expanded into the CCS space, further CCS rollouts in the US could be compromised.
- In other countries, the pace of CCS development depends on the extent of government ambition in terms of direct incentives, carbon taxes, and government funding support. If these are reduced or withdrawn, early CCS investors may suffer negative financial impacts.
- Carbon pricing, in terms of carbon tax levels or carbon allowance pricing under ETSs, can also impact CCS adoption rates. Investors in CCS capture, transport and storage infrastructure may be negatively impacted if carbon taxes or ETS prices turn out to be lower than expected, possibly due to governments lowering the trajectory of proposed future carbon tax rate increases, or due to an increase in the supply of free emission allowances due to political factors.

Cross chain risks

- In partial chain business models, emitters who invest in capture infrastructure may not be able to secure sufficient T&S capacity, while T&S infrastructure investors may not be able to secure sufficient CO2 supply from emitters. Government intervention may be required to ensure full chain coordination and to prevent market failure.
- Meanwhile, emitters are subject to T&S tariffs charged by infrastructure providers. Government intervention may be required to legislate T&S tariffs in order to prevent the abuse of the T&S providers' semi-monopolistic position.

(F) CCUS DEVELOPMENTS IN NORTH AMERICA

The US 'carrot' approach

The US adopts a 'carrot' approach to CCUS, unlike Europe which employs a 'carrot-and-stick' approach. This 'carrot' approach has successfully turned the US into the country with the most prolific deployment of CCUS globally.

The US has a major incentive for CCUS projects provided by the 45Q tax credits (per tonne of CO2 captured); these credits were first introduced in 2008 and have been enhanced several times and continue to receive bipartisan support under the 'One Big Beautiful Bill Act' (2025) in the second Trump administration, according to GCCSI.

The 45Q tax credit scheme provides tax credits to the emitter for 12 years from the date the carbon capture equipment is first placed in service. Project developers can also sell their carbon capture tax credits to third-party buyers for cash.

Under the previous Inflation Reduction Act (2022), the 45Q tax credit was always lower if the CO2 is utilised rather than permanently sequestered in dedicated geologic storage. However, enhancements under the 'One Big Beautiful Bill Act' (2025) now include parity for the utilisation of CO2.

This means the same tax credit of **US$85/tCO2** is provided to the emitter, regardless of whether:

- The CO2 is permanently sequestered in a dedicated geologic storage site; or
- The CO2 is utilised by way of conversion into valuable products, or utilised by way of injection and geological storage in a qualified EOR/EGR project site.

Meanwhile, the same tax credit of **US$180/tCO2** is provided to the emitter, regardless of whether the CO2 is captured by a direct air capture (DAC) facility and

- Sequestered in a dedicated geologic storage site; or
- Utilised by way of conversion into valuable products, or utilised by way of injection and geological storage in a qualified EOR/EGR project site.

Figure 35: The US 45Q tax credit scheme

Feature	Inflation Reduction Act (2022)	One Big Beautiful Bill Act (2025)
Credit Value (per ton)	• $85: Point source → Geologic storage (GS) • $180: DAC → GS • $60: Point source → Utilisation / GS with enhanced recovery • $130: DAC → Utilisation / GS with enhanced recovery	• $85: Point source → GS • $180: DAC → GS • $85: Point source → Utilisation / GS with enhanced recovery • $180: DAC → Utilisation / GS with enhanced recovery
Transferability	Allowed as of 2023	Allowed as of 2023
Inflation Adjustment	Commences 2027, with 2025 base index year	Commences 2027, with 2025 base index year
Foreign Entity of Concern (FEOC) Restrictions	Not applicable	New restrictions

SOURCE: GLOBAL CCS INSTITUTE, 2025

Developments in Canada

Canada has a CCUS tax credit scheme, which is a refundable tax credit for corporations that incur eligible expenses for qualified CCUS projects.

Legal firm Norton Rose Fulbright noted that the credit rates stand at:

- Direct Air Capture projects: Up to 60% (2022-2030F), halving to 30% (2031-2040F)
- Point Source Carbon Capture: Up to 50% (2022-2030F), halving to 25% (2031-2040F)
- Transportation, Storage, and Use (TS&S): Up to 37.5% (2022-2030F), halving to 18.75% (2031-2040F)

However, earlier this year, Canada extended the full rate of the CCUS tax credits through to 2035F (instead of ending in 2030F) under new prime minister Mark Carney.

Meanwhile, Canada has also stated its goal of investing US$14m into the Energy Innovation Programme, which is a government initiative that supports research, development, and demonstration projects for clean energy technologies.

GCCSI expects that FID will be taken in 2025F for US$16.5bn The Pathways Alliance Oil Sands CCS project, which is to begin operations in 2027F and transport 22 Mtpa of CO_2 by 2030F from over 20 oil sands operations in Alberta for underground storage. The federal government's Canada Growth Fund is negotiating a support deal for the project. At the point of writing, FID had not yet been taken.

Key risks

Trump 2.0 has reversed some of Biden's climate policies, including plans to pull the US out of the UN Framework Convention on Climate Change (UNFCCC).

Meanwhile, the US Environmental Protection Agency (EPA) has proposed the repeal of GHG emissions standards for fossil-fuel-fired power plants.

Also, the US Department of Energy (DOE) in May 2025 terminated 24 clean energy projects worth US$3.7bn that were primarily earmarked for CCS and decarbonisation projects.

The good news is that there remains strong bipartisan support for the 45Q tax credit scheme, and this would likely continue encouraging further CCUS developments in the US, in our view.

(G) CCUS DEVELOPMENTS IN EUROPE

The European Union (EU) adopts a 'carrot-and-stick' approach to decarbonisation, including for CCUS development and promotion.

The 'sticks'

1. The European Union (EU) and the UK **Emissions Trading Schemes (ETS)** form the backbone of the disincentives for emitters.
   - The EU ETS price stood at US$92/tCO2 (€79; EECXM1 SONA Index) as at 21 Oct 2025.
   - According to forecasts by DNV in Jun 2025, the EU ETS prices for ETS-1 sectors (large industry) are expected to reach US$150/tCO2 by 2030F, US$220/tCO2 by 2040F, and US$250/tCO2 by 2050F. DNV forecasts ETS-2 sector (buildings and road transport) prices to reach US$50/tCO2 by 2030F and US$220/tCO2 by 2050F (forecasts by DNV in Jun 2025).
   - The UK ETS price stood at US$72/tCO2 (£54; UKAAUPR Index) as at 15 Oct 2025.
   - In May 2025, the EU and UK agreed to establish links between the EU ETS with the UK ETS in the future, which should promote the lowest-cost decarbonisation pathways for Europe as a whole.
2. Meanwhile, the EU's **Net-Zero Industry Act (NZIA)** that was adopted in Jun 2024:
   - Mandates 44 European oil and gas producers to collectively develop 50 Mtpa of CO2 storage capacity by 2030F (no longer voluntary); with
   - Penalties for non-compliance to be determined in 2026F.
3. The **European Commission (EC)** also actively monitors the CCUS developments. Since Dec 2024, EU member states must submit annual reports to the EC regarding ongoing CO2 capture, transport and storage projects.

The 'carrots'

1. The **EU Innovation Fund** has been a key financial supporter of CCS projects in Europe.
   - The EU Innovation Fund paid US$2bn or c.70% of the capex cost of Norway's Longship and Northern Lights project, according to DNV, and will also fund project opex for first 10 years.
   - In Dec 2024, the EU Innovation Fund made a €2.4bn call for proposals to support a range of decarbonisation projects, with deadline for submission in Apr 2025.
2. The **EU Clean Industrial Deal** is a strategy presented by the EC in Feb 2025 to support European industry decarbonisation with proposals to:
   - Create the Industrial Decarbonisation Accelerator Act;
   - Expand the EU ETS to cover CDRs (currently CDRs are not eligible towards fulfilling obligations under EU ETS and UK ETS); and
   - Establish the Industrial Decarbonisation Bank, among others.
3. The **UK government** has also provided support for CCS projects:
   - For emitters, the UK provides capital grants via the CCS Infrastructure Fund, and funds CCS levelised costs via CCfDs over 10 years with options for up to five 1-year extensions.
   - For transport and storage infrastructure providers, the UK provides capital grants and regulates its tariffs via the Regulatory Asset Base (RAB) model. Examples include the 'Track-1' and 'Track-2' shared transport and storage infrastructure projects (more on this later).

Financial support for CCS in UK and Europe

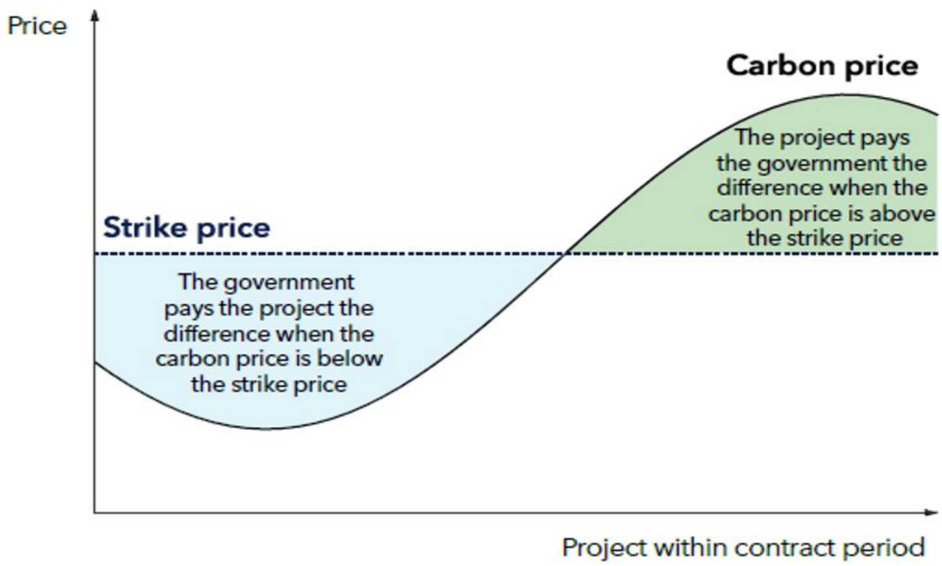
Carbon Contracts for Difference (CCfD) is one of the ways in which governments in Europe support the development of capture projects at emitters' facilities.

CCfDs are employed by the UK, Netherlands, Denmark and France. CCfDs are contracted between the government and the CCS project owner, typically over 10-15 years. The 'strike price' is defined as the levelised CO2 removal cost of the CCS project over its lifetime. The 'carbon price' is the prevailing carbon tax or ETS price.

If the carbon price is below the strike price, the government pays the project owner the difference. In this case, CCfDs compensate the project owner for the additional costs involved in implementing capture projects when carbon prices are still low and capture projects' levelised costs are still high.

However, if the carbon price is above the strike price, presumably due to the tightening of the available allowances, then the project owner will pay the government the difference, thereby ensuring fairness to both parties.

Figure 36: Principle behind CCfD



SOURCE: DNV, 2025

GCCSI also noted in its 2025 report that non-recourse **private debt financing** was being secured in the UK for various projects such as Net-Zero Teesside's (NZT) 742 MW gas-fired power plant with CCS, and Northern Endurance Partnership's (NEP) CO2 pipeline network to the Endurance storage site in southern North Sea. Financial close has been achieved for several bankable projects in Europe, such as the Northern Lights Phase 2 project in Norway, the Eni Hynet North West project in the UK (to transport and store CO2 from various industrial facilities in Northwest England), and the Stockholm Exergi BECCS project in Sweden.

Meanwhile, **private equity capital** is also stepping in, with NZT and NEP securing £8bn in private equity funding, with the project backed by BP, Equinor and TotalEnergies, while a JV between Eni and Global Infrastructure Partners (GIP) in May 2025 agreed to co-own CCS assets in the UK, Netherlands and Italy.

Finally, GCCSI noted that **Voluntary Carbon Markets (VCM)** were expanding their support of CDR projects, with Microsoft increasing its BECCS offtake from Stockholm Exergi to over 5 Mt, and the European Commission (EC) exploring an EU-wide CDR purchasing programme to increase the demand for CDR technologies.

Norway's Longship and Northern Lights CCS project

The **Longship project** is Norway's landmark full-scale CCS initiative and Europe's first project to establish a complete value chain for industrial CO2. It is a collaborative effort involving government funding and industrial partners.

The **Northern Lights JV** is the transport and storage (T&S) partner of the Longship CCS project. It is a JV owned by Equinor, Shell, and TotalEnergies. It is designed as an open-access facility to provide CO2 transport and storage as a service to industrial emitters across Europe.

The Northern Lights project's injection capacity is expanding significantly in two phases.

- Phase 1 capacity: 1.5 Mtpa of CO2 injection capacity completed in 2024, and fully booked by industrial clients in Norway, Netherlands and Denmark.
- Phase 2 capacity: CO2 injection capacity to increase to 5 Mtpa from 2H28F.

The project's capacity will be subsequently expanded to meet the growing demand for CO2 transport and storage in Europe.

Northern Lights is the world's first CCS project to transport CO2 by ship. The JV ordered 4 x 7,500 cbm medium-pressure LCO2 ships from Dalian Shipbuilding Offshore Co (DSOC). Two were delivered in late-2024, with one to be delivered in late-2025F and another in 2026F.

The Norwegian government subsidised US$2bn (c.70%) of the Longship project capex, including Northern Lights, and will cover all opex for 10 years, according to DNV. Another US$600m came from Equinor, Shell, and TotalEnergies; while US$150m came from EU funding.

Capture

CO2 is captured at two industrial facilities:

- The Heidelberg Materials (Brevik) cement plant which began operations in 2025 and is the world's first industrial-scale CCS plant at a cement production site; and
- The Hafslund Celsio (Oslo) waste-to-energy plant, which will operate from 2029F.

Transport

Captured and liquefied CO2 from these sites is transported by custom-built 7,500 cbm LCO2 ships.

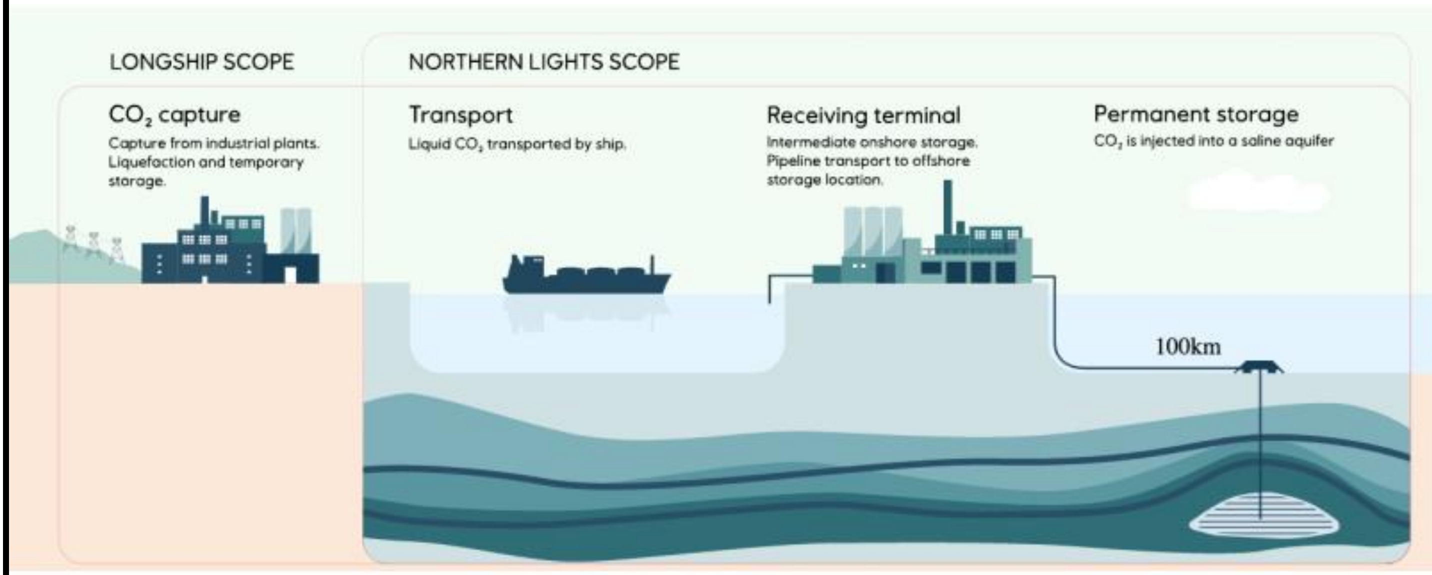
The first shipment from the Brevik plant arrived at the Northern Lights terminal in Jun 2025. The first successful CO2 injection into the reservoir took place in Aug 2025.

Storage

The CO2 is received at the Northern Lights onshore terminal in Øygarden, near Bergen before being transported by pipeline to an offshore site.

It is then permanently injected into a geological formation 2.6km beneath the North Sea seabed.

Figure 37: Norway's Longship and Northern Lights CCS project



SOURCE: LONGSHIP

Figure 38: Map of how CO2 is shipped from the emitters to the storage site

SOURCE: LONGSHIP

(H) CCUS DEVELOPMENTS IN MIDDLE EAST

Decarbonisation goals, protecting exports to Europe

Middle East countries have their individual decarbonisation goals, including various levels of CCS capacities over a certain time frame. They are also integrating CCS to product low carbon fuels like hydrogen, ammonia and Sustainable Aviation Fuel (SAF) in order to protect their exports to Europe, where the CBAM will be effective from 2026F to cover imports of cement, electricity, fertilisers, iron and steel, aluminum, and hydrogen. The EU CBAM will be extended by 2030F to cover all sectors included in the EU ETS, including chemicals and plastics, providing even more motivation for CCS adoption in the Middle East.

The positives for Middle East countries regarding CCUS projects include:

- EOR providing immediate commercial justification for projects, including that for Saudi Aramco's Uthmaniyah gas processing plant CO2-EOR facility and Emirates Steel's Al Reyadah steel plant; and
- The direct involvement of NOCs in all stages of the CCUS projects, from funding and into capture, transport and storage execution, thereby eliminating any cross chain project risks.

The challenges for Middle East countries regarding CCUS projects include underdeveloped carbon markets, the absence of regulatory frameworks for transport and storage, and limited access to finance, according to GCCSI, but these are more than compensated by NOCs' involvements.

Saudi Arabia

Saudi Arabia's existing CCUS facilities include:

- Saudi Aramco's Uthmaniyah CO2-EOR facility: 0.8 Mtpa of CO2 is captured from the Hawiyah natural gas liquids recovery plant, compressed, and transported via an 85-km pipeline to the Uthmaniyah field for EOR.
- Saudi Basic Industries Corporation's (SABIC) United Jubail Petrochemical facility, which captures 0.5 Mtpa of CO2 from ethylene glycol plants and used to produce food-grade liquid CO2 and feed a SABIC-affiliated urea plant.

Saudi Arabia's CCS goals are to achieve:

- National CCS capacity of 44 Mtpa by 2035F (current capacity is 1.3 Mtpa);
- Saudi Aramco's CCS capacity of 14 Mtpa by 2035F (current: 0.8 Mtpa from the Uthmaniyah CO2-EOR facility); and
- The development of CCUS hubs in the industrial hubs of Jubail and Yanbu with strong support from Saudi Aramco and the Saudi Arabian Ministry of Environment.

Saudi Arabia's **Jubail CCS hub** (east coast of Saudi Arabia) is led by Aramco (60% stake), with SLB (20%) and Linde (20%) as partners. It aims to aggregate CO2 from multiple sources, including 6 Mtpa from Aramco's gas processing operations, and 3 Mtpa from other industrial emitters, from 2027F onwards. Its target is to capture and store 9 Mtpa by 2028F in saline aquifers.

Saudi Arabia's **Yanbu Green Hydrogen hub** (west coast of Saudi Arabia) is currently being developed at Yanbu Industrial City, to be operational by 2030F. The initial phase aims to capture and utilise 2 Mtpa of CO2 to produce green methanol, low-carbon urea, and other products. The project is led by ACWA Power (44.52% owned by Saudi Arabia's Public Investment Fund).

UAE

Since 2016, 0.8 Mtpa of CO_2 is being captured from Emirates Steel's Al Reyadah steel plant in the UAE, and injected via a 42km pipeline into oil fields for EOR.

New projects under development include

- ADNOC's Habshan and Ghasha CCS, which will capture and store 1.5 Mtpa each of CO_2 from the Habshan gas processing plant (from 2026F); and
- ADNOC's Hail and Ghasha ultra-sour gas development (from 2028F) which will capture the CO_2 from the natural gas.

UAE's CCS goals include to develop:

- National CCS capacity of 43.5 Mtpa by 2030F (current capacity is 0.8 Mtpa); and
- ADNOC CCS capacity of 10 Mtpa by 2030F (current capacity of 0.8 Mtpa).

Qatar

QatarEnergy targets CCS capacity of 11 Mtpa by 2035F, with the current capacity of 2.2 Mtpa at QatarEnergy's gas processing operations.

The CO_2 is currently captured from gas processing at the LNG trains at the QatarGas North and QatarGas South complexes, and injected into new wells for permanent geological storage at sites located within Ras Laffan Industrial City (RLIC). The current CCS capacity is 2.2 Mtpa, and QatarEnergy has plans to scale this to 7-9 Mtpa by 2030F and to more than 11 Mtpa by 2035F.

QatarEnergy is working on a new project to capture CO_2 from gas processing at the LNG trains at Ras Laffan Industrial City (RLIC) and transport CO_2 via pipeline to the onshore Dukhan fields for EOR from 2027F.

QatarEnergy also plans to capture CO_2 for blue ammonia production, and to capture post-combustion emissions from gas-fired power plants in the future, according to GCCSI.

Oman

According to GCCSI, Oman has several CCUS initiatives:

- OQ Gas Networks (OQGN), an exclusive state owner and operator of the natural gas transmission network in Oman, is planning a national CO_2 transportation network, development of underground CO_2 storage projects with Shell, and development of CO_2 pipeline for EOR in with Occidental of Oman (Oxy Oman).
- Omani state-owned energy company OQ, state-owned upstream oil and gas company Petroleum Development Oman (PDO), and Shell are collaborating on a Blue Horizons low carbon ammonia project development.
- Majority state-owned Oman LNG is exploring the export of CO_2 from its Acid Gas Removal Unit (AGRU) for utilisation at Sur Industrial City, and geological storage in depleted wells.
- Oman is looking to establish a hydrogen hub in Sur to produce green ammonia, synthetic natural gas, and e-methanol.
- Oman has also teamed up with Netherland's Nederlandse Gasunie to develop a hydrogen corridor to export low-carbon hydrogen from GCC countries to Europe.

(I) CCUS DEVELOPMENTS IN CHINA

Strong policy support for CCUS

China has launched several policies that support its climate goals and promote CCUS.

- Its 13th Five-Year Plan (2016-2020) announced the 'Dual Carbon Goals' which is to (1) control total energy consumption and (2) control energy intensity per GDP, while achieving peak carbon in 2030F.
- China's 14th Five-Year Plan (2021–2025) was the first to explicitly include CCUS, with policies supporting research and demonstration projects.
- Details of the 15th Five-Year Plan (2026-2030F) have not been released but will likely establish CCUS as an ongoing priority, in our view.
- The Implementation Plan for Science and Technology Supporting Carbon Peak and Carbon Neutrality (2022–2030F) outlines specific CCUS goals, including to reduce the energy consumption required for carbon capture by 30% by 2030F and demonstrating full CCUS processes at a million-tonne scale.
- Meanwhile, the Chinese central government has signalled support for large-scale CCS demonstrations, particularly within coal-fired power generation, according to GCCSI.

Separately, China's ETS was launched in 2021 covering the power sector. China's ETS is another policy signal supporting CCUS implementation, in our view.

- In Mar 2025, China's ETS was officially expanded to include cement, steel, and aluminum. All major industrial sectors are to be covered by 2027F.
- By 2030F, the ETS will transition from its current intensity-based model to a full absolute cap-and-trade system, which could further incentivise emission reduction.

Key projects are driven by Chinese SOEs

According to GCCSI, Chinese technology innovators and equipment providers are making strong progress in improving capture efficiency and reducing costs. Meanwhile, key projects are being driven by Chinese SOEs, and GCCSI lists several recent examples below.

Power generation space

- **Huaneng Longdong Energy Base**'s 1.5 Mtpa CCS project was commissioned in 2025, which GCCSI described as the world's largest CCS project attached to a coal-fired power plant, which has a generation capacity of 2 x 1,000 MW. The CCS project uses Huaneng's proprietary HNC-7 hybrid solvent technology to capture CO_2 with low energy consumption, resulting in a levelised capture cost at below US$30/t$CO_2$ (Rmb220), according to GCCSI. Of the captured CO_2, 0.5 Mtpa is transported to the nearby Changqing Oilfield for EOR, while 1 Mtpa is injected into saline aquifers for geological storage.
- **China National Petroleum Corporation**'s (CNPC) coal power plant CCS project broke ground in Apr 2025 in Xinjiang; it will capture 1 Mtpa of CO_2, and aims to scale up to 2 Mtpa in the future.
- In Nov 2024, the **CHN Energy Jinjie Company** began development of a 4 Mtpa CO_2 capture demonstration project at a coal-fired power plant in Shaanxi.

Chemicals sector

- **CHN Energy Ningxia Company** began operating a 500 ktpa CCS facility at one of its coal-to-liquids plants in Yinchuan city in Sep 2024, which is to scale up to 3 Mtpa by 2030F.

Cement industry

There are also various projects in the cement industry, also driven by SOEs.

- In 2024, **Beijing BBMG Group** launched a 100 ktpa CCS demonstration project in Beijing, marking China's third operational CCS project in the cement industry.
- **China Resources Building Materials Technology Holdings** began constructing a 60 ktpa cement CCS facility in Hainan in 2024.
- In 2024, **China United Cement Group** started an oxy-fuel combustion CCS project in the cement sector with an capture capacity of 200 ktpa, the largest in the world of its kind, according to GCCSI.

Oil and gas sector

- In the oil and gas sector, **CNOOC** launched China's first offshore CO2-EOR project in May 2025, 200km southwest of Shenzhen, and targets to inject over 1 Mt of CO2 over the next decade, according to GCCSI.
- In Apr 2025, **CNPC** began construction of a two-phase 400 km supercritical or dense-phase CO2 transport pipeline with a capacity of 4 Mtpa in the Jilin province, China, to be used for EOR purposes. It will be four times larger than the capacity and length of Sinopec's first industrial-scale CO2 pipeline in Shandong, according to GCCSI.

(J) CCUS DEVELOPMENTS IN JAPAN

Policy support in Japan

CCUS has received multiple levers of policy support in Japan.

- In 2020, Japan's Ministry of Economy, Trade and Industry (METI) affirmed CCS as a central pillar of the country's Net Zero 2050 strategy.
- In 2023, METI set a target to develop 120-240 Mtpa of CO2 storage capacity by 2050F. This amounted to 12-24% of Japan's 1,017 Mt of CO2 emissions in 2023, based on data from to Japan's Ministry of the Environment.
- In terms of legislation, GCCSI noted that Japan passed the CCS Business Act in May 2024 which introduced a licensing regime (both onshore and offshore) for geological exploration rights, CO2 injection and storage rights, and CO2 pipeline transportation.
- Meanwhile, Japan plans to introduce a cap-and-trade emissions trading system in Apr 2026F which is intended to cover 50-60% of Japan's CO2 emissions, according to Japan's Institute of Energy Economics. Japan currently only has a low carbon tax of c.US$2/tCO2 (JPY289), according to consultancy Carbon Watch.
- In terms of funding, from Feb 2024 onwards, Japan's government began issuing Japan Climate Transition Bonds and set a target to provide US$130bn (JPY20tr) of support for CCS and other transition infrastructure.
- In Jan 2025, GCCSI noted that METI initiated discussions for a new CCS funding scheme that is expected to be finalised by end-2025F. It aims to support CCS capex spending as well as provide opex support to sustain the CCS project.
- Separately, since 2021, Japan's METI has set aside US$13bn (JPY2tr) under the Green Innovation Fund to advance CO2 separation and capture technologies, targeting low-concentration (below 10%) and low-pressure flue gas sources such as from natural gas power plants and industrial exhausts, according to GCCSI. This fund is managed by the New Energy and Industrial Technology Development Organization (NEDO), and the initiative aims to achieve a CO2 capture cost of below US$13/tCO2 (JPY2,000) by 2030F.
- Finally, GCCSI also noted that NEDO has set aside US$250m (JPY38bn) to fund seven major R&D projects up to 2030F to improve carbon capture efficiencies, covering a broad range of technologies such as solid sorbents, membranes, cryogenic methods, electrochemical separation, and innovative absorbents.

Japan's nine advanced CCS projects, by 2030F

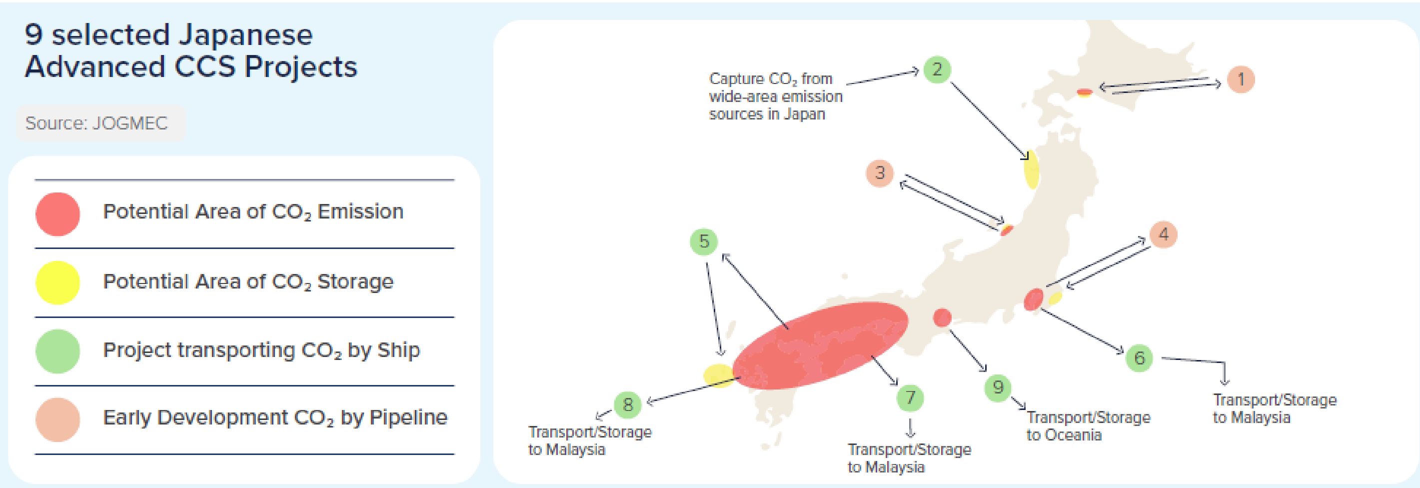
In Jun 2024, JOGMEC announced nine advanced CCS projects, to be in place from 2030F:

- Tomakomai Area CCS (Hokkaido)
- Tohoku Region West Coast CCS (Tohoku)
- Higashi-Niigata Area CCS (Niigata)
- Metropolitan Area CCS (Tokyo Bay Area and Chiba)
- Offshore Western Kyushu (Offshore Kyushu)
- Northern Offshore of Peninsular Malaysia CCS (Tokyo Bay Area, for transport to and storage in Malaysia)
- Offshore Sarawak CCS (Western Japan, for transport to and storage in Malaysia)
- Southern Offshore of Peninsular Malaysia CCS (Western Japan, for transport to and storage in Malaysia)
- Oceania CCS (Chubu, for transport to and storage in Australia)

FID will be needed in 2026F in order for the nine advanced CCS projects to be in place in 2030F, according to GCCSI.

Projects #6 to #9 involve cross-border transportation and storage of CO2 in Malaysia and Australia.

Figure 39: Nine selected Japanese advanced CCS projects



SOURCE: GLOBAL CCS INSTITUTE, 2025

(K) CCUS DEVELOPMENTS IN ASEAN

Three CCUS projects in development

There are currently no operating CCUS in ASEAN; however, several are under development.

- Kasawari, Malaysia – high CO_2 natural gas production for the Bintulu LNG liquefaction plant; the captured CO_2 is to be injected into the depleted M1 field from 2026F or later.
- Arthit, Thailand – high CO_2 natural gas; the captured CO_2 is to be injected into saline aquifers and depleted gas fields from 2027F.
- Tangguh, Indonesia – captured CO_2 from the Tangguh LNG plant in West Papua to be used for EGR from 2028F.

Potential sectoral applications and the economic rationale

As can be seen from the examples above, CCS in ASEAN is mainly used in the oil and gas industry to develop sour gas reserves, or for EOR/EGR. Applications in the non-O&G industry are currently limited or non-existent.

The rationale for applications in the O&G industry

Natural gas processing separates CO_2 from the methane gas in the natural gas streams; instead of venting the CO_2, the CO_2 is injected in subsea reservoirs for permanent storage or used for EOR/EGR. The cost of CCS is potentially recovered by way of additional oil and gas production.

Meanwhile, without CCS for gas processing, sour gas reserves may not be viewed favourably by environmentally-conscious buyers. In the long term, there is a risk that sour gas reserves developed without CCS may be shunned by international buyers.

According to an IEEFA in 2022, "in recent years, several long-term LNG sales purchase agreements (SPA) have been signed between Singapore's Pavilion Energy, Qatar Petroleum and Chevron, which mandated the reporting of emissions for each LNG cargo. The Carbon Neutral LNG Buyers Alliance was established in Japan in 2021, comprising 15 companies with notable leadership from Tokyo Gas." The purpose of the Carbon Neutral LNG Buyers Alliance is to promote the use of carbon-neutral LNG (CNL) to help achieve Japan's 2050 carbon neutrality goals.

Separately, CCS can be used to develop low-carbon hydrogen and ammonia production. Sarawak is currently evaluating options to produce such products in Bintulu via its H2biscus and H2ornbill initiatives.

Potential applications in the non-O&G industry

As previously explained in the CCUS Economics section, the viability of CCS for **power sector** is questionable, but **Malaysia**'s Tenaga Nasional Bhd (TNB) is exploring its options at the moment without making any investment commitments. According to TNB's website:

- In Nov 2023, TNB signed an MOU with Petronas to explore and potentially introduce full-scale CCS technology to gas-fired power plants in Malaysia.
- Since Jun 2023, TNB has been working with Toshiba Energy Systems & Solutions on CO_2 capture technology at thermal power plants, including the **Jimah East Power** coal-fired plant.
- TNB's research subsidiary, TNB Research, has been engaged in R&D, with pilot projects (e.g., Project Dragon at the Jimah East power plant) that have shown promising results, reportedly absorbing up to 90% of carbon emissions from flue gas on a pilot scale.

GCCSI noted that two CCS projects for **Indonesia**'s power plants are in "early development", meaning that they are currently in evaluation stage. These are the **Indramayu CCS** project for the coal-fired power plant, and the **Tambak Lorok CCS** for the gas-fired power plant. Indonesian state-owned electricity company PT Perusahaan Listrik Negara (Persero) was quoted by the Jakarta Post in Jan 2025 as saying that the cost of CCS at Indramayu would be c.US$40/tCO2, which is considered unviable in light of the current electricity tariffs.

In **Vietnam**, the Vietnam Petroleum Institute (VPI), a research centre under Petrovietnam, has commissioned a feasibility study on incorporating CCS into **three coal-fired power plants**, i.e. the Song Hau 1, Thai Binh 2, and Vung Ang 1 plants.

In the **cement industry**, the Siam Cement Group (SCG) in **Thailand** began conducting a pre-feasibility study in 2024 to evaluate the viability of CCUS at one of its **cement** plants. Meanwhile, SCG is taking a lead in evaluating options to transform Saraburi, Thailand's largest cement production hub, into a low-carbon industrial area with shared CCUS infrastructure.

Malaysia's Malayan Cement currently produces what it terms as 'low-carbon' cement and 'low-carbon' concrete by way of using recycled materials and repurposing waste to reduce the embodied CO2 in its products. We believe that Malayan Cement has not implemented CCS, although CCS has been identified as a 'mid-to-long-term development' for the production of cement and concrete.

Figure 40: Three distinct CCUS tracks in SE Asia

CCUS Category	Technology Maturity	Cost of CCUS	Potential Dominant Parties Involved in SEA
Gas Processing Capture of CO_2 associated with excess CO_2 content (impurities) in gas production, particularly salient for gas reserves with high CO_2 content	Mature. Has been applied since the 1970s to meet required gas specifications	Low	**Host governments, private/state-owned entities** Gas production with royalty/revenue share between the host government and oil and gas operator. Cost of CCUS will likely be borne by both parties with end-product sold at market or regulated price. The portion of cost allocations potentially determined by inherent leverages and policies of each party. Example: Gas production CCUS
Products: Hydrogen/Ammonia Production Capture of CO_2 associated with industrial process	Cost reduction required to improve product competitiveness	Medium to high	**Private/state-owned entities** – owner of plants. Cost of CCUS passed through to customers with low-carbon products sold at a premium price. Example: 'Blue' hydrogen or ammonia production[13]
Power Plants (coal and gas) Capture of CO_2 associated with fuel combustion	Low to medium, commercially challenging. Technical challenges remain prominent in existing projects	High to very high Low CO_2 concentration from flue gas 12-15% (coal) Very low for gas 4% (gas combined cycle)	**Private/state-owned entities** – owner of power plants **Host government** – as applicable Costs (inclusive of energy penalty costs) passed through to consumers or host governments depending on the power market structure. Example: Power plants operating under Power Purchase Agreements with/without take-or-pay clause

Examples

In construction:
- Kasawari, Malaysia
- Arthit, Thailand
- Tangguh, Indonesia

In evaluation:
- H2biscus, Sarawak: 0.8 Mtpa of low-carbon ammonia for export to South Korea (potential to be downsized).
- H2ornbill, Sarawak: 50 ktpa of low-carbon hydrogen to be converted into methylcyclohexane for export to Japan.

FID expected by June 2026F, with start-up targeted for 2028-2029F.

In early development (timing uncertain):
- Indramayu CCS, Indonesia (coal)
- Tambak Lorok CCS, Indonesia (gas)

SOURCES: CGSI RESEARCH; IEEFA, 2022; GLOBAL CCS INSTITUTE, 2025

Challenges for CCUS in ASEAN

Apart from CCS applications for the economic development of sour gas reserves or for EOR/EGR, there are many other applications which are not economically viable in SE Asia. This is because carbon pricing in SE Asia is either too low or non-existent, except for Singapore.

The regional carbon pricing are depicted below:

- **Singapore** had a carbon tax of <US$4/tCO2 (S$5) in 2019-2023, but this has now increased to US$19 (S$25) for 2024-2025F, and is set to rise to US$35 (S$45) in 2026-2027F. The carbon tax is projected to reach US$40-60 (S$50-80) by 2030F, based on Singapore government announcements. Singapore's carbon tax applies to the manufacturing, power generation, waste, and water sectors.
- **Indonesia** had proposed to implement a US$2/tCO2 carbon tax (Rp30,000) on coal-fired power plants from 2022, but implementation has been postponed to an undefined future date. While Indonesia requires coal-fired power plants to offset their excess emissions via the Indonesia Stock Exchange's (IDX) Carbon Exchange, the carbon intensity emissions cap has been set too high, thereby limiting transactions on IDX Carbon Exchange and ensuring a low IDX carbon price of just US$3.50/tCO2 (Rp58,800) as at 12 Nov 2025, according to an IEEFA report in 2025.
- **Malaysia** has unofficially proposed a carbon tax at US$3.60/tCO2 (RM15) from 2026F on the iron, steel and the power-generation sectors, as reported by The Edge in Nov 2025.
- **Thailand** approved a carbon tax of US$6.20/tCO2 (THB200) on petroleum products (gasoline, gasohol, kerosene, jet fuel, diesel, biodiesel, and liquefied petroleum gas) effective Feb 2025, but the retail fuel prices have not changed as the carbon tax will be offset by a reduction of the excise tax. This renders the carbon tax moot in the eyes of Thai consumers.
- **Vietnam** does not have a carbon tax, but launched a pilot ETS in Aug 2025 with free emissions allowances allocated to thermal power plants, iron and steel production, and cement producers up to 2028F.

Even in North Asia, carbon prices are very low. In Japan, the US$2/tCO2 (JPY289) carbon tax levied on fossil fuel sales has been in effect since 2016. In South Korea, ETS prices stood at c.US$6-7/tCO2 in mid-2025, according to GCCSI. According to Bloomberg, the benchmark China Emission Allowances stood at US$8.25/tCO2 (Rmb58.80) in early-Oct 2025.

Current low carbon prices suggest that government support will be necessary in order to scale up CCS in the Asia-Pacific region.

CCUS regulation in ASEAN

CCUS regulation in ASEAN is being gradually developed.

Malaysia passed the CCUS Act on 25 Mar 2025 – this establishes a framework, but many of the details are yet to be regulated. This federal-level **CCUS Act 2025** does not apply to Sabah and Sarawak.

Sarawak has its own state-level legislation, the **Land (Carbon Storage) Rules 2022** (passed on 22 Dec 2022).

Sabah has yet to promulgate any CCUS-related state laws.

Indonesia's Ministry of Energy and Mineral Resources Regulation No. 2 of 2023 (**MEMR 2/2023**) on the Organisation of CCS and CCUS for Upstream Oil and Gas Business Activities, governs the implementation of CCS/CCUS within existing upstream oil and gas working areas under PSCs.

Indonesia's **MEMR 16/2024** on the Organisation of Carbon Storage in Carbon Storage Permit Areas, provides authorisation for geological storage, resource exploitation, and CO2 storage and transport, *independent of hydrocarbon E&P activities*, on the back of Presidential Regulation 14/2024.

Thailand currently does not have specific laws governing CCS, but a key amendment is being introduced through the existing Petroleum Act, B.E. 2514 (1971) to introduce the concept of a carbon business which would regulate the development of storage of CO2 in geological sites, similar to the framework for conventional petroleum concessions (source: Luther Law Firm).

CCS initiatives in Malaysia

CCS developments in Malaysia can be broadly categorised into two areas.

The first is the development of sour gas reserves, which is to include the capture and permanent sequestration of the CO_2 present in the natural gas stream:

- Sour gas production commenced at Petronas's **Kasawari** field, offshore Sarawak in Aug 2024, and CCS may commence at the location in 2026F at the earliest.
- The development of sour gas reserves at the **Lang Lebah** field, offshore Sarawak was to have commenced in 2026F, but the EPCC tenders were cancelled by PTTEP in Feb 2025, with PTTEP now working to reduce costs. We think that the original first gas date of 2028F is now likely delayed.
- The **BIGST** fields (Bujang, Inas, Guling, Sepat, and Tujoh) are primed to be the first high-CO_2 development in Peninsular Malaysia with CCS, with production set to commence from 2029F, according to website Offshore Technology.
- PM3 CAA – Hibiscus to develop injection and storage for the CO_2 captured during natural gas processing.

The second is the development of storage sites, in particular for the importation and storage of CO_2 from foreign countries:

- Malaysia is currently working on the development of 15 Mtpa CO_2 storage capacity by 2030F in the **M3** field (Eastern Cluster, Sarawak), the **Lawit** field (Northern Cluster, Peninsular Malaysia), and in the **Duyong** field (Southern Cluster, Peninsular Malaysia).
- In 2024, Petronas, ADNOC and Storegga agreed to collaborate to evaluate and develop offshore CO_2 storage in the **Penyu basin**, offshore Pahang. The goal is to have a capacity of at least 5 Mtpa by 2030F.
- In Jul 2024, the **Sarawak Bid Round** offered three carbon storage regions with a total estimated storage capacity of 1,000 Mt of CO_2. However, the outcome is not yet known. The three offshore storage regions are in Southwest and Western Luconia, Balingian, and Central Luconia.

Figure 41: CCS initiatives in Malaysia

PROJECT	STATE	COMPANIES INVOLVED	STATUS
M3	Sarawak	Petronas, Petros, eight Japanese companies	Undergoing a feasibility study to turn the depleted gas field into a carbon storage site
Kasawari	Sarawak	Petronas	The gas field, which commenced production in 2023, is also being developed for CCS. Carbon dioxide will be captured from flaring to be stored in the site.
Lang Lebah	Sarawak	Petros	Undergoing a study for CCS in the huge gas field, which is expected to come onstream in 2027
Southwest and Western Luconia	Sarawak	Petros	Offered during the Sarawak Bid Round (SBR 2024), which will enable sour gas fields development and decarbonisation of industries
Balingian	Sarawak	Petros	Offered during SBR 2024, comprising depleted fields near their end of life. Its location close to shore allows for potential development of a new onshore gas plant.
Central Luconia	Sarawak	Petros	Offered during SBR 2024, featuring saline aquifers and depleted fields, with potential nearby sour gas field development
BIGST Field	Terengganu	Petronas and JX Nippon Oil & Gas Exploration	Production Sharing Contract signed for development and production of high CO2 gas fields, which will incorporate CCS technology
Lawit Field	Terengganu	Petronas and ExxonMobil	Evaluation of potential for carbon storage in the active gas field operated by ExxonMobil, where extraction is expected to continue to 2031
Penyu Basin	Pahang	Petronas, ADNOC, Storengga	Undergoing study to store captured carbon in its saline aquifer. In 2021, Petronas awarded Small Field Asset Production Sharing Contracts to develop some small oil fields in the Basin.
Duyong Field	Pahang	Petronas, TotalEnergies, Mitsui	Undergoing a pipeline site survey to turn the mature gas field into a storage site for carbon dioxide captured onshore

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Development of sour gas reserves

Development of storage capacity

The Sarawak Bid Round in 2024 offered three carbon storage sites with a total estimated storage capacity of 1 Gt of CO2: Southwest and Western Luconia, Balingian, and Central Luconia.

SOURCES: CGSI RESEARCH; THE EDGE, 2025

Petronas Kasawari CCS project

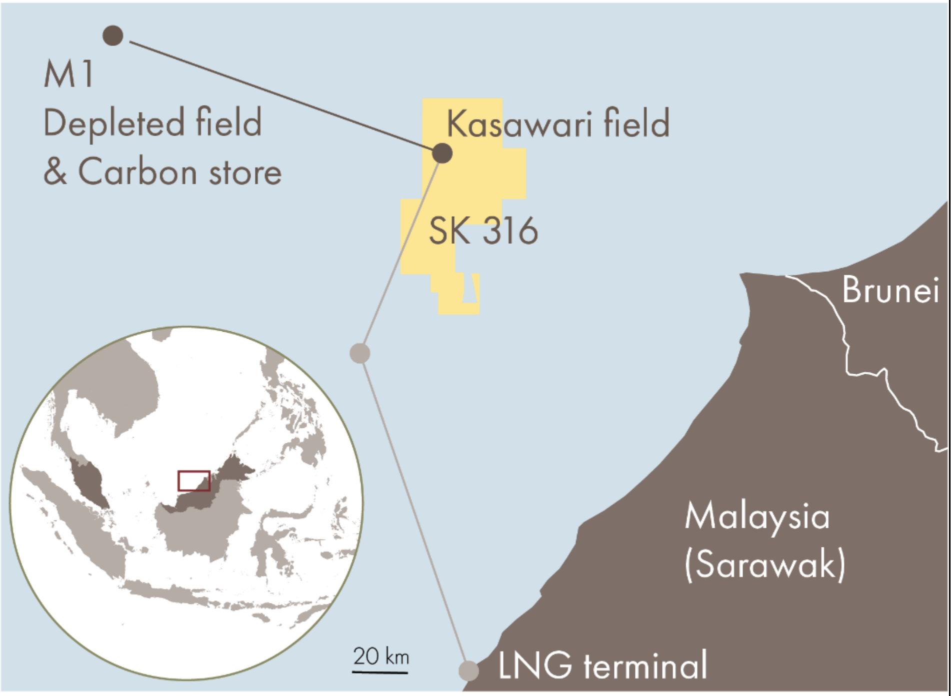
The Kasawari gas field is located offshore Sarawak (block SK316), contains 3.2 Tcf of recoverable gas, of which an average of 22% is CO_2 (up to a maximum of 40%). Gas production commenced in Aug 2024, according to Upstream.

Petronas Carigali holds a 90% participating interest and is the operator of the Kasawari field, with the remaining 10% interest is held by Exploration and Production Malaysia Venture (EPMV) which is a wholly-owned subsidiary of Petronas.

The Kasawari CCS project is premised on the rationale that Malaysia needs to develop high-CO_2 gas fields to backfill the Bintulu LNG complex, while still meeting Malaysia's and Petronas's commitment to reduce emissions. The Kasawari CCS project is intended to have a CO_2 capture capacity of 3.3 Mtpa, according to Petronas. The CO_2 comes from the natural gas reservoir, but needs to be separated to ensure that the sale gas meets maximum CO_2 content thresholds.

The Kasawari CCS project involves the fabrication of a dedicated CCS offshore platform next to the gas production facilities; the fabrication work is being performed by Malaysia Marine and Heavy Engineering (MMHE), which reported 68% completion rate as at 30 Sep 2025. The CO_2 will be piped over 138km from the platform for injection into the depleted M1 field. The CO_2 injection was originally supposed to commence at end-2025F but could be delayed into 2026F or later, in our view. Petronas estimated that up to 76 Mt of CO_2 in total could be injected into the M1 reservoir from the Kasawari gas field.

Figure 42: Petronas Kasawari CCS project



SOURCE: CEOEXPRO

S&P Global estimated in Apr 2023 that the Kasawari CCS project will reduce lifecycle CO_2 emissions of the Kasawari field by 46 Mt, or 69%, but this may come at a significant cost to both Petronas and the Malaysian government, because over the operating life of the field:

- The overall capex could rise by 50% from US$1.8bn to US$2.7bn;
- The lifecycle opex could increase by 36% from US$5.8bn to US$7.9bn;
- The NPV of the Kasawari gas field to Petronas may be slashed by 74%, at 10% WACC; and
- The NPV to Malaysian government may be reduced by 20%, at 10% WACC.

Meanwhile, the breakeven upstream gas price rises 38% from US$2.30/MMBtu to US$3.20/MMBtu, although this is still profitable against JKM spot LNG price of US$11.66/MMBtu as at 28 Nov 2025, and IEA's JKM spot LNG price forecast of US$8/MMBtu by 2030F.

The Kasawari CCS capex and opex costs are essentially fully borne by Petronas and the Malaysian government because Petronas cannot sell the LNG produced from sour gas with CCS at any higher price that the LNG produced from sweet gas without CCS. However, implementing CCS at Kasawari may help to avoid the issue of stranded gas reserves should LNG buyers decide in the future not to purchase LNG with high CO2 emissions.

Figure 43: S&P Global noted that the inclusion of CCS into the Kasawari project entails a significant reduction in emissions, but at a cost to both Petronas and the Malaysian government

No CCS		CCS	Difference	Difference (%)
6 Tcf	Recoverable reserves	6 Tcf	-	-
4.68 Tcf	Sales gas	4.68 Tcf	-	-
$1,800	CAPEX (millions USD – Real 2021)	$2,700	+ $900	+ 50%
$5,800	Lifecycle OPEX (millions USD – Real 2021)	$7,900	+ $2,100	+ 36%
67.1	Upstream CO_2 emissions (million tonnes CO_2e)	21.0	- 46.1	- 69%
84.9	Upstream CO_2 intensity (kg/boe)	26.6	- 58.3	- 69%
$580	PETRONAS NPV10 (millions USD)	$150	- $430	- 74%
$4,000	Government NPV10 (millions USD)	$3,200	- $800	- 20%
$2.4	Breakeven upstream gas price ($/Mcf)	$3.3	+ $0.9	+ 38%

SOURCE: S&P GLOBAL, 2023

Note: Economics undertaken at Brent of US$60/bbl, with an assumed upstream gas price of US$3.90/MMBtu

PTTEP Lang Lebah CCS project

The Lang Lebah gas field is located offshore Sarawak (block SK410B) and contains 6-7 Tcf of recoverable gas, with an average of 17% CO_2 content, according to the Journal of Petroleum Technology.

PTTEP holds a 42.5% participating interest in the Lang Lebah project, with KUFPEC Malaysia (a subsidiary of Kuwait Foreign Petroleum Exploration) holding a 42.5% interest, and the final 15% interest held by Petronas Carigali.

The Lang Lebah gas plant is to be developed as part of the Sarawak Integrated Sour Gas Evacuation System (SISGES) Development to expedite the development of untapped sour gas resources off the coast of Sarawak, according to Petronas. The gas output of the field will be treated at an onshore gas plant (OGP-2) in the Petchem Industrial Park in Tanjung Kidurong, Bintulu. The treated gas will be transferred to the Bintulu LNG Complex, while the CO_2 from the gas stream at the OGP-2 will be compressed and exported through a pipeline to an offshore wellhead platform where it will be reinjected into the depleted Golok field.

The Lang Lebah gas project was to have commenced in 2026F, but the EPCC tenders were cancelled by PTTEP in Feb 2025, with PTTEP now working to reduce costs. We think that the original first gas date of 2028F is now likely delayed.

Note on the SISGES project at the Petchem Industrial Park in Tanjung Kidurong (source: Petronas)

- The SISGES project intends to monetise more than 10 Tcf of gas discoveries with high contaminants, offshore Sarawak.
- Under the first phase, OGP-1 will receive gas from Shell's Rosmari & Marjoram (R&M) gas fields in Block SK318 (to come onstream by 2026F).
- The second phase will see gas from the Lang Lebah field flowing into OGP-2.

Figure 44: Location of Lang Lebah oil and gas field

SOURCES: GOOGLE MAPS; GLOBAL ENERGY MONITOR WIKI

Petronas BIGST CCS project

The Petronas BIGST cluster is a high-CO_2 gas field project offshore Peninsular Malaysia that will incorporate CCS. The fields are Bujang, Inas, Guling, Sepat, and Tujoh (BIGST) in Block PM313.

The PSC partners are Petronas Carigali and Eneos Xplora (previously known as JX Nippon Oil & Gas Exploration), each holding 50% interest.

Petronas expects to develop BIGST at a capex of US$2.9bn, with commercial production to begin in 2029F. The gas supply from the BIGST fields is vital to boost gas supply to Peninsular Malaysia.

According to Petronas, the development is expected to serve as a catalyst for future projects involving other high-contaminant fields in Peninsular Malaysia by establishing the necessary CO_2 handling infrastructure.

Although BIGST has an estimated recovery of c.4 Tcf, it has not been developed until now due to the high concentration of CO_2 along with gas, according to Eneos Xplora.

Figure 45: Location of BIGST oil and gas fields

SOURCE: ENEOS (PREVIOUSLY JX NIPPON)

Hibiscus PM3 CAA CCS project

The PM3 CAA PSC is located in the Malaysia-Vietnam Commercial Arrangement Area (CAA), off the coast of Malaysia and Vietnam. Hibiscus holds a **35%** participating interest in the PSC, with Petronas Carigali holding 35% and PetroVietnam Exploration Production Corp holding the remaining 30%.

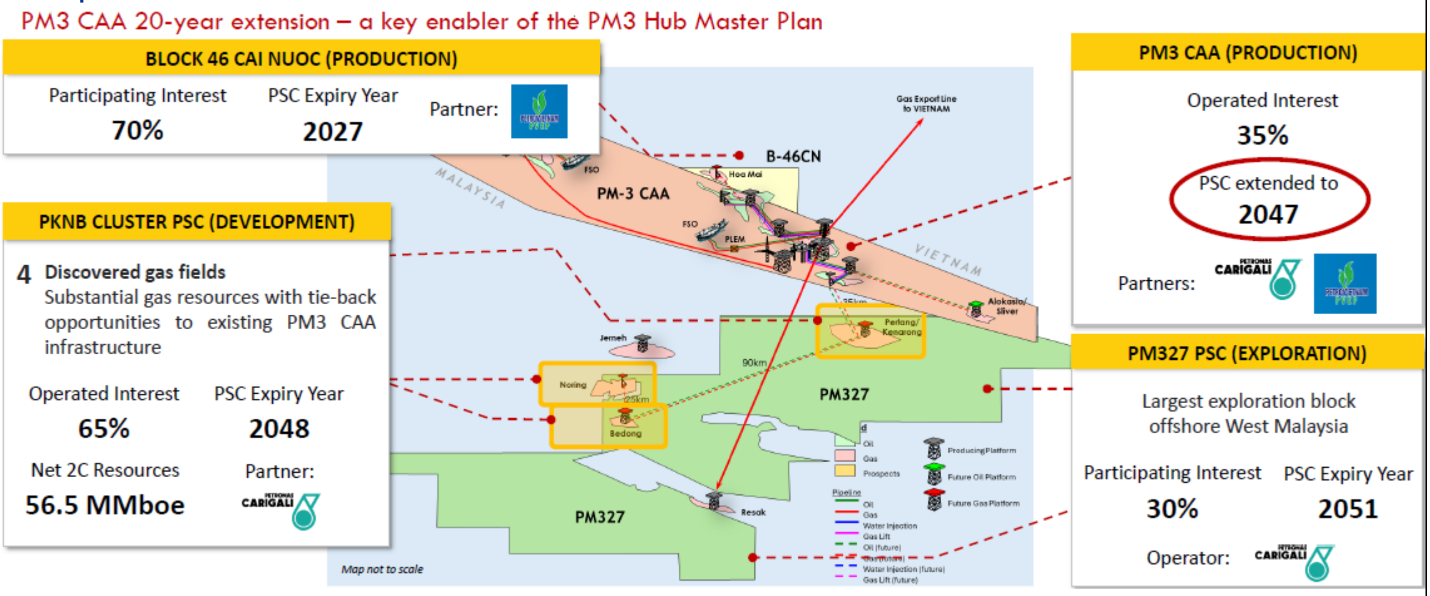
Because of the high content of contaminants in the natural gas produced at PM3 CAA, the mercury must first be removed from the gas, and the CO2 content must also be substantially reduced from 44-45% content to a maximum of 8%, as specified by the buyers of the gas. The CO2 removal is achieved through the Acid Gas Removal Unit (AGRU) which is located on one of the offshore platforms, and the CO2 is then vented into the atmosphere.

According to Hibiscus, the CCS Phase 1 project for PM3 CAA is likely to be operational in the 2028-2029F timeframe, with the CO2 to be reinjected into depleted PM3 CAA gas reservoirs for geological storage. Hibiscus estimates that CCS Phase 1 can reinject between 1.4 MtCO2e and 2.3 MtCO2 p.a.

The AGRU vented 2.8 MtCO2e into atmosphere in Hibiscus's FY6/25; this suggests that the CCS Phase 1 project could have prevented between 50% and 82% of the CO2 emissions from the AGRU if it had been implemented at the start of FY25.

CCS Phase 2 (post-FY30F) may involve a larger volume of CO2 removal of between 2.9 MtCO2e and 8.6 MtCO2e, and will be executed in conjunction with the start-up of the operations at the Pertang, Kenarong, Noring and Bedong (PKNB) Cluster and PM327 fields, which will be developed in the future via tie-back to the PM3 CAA facilities.

Figure 46: The PM3 CAA is the cornerstone of the PM3 Hub Master Plan that will incorporate the PKNB Cluster and the PM327 developments



SOURCE: HIBISCUS

Cross-border storage projects – viable business case for ASEAN?

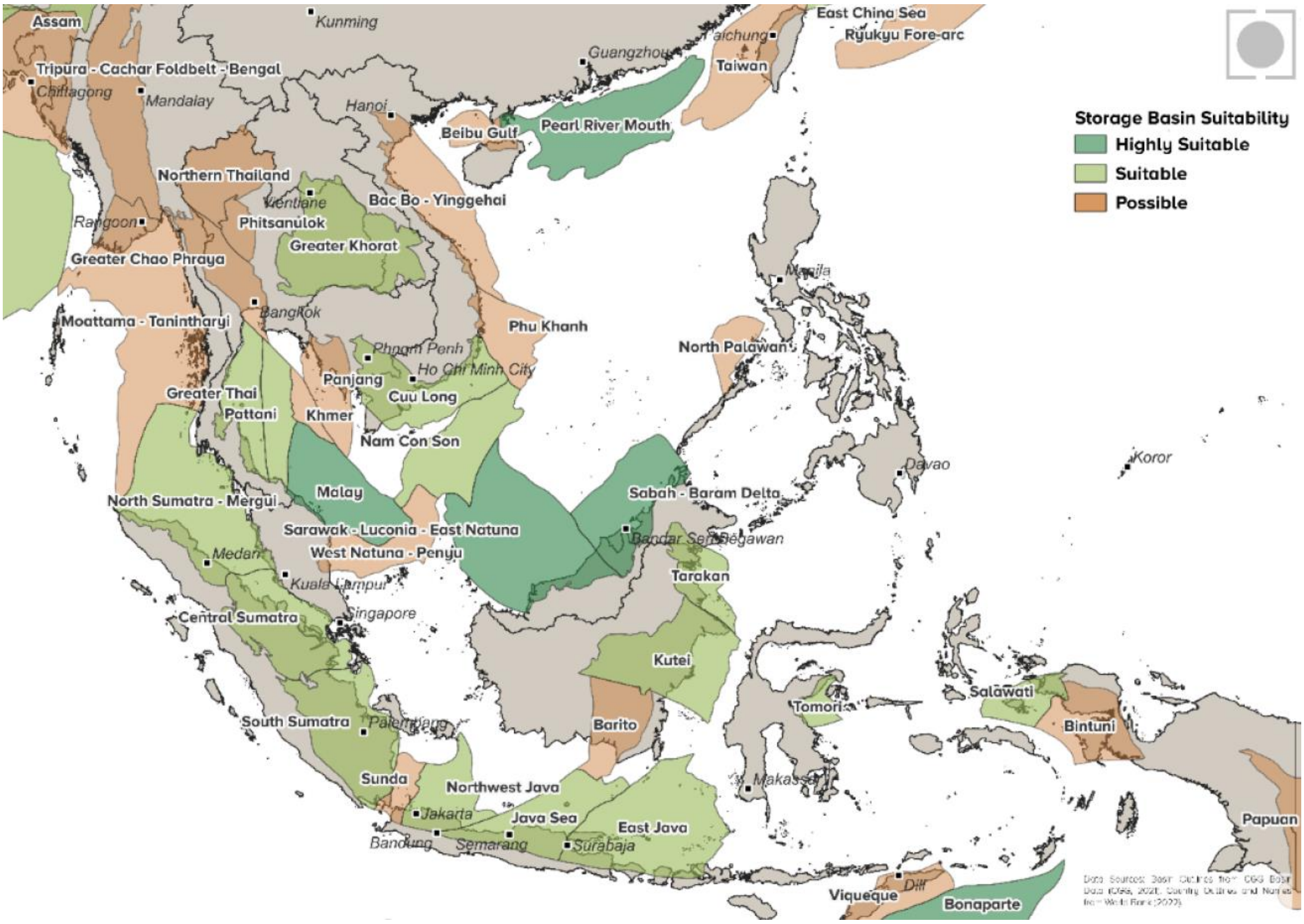
Malaysia's Petronas has signed MOUs with companies and government entities from various countries to develop Malaysia's potential to import foreign CO2 emissions for storage in depleted oil and gas fields offshore Peninsular Malaysia and Sarawak. Potential exporters of CO2 include Japan, South Korea, and Singapore. Indonesia has also signed MOUs and collaboration agreements with Japan, South Korea, and Singapore for cross-border CCS projects. Malaysia was assessed by the IEA and several other agencies to have the largest storage potential of 80 GtCO2 in SE Asia.

Figure 47: Storage estimates for countries in SE Asia

Country	Type of storage	Estimated volume	Total volume
Brunei	Oil and gas fields	0.6 Gt CO_2	0.6 Gt CO_2
Indonesia	South Sumatra Basin	7.65 Gt CO_2	8.4 Gt CO_2
	Java Basin (deep saline layers)	386 Mt CO_2	
	Tarakan Basin	130 Mt CO_2	
	Central Sumatra Basin	229 Mt CO_2	
Malaysia	Malay Basin	80 Gt CO_2	80 Gt CO_2
Philippines	Saline Aquifers	22 Gt CO_2	22.3 Gt CO_2
	Gas fields	0.3 Gt CO_2	
Thailand	Saline formation in the Greater Thai Basin and Pattani Basin	8.9 Gt CO_2	10.3 Gt CO_2
	Gas and oil fields	1.4 Gt CO_2	
Viet Nam	Deep saline reservoirs	10.4 Gt CO_2	11.8 Gt CO_2
	Depleted oil and gas fields	1.4 Gt CO_2	

SOURCES: IEA, 2021; ADB, 2013; METI, 2020; ERIA, 2021

Figure 48: Potential CO2 storage sites in SE Asia



SOURCE: GLOBAL CCS INSTITUTE, as quoted in Consoli et al., Geological Storage Potential of CO_2 in Southeast Asia

According to the IEA, most of the storage in SE Asia is expected to be in saline aquifers, but also in depleted oil and gas fields. Only a fraction of the potential storage capacity may be economically and technically viable, but the available storage capacity in SE Asia will likely still exceed storage demand multifold, according to the agency.

Developing storage capacity is time consuming, according to the IEA, because the process of characterising and assessing CO2 storage sites for suitability can be time consuming and take up to 10 years. Meanwhile, regulations need to be put in place to facilitate transport and storage of CO2, including specifying the composition of CO2 streams, legislating property rights to storage sites, legislating permits for exploration and development of storage sites, establishing ownership and liability for stored CO2 (including for long-term liability post closure of storage site), and specifying obligations for monitoring, reporting and verification, and for corrective or remedial actions in the case of leaks or other safety issues.

CO2 storage projects in Malaysia

Petronas's Malaysia Petroleum Management (MPM) division noted in Jan 2022 that an estimated 46 Tcf of potential carbon storage capacity (2.4 Gt) has been identified across 16 of Malaysia's depleted fields. Eleven of these 16 potential CCS sites are at fields offshore Sarawak while the other five are located offshore Peninsular Malaysia.

Malaysia plans to develop three CCS hubs with 15 Mtpa of storage capacity by 2030F. Another three CCS hubs to be developed by 2050F to raise cumulative storage capacity to 40-80 Mtpa, according to the Malaysia's NETR released in 2023.

Malaysia's three CCS hubs to be developed by 2030F are:

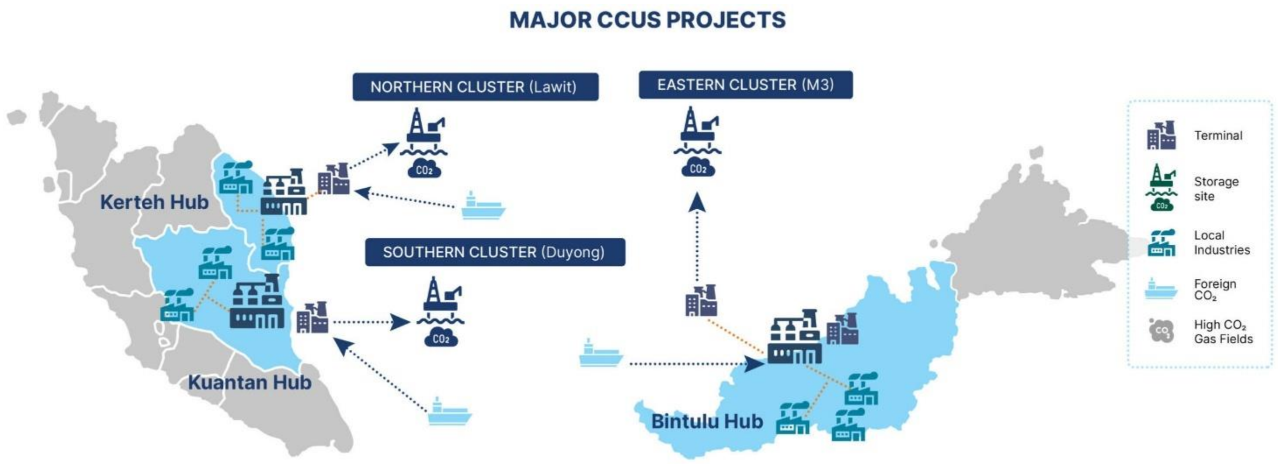
1. Northern Cluster, Peninsular Malaysia (based in Kertih) – storage at the depleted Lawit field.
2. Southern Cluster, Peninsular Malaysia (based in Kuantan) – storage at the depleted Duyong field (next to Malaysia-China Kuantan Industrial Park).
3. Eastern Cluster, Sarawak (based in Bintulu) – storage at the depleted M3 field.

The three CCS hubs are to cater for the storage of the emissions coming from non-O&G industries, including foreign CO2 from Japan transported to Malaysia via LCO2 ships. The CO2 is intended to be piped from the CO2 terminals at Kertih, Kuantan and Bintulu to the Lawit, Duyong and M3 storage sites via pipelines.

The tentative date for the first CO2 injections for Petronas CCS projects for the hard-to-abate industries is towards end-2029F or early-2030F, subjected to the readiness of the foreign clients, according to Petronas' Carbon Management Division.

Separately, the depleted M1 field, offshore Sarawak is intended for the storage of the CO2 extracted from within the Kasawari natural gas reserves, but the excess storage capacity can also be monetised to store third-party CO2, according to legal firm Norton Rose Fulbright.

Figure 49: Major CCUS storage projects in Malaysia



SOURCE: ECONOMIC MINISTRY (MALAYSIA)

Concurrently, Sarawak has stated its aim to establish four carbon storage sites by 2030F. According to an Upstream report in 2022, these include the M Cluster comprising the M1 and M3 sites (which are the first to be developed); the B Cluster (forecast to be available in early-2030F); the F Cluster (with estimated potential storage capacity of close to 11 Tcf); and Cluster 4.

In Jul 2024, Sarawak took steps to realise its goals by offering three carbon storage geographical regions with a total estimated storage capacity of 1 Gt (1bn tonnes) of CO_2 to potential developers in the Sarawak Bid Round. However, the outcome of the bid round has not been made known. According to Upstream, the three storage regions are:

1. Saline aquifers in Southwest and Western Luconia (which could be used to help exploit sour gas fields and to decarbonise industries in the Kuching area);
2. Several depleted oil and gas fields nearing the end of their life in the Balingian province; and
3. Saline aquifers and depleted fields in the Central Luconia region, near existing oil and gas infrastructure and located close to discovered sour gas fields.

Meanwhile, Petros has been appointed by the Sarawak state government as the resource manager for the state's CCUS efforts, reported the Borneo Post in Mar 2025. Petros is cooperating with Petronas to develop Sarawak's CCS storage sites. For example, in Feb 2024, Petros, Petronas, and Japanese Consortium Parties comprising Japan Petroleum Exploration Co (JAPEX), JGC Holdings Corp (JGC) and Kawasaki Kisen Kaisha (K Line) signed a Storage Site Agreement (SSA) for the M3 depleted field offshore Sarawak. The SSA is intended to facilitate the feasibility studies of the CO_2 storage sites starting with the M3 depleted field, but also the planning of relevant CO_2 storage site development, including onshore terminals and transportation pipelines, as well as assessment of its techno-commercial feasibility (source: Petronas).

In terms of the business model:

- Petronas and/or Petros will likely develop the infrastructure for CO_2 collection, buffer storage at various terminals, pipeline transportation and injection of CO_2 in offshore reservoirs.
- Petronas or Petros can earn revenues by charging tariffs to foreign emitters for the services provided to store their exported CO_2, as well as charging domestic polluters to store CO_2 when there is sufficiently-high carbon tax regime in Malaysia in the future.

Apart from potential Japanese storage customers, the SE Asian CO_2 storage sites may also be used to store emissions from **Singapore**. In Mar 2024, Singapore's Economic Development Board (EDB) announced that it "will work with a Carbon Capture and Storage (CCS) Lead Developer (i.e. S Hub, a consortium comprising Shell and ExxonMobil) to study the viability of developing a cross-border CCS project from Singapore. This includes evaluating the technical feasibility of aggregating CO_2 emissions in Singapore, and collaborating with international partners to study potential CO_2 storage sites." EDB aims to commence the cross-border CCS project by 2030F.

Other CCS storage and transport collaboration projects in Malaysia

Source: Consultant, Environmental Resources Management (ERM); Petronas

Petronas-POSCO MOU (2021)

Petronas signed a MOU with POSCO International Corporation and POSCO Engineering & Construction to jointly explore opportunities in CCS technologies as well as CO2 storage solutions in Malaysia.

Petros-POSCO MOU (2022)

CO2 generated from steel mills in South Korea, and CO2 captured from blue hydrogen production may be transported to Sarawak for geological storage in depleted gas fields.

Petronas MOU with six South Korean companies (2022)

This MOU is to undertake conceptual and feasibility studies towards CO2 capture, transport from South Korea, and storage at block SK427, offshore Sarawak. The six companies are Samsung Engineering, Samsung Heavy Industries, SK Earthon, SK Energy, GS Energy Corporation and Lotte Chemical Corp.

Petronas-Sarawak Shell (2022)

Petronas signed a Joint Study and Collaboration Agreement (JSCA) with Sarawak Shell to explore CCS solutions in Sarawak and region. This includes exploring the provision of decarbonisation service to Shell's local and cross-border facilities, as well as to other potential regional customers.

Petronas-ExxonMobil Malaysia (2023)

Petronas signed two Project Development Agreements with ExxonMobil Exploration and Production Malaysia to jointly pursue CCS activation projects in Malaysia.

Petronas-TotalEnergies-Mitsui (2023)

Petronas signed Development Agreement with TotalEnergies Carbon Neutrality Ventures (TotalEnergies) and Mitsui & Co Ltd to jointly pursue a CCS project in Malaysia. This includes evaluating maturing depleted field and saline aquifers for storage, identifying potential customers, and establishing the necessary commercial and legal frameworks. This is for CO2 storage for industrial emitters in the Asia Pacific region.

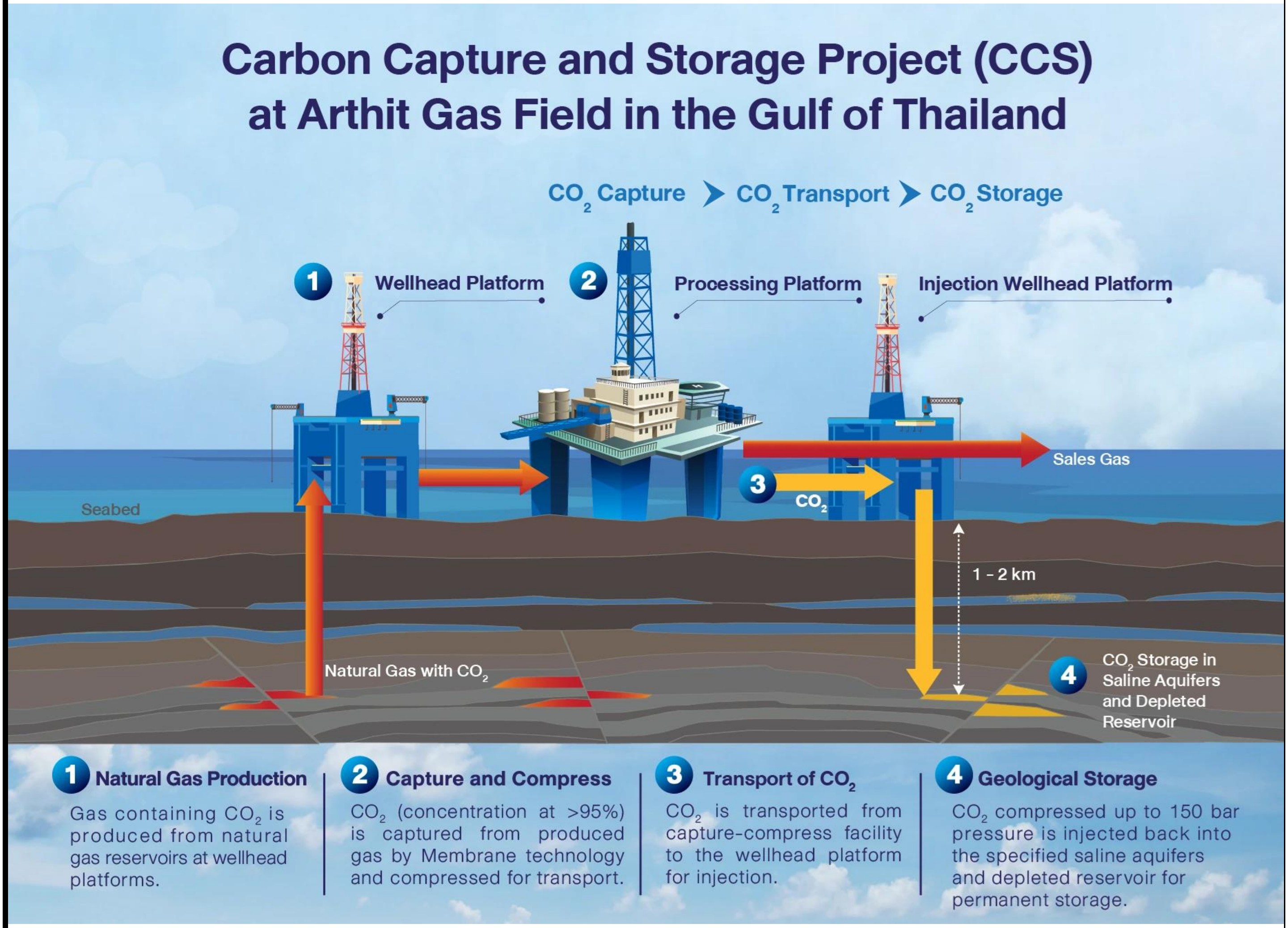
Petronas-MISC-MOL (2025)

Petronas CCS Ventures, MISC and MOL incorporated the Jules Nautica Sdn Bhd joint venture company, to lead the development and act as the ultimate owner of LCO2 carriers. The JV is currently developing a 62,000 cbm 'Low Pressure Low Temperature' LCO2 carrier.

PTTEP Arthit CCUS project

PTTEP initiated Thailand's first CCS project study in 2021 at Arthit field, an offshore gas exploration field in the Gulf of Thailand operated by PTTEP. The raw natural gas from Arthit has 32% CO2 content. PTTEP intends to take FID on the CCS project in 2025F and to operationalise the project by 2028F. PTTEP expects the Arthit CCS project to entail capex of US$300m over five years, and to reduce the field's CO2 emission by c.0.7 – 1 Mtpa.

Figure 50: PTTEP Arthit CCUS project



SOURCE: GLOBAL CCS INSTITUTE, 2025

CO2 storage projects in Thailand

Separately, in Dec 2023, PTTEP signed an agreement to conduct a joint study on the carbon storage potential in the Northern Gulf of Thailand with Japan Organization for Metals and Energy Security (JOGMEC) and Inpex Corp. It will outline Thailand's CCS development plan in the Gulf of Thailand and support the reduction of industrial carbon emissions from the Eastern Economic Corridor (EEC).

According to a report written by CGSI Thai O&G analyst Amornrat on 11 Jul 2025, "PTT group's ambition is to build a CCS hub near the eastern seaboard of Thailand where various industrial plants, including refineries and chemical complexes under PTT management are located. The transportation of CO2 will be via pipeline, primarily connecting Thai Oil's refinery and power plants in Sri Racha, Global Power Synergy Pcl's (GPSC) power plants in the eastern region and PTTGC/IRPC refineries/chemical plants in Map Ta Phut. Then CO2 captured could be injected in the northern part of the Gulf of Thailand which is adjacent to the current petroleum area. The initial phase of the project should reach c.6 Mtpa of CO2. PTT group estimates commercial commencement by 2034F."

"In the longer term, PTT and PTTEP plan to expand CCS service to regional markets, such as South Korea and Japan. Another potential storage site is at the south of Pattani basin (the existing petroleum field in the Gulf of Thailand), which is not likely to be used for domestic decarbonisation activity."

CCUS projects in Indonesia

Upstream reported in Apr 2023 that there were "15 CCS/CCUS projects in Indonesia that are in the study and preparatory stages, most of which are expected to start up by 2030F."

The 15 projects are as follows:

1. **Jatibarang field sour gas development and EOR**

   The Jatibarang oil field is located onshore West Java and is operated by Indonesia's NOC, Pertamina, which also operates the onshore Subang gas field in West Java. The CO2 captured from the Subang gas field is transported and injected into the Jatibarang oil field for EOR purposes; the first CO2 injection took place in Oct 2022, according to Upstream, and also represented Indonesia's first ever CO2-EOR project.

2. **Tangguh Ubadari sour gas development and EGR**

   BP and its Tangguh LNG JV partners are planning a CCS facility at the Tangguh LNG plant in West Papua, Indonesia. The project is formally known as the Tangguh Ubadari CCUS and Compression (UCC) project, and FID was taken in Nov 2024 with a capex estimate of US$7bn. First gas from the associated Ubadari field will be produced from 2028F, according to BP. The CO2 separated from the Ubadari natural at the new onshore processing and compression facilities will be transported via a new offshore pipeline and injected into the Vorwata reservoirs for EGR purposes. The project is expected to unlock an additional 3 Tcf of natural gas resources and aims to sequester c.15 Mt of CO2 in its initial phase (annual injection rate of 3 Mtpa), with a total potential for up to 30 Mt by 2035F, according to BP.

3. **Sakakemang sour gas development and geological storage**

   Repsol and its partners Petronas and Mitsui are developing the onshore natural gas reserves in Sakakemang Block located in South Sumatera, Indonesia, that have 26% CO2 content. The CCS component of the project is intended to inject 1.5-2 Mtpa of CO2 into the depleted Dayung and Gelam fields, with a projected cumulative storage of about 30 Mt over 15 years, according to GCCSI. First gas was originally targeted for 2028F, but this is under review given that the gas reserves were downgraded after disappointing appraisal results, according to Upstream.

4. **Gundih sour gas development and EGR/geological storage**

The Gundih onshore gas field is located in Central Java, Indonesia. Pertamina aims to capture the 20-23% CO_2 content from the raw natural gas from the Gundih field, and inject it into proximate depleted reservoirs for permanent sequestration. However, Norton Rose Fulbright noted that the project was also intended for EGR purposes. The pilot phase of the CCS project aims to inject 10 ktpa of CO_2 for two years, out of the 288 ktpa of CO_2 emissions from the gas processing plant. The IEA noted in 2023 that the CCS project was supposed to be operationalised in 2026F, however, we have no updates about the timeline.

5. **Gemah field sour gas development and EOR**

   The Gemah field EOR project is located in the South Sumatra Basin, offshore Indonesia. Partners PetroChina International Jabung, PT Pertamina Hulu Energi Jabung and Petronas Carigali (Jabung) are working to use the CO_2 separated from natural gas production in the Gemah field for reinjection into oil wells for EOR purposes. A preliminary field trial was conducted in Dec 2022. GCCSI reported in Oct 2025 that this project may be operational in 2028F.

6. **Ramba field sour gas development and EOR**

   The Ramba field EOR project is located in the South Sumatra Basin, offshore Indonesia. The project is operated by Pertamina. In its Oct 2025 report, GCCSI characterised this project as being in "early development".

7. **Sukowati CO2 capture for EGR**

   Pertamina plans to inject and store 1.4 Mtpa of CO_2 into the Sukowati oil field in West Java, Indonesia for EOR by 2028F, according to GCCSI. Initial pilot tests have been done in 2023 and 2024. When operationalised, the CO_2 may be transported from the nearby Jambaran-Tiung-Biru (JTB) gas field to the Sukowati oil field, according to data provider Argus Media.

8. **Abadi LNG CCS**

   The Abadi LNG project is situated on the remote Masela PSC near Indonesia's maritime boundary with Australia, with onshore liquefaction facilities planned for the remote Tanimbar Islands. The project is led by Japan's Inpex, with Pertamina and Petronas as its partners. The project's targeted start-up date has been pushed beyond 2030F, according to GCCSI. The CCS project aims to capture CO_2 produced and reinjecting the CO_2 into permanent storage. Inpex expects this to be the first LNG project in Indonesia where CCS-related costs are eligible for recovery under the PSC framework.

9. **Central Sumatra Basin CCS hub**

   Also known as the Asri Basin Project CCS hub, the partnership between ExxonMobil and Pertamina is working to develop this geologic storage potential of up to 3 Gt of CO_2. According to an Indonesia Business Post article in May 2024, FID is expected by 2026F with operations potentially starting around 2027-2030F. GCCSI noted that this project involves capturing CO_2 from industrial sources, both domestic and international, and storing it permanently offshore in the Sunda-Asri Basin in the Java Sea.

10. **Sunda Asri Basin CCS hub**

    This appears to be a separate CCS hub project in West Java, but we have not been able to find any publicly-available details. GCCSI noted that this project was under evaluation and may come online in 2029F.

11. **Arun CCS hub**

    The Arun CCS project is located in Aceh, North Sumatra. It is designed to be an open-access regional CO_2 storage hub, and is being developed by a JV called Pema Aceh Carbon (PAC), involving the Indonesian company PT Pembangunan Aceh Perseroda (PEMA) and Carbon Aceh, with participation from PT Energi Mega Persada (EMP) and its subsidiary PT Pema Global Energi (PGE), reported Upstream in Nov 2022. The Arun field is largely depleted, and can store over 1 Gt of CO_2, making it one of the largest CO_2 storage sites globally. The storage capacity can be used to develop proximate high-CO_2 gas reserves, or for the storage of imported foreign CO_2. Upstream reported in Nov 2022 that the feasibility study was targeted for completion in mid-2025, and the project was expected to be operational by 2029F. However, in its Oct 2025 report, GCCSI characterised this project as being in "early development".

12. Kutai Basin CCS hub

The Kutai Basin CCS hub is a proposed commercial CCS initiative in East Kalimantan, Indonesia. Pertamina, Eni and Petronas may be involved in planning for the CCS hub, which may have a potential storage capacity of c.270 Mt of CO2 within the basin's geological formations, including depleted reservoirs and deep saline aquifers, according to the Indonesia Business Post.

13. East Kalimantan CCS hub

Pertamina is in the early stages of exploring the development of the East Kalimantan CCS hub, which may be used to store captured CO2 emissions from a variety of nearby industrial sources, including the Pertamina RU V Balikpapan refinery, gas processing plants, and potentially emissions from other countries, to store them permanently in depleted reservoirs and saline aquifers, according to environmental website Reccessary.

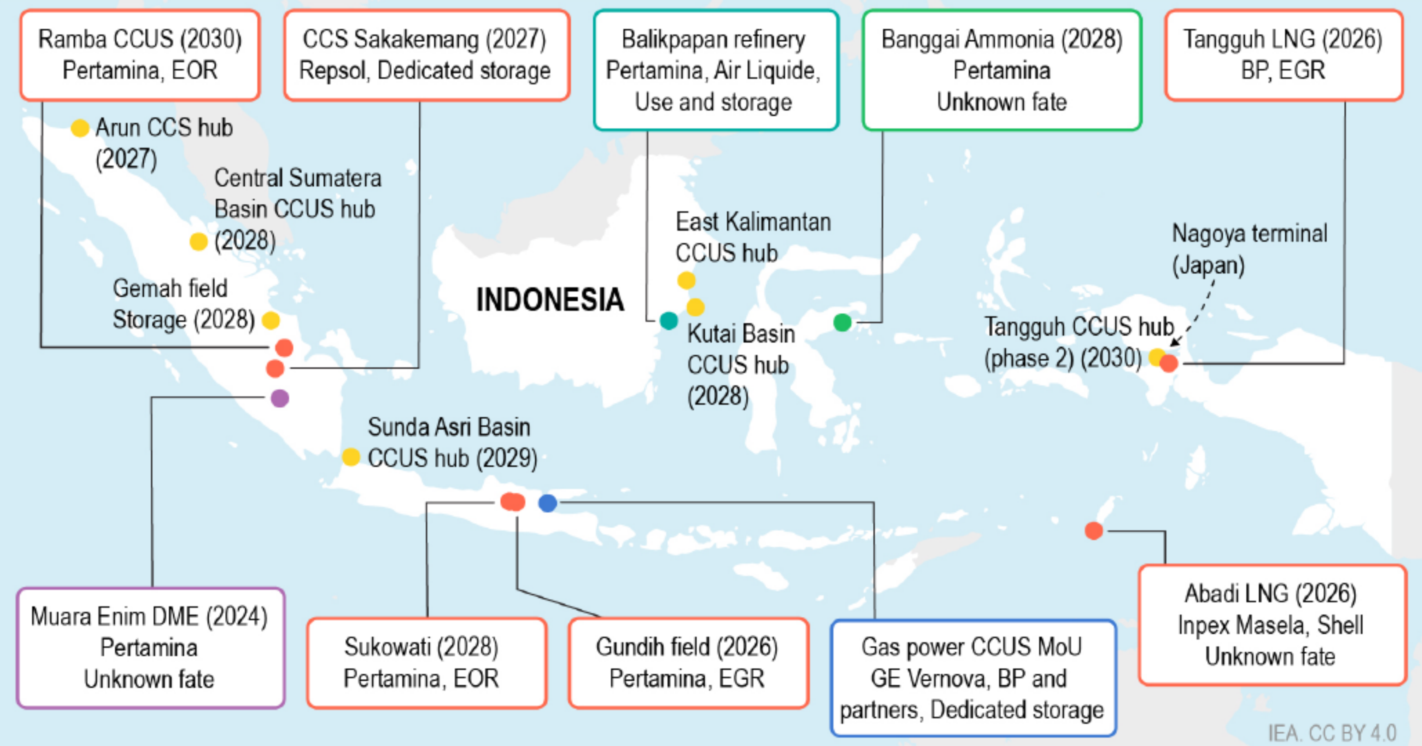
14. PAU Central Sulawesi Clean Fuel Ammonia

PT Panca Amara Utama (PAU) is actively working to add a carbon sequestration unit to its existing ammonia plant. The goal is to capture c.69% of total CO2 emissions, targeting operation around end-2027F. PAU's ammonia plant produces 700 ktpa of ammonia, which is made via natural gas reforming, according to GCCSI.

15. RU V Balikpapan CCU and methanol production

The Pertamina Refinery Unit (RU) V in Balikpapan, East Kalimantan, Indonesia is conducting a study to incorporate carbon capture into the refinery, with the captured CO2 to be potentially utilised for conversion into products like methanol, according to GCCSI.

Figure 51: Various capture projects and dedicated CO2 storage hubs in development (IEA, 2023)



SOURCE: IEA, 2023

CCUS project in Timor-Leste

There is one CCS project in Timor-Leste, which is the **Santos Bayu-Undan CCS** project.

Australia's Santos plans to convert the depleted Bayu-Undan gas field in the Timor Sea into a large-scale CCS hub, to store CO2 captured from the Darwin LNG facility in Australia, as well as the CO2 from Santos' new Barossa gas field which has 18% CO2 content. The project has the potential to store up to 10 Mtpa of CO2 and has an estimated total storage capacity exceeding 250 Mt, according to Santos.

The Darwin LNG facility historically obtained its natural gas supplies via a 500km pipeline from the Bayu-Undan gas field, but with the depletion of the Bayu-Undan gas field, Darwin LNG now secures its natural gas supplies from the offshore Barossa gas field, located northeast of Darwin. Moving forward, the 500km pipeline will be repurposed to transport CO2 from Darwin LNG to Bayu-Undan for permanent sequestration. GCCSI noted that the Bayu-Undan CCS project is targeted for commercialisation in 2028F.

CCUS developments in Singapore

In Mar 2024, Singapore's Economic Development Board (EDB) announced that it "will work with a Carbon Capture and Storage (CCS) Lead Developer (i.e. S Hub, a consortium comprising Shell and ExxonMobil) to study the viability of developing a cross-border CCS project from Singapore. This includes evaluating the technical feasibility of aggregating CO2 emissions in Singapore, and collaborating with international partners to study potential CO2 storage sites." EDB aims to commence the cross-border CCS project by 2030F.

In Jul 2025, Singapore's energy regulator, the Energy Market Authority (EMA) announced that three power-generation companies – Keppel Corp, PacificLight Power (PLP), and YTL PowerSeraya (part of the YTL Power group) – will conduct a total of five CCS feasibility studies covering both pre-combustion and post-combustion capture technologies. Each study will receive S$350,000 in research grants from the EMA, with the studies expected to be completed by end-Jan 2026F, according to environmental website Reccessary.

Brief list of ASEAN CCUS projects

Source: GCCSI, 2025

Malaysia

Storage projects – advanced development

Northern Offshore Peninsular Malaysia CCS (2030F)

Southern Offshore Peninsular Malaysia CCS (2030F)

Malaysia Sarawak Offshore CCS (2030F)

Gas processing – advanced development

Petronas Kasawari (2026F)

PTTEP Lang Lebah (timing uncertain)

Thailand

Storage projects – early development

PTTEP Northern Gulf of Thailand (timing uncertain)

Gas processing – advanced development

PTTEP Arthit (2028F)

Timor-Leste

Gas processing – advanced development

Santos Bayu-Undan (2028F)

Vietnam

Power plants – early development (timing uncertain)

Song Hau 1 Thermal Power Plant

Thai Binh 2 Thermal Power Plant

Vung Ang 1 Thermal Power Plant

Indonesia

Storage/EOR projects – advanced development

Gemah field EOR (2028F)

Storage projects – early development (timing uncertain)

Ramba CCUS

Carbone Aceh Arun Hub

Sunda Asri Basin CCUS hub

Central Sumatera Basin CCS hub

BP Nagoya port cluster

ExxonMobil Indonesia Regional Storage Hub

Gas processing – advanced development

BP Tangguh LNG (2028F)

Abadi CCS (after 2030F)

Repsol Sakakemang (2028F)

Power plants – early development (timing uncertain)

Indramayu CCS (coal)

Tambak Lorok CCS (gas)

Chemical plants – early development (timing uncertain)

Tanjung Enim CCS

Marubeni South Sumatera

Offshore oil and gas – early development (timing uncertain)

West Java Sea – rig to CCS

Oil extraction – early development (timing uncertain)

Pertamina Sukowati

Ammonia – early development (timing uncertain)

PAU Central Sulawesi Clean Fuel Ammonia

Gas processing – early development (timing uncertain)

Pertamina Jatibarang

(L) CCUS DEVELOPMENTS IN AUSTRALIA AND NEW ZEALAND (ANZ)

Three CCUS projects in ANZ

There are currently three CCUS projects operating in ANZ:

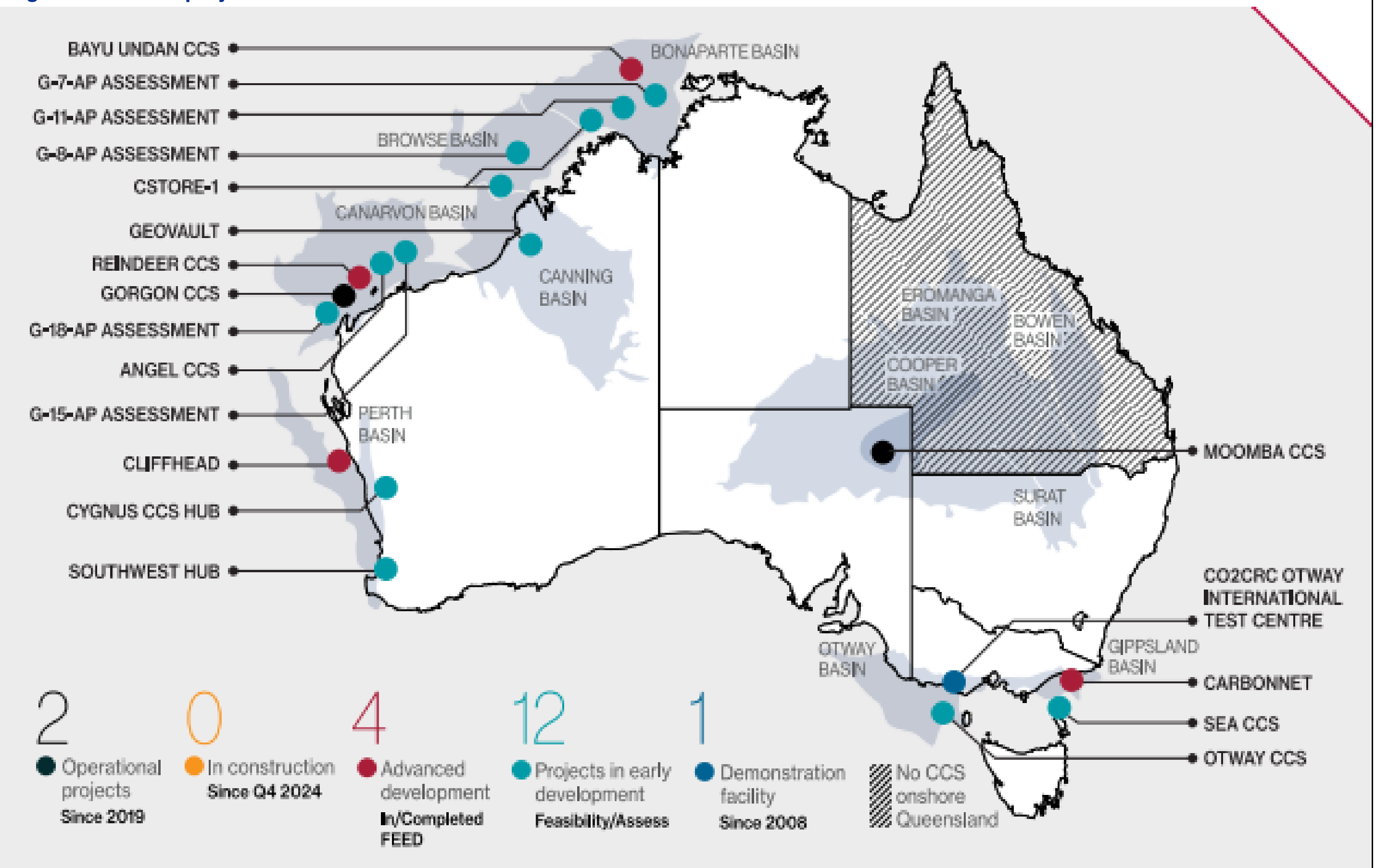
1. Gorgon, Australia – led by Chevron – 4 Mtpa CO2 capture capacity.
2. Moomba, Australia – led by Santos – 1.7 Mtpa CO2 capture capacity in Phase 1.
3. Ngawha Geothermal Power Station, New Zealand – 0.12 Mtpa CO2 capture capacity.

Under Australia's Safeguard Mechanism:

- Companies that emit more than 100,000 tCO2e p.a. must reduce their emissions below their baseline by 4.9% p.a. between 2023 and 2030F.
- Emissions reduction rates beyond 2030F have not been announced by the Australian government.
- The mechanism is designed to help Australia meet its national emissions reduction targets of 43% below 2005 levels by 2030F and net zero by 2050F.

In Aug 2025, Royal Vopak signed an MOU with the Northern Territories government in Australia to build a CO2 import terminal and common-user facility in Darwin, with the aim to begin operations in 2030F.

Figure 52: CCUS projects in Australia and New Zealand



SOURCE: CO2CRC

Chevron's Gorgon CCS project

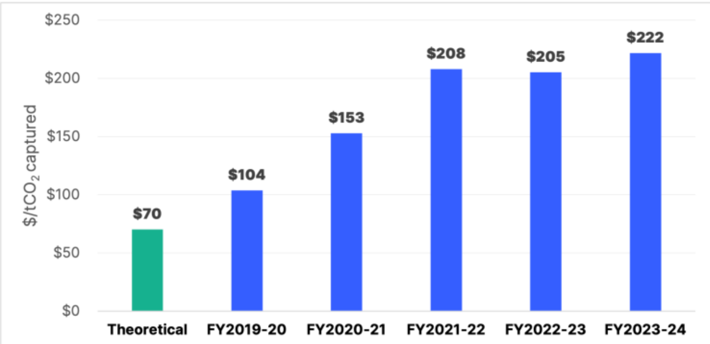
Gorgon, Australia is a gas and LNG project offshore Western Australia. It is led by Chevron (47.3% share), with partners ExxonMobil (25%) and Shell (25%). Natural gas has been liquefied at an LNG plant on Barrow Island since 2016.

The Gorgon natural gas has an average 14% CO2 content, and the project's regulatory approval by the Western Australian government was conditional on the Chevron ensuring that 80% (on a five-year rolling average basis from Jul 2016) of the embedded CO2 is captured and injected for permanent sequestration, according to The Guardian. The CCS project was designed with a capture capacity of 4 Mtpa from the raw natural gas stream (comprising 40% of total facility emissions). The captured CO2 is transported via a 7km pipeline to be injected more than 2km below Barrow Island, offshore Western Australia, into a deep sandstone formation.

Unfortunately, the CCS commenced only in 2019 after delays. Capture rates have also underperformed expectations, according to an IEEFA report in Nov 2024. Consequently, Chevron has had to purchase 10m carbon offsets to compensate for the shortfall. Technical issues resulted in low injection rates, including sand clogging of wells, excessive reservoir pressure in the injection zone, and water-block in the injection wells due to premature condensation. To control pressure, the system must extract water from the reservoir, but this process has been unreliable.

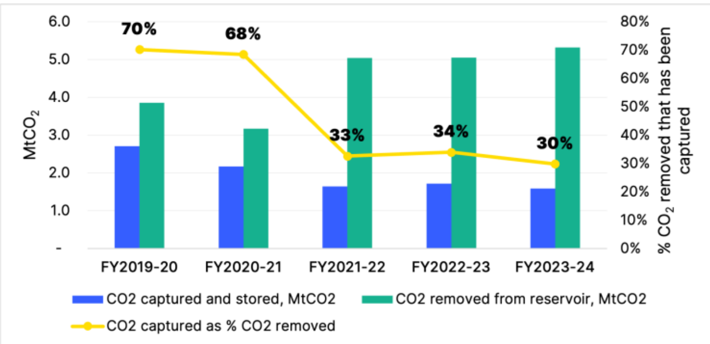
According to IEEFA, the Gorgon CCS project capex cost increased from the US$2.5bn estimated in 2020 to US$3.2bn and may rise further; by comparison, the overall LNG facility capex was c.US$54bn. The cost of CO2 captured for the project increased from an initially estimated US$70/tCO2 to more than US$200/tCO2.

Figure 53: Average cost of CO2 capture (US$/tCO2) from Gorgon CCS project



SOURCE: IEEFA, 2024

Figure 54: Proportion of CO2 captured and stored from Gorgon CCS project



SOURCE: IEEFA, 2024

Assumptions: Theoretical cost is calculated based on initial project costs of US$2.5bn and annual capture rate of 4 MtCO2, excluding US$60m grant received from Australian government, and excluding Chevron's cost of purchasing carbon offsets.

Santos' Moomba CCS project

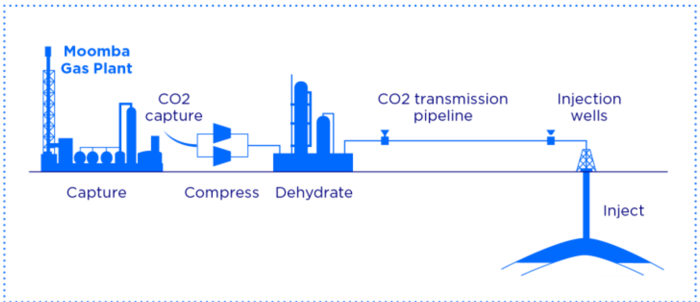
Moomba, Australia is an onshore gas field in South Australia's Cooper Basin. The project is led by Santos at 66.7%, with Beach Energy holding 33.3% interest. FID was taken in 2021. The natural gas stream has up to 30% CO2 content.

The onshore CCS project commenced in Oct 2024 with a 1.7 Mtpa CO2 capture rate in Phase 1, with the total CCS project cost at US$250m.

The Moomba CCS process consists of four main stages. The CO2 is first captured at the Moomba Gas Plant via Acid Gas Removal Units (AGRU) and fed into the main CO2 processing facility where water is removed. The CO2 is compressed into liquid, and then transported 50km via a pipeline to a storage site. CO2 is safely and permanently stored in depleted onshore hydrocarbon reservoirs (the Strzelecki-Marabooka depleted gas reservoir 1.8km below the surface). Excess storage capacity can be monetised in the future by storing third-party CO2.

Santos claims that the lifecycle cost is below US$30/tCO2 captured, one of the lowest-cost CCS projects globally. The captured CO2 creates Australian Carbon Credit Units (ACCU) for 25 years; ACCUs traded at US$23/tCO2 in Jul 2025 (A$35), there by adequately funding the cost of the CCS project.

Figure 55: Moomba CCS project schematic



SOURCE: SANTOS

Figure 56: Moomba CCS project location onshore Southern Australia and Queensland

SOURCE: SANTOS

(M) SHIPPING OF CO_2

Recent shipping developments

A joint study by the Global Centre for Maritime Decarbonisation (GCMD) and Boston Consulting Group (BCG) released in Dec 2024 highlighted the following:

- Approximately 100 Mtpa of captured CO_2 may be transported across national borders in Asia-Pacific by 2050F.
- Transporting this annual tonnage would require 85-150 liquefied CO_2 (LCO_2) carriers of 50,000 cbm each.
- Total investments needed for these vessels by 2050F could be US$10bn-25bn.

The same report also noted that shipping tends to be more economical than pipelines for:

- Distances of **more than 500 km**; and/or
- Transporting volumes of **less than 5 Mtpa** of CO_2.

Conversely, pipeline CO_2 transportation is more economical than shipping for moving CO_2 over shorter distances and/or in larger volumes.

The emerging cross-border CCUS hubs and routes that are aligned with this criteria for CO_2 shipping include:

- The Northern Lights project, which spans 500 to 1,000 km;
- Intra-SE Asia routes ranging from 450 to 970 km; and
- NE Asia to Australia, which extends from 6,000 to 11,000 km.

GCMD/BCG noted that the average levelised cost of shipping per project for the NE Asia to SE Asia route is **US$25-50/t$CO_2$**, with this shipping route requiring 1-3 LCO_2 vessels of 30,000-50,000 cbm operating 270-340 days p.a.

The investment required to scale up cross-border CCUS, including shipbuilding, port and terminal infrastructure development, is substantial. The end-to-end levelised cost of cross-border CCUS with shipping ranges from

- $141-$174/tCO_2 for intra-SE Asia routes; and
- $167-$287/tCO_2 for NE Asia-Australia routes, according to GCMD/BCG.

There is currently no CCS-linked CO_2 being shipped in Asia for geological storage. In Europe, however, the **Northern Lights project** has been operating since 2024, with the first CO_2 shipment from the Heidelberg Materials (Brevik) cement plant arriving at the Northern Lights terminal in Jun 2025, followed by the first successful CO_2 injection into the North Sea reservoir in Aug 2025.

The Northern Lights project has contracted four **7,500 cbm LCO_2 vessels** in total from Dalian Shipbuilding Offshore Co (DSOC). Since 2024, K Line has managed two LCO_2 carriers for the Northern Lights JV, i.e. the 7,500 cbm Northern Pioneer and the 7,500 cbm Northern Pathfinder. K Line will also manage the 7,500 cbm Northern Phoenix when delivered in 2025F. A fourth 7,500 cbm LCO_2 carrier will be owned by German shipowner Bernhard Schulte.

Figure 57: The Northern Pathfinder 7,500 cbm LCO2

SOURCE: LNG PRIME

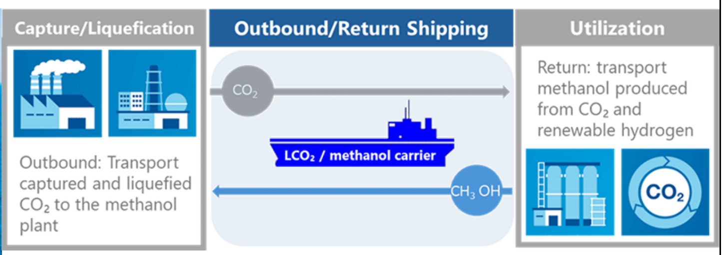
Shipyards in South Korea and Japan are working on designs for much larger LCO2 ships, up to 70,000 cbm.

- HD Hyundai Heavy Industries (HHI) and the Korea Shipbuilding & Offshore Engineering (KSOE) group have received classification society approval-in-principle for designs of 30,000 cbm, 40,000 cbm, and 74,000 cbm vessels, with the latter currently the largest capacity concept in development, according to Offshore Energy.
- HD Hyundai Mipo Dockyard is building four 22,000 cbm LCO2 carriers for Greece-based Capital Gas Ship Management, the first of which was launched in April 2025 and is currently the largest built vessel of its kind. These vessels are also capable of transporting LPG and ammonia, according to shipping website Splash247.com.
- MOL and Mitsubishi Shipbuilding have jointly developed a 50,000 cbm LCO2 carrier design for long-distance transport, which has received approval-in-principle from ship classification societies DNV and ABS, according to shipping website LNGPrime.
- In Jun 2025, MOL and Mitsubishi Shipping received approval from the ship classification society, ClassNK, to develop the world's first low-pressure LCO2 and methanol combined carrier, according to MOL. This vessel will carry captured CO2 to a synthetic methanol plant on the first leg of its journey. Then carry methanol on its second leg, thereby avoiding ballast return trip and improving the economics of the shipping operations.

Figure 58: HD Hyundai Heavy Industries' 22,000 cbm LCO2 carrier, built for Capital Gas Ship Management

SOURCE: HHI

Figure 59: MOL/Mitsubishi Shipbuilding's LCO2 and methanol combined carrier



SOURCE: GLOBAL CCS INSTITUTE, 2025

The London Protocol

The London Protocol was enacted in 1996 under the United Nations' International Maritime Organization (IMO) to prohibit disposal of waste at sea. Currently, CO2 is characterised as waste under the London Protocol.

The Protocol was amended in 2009 to enable safe and secure *sequestration* of CO2 in geological formations under the seabed, but only if the CO2 streams consist overwhelmingly of CO2, and no waste or other matter have been added.

However, restrictions remain regarding the *export* of CO2 for offshore storage. An amendment to allow export of CO2 for offshore storage has yet to enter into force because it lacks the necessary ratification by two-thirds of IMO members.

An interim resolution was adopted in Oct 2019 which allows for export where:

- A country declares provisional application of the 2009 amendment to the IMO; and
- Bilateral agreements between CO2 exporting countries and CO2 importing countries are lodged with the IMO.

Malaysia is not a signatory to the London Protocol and has not ratified the 2009 amendment. According to the NETR and Norton Rose Fulbright, to facilitate importation of foreign CO2 for storage:

- Malaysia's CCUS laws must include provisions equivalent to those in the London Protocol's 2009 amendment and its associated guidance, particularly regarding permits and environmental protection.
- To facilitate cross-border CO2 exports from Japan and South Korea to Malaysia, Malaysia will need to enter into bilateral agreements with the CO2 exporting countries. The agreement must confirm that the project will be managed in a way that meets the environmental protection standards of the London Protocol, including requirements for risk assessment and environmental impact.

Figure 60: Cross-border maritime CO_2 transport under the 2009 Amendment and 2019 Resolution for Provisional Application of the London Protocol

		LP status of country receiving CO_2 for storage:	
		Contracting party	**Non-contracting party**
LP status of country capturing CO_2 for export:	**Contracting party**	CPs must establish agreements or arrangements, depositing formal declarations to the IMO detailing compliance with environmental conditions related to the composition of CO_2 streams, and CO_2 storage	Exporting CP must ensure that control conditions and permits as applicable to CPs. CP must ensure agreements or arrangements are maintained by the receiving country
	Non-contracting party	Receiving CP must ensure that exporting country demonstrates appropriate consideration of incidental associated substances in CO_2 stream, and treatment if needed. CP must ensure agreements or arrangements are maintained by the exporting country.	Not governed by the LP; may be subject to UNCLOS

SOURCE: IEA, 2021

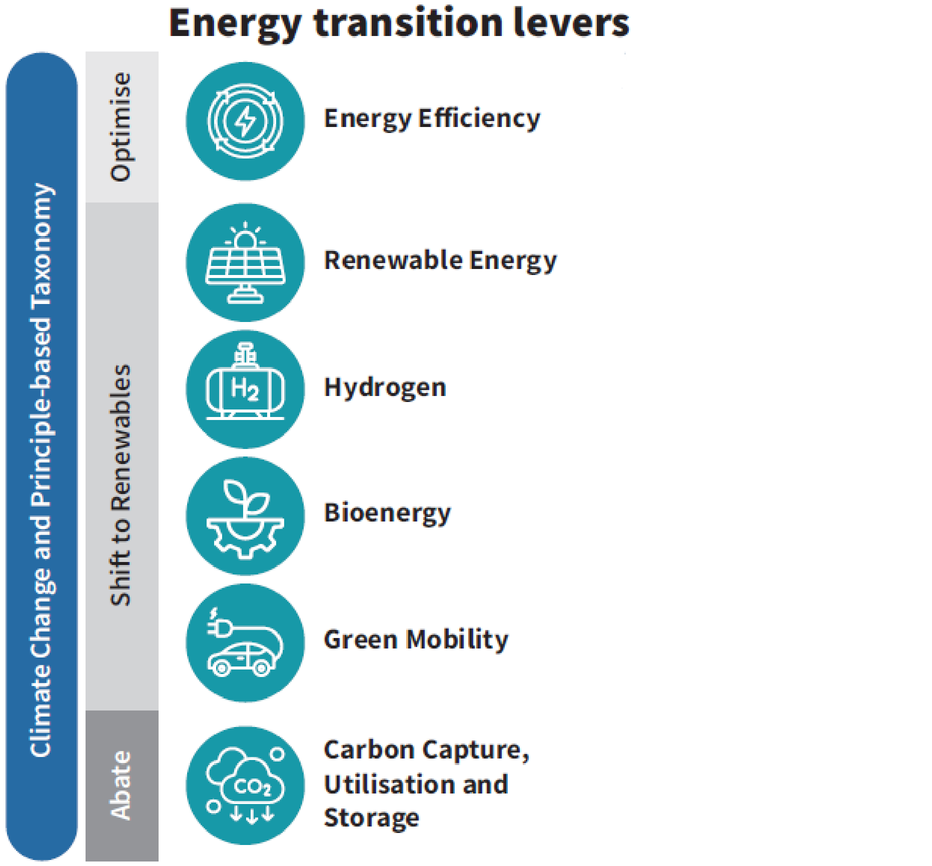
(N) POLICY AND REGULATORY DEVELOPMENTS IN MALAYSIA

Four policy documents

Malaysia has four policy documents which touch on the implementation of CCUS as a means of achieving Malaysia's environmental goals and energy transition. In terms of environmental goals, Malaysia aims to achieve net-zero emissions by 2050F, reduce GHG emission intensity against GDP by 45% by 2030F vs 2005.

1) **12th Malaysia Plan (2021 to 2025) – issued Sep 2021**
   - Outlines vision of a low-carbon Malaysia by 2040.
   - Promotes instruments such as carbon pricing to attract investment in green technologies, including CCUS.
2) **National Energy Policy (NEP) 2022-2040 – issued Sep 2022**
   - Recognises CCUS as a means for EOR and for the development of sour gas fields (with high CO2 content) to achieve sustainable energy production.
3) **New Industrial Master Plan (NIMP) 2030 – issued Sep 2023**
   - Promotes CCUS as solution for carbon abatement, particularly for the hard-to-abate sectors.
   - CCUS regarded as a new economic growth sector.
4) **National Energy Transition Roadmap (NETR) – issued Aug 2023**
   - Identifies CCUS as one of six critical energy transition levers.
   - Key initiatives include to:
     a) Develop a CCUS regulatory framework.
     b) Establish carbon pricing to drive adoption of CCUS among stationary emitters.
     c) Establish fiscal incentives for CCUS adoption for emitters, including public catalytic funds, tax credits, and CCfD.
     d) Facilitate CCUS hub infrastructure development via collaboration with financiers and investors.
     e) Establish transboundary CO2 agreements to facilitate the importation of foreign CO2 into Malaysia for geological storage.
     f) Encourage CO2 utilisation by setting mandates for CO2 in industry, e.g. for cured concrete and urea.
     g) Establish three CCS hubs in Malaysia by 2030F (15 Mtpa of CO2 storage capacity).
     h) Establish one more CCS hub in Malaysia by 2040F (cumulative 40 Mtpa storage capacity).
     i) Establish a further two CCS hubs in Malaysia by 2050F (cumulative 80 Mtpa storage capacity).

Figure 61: Six energy transition levers under Malaysia's NETR – CCUS is listed as one of the levers needed to abate hard-to-abate emissions in certain industrial sectors



SOURCE: NETR, 2023

In addition to the four policy documents above, Malaysia has also introduced legislation to facilitate CCUS activities. These are the federal-level CCUS Act 2025 and Sarawak's state-level Land (Carbon Storage) Rules 2022.

Malaysia's CCUS Act 2025: key provisions

Malaysia passed the Carbon Capture, Utilization and Storage Act on 25 Mar 2025, which came into effect on 1 Oct 2025. The key provisions are listed below.

Scope and administration

- Applies only to Peninsular Malaysia and Federal Territory of Labuan; does not apply to the states of Sabah and Sarawak.
- Administered by the Ministry of Economy.
- Sets up the Malaysia CCUS Agency (MyCCUS Agency) to regulate CCUS activities.

Permitting requirements

- Requires registration of any carbon capture installation, CO2 transportation services, and utilisation of CO2 captured in Malaysia.
- An import permit is needed for CO2 captured outside of Malaysia.
- A permit is required for any geological assessment of potential offshore/onshore storage complexes.
- Licences are required for the operation of offshore/onshore CO2 storage sites.

Obligations pre-closure of the storage site

- The operator of the storage site must monitor the storage complex and take corrective measures in the event of any CO2 leakage.
- The operator of the offshore storage site must pay an 'injection levy' to the government. The rate of injection levy is based on the leakage risk probabilities of each storage site. Operators of onshore storage sites do not need to pay the injection levy.

Obligations post-closure of the storage site

- When the offshore/onshore storage site is closed, the operator must monitor and take corrective measures on the storage site for a prescribed time period (CGSI comment: the precise duration has not been determined). Only after this prescribed period will the obligations for monitoring and corrective action be transferred to the government.
- The injection levy will be used to fund the 'post-closure stewardship fund'. This fund is managed by the MyCCUS Agency for the purpose of long-term monitoring of each offshore storage site by the Malaysian government after the site is closed.

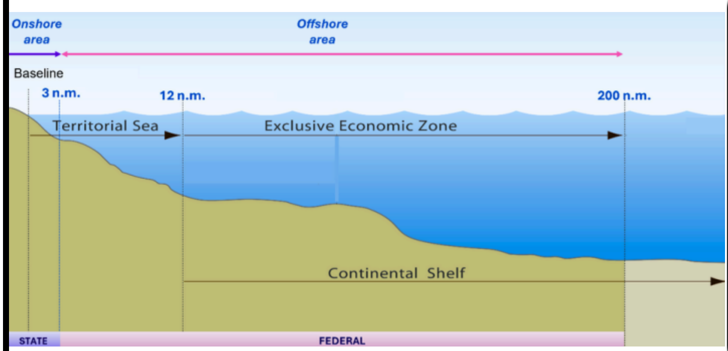
The CCUS Act 2025 also requires that the **CO2 acceptance criteria** need to be complied with prior to injection, i.e. that the CO2 "shall consist overwhelmingly of CO2, and no waste or other matter may be added into the CO2 stream for the purpose of disposing the waste or other matter." Impurities can include N2, O2, H2O, SOx, NOx, HCl, HF, mercury, chemical solvents used in the post-combustion capture, etc. This is because impurities can compromise the integrity of the storage site or the relevant transport infrastructure or pose a significant environmental or health risk.

Offshore storage is defined as storage areas *beyond three nautical miles from the coastline*, including the EEZ and continental shelf.

The CCUS Act 2025 notes that CO2 captured outside of Malaysia can only be geologically stored and cannot be utilised; this means **only domestically-captured CO2 can be utilised in Malaysia**. We believe that this is to provide opportunities to domestic emitters to tap the local CO2 utilisation market.

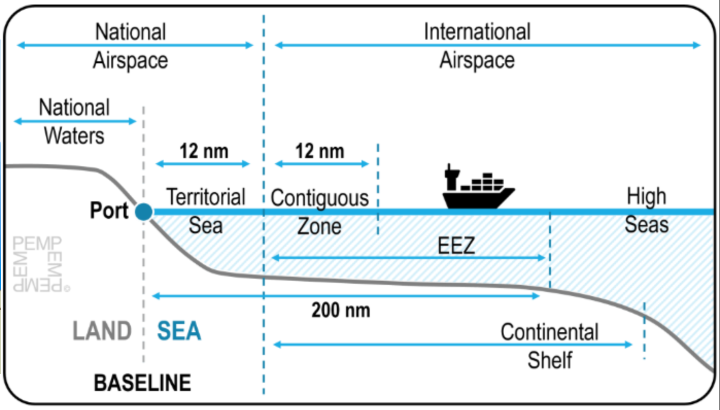
We note that secondary legislation and detailed regulations will still be required to provide additional information regarding injection levies, to specify the technical standards, to determine the prescribed time period for post-closure obligations prior to the transfer of obligations to the Malaysian government, to define the long-term liabilities for CO2 leakage, etc.

Figure 62: Maritime definitions



SOURCE: ZAID IBRAHIM & CO; WIKIPEDIA

Figure 63: Maritime definitions



SOURCE: PORT ECONOMICS MANAGEMENT

On 30 Sep 2025, Malaysia's Attorney General's Chambers issued the **Carbon Capture, Utilisation and Storage (Offshore Permit and Licensing) Regulations 2025**, under the CCUS Act 2025. Both the Act and the Regulations came into effect on 1 Oct 2025. These regulations apply to the offshore geological assessment and permanent storage of CO_2 in offshore areas. Some of the provisions are listed below.

- An application for an **offshore assessment permit** shall be made to the MyCCUS Agency, and include details such as the fixed area that is intended for offshore geological assessment which may include more than one storage complex, and the methods and techniques intended for offshore geological assessment.
- The offshore assessment permit holder shall undertake the offshore geological assessment within a period not exceeding **three years** from the date of the offshore assessment permit or any extension of time granted.
- The offshore assessment permit holder must apply for an **offshore storage licence** before the expiry of its offshore assessment permit, failing which the offshore assessment permit shall be automatically relinquished.
- Any person who intends to carry out the operation of a storage site may apply to the CCUS Agency for an offshore storage licence. The applicant must prove that it has sufficient **financial security** to cover the costs arising from all obligations, liabilities and risks, and the obligation to pay all costs to the MyCCUS Agency, including the costs associated with the closure of a storage site and post-closure of storage site obligations before such obligations are transferred to the government.
- The application for the offshore storage licence must also provide the results of the site characterisation process for the proposed storage complex, including the location and extent of area of the storage site, estimate the total quantity of CO_2 that can be stored, describe the composition of the CO_2 streams which must comply with the CO_2 stream acceptance criteria, describe the maximum injection rates and pressures and measures to prevent leakages, and provide other technical details such as the proposed plan for storage site closure.
- After a storage site closure certificate has been issued to the offshore storage licence holder, a **minimum period of at least 10 years** is needed before the obligations regarding the CO_2 storage site can be transferred from offshore storage licence holder to the government, among other conditions. The minimum period can be extended by the MyCCUS Agency if it is not satisfied that the stored CO_2 is completely and permanently contained.

On 10 Nov 2025, Petronas announced that its wholly-owned subsidiary, **Petronas CCS Ventures (PCCSV)** was granted on 10 Oct 2025 Malaysia's first-ever Offshore Assessment Permit for CCS for the Duyong field, offshore Peninsular Malaysia, by the MyCCUS Agency. This allows PCCSV, TotalEnergies and Mitsui to evaluate the Duyong area's potential as a carbon storage site, which is part of Petronas's Southern CCS offshore hub development.

Sarawak's Land (Carbon Storage) Rules 2022

Sarawak passed its Land (Carbon Storage) Rules on 22 Dec 2022, and the rules came into effect on 1 Jan 2023. This establishes guidelines for developing and managing onshore/offshore carbon storage sites in Sarawak.

Parties to which the regulations apply include:

1. Petroleum operators and industrial companies that intend to develop CO2 onshore/offshore storage sites in Sarawak;
2. Storage users, both domestic and foreign, who wish to store CO2 in onshore/offshore storage sites in Sarawak.

Specific land areas to be used for storing "scheduled gases" include:

- Abandoned onshore/offshore petroleum sites in Sarawak (locations where petroleum production has ceased for more than 12 months);
- Deep saline aquifers;
- Coal seams; and
- Additional onshore/offshore sites in Sarawak deemed suitable and safe for gas storage.

Note: "Scheduled gases" means atmospheric CO2 and any other GHG, and any incidental substances (substance which has become associated with the scheduled gases either at its original source or as a result of the process of capture or injection) or trace substances (substances which have been added to the scheduled gases in order to assist in the monitoring and verifying of its migration after injection) which may be injected into a storage site.

Procedures to obtain the carbon storage licences and permits are as follows:

1. Operators of carbon storage sites will be required to first apply for a storage licence. A licence may be issued over an area not exceeding 2m hectares, unless exceptions are granted; the licence shall not exceed 60 years' duration.
2. Thereafter, operators/licence holders will be required to apply for the storage permit which would allow for the storage of "scheduled gases" on the specific onshore/offshore land.
3. Operators/licence holders must specify the identity of the storage users, the nature and estimated quantity of scheduled gases to be stored, estimated duration for such storage, prospective sources and transport methods, composition of the schedule gases streams that are to be injected, proposed injection rates and pressures, and other details.

Responsibilities and obligations of the operators who have obtained storage licences and permits include:

1. Monitoring, maintenance, ensuring safety of the storage sites;
2. Reporting damages and incidents to the authority and taking any corrective actions mandated;
3. Ensuring compliance with all laws and licence conditions by all parties; and
4. Being liable for damages caused by failures or negligence of associated parties, providing regular reports on the storage site's condition, gas quantities and incidents (if any).

Closure of storage site (but before termination of storage permit)

After the storage site has been closed but before the storage permit is terminated, the storage user shall continue to:

a) monitor the storage site;

b) comply with its reporting and notification obligations in relation to leakages and significant irregularities; and

c) comply with its obligations to take corrective measures.

Prior to terminating the storage permit, the State Authority shall determine the amount and form of financial contribution from the storage user that will be sufficient to cover the estimated post-transfer costs.

Termination of storage permit (minimum 20 years after closure of storage site)

- The State Authority shall notify the storage operator of the minimum period that shall elapse between the date of the closure of the storage site and the termination of the storage permit.
- The minimum period between the date of the closure of the storage site and the termination of the storage permit shall not be less than 20 years, subject to exceptions such as if all available evidence indicates that the stored scheduled gases will be completely and permanently contained, the storage site has been sealed, and the abandonment programme has been carried out, etc.

Sarawak state takes over responsibility for long-term CO2 storage site monitoring

- Once the storage permit is terminated, the Sarawak state assumes responsibility for monitoring and managing the CO2 storage site, including any future leakage risks.
- However, if the leakage occurs after termination but is attributable to actions or omissions before termination, the former operator remains liable.

Fees payable

A storage licensee and storage user shall pay all fees, levies, dues, rents, cess and other payments for the use and occupation of the land for exploration, appraisal and development of a storage site.

The cess collected from the storage licensee shall be used for the discharge of all obligations under the closure and post-closure plans and shall be accounted for in a fund to be established by the State Authority.

Figure 64: Fees payable under the Sarawak Land (Carbon Storage) Rules 2022

NO.	ITEM	FEES
1.	Application for licence	RM 50,000.00 per application.
2.	Licence Fee	RM 1.00 per hectare/ per year
3.	Application for permit	RM50,000.00 per application.
4.	Permit Fee	RM 25.00 per m^3 metric tonne /per year
5.	Levy on Carbon Storage Charges	An amount to be determined by the Authority
6.	Cess	An amount to be determined by the Authority.
7.	Preparation and Registration of issuance of licence	RM300.00 per licence.
8.	Preparation and Registration of issuance of permit	RM300.00 per permit.
9.	Registration and Issuance of Certificate of Storage Operator	RM 1,000.00 per certificate.

SOURCE: SARAWAK LAND (CARBON STORAGE) RULES 2022

Malaysia's CCS tax and trade incentives (Budget 2023)

Malaysia introduced tax and trade incentives for CCS activities at Budget 2023 (announced in Oct 2022).

For companies with in-house CCS activity

- Investment Tax Allowance (ITA): A 100% ITA allowance on qualifying capex will be available for 10 years.
- Import and sales tax: A full exemption from import and sales taxes on equipment for CCS technology will be in effect from 2023 to 2027F.
- Pre-commencement expenses: Tax deduction for pre-commencement expenses incurred within five years before operations begin will be available.

For companies providing CCS services

- Option 1: A 100% ITA can be secured on qualifying capital expenditure for 10 years.
- Option 2: A 70% income tax exemption on statutory income can be obtained for 10 years.
- Import and sales tax: A full exemption from import and sales taxes on equipment for CCS technology will be in effect from 2023 to 2027F.

For companies using CCS services

- Tax deduction: Companies using CCS services can receive a tax deduction on the fees they pay.

In our assessment, the tax incentives are by themselves insufficient to spur CCS activities, although they are an important starting point for further enhancements to the package of incentives that the government may introduce in the future.

(O) COMPANIES INVOLVED WITH CCS

Yinson: Havstjerne CCS

The Havstjerne CCS project is a CO_2 transportation and storage project in the Norwegian sector of the North Sea. The Havstjerne CCS project provides a flexible, large-scale and shared maritime infrastructure for smaller or geographically-dispersed industrial emitters to access storage facilities.

History

The initial license was originally awarded by the Norwegian government in Mar 2023 to Havstjerne ANS (HANS), a 60:40 partnership between Wintershall Dea and Altera Infrastructure.

In Sep 2024, Harbour Energy acquired Wintershall Dea's 60% stake in HANS. Harbour Energy is the operator of the reservoir.

In Feb 2025, Yinson Production (Unlisted, wholly-owned subsidiary of Yinson Holdings) acquired a 100% interest in Altera Infrastructure's subsidiary Stella Maris CCS AS. Stella Maris CCS AS has a 40% interest in HANS. Consequently, Yinson has an indirect 40% interest in the Havstjerne CO_2 injection and storage project.

EU financial support

In 2024, the EU's Innovation Fund granted the Havstjerne CO_2 injection and storage project up to €225m, payable against expenditures upon certain investment and commercial operation milestones. This represents the largest EU grant for a CCS project, according to Yinson.

How it works

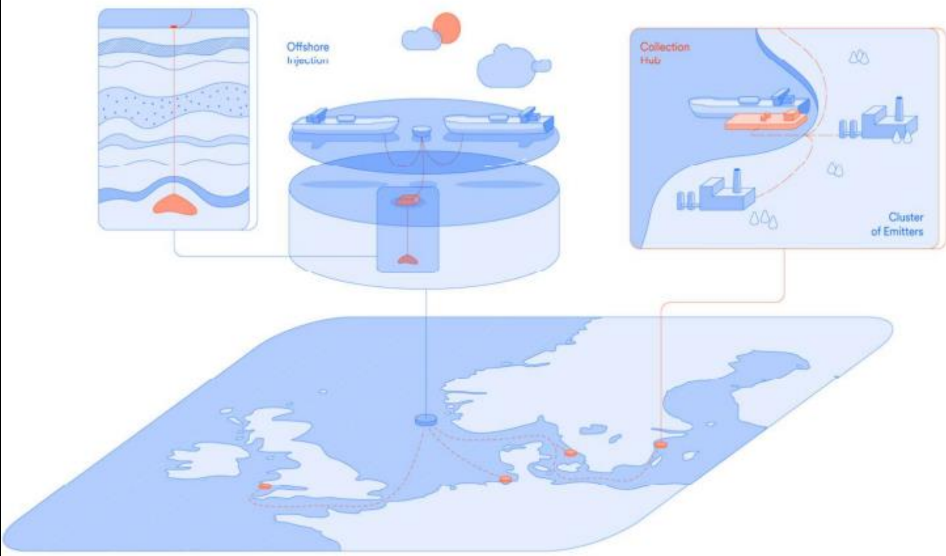
CO_2 is captured at industrial sites and collected at FSO units, located at strategic port areas in Northern Europe. A fleet of CO_2 shuttle tankers transports the CO_2 from the collection hubs to the offshore storage site.

At the Havstjerne storage site in the North Sea (100 km southwest of Egersund, Norway), a floating storage and injection unit (FSIU) codenamed STARFISH receives the CO_2 from the shuttle tankers and injects it into a deep saline aquifer for permanent sequestration.

The project aims to store up to 10 Mtpa of CO_2, with the Havstjerne reservoir having a total capacity of around 200 Mt. Phase 1 is expected to store 42.75 Mt of CO_2 over the first 10 years of operation. The first CO_2 injection was originally planned for 2027F, though project timelines are subject to change.

Note: STARFISH stands for Sequestration Technology And Reservoir: Floating Injection and Storage in Havstjerne.

Figure 65: Schematic of the Havstjerne CCS project



SOURCE: ALTERA

MOU between HANS and K Line to develop transportation, injection and storage solutions (Sep 2025)

In Sep 2025, an MOU was signed between Havstjerne ANS (HANS) and K Line Energy Shipping (UK) Limited (KLES), an unlisted London-based subsidiary of K Line to jointly identify the transportation, injection and storage solutions best suited for the Havstjerne CO2 storage license on the Norwegian Continental Shelf.

KLES and HANS will collaborate to optimise solutions for a marine CCS solution involving FSIUs and LCO2 carriers. FSIUs are useful where it is difficult to secure sufficient land for an onshore CO2 receiving terminal, or where the distance between the receiving terminal and the offshore storage site would require an extended pipeline, according to Upstream.

We expect that HANS will eventually own and operate the FSIUs, while KLES will own and operate the LCO2 carriers.

Figure 66: An illustration of an FSIU (in the foreground) receiving cargo from an LCO2 carrier (in the background)

SOURCE: K LINE

MISC: CCS platform fabrication, LCO2 shipping services, and other CCS-linked ventures

MISC established its **New Energy and Decarbonisation (NED)** division in 2023 to spearhead strategic investments in carbon abatement and new energy solutions. It has since announced several CCS-related ventures or future prospects.

1. **Fabrication of Malaysia's first CCS platform for the Kasawari CCS project**
   - MISC's 66.5%-owned subsidiary Malaysia Marine and Heavy Engineering Holdings Berhad (MMHE) was awarded the EPCIC contract for the Kasawari CCS platform on 3 Nov 2022 by Petronas Carigali.
   - The contract involves the construction of a 14,000 tonne topside, a 15,000 tonne eight-legged jacket for the platform, and a bridge linking the new CCS platform to the existing Kasawari Central Processing Platform (CPP).

2. **Jules Nautica JV to own LCO2 carriers**
   - In Jun 2025, MOL, Petronas CCS Ventures (PCCSV) and MISC announced the incorporation of a JV, Jules Nautica Sdn Bhd, to lead the development and to be the owner of LCO2 carriers.
   - The JV awarded the FEED for a 62,000 cbm ‘Low Pressure Low Temperature’ LCO2 carrier to Shanghai Merchant Ship Design And Research Institute (SDARI). General Approval for Ship Application (GASA) certification from DNV was received in Dec 2024.
   - According to Petronas, the JV aims to become a leading owner of LCO2 carriers to support future CCS projects across the Asia Pacific region.

Figure 67: Illustration of a potential Jules Nautica JV LCO2 carrier

SOURCE: MOL

3. **Onboard carbon capture (OCC) on ships**
   - According to MISC, it is collaborating with the Petronas Project Delivery and Technology (PD&T) to adapt their carbon capture technology for maritime applications and develop an Onboard Carbon Capture (OCC) solution.
   - In Jan 2023, MISC signed MOUs with Mitsui, Samsung Heavy Industries and Andritz AG to tap into opportunities for CCS solutions in the maritime value chain, including identifying storage hubs, development of floating solutions, as well as carbon capture parts and equipment.

4. ZEUS power generation with CO_2 capture and storage

- In Aug 2024, MISC signed an MOU with Aker Solutions, Petronas Carigali and Clean Energy Systems Inc to initiate a pilot project for ZEUS.
- The ZEUS technology utilises oxyfuel combustion to convert high-CO_2 natural gas into dispatchable power while capturing 100% of CO_2 emissions. The captured CO_2 is then immediately injected into a reservoir for permanent storage or utilised for EOR/EGR before being permanently sequestered, according to MISC.
- Oxyfuel combustion technology enables the direct burning of untreated gas straight from the well, including gas with up to 90% CO_2 content. This makes it possible to commercialise gas reserves that would otherwise be deemed uneconomical for development.

5. Other CCS-linked commercial opportunities

- MISC, as part of Petronas Group's Gas and Maritime division, can serve Petronas' needs for hydrogen and ammonia transportation.
- Very large ammonia carrier (VLAC) and medium gas carrier (MGC) sectors offer potential business opportunities for MISC once the shipping of low-carbon ammonia takes off in large volumes in trans-Pacific trades or transatlantic or intra-regional trades.

Bumi Armada: FSIU

Bumi Armada-Navigator Holdings non-binding MOU

In Jun 2023, Bumi Armada and UK-based Navigator Holdings signed an MOU to establish a 50:50 JV company called Bluestreak CO2 to provide LCO2 shipping and injection solutions in the UK.

The LCO2 shuttle tankers will lift liquefied CO2 from various emitters and then deliver it to a floating carbon and storage unit (FCSU) or a floating storage and injection unit (FSIU), which will subsequently inject CO2 into saline aquifers and/or depleted oil and gas reservoirs offshore UK, according to Bumi Armada.

The UK government has a target to capture and store 20-30 MtCO2 (including removals) p.a. by 2030F and over 50 MtCO2 by 2035F, according to the UK's North Sea Transition Authority (NSTA). At the moment, there is no commercial application for CCS in the UK.

ABS grants approval-in-principle for Bumi Armada's FSIU

In Sep 2023, ship classification society ABS issued approval-in-principle for Bumi Armada's design for an FSIU. The FSIU will temporarily store CO2 onboard at low or medium pressure, then transport and inject it into reservoirs. The approval covers both newbuilds and retrofit carriers, according to Bumi Armada.

Bluestreak CO2 MOU with Uniper

In Jul 2024, the Bluestreak CO2 JV signed an MOU with Uniper, a major power-generation company headquartered in Germany, to explore the feasibility of implementing a jetty-moored floating LCO2 storage facility and LCO2 carrier solution, for the export of CO2 from Uniper's proposed Grain Carbon Capture project on the Isle of Grain, UK. Collaboration with Uniper will demonstrate how Bluestreak CO2 is able to serve emitters with no access to pipeline infrastructure in effectively managing their CO2 emissions. The Grain Power Station is one of the most efficient gas plants in Uniper's fleet, and retrofitting carbon capture technology would remove millions of tonnes of CO2, according to Uniper.

Bumi Armada has not made any further announcements with respect to the status of the Bluestreak CO2 JV or its MOU with Uniper.

A potential customer for Bumi Armada's FSIU solution

During Bumi Armada's 3Q25 results analyst briefing on 27 Nov 2025, the company disclosed that it is in discussions with a separate customer on deploying the FSIU solution, unrelated to the Bluestreak CO2 JV. No details were provided.

Figure 68: Illustration of Bumi Armada's FCSIU

SOURCE: BUMI ARMADA

Vopak (and potentially Petronas Gas): CO2 terminals

Vopak, headquartered in Rotterdam, the Netherlands, is one of the world's largest independent tank storage and terminals company, specialising in the handling of bulk liquid products and gases. In SE Asia, Vopak is the largest tank terminal operator by storage capacity, owning large terminals in Singapore, as well as in Malaysia via partnerships with Petronas and Dialog, among others.

Vopak is currently moving into the provision of CO2 storage services at Rotterdam and at Darwin, Australia.

CO2next project at Maasvlakte, Rotterdam

In Jun 2024, Vopak, Gasunie, Shell and TotalEnergies announced that they are investigating the development of CO2next, an open access terminal for liquid CO2 on the Maasvlakte harbour and industrial area in the Port of Rotterdam. Shell and TotalEnergies have joined the development of the CO2next project, which up to Jun 2024 was led by Gasunie and Vopak.

The independent hub terminal will be able to receive and deliver liquid CO2 via ships (potentially railcars in future) and will be connected to depleted gas fields in the North Sea via the Aramis trunkline for storage (under the Aramis CCS project), according to Vopak.

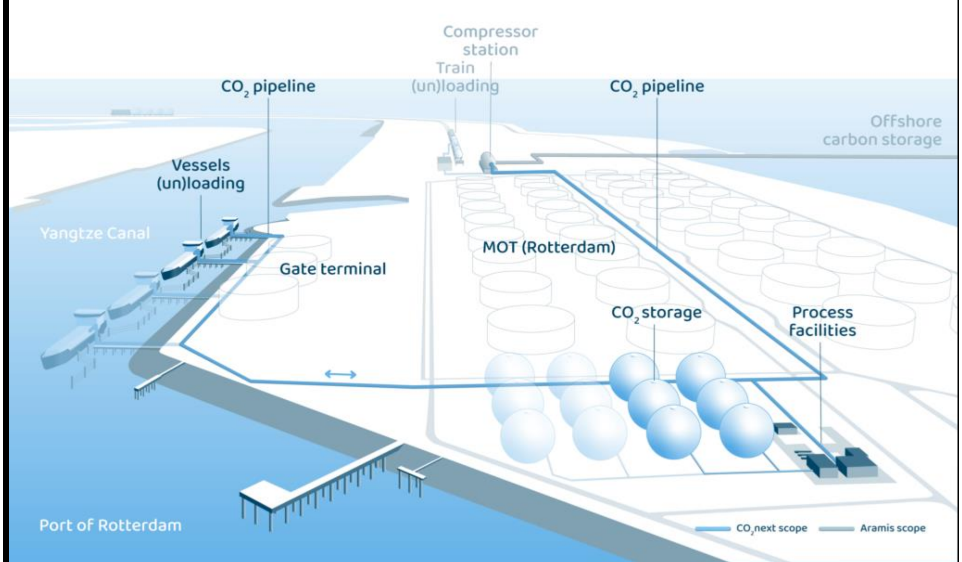
The terminal has a launch capacity of c.5.4 Mtpa and a potential to grow its capacity to c.15 Mtpa, depending on market demand and the development of the Aramis CCS project and other CCS chains.

Following the FID planned for 2026-2027F, subject to permits being granted by relevant authorities, Vopak expects the CO2next terminal to commence commercial operations in 2029-2030F.

Notes:

1. *Gasunie is a European energy infrastructure company that manages and maintains a large gas pipeline network in the Netherlands and northern Germany.*
2. *Aramis CCS is a large-scale, open-access CCS initiative in the Netherlands designed to transport and store carbon dioxide from industrial sources in Northwest Europe into depleted North Sea gas fields. The hub includes the CO2next terminal, which receives liquid CO2 transported by ships, which then transports CO2 via a 200 km pipeline to the North Sea for sequestration.*

Figure 69: CO2next port layout and design in Maasvlakte, Rotterdam



SOURCE: CO2NEXT

CO2 import terminal at Darwin, Australia

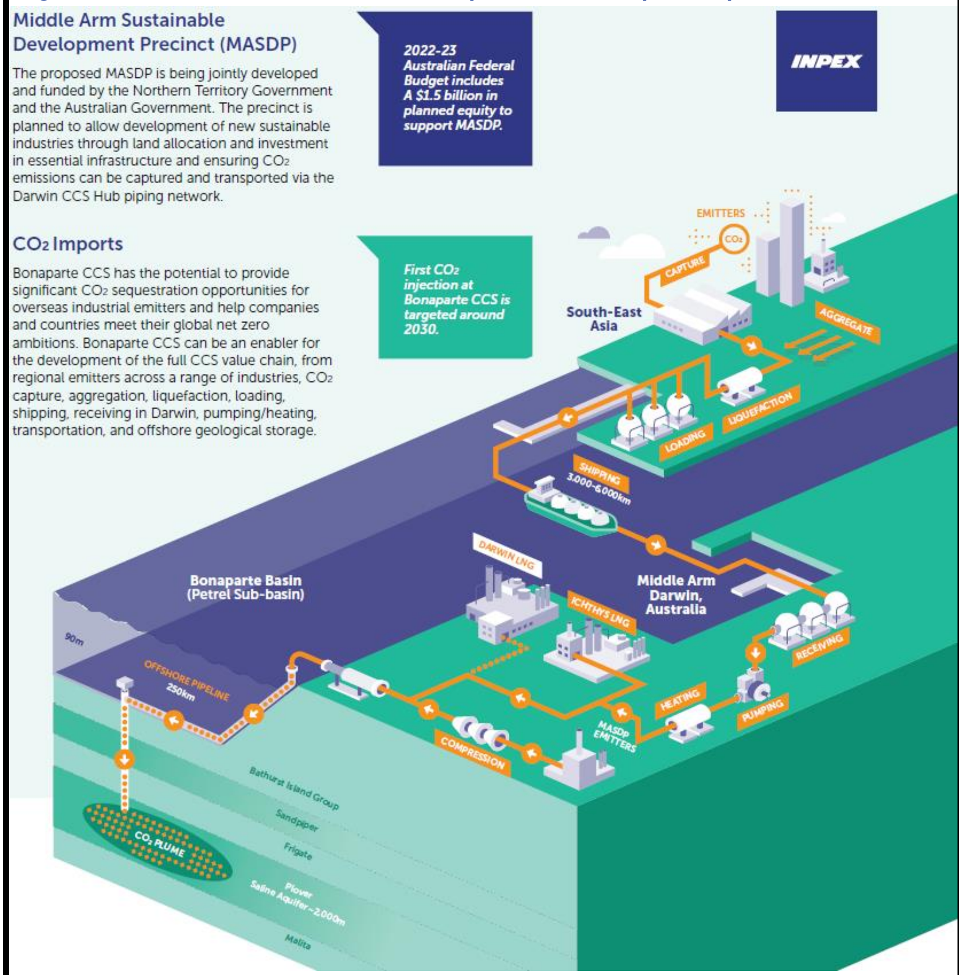
In Jul 2024, Vopak and Australia's Northern Territory Government signed an MOU to develop common-user infrastructure including a CO2 import terminal at Darwin in the Middle Arm Sustainable Development Precinct — Northern Territory, Australia.

The Middle Arm Sustainable Development Precinct is an industrial area for advanced manufacturing and green energy production. CCUS capability is a core component of the circular economy design of this Precinct. The CO2 import, storage and handling infrastructure will be shared infrastructure that can be used by various companies to help manage CO2 emissions, according to Vopak.

The imported CO2 can come from different sources such as industrial plants, as well as CO2 imports from neighbouring countries. Once the CO2 is imported, it needs to be stored safely in large tanks before it will be transferred to a permanent destination, for example in underground facilities CCS, or followed by recycling the CO2 for utilisation (CCUS).

Vopak expects the Middle Arm CCS project to start construction on its enabling infrastructure by 2026F, while the CO2 injection into the Bonaparte CCS project is targeted for around 2030F.

Figure 70: Middle Arm Sustainable Development Precinct (MASDP)



SOURCE: INPEX

Development of CO2 terminals in Malaysia

Petronas Gas disclosed at its 3Q25 results analyst briefing on 27 Nov 2025 that it is pursuing growth opportunities in the form of a CCS facility, which is currently at the engineering and commercial feasibility stage. No further details were revealed.

We interpret this as Petronas Gas potentially participating in the ownership of CO2 terminals in Malaysia, which Petronas is looking at constructing at Kertih, Kuantan and at Bintulu, each corresponding to Malaysia's three CCS hubs in the Northern Cluster, Southern Cluster, and Eastern Cluster. These three CCS hubs are intended to facilitate the importation of liquefied CO2 (LCO2) from foreign industrial sources, e.g. from Japan, South Korea and/or Singapore, the storage of that LCO2 in buffer tanks at the CO2 terminals, prior to regasification, transportation via pipeline, and injection into offshore subsea reservoirs.

Petronas Gas already owns two LNG regasification facilities in Malaysia, that is the: 1) Regasification Terminal Sungai Udang in Malacca, and the 2) Regasification Terminal in Pengerang under Petronas Gas's subsidiary, Pengerang LNG (Two) Sdn Bhd. Hence, we think that it will be natural for Petronas Gas to also participate in the LCO2 regasification terminals in the future.

Appendices

APPENDIX 1: MALAYSIA'S CLIMATE GOALS

Malaysia's climate goals and projections (as per NETR)

Malaysia's official climate goals are to:

- Reduce the carbon intensity of GDP by 45% by 2030F vs. the 2005 baseline; and
- Achieve net zero carbon emissions by 2050F.

Not accounting for the use of CCS in the energy sector, the NETR projects that via five energy transition levers, Malaysia will achieve a 32% reduction in energy sector's GHG emissions:

- from 259 MtCO2e (7.9 MtCO2e per capita) in 2019
- to 175 MtCO2e (4.3 MtCO2e per capita) in 2050F.

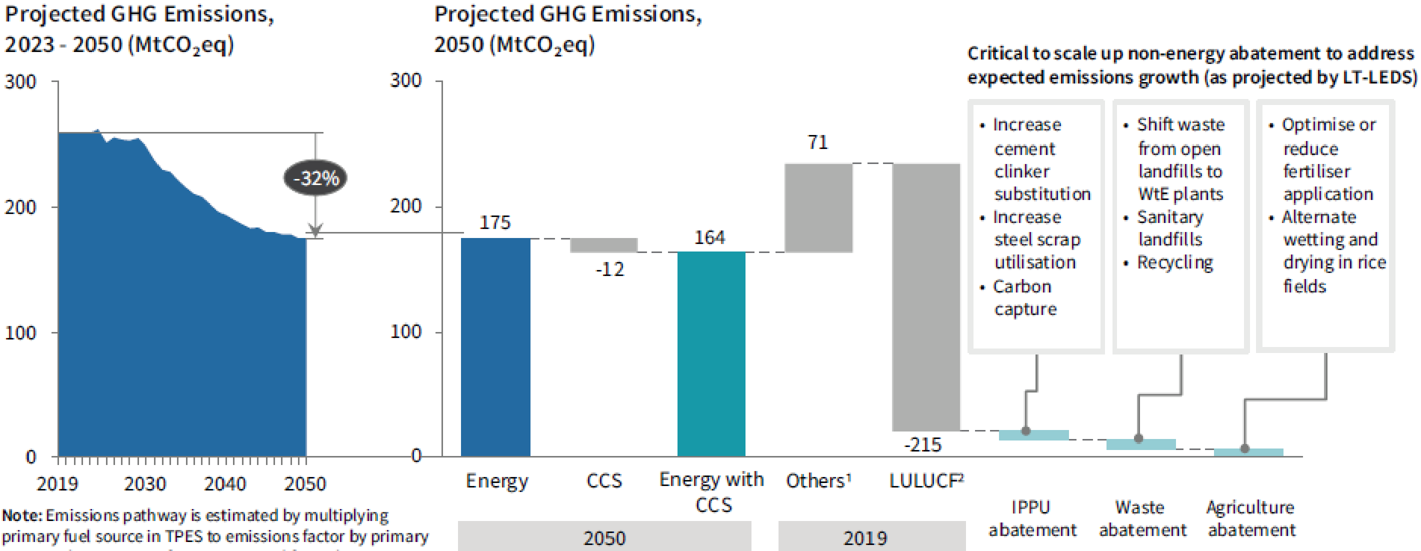
Utilising CCS in the energy sector will deliver an additional 12 MtCO2e reduction in GHG emissions (4.6% of 2019 base) to 4.1 MtCO2e per capita in 2050F.

The NETR projects that Malaysia will need RM1.3tr to achieve net zero by 2050F, of which CCUS will cost RM170bn.

The NETR recognises that CCUS will need significant governmental funding support due to its status as "marginally bankable" and as it comprises projects that have "below market rate returns" and with "higher risk" of failure.

Malaysia has launched the National Energy Transition Fund (NETF), with an initial seed funding of RM2bn. This is intended to finance marginally bankable energy transition projects or those yielding below-market returns, such as EV charging, hydrogen and CCUS technologies.

Figure 71: Trajectory of Malaysia's GHG emissions to 2050F



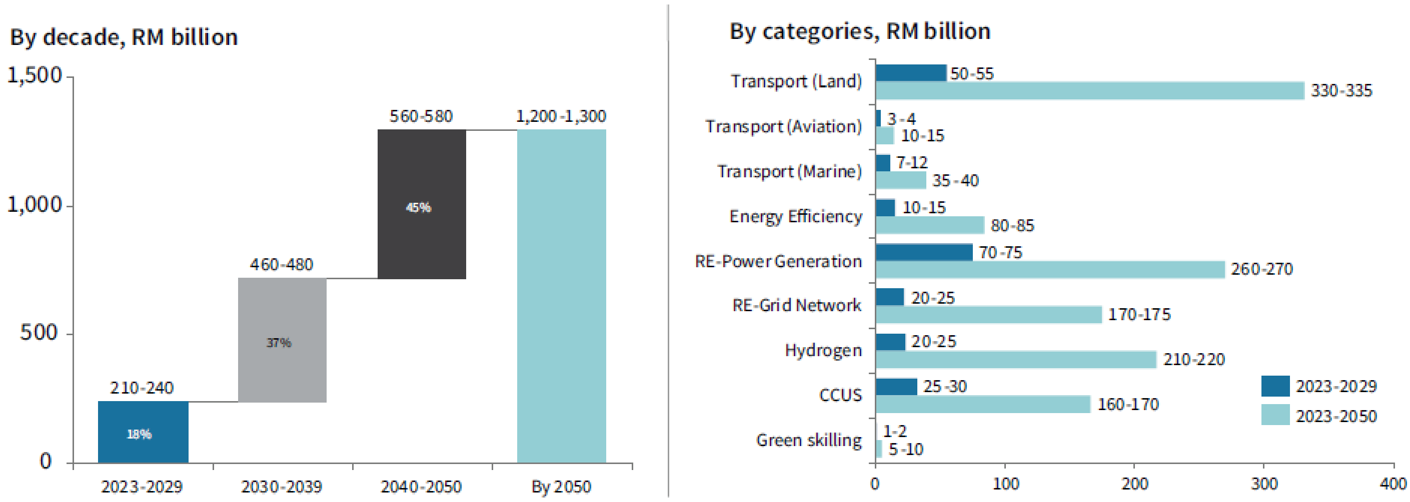
Note: Emissions pathway is estimated by multiplying primary fuel source in TPES to emissions factor by primary source. The emissions factor is sourced from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The objective of this method is to provide directional guidance on policy decisions and is not intended as a submission to UNFCCC nor any other international bodies.

1. Includes IPPU (industrial processes and product use), waste and agriculture
2. LULUCF = land use, land-use change and forestry

SOURCE: NETR, 2023

Note: "Energy" sector includes CO2e emissions from oil and gas activities, power generation, manufacturing, construction, other sectors, fugitive emissions from fuels, and transport sector emissions; the Energy sector contributed to 78.5% of Malaysia's CO2e emissions in 2019, of which transport contributed 21%.

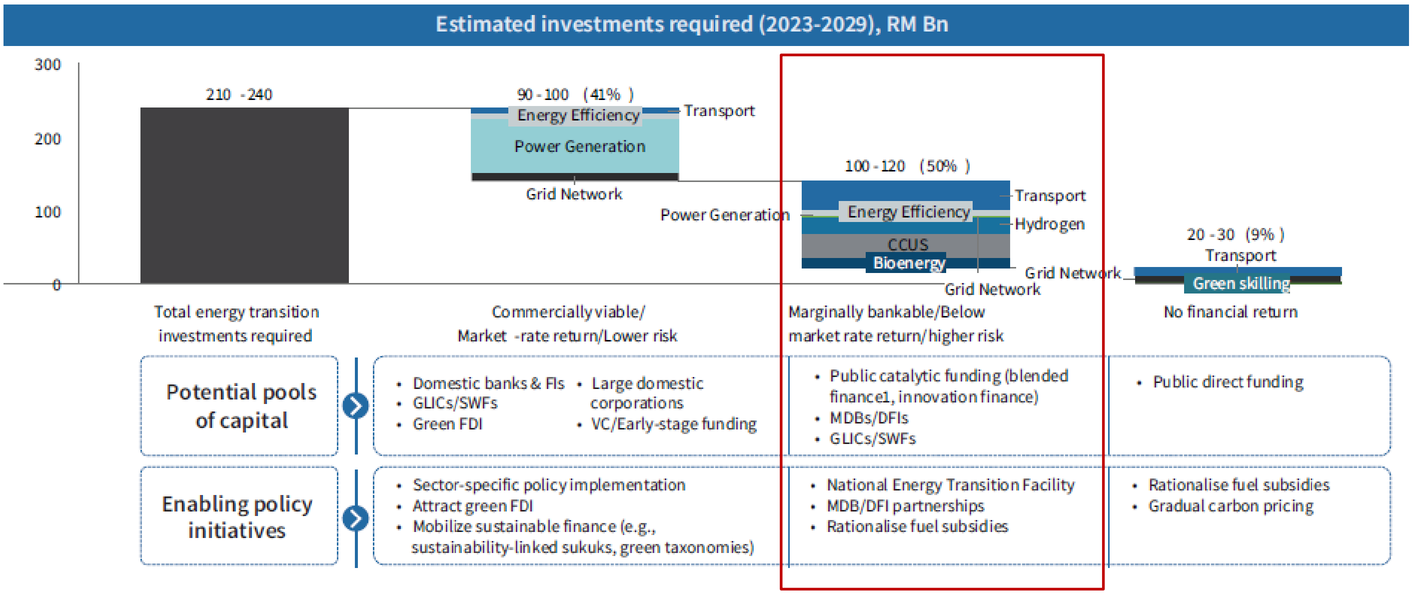
Figure 72: Malaysia will need RM1.3tr to achieve net zero by 2050F, of which CCUS will cost RM170bn



Note: NETR financing needs are additive and do not include business-as-usual investment required or projects already being financed (e.g., transmission and distribution, ongoing public transport projects) Source: PLEXOS, NETR team analysis

SOURCE: NETR, 2023

Figure 73: Malaysia recognises that CCUS will need significant governmental funding support due to its status as "marginally bankable", projects that have "below market rate returns", and with "higher risk" of failure



Financial Institution (FI), Government Link Investment Company (GLIC), Sovereign Wealth Funds (SWF)
Foreign Direct Investment (FDI), Venture Capital, Multilateral Development Bank (MDB), Development Finance Institution (DFI)

SOURCE: NETR, 2023

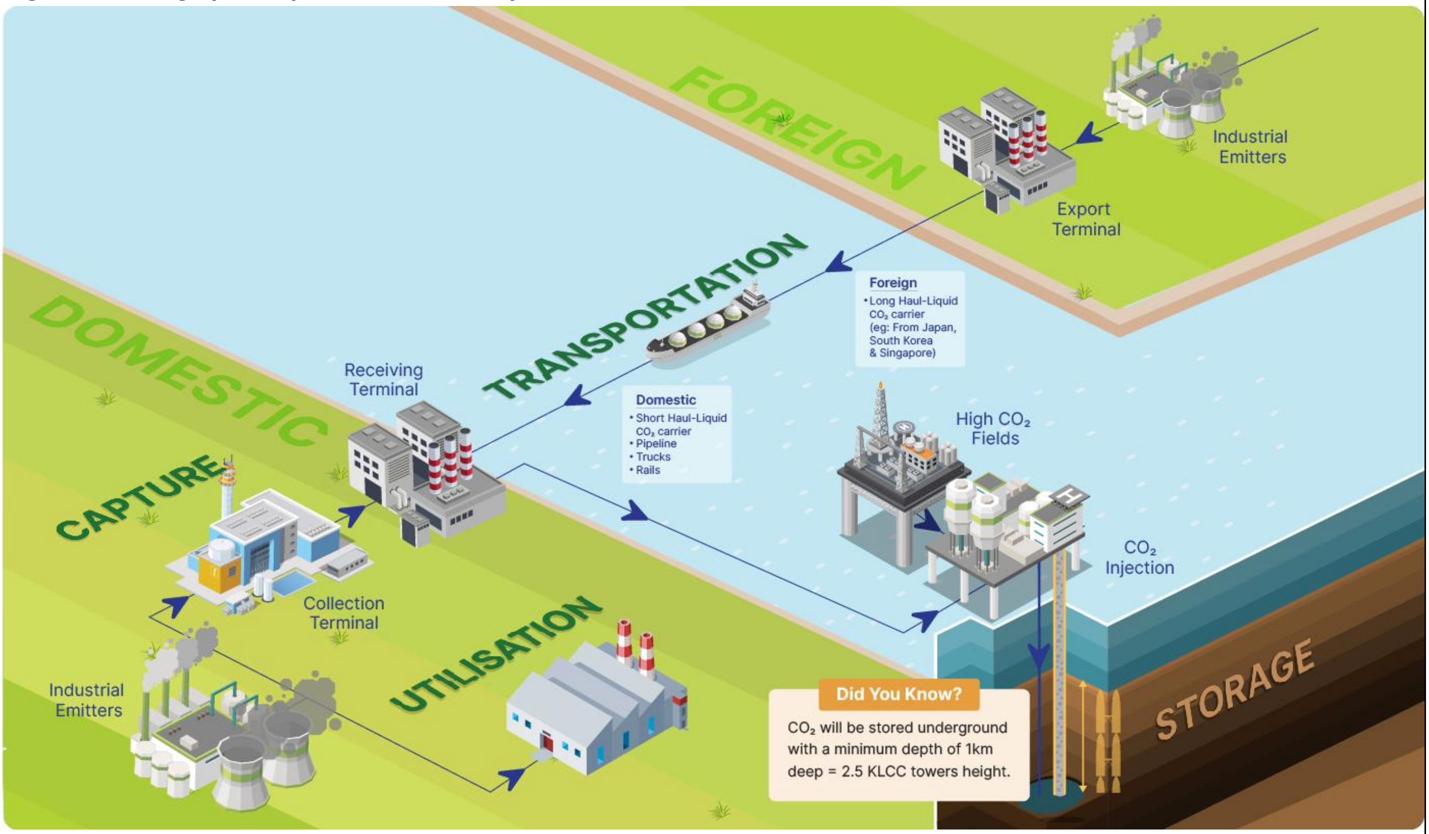
APPENDIX 2: WHAT IS CCUS?

CCUS involves capture, transport and storage/utilisation of CO2

To illustrate CCUS, we have selected five diagrammatic representations from different sources.

The diagram below from the Ministry of Economy, Malaysia shows how domestic CO2 is captured by industrial emitters; either: 1) sent to a CO2 receiving terminal and then piped to an offshore injection unit on a fixed platform before being permanently sequestered under the seabed; or 2) piped to another industrial plant for utilisation purposes. Alternatively, foreign industrial emitters may export their liquefied CO2 by sea via an export terminal using LCO2 vessels.

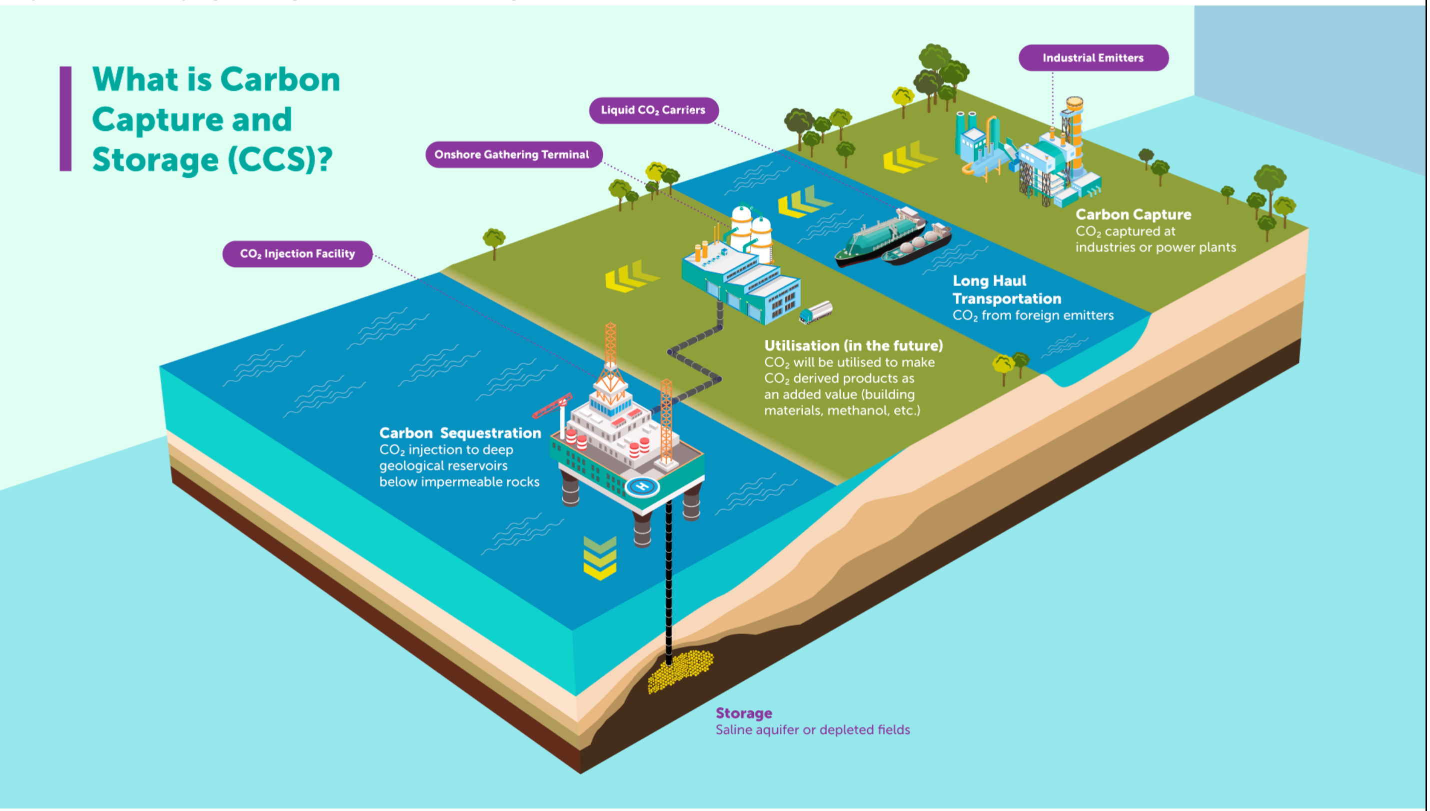
Figure 74: Pictographic depiction of the CCUS process



SOURCE: MINISTRY OF ECONOMY (MALAYSIA)

The illustration below from Petronas shows that CO2 can be injected into either depleted oil and gas fields, or saline aquifers.

Figure 75: Pictographic depiction of the CCUS process

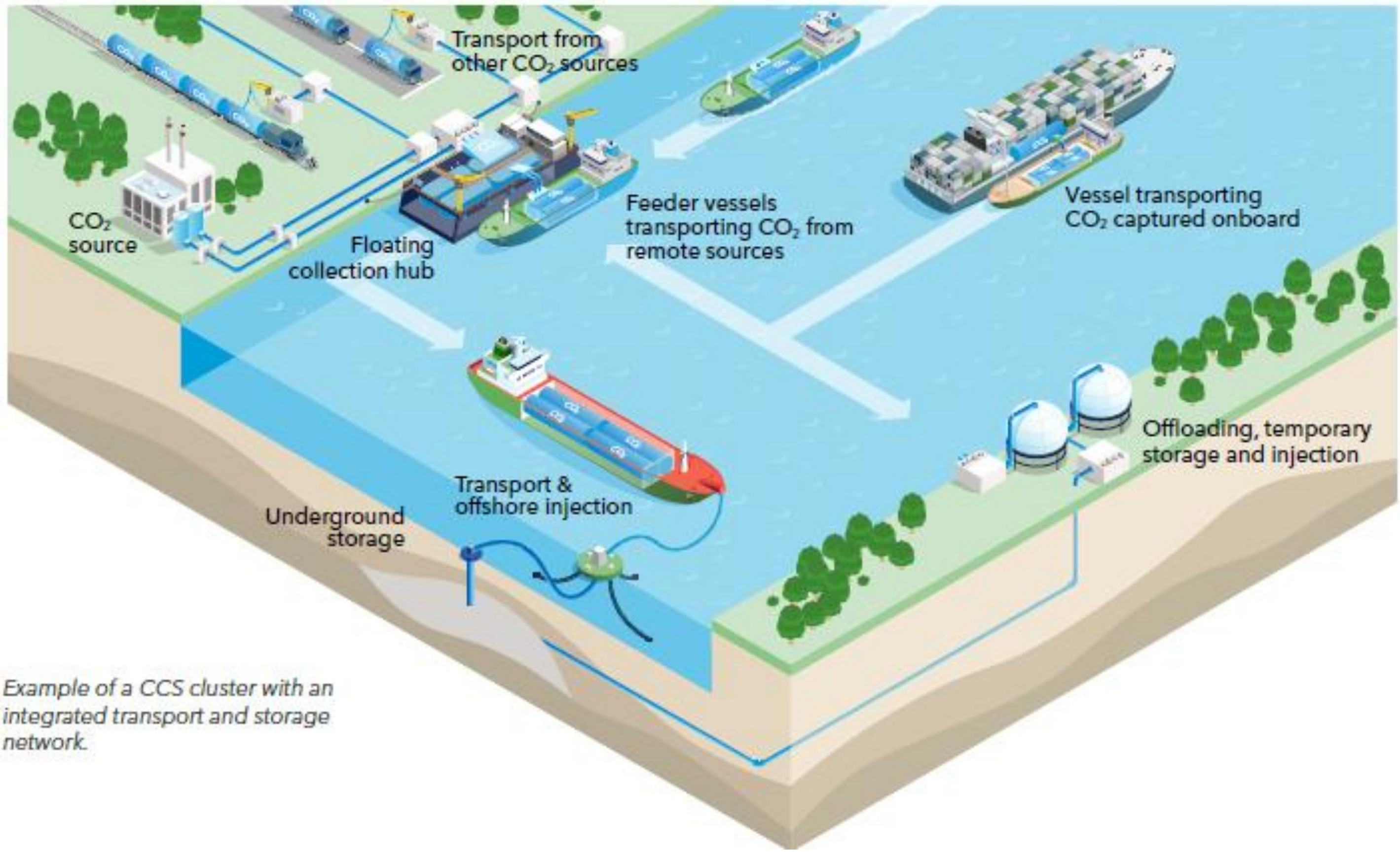


SOURCE: PETRONAS

The illustration below from DNV shows the application of a ship-shaped floating storage injection unit (FSIU) that will receive the CO2 via feeder vessels bringing CO2 from remote sources. This same FSIU will inject the CO2 injection under underground storage below the seabed.

DNV also shows the potential for carbon capture on board shipping vessels (container vessel illustrated here), with a feeder vessel offloading the LCO2 from the containership and delivering the CO2 to an onshore CO2 terminal before injection via pipeline, or delivering the CO2 to a floating collection hub before the CO2 is delivered to the FSIU for injection.

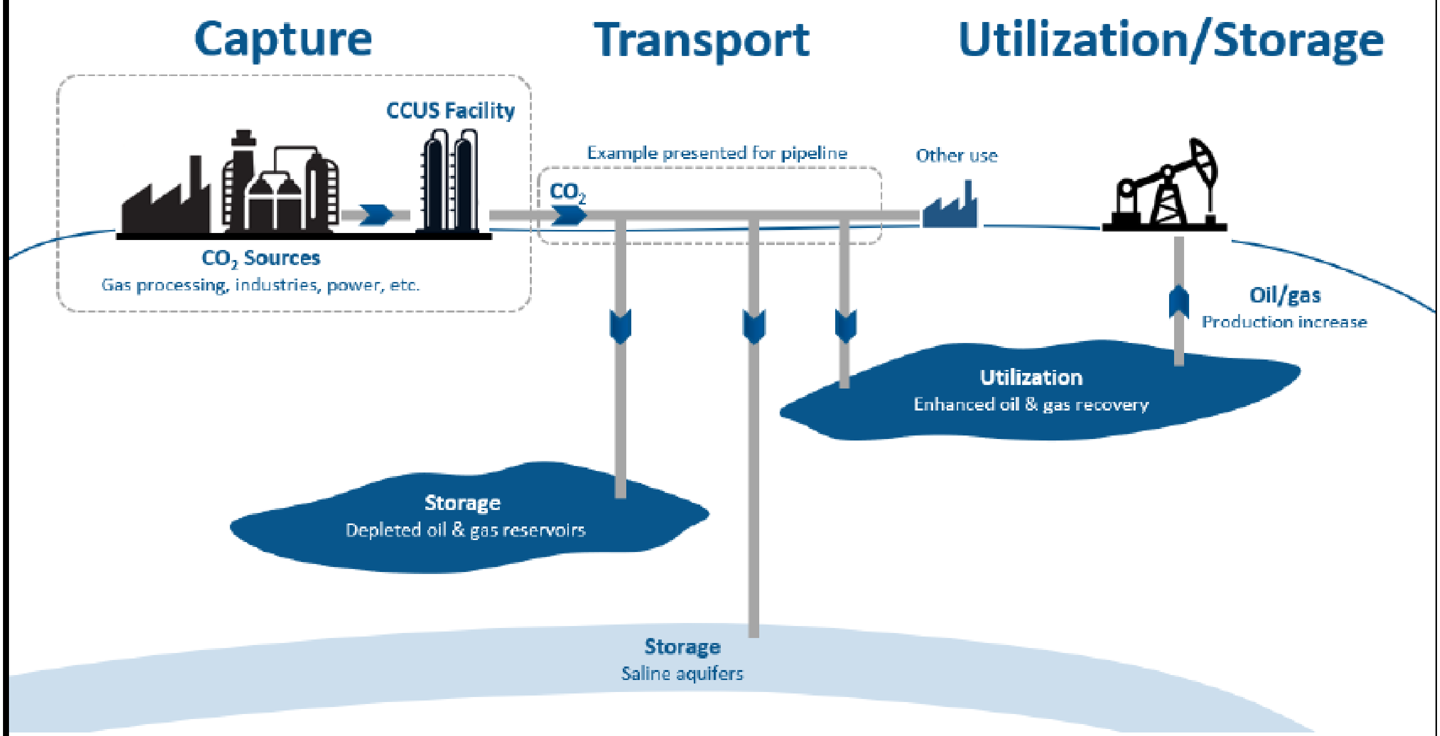
Figure 76: Pictographic depiction of the CCUS process



SOURCE: DNV, 2025

The diagram from IEEFA below shows that CO2 captured from industrial facilities can be piped for enhanced oil recovery (EOR) or enhanced gas recovery (EGR) in existing oil and gas reservoirs, among other uses. Alternatively, it can be permanently sequestered in depleted oil and gas reservoirs or in saline aquifers.

Figure 77: Pictographic depiction of the CCUS process



SOURCE: IEEFA, 2022

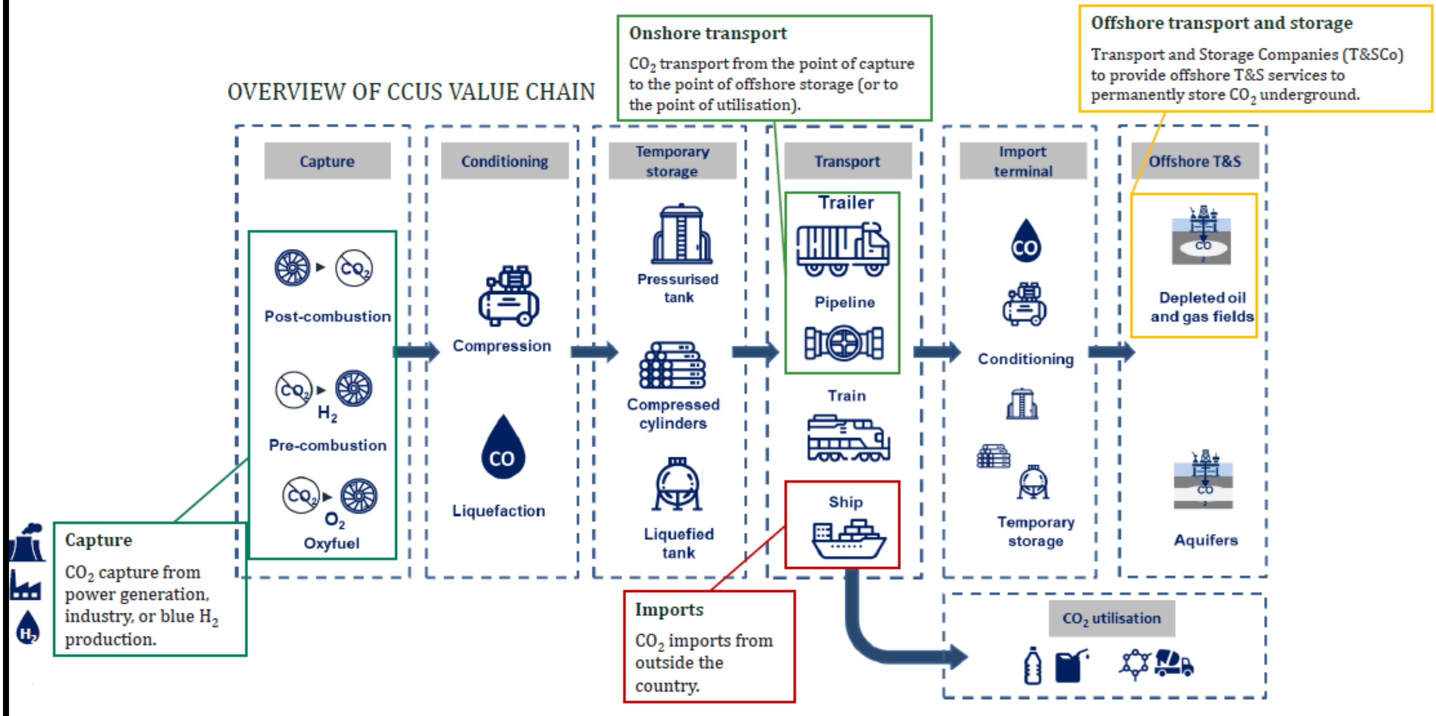
Finally, a more detailed look is presented by ERM.

CO2 capture can be either at the post-combustion stage, the pre-combustion stage, or using oxy-fuel separation (more on this later).

To ensure the integrity and efficiency of CO2 transport and storage networks, capture plants must achieve a particular CO2 purity specification that often requires additional treatment and purification (or 'conditioning'). The purity of the CO2 stream produced by capture systems is typically above 90 mol% CO2, with some technologies able to achieve far higher purities. However, trace impurities from the flue gas and the capture process can still be present. These can pose integrity risks and operational challenges to CO2 transport and storage networks, according to DNV.

The conditioned CO2 is then compressed for pipeline transport to the temporary storage in the CO2 export terminal. From here, the CO2 may be piped to an import terminal prior to injection, or liquefied for shipping to an import terminal and then injected.

Figure 78: Pictographic depiction of the CCUS value chain



SOURCE: ERM, 2024

CCUS's contribution to the economy

According to GCCSI, CCUS can contribute to countries' economies in six key ways:

1. **Decarbonising hard-to-abate industrial sectors, like cement, iron and steel, and chemicals**
    - Cement production involves heating limestone (calcium carbonate), which breaks down into calcium oxide and CO2; these process emissions (not counting fossil fuel use) account for two-thirds of total emissions from cement production, and cannot be avoided without CCS.
    - Switching from fossil fuels to low-carbon fuels to generate high-temperature heat in industrial facilities would require significant and expensive modification to the facilities; investing in CCS is an alternative way to reducing emissions.
    - The steam methane reforming process releases a lot of CO2 in the process of producing methanol, ammonia and urea from natural gas; CCS is the only way of reducing CO2 emissions from this process.
2. **Extending the lifespan of young coal- and gas-fired power generation capacity**
    - Instead of abandoning young fossil-fuelled power plants, their lifespans can be extended via CCS as that can enable the production of low-carbon power while meeting national emissions goals.
    - Meanwhile, increased renewable energy (RE) uptake will also require dispatchable fossil-fuel power generation to address the intermittent nature of RE power generation.
3. **Hydrogen can be used to decarbonise hard-to-abate sectors**
    - Production of green hydrogen via electrolysis of water using renewable energy is expensive, although the cost of electrolysers will likely fall in the future, in our view.
    - Hydrogen production with CCS (either steam methane reforming with CCS or coal gasification with CCS) is the lowest-cost option for producing low-carbon hydrogen due to the high-concentration of CO2, according to a GCCSI report in 2020.
4. **Creation of new jobs in the CCUS industry**
    - This includes jobs in carbon transport and storage, low-carbon hydrogen, low-carbon ammonia and low-carbon fertiliser industries.
5. **CCS can be beneficial for the oil and gas industry**
    - CCS can reuse existing oil and gas infrastructure (e.g. pipelines and depleted oil and gas wells) by repurposing it for CO2 transport and storage. This may also benefit the industry by delaying decommissioning capex on depleted fields.
    - The captured CO2 can be used for EOR/EGR which can extend productive life of oil and gas assets.
6. **Opening domestic CO2 storage locations to cross-border emitters as a new business model**
    - Countries with limited storage capacity, such as Japan, South Korea and Singapore, can tie-up with regional storage providers, e.g. Malaysia, Indonesia, Thailand and Australia.
    - The regional storage providers can earn revenues and profits from providing the injection and storage services.

CO2 capture

DNV illustrates that CO2 can be captured from four different points.

1. **Post-combustion**

   This captures the CO2 from the exhaust gases (also known as flue gases) of the combustion of coal, oil, gas or biomass in power generation. The CO2 concentration in the post-combustion flue gas are usually low.

2. **Pre-combustion**

   The CO2 is captured prior to combustion. For instance, natural gas is reacted with steam and oxygen at high temperatures and pressures (steam reforming process) to produce a synthesis gas, which is mainly composed of carbon monoxide and hydrogen. The synthesis gas is sent to a catalytic reactor where additional steam is added to convert the carbon monoxide into CO2 and more hydrogen. The resulting gas mixture, now primarily hydrogen and CO2, is cooled and sent to a separation unit, whereby the CO2 is separated from the hydrogen. The CO2 concentration is typically very high in pre-combustion capture.

   Alternatively, coal is reacted with steam and oxygen under high temperature and pressure in a gasifier. This process converts the solid coal into a raw synthesis gas, and the rest of the process is the same as described above.

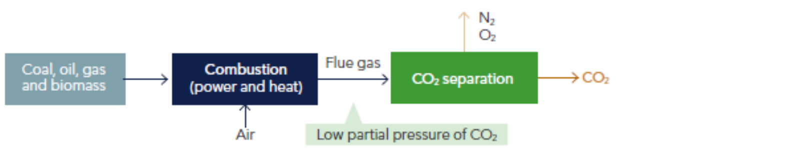
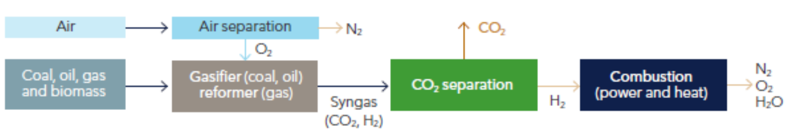
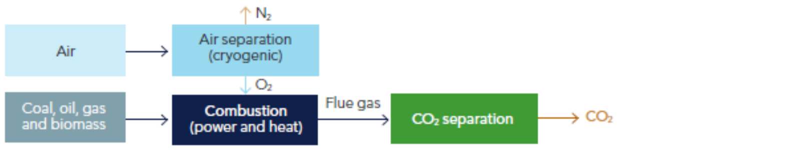
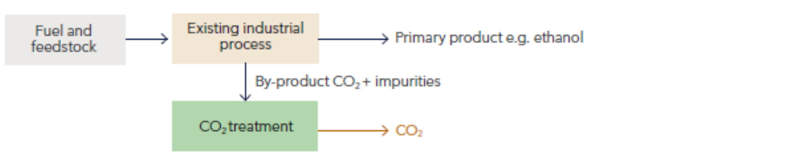
3. **Oxy-combustion**

   Oxy-combustion in power generation plants uses pure oxygen to combust the fuel in power generation plants, instead of the use of air. This results in a flue gas that is overwhelmingly composed of CO2 and water vapor, with very little nitrogen. With high concentrations of CO2, the CO2 separation process can be less costly and more efficient than post-combustion capture.

4. **Inherent capture**

   Ethanol production involves the yeast fermentation of plant-based biomass such as corn or sugarcane, where the starch or sugars are converted into ethanol and CO2, which is naturally produced during the fermentation process. Consequently, the concentration of CO2 is usually very high, and the cost of capture is one of the lowest in the CO2 capture cost curve.

Figure 79: CO2 can be captured from four different sources

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

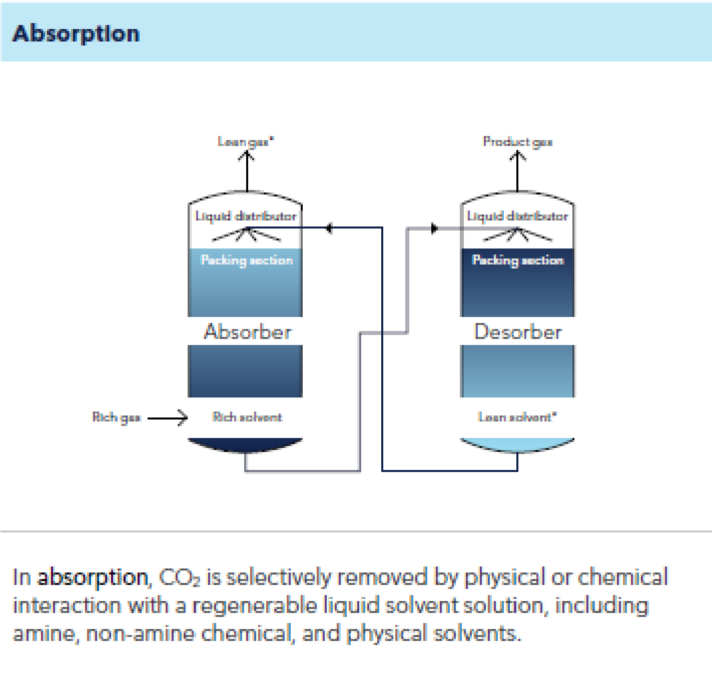
SOURCE: DNV, 2025

Principal capture technologies

This section is sourced from commentary by DNV (2025) and IEA (2023).

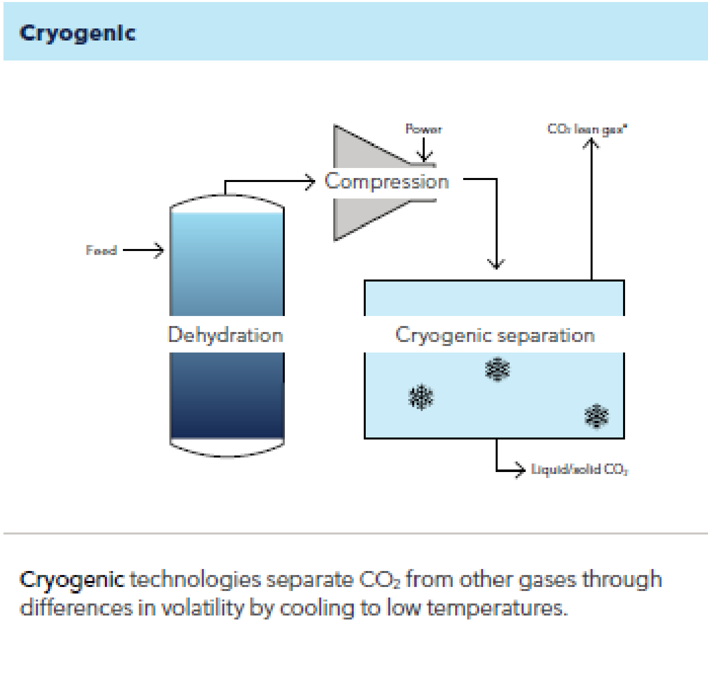
DNV explains that there are four main families of capture technology, i.e. absorption, cryogenic, adsorption, and membrane.

Figure 80: Absorption



SOURCE: DNV, 2025

Figure 81: Cryogenic



SOURCE: DNV, 2025

Absorption can either be physical or chemical in nature.

Physical absorption makes use of a liquid solvent (e.g. Selexol or Rectisol). Physical separation is currently used mainly in ammonia, methanol, and high value chemical production, and coal with CCUS processing, with numerous large plants in operation, according to the IEA.

Chemical absorption (complete immersion) of CO2 is a common process operation based on the reaction between CO2 and a chemical solvent (such as ethanolamine compounds).

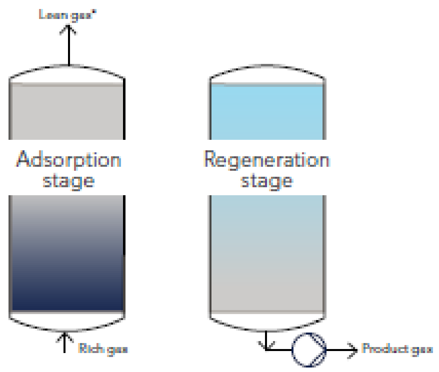
- This operation is usually performed using two columns, one for the absorption and the other operating at a higher temperature, releasing pure CO2 and regenerating the chemical solvent for further operation.
- Chemical absorption using **amine-based solvents** is the most advanced CO2 separation technique. It has been widely used for decades and is currently applied in a number of small- and large-scale projects worldwide in power generation, fuel transformation and industrial production, according to the IEA.

According to DNV, the vast majority of CO2 capture deployment up to 2030F will utilise amine absorption technologies due to their relative maturity and established commercial-scale deployment. Reducing the 'energy penalty' of the CCS process is the key to reducing the gap between the CO2 captured and CO2 avoided. The regeneration of the chemical solvents is a very energy intensive process.

Cryogenic separation is when CO2 is separated from other gases by cooling to low temperatures, as different gases have different condensation points. It is used commercially for streams that already have high CO2 concentrations (typically more than 90%) but it is not used for more dilute CO2 streams, according to website CO2 Capture Project. A significant amount of energy for cooling, but the advantage is that it enables direct production of liquid CO2, which can facilitate shipping.

Figure 82: Adsorption

Adsorption

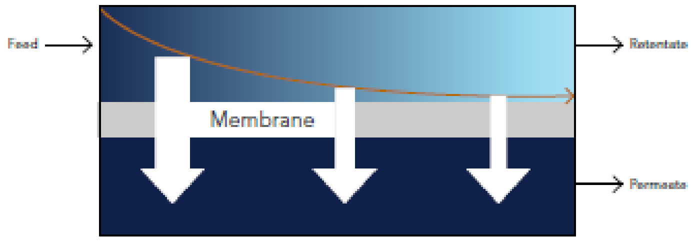


In **adsorption**, CO_2 is selectively trapped on the surface of a solid material through chemical or physical bonds before thermal- or pressure-driven regeneration of the solid material.

SOURCE: DNV, 2025

Figure 83: Membrane

Membrane



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

SOURCE: DNV, 2025

Physical adsorption (surface adhesion) makes use of a solid surface (e.g. activated carbon, alumina, metallic oxides or zeolites).

- After capture by means of an adsorbent, CO2 is released by increasing temperature or reducing pressure (pressure swing adsorption [PSA] or vacuum swing adsorption [VSA]).
- Physical separation is currently used mainly in ammonia, methanol, and high value chemical production, and coal with CCUS processing, with numerous large plants in operation.

Membrane separation is based on polymeric or inorganic devices (membranes) with high CO2 selectivity, which let CO2 pass through but act as barriers to retain the other gases in the gas stream. Membranes for CO2 removal from syngas and biogas are already commercially available, while membranes for flue gas treatment are currently under development.

Technology readiness level of various capture technologies

The US National Aeronautics and Space Administration (NASA) has a Technology Readiness Level (TRL) scale that assesses the maturity of a technology, ranging from basic principles to a fully-proven system. The scale runs from 1 to 9, and is shown below. NASA's TRL scale has been adapted to describe CO2 capture technologies.

Figure 84: Technology Readiness Levels categories

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

SOURCE: GLOBAL CCS INSTITUTE, 2025

For chemical absorption, the highest TRL of 9 is for amine-based solvents and Hot Potassium Carbonate (HPC). According to Swedish energy company Stockholm Exergi, HPC is a chemical process used to capture CO2 from gas streams, primarily by using a hot, aqueous solution of potassium carbonate for chemical absorption.

For physical absorption, the use of liquid solvents also has the highest TRL of 9.

Figure 85: Technology readiness levels of various capture technologies

CATEGORY	TECHNOLOGY	2020 TRL ASSESSMENT	2024 TRL ASSESSMENT	DETAILS
Chemical Absorption	Amine based Solvents	9	9	Widely used in fertiliser, soda ash, natural gas processing plants, e.g. Sleipner, Snøhvit, and used in Boundary Dam
	Hot Potassium Carbonate (HPC)	9	9	Fertiliser plants, e.g. Enid Fertilizer
	Sterically hindered amine	6-9	6-9	Demonstration to commercial plants, depending on technology provider
	Carboxylic Acid based solvent	6-7	6-7	Pilot tests to demonstration plant feasibility studies
	Chilled Ammonia Process	6-7	6-7	Pilot tests to demonstration plant feasibility studies
	Phase change Solvents	5-6	6-7	DMX™ Demonstration
	Water-Lean Solvent	4-7	6-7	Pilot test and commercial scale FEED studies: Gerald Gentleman Station carbon capture plant, the Jinjie pilot plant
	Amino Acid based solvent/Precipitating Solvents	4-5	4-5	Lab test to conceptual studies
	Ionic Liquids	4-5	4-5	Pilot tests
	Encapsulated solvents	2-3	2-3	Lab tests

SOURCE: GLOBAL CCS INSTITUTE, 2025

Figure 86: Technology readiness levels of various capture technologies

CATEGORY	TECHNOLOGY	2020 TRL ASSESSMENT	2024 TRL ASSESSMENT	DETAILS
Physical Absorption	Physical Solvents	9	9	Widely used in natural gas processing, coal gasification plants; e.g. Val Verde, Shute Creek, Century Plant, Coffeyville Gasification, Great Plains Synfuels Plant, Lost Cabin Gas plant
Enzyme-based absorption	Enzyme Catalysed Absorption	6	7-8	Commercial demonstration facility in Quebec
Solid Adsorbent	Pressure Swing Adsorption/Vacuum Swing Adsorption	9	9	Port Arthur SMR VPSA
	Temperature Swing Adsorption	5-7	6-7	Kern River Pilot
	Sorbent-Enhanced Water Gas Shift	5	5	Pilot tests, e.g. STEPWISE
	Electrochemically Mediated Adsorption	2-3	2-3	Lab testing
Membrane	Gas separation membranes for natural gas processing	9	9	Santos Basin Pre-Salt Oil Field CCS
	Polymeric Membranes	7	7	FEED studies for large pilots
	Electrochemical membrane integrated with Molten Carbonate Fuel Cells	7	8	Large pilots at Plant Barry, demonstration plant in South Korea
	Polymeric Membranes / Cryogenic Separation Hybrid	6	6-8	Demonstration plants and pilot studies
	Polymeric Membranes/ Solvent Hybrid	4	4	Conceptual studies
	Room Temperature Ionic Liquid (RTIL) Membrane	2-3	2-3	Lab testing

SOURCE: GLOBAL CCS INSTITUTE, 2025

Figure 87: Technology readiness levels of various capture technologies

CATEGORY	TECHNOLOGY	2020 TRL ASSESSMENT	2024 TRL ASSESSMENT	DETAILS
Solid Looping	Calcium Looping (CaL)	6-7	6-8	STRATOS plant in Texas (0.5 Mtpa) is under construction
	Chemical Looping Combustion	5-6	5-6	Pilot test at ALSTOM's existing Multipurpose Test Facility (3 MWth) and at a technical university in Germany
Inherent Capture	Allam-Fetvedt Cycle	6-7	6-7	50 MW demonstration plant in La Porte
	Lime Processing Kilns	5-6	6-7	Leilac-1, with Leilac 2 under development
Electrolysis	Electrodialysis of Oceanwater	6	6-7	Ongoing field trials
Cryogenic Separation	Cryogenic Distillation	9	9	Deployed on various projects around the world

SOURCE: GLOBAL CCS INSTITUTE, 2025

Carbon dioxide removal (CDR) technologies

This section is sourced from commentary by DNV (2025) and IEA (2023).

There are two key CDR technologies, i.e. direct air capture (DAC) or direct air carbon capture and storage (DACCS), and bioenergy with CCS (BECCS).

DAC/DACCS can remove CO2 directly from the air.

- Challenges include the amount of energy required due to the low concentration of CO2 in the atmosphere. Most DAC technologies require both electricity and heat.
- Electricity is needed for the fans to pull the air through the system, for pumps, CO2 treatment, and to operate other auxiliaries.
- Heat is required for the desorption in solid-sorbent DAC and to regenerate the solvent for liquid-solvent DAC.
- If renewable electricity is used, carbon removal efficiency can be up to 97% (IEA, 2022). However, if natural gas is used without capturing the CO2, carbon removal efficiency can drop to 60% (IEA, 2022).

DAC is generally more expensive than BECCS since it captures CO2 from lower concentrations in the air.

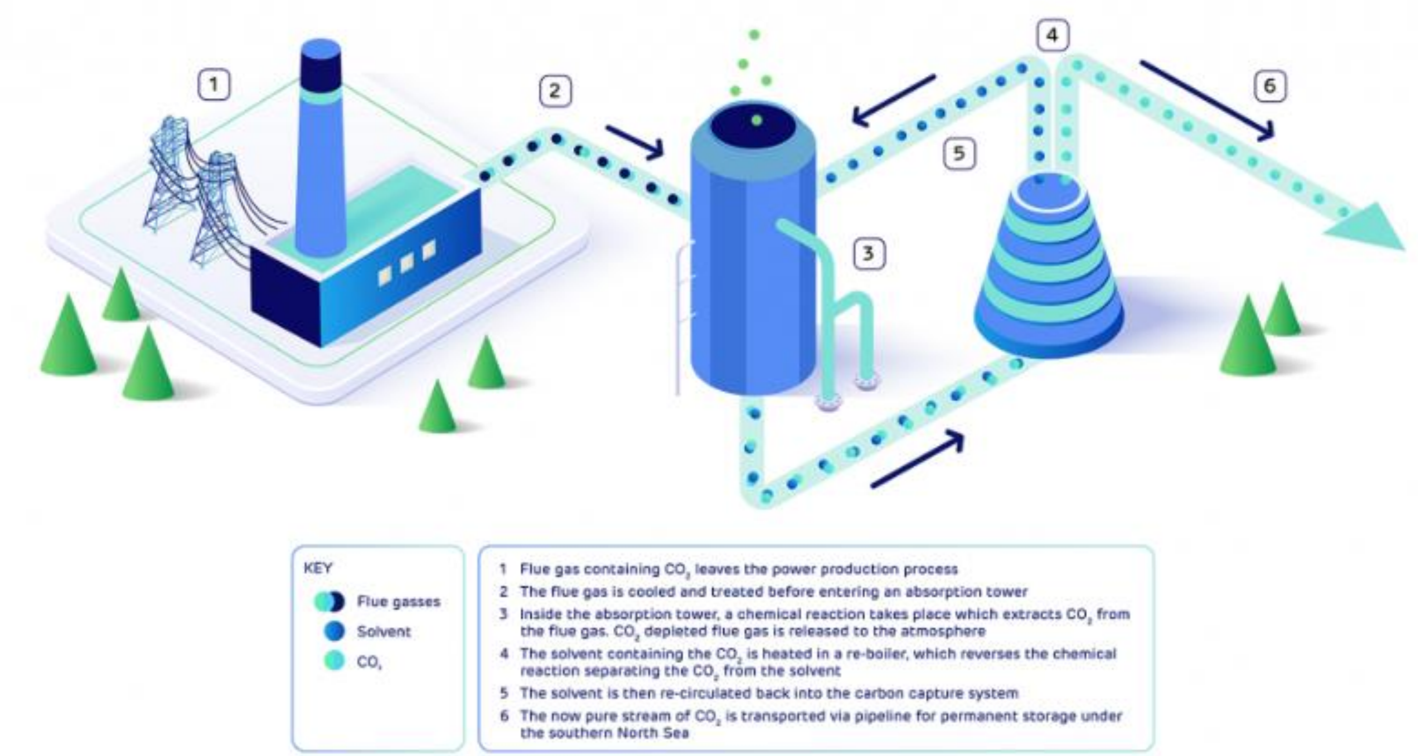
Figure 88: The Climeworks Orca DACCS plant in Iceland (capacity 4 ktpa of CO2)

SOURCE: CLIMEWORKS

BECCS captures biogenic CO2 emissions to deliver net-negative emissions.

- Plants absorb CO2 as they grow. The biomass is converted into fuels or directly burned to generate energy. The captured CO2 is sequestered. This is a way of removing CO2 from the atmosphere.
- Only around 2 Mtpa of biogenic CO2 is currently captured, mainly in bioethanol applications due to the US 45Q tax credit of US$85/tCO2 captured and stored.
- The large-scale deployment of BECCS faces challenges, including competition for land with food production, impacts on biodiversity, water resource stress, and socio-economic equity issues.
- Based on projects currently in the early and advanced stages of deployment, capture on biogenic sources could reach around 60 Mtpa by 2030F, which falls far short of the c.185 Mtpa by 2030F in the IEA's Net Zero Emissions by 2050 (NZE) Scenario.

Figure 89: Illustration of BECCS, from Drax Group, which plans to make a final investment decision in 2027F to convert an existing power plant in Selby, UK, into BECCS power plant



SOURCE: DRAX GROUP

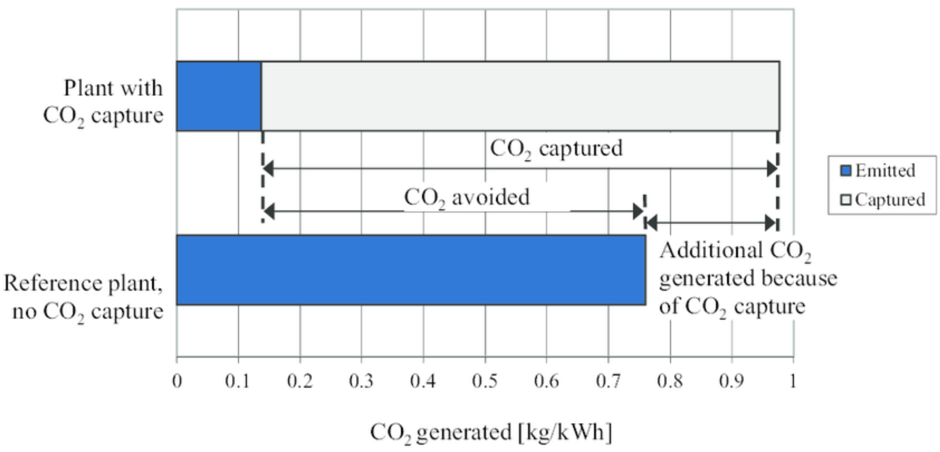
CDR is primarily incentivised through the voluntary carbon market (VCM), as it is not counted in the EU ETS for compliance purposes because it could undermine the EU's primary goal of reducing emissions. DNV anticipates CDR being increasingly incorporated into compliance markets increasingly up to 2050F, and this could stimulate the business case for DACCS and BECCS.

CO2 captured vs. CO2 avoided

This section is sourced from commentary by GCCSI (2025) and IEA (2023).

The volume of CO2 captured by a CCS facility is always greater than the volume of CO2 avoided. This is because the CCS facility also generates its own emissions. Hence, the volume of CO2 avoided is the volume of CO2 captured minus the addition emissions generated by the plant due to the presence of the CCS facility. In other words, the volume of CO2 avoided is the *net* CO2 emissions reduction after the CCS facility is installed, compared to a reference plant without CCS.

Figure 90: CO2 capture vs. CO2 avoided



SOURCE: COMPARISON OF COSTS FOR NATURAL GAS POWER GENERATION WITH CO2 CAPTURE, 2013

Levelised cost of capture (LCC)

- The LCC describes the average cost incurred per unit of CO2 captured over the lifetime of a capture project. It includes capital and operational expenses associated with capturing CO2 from a point source.
- This metric can be added to the levelised cost of transporting and storing (or utilising) CO2 to calculate the economic impacts of implementing CCUS in a given sector.

Figure 91: Levelised cost of capture (LCCUS) formula

$$LCCUS\ (USD\ per\ tonne\ CO_2\ captured) = LCC + CO_2\ T\&S\ cost$$

SOURCE: IEA, 2023

Figure 92: Levelised cost of CO2 avoided (LCCA) formula

$$LCCA = \frac{Levelised\ cost\ (plant\ with\ capture) - Levelised\ cost\ (plant\ without\ capture)}{CO_2\ emissions\ (plant\ without\ capture) - CO_2\ emissions\ (plant\ with\ capture)}$$

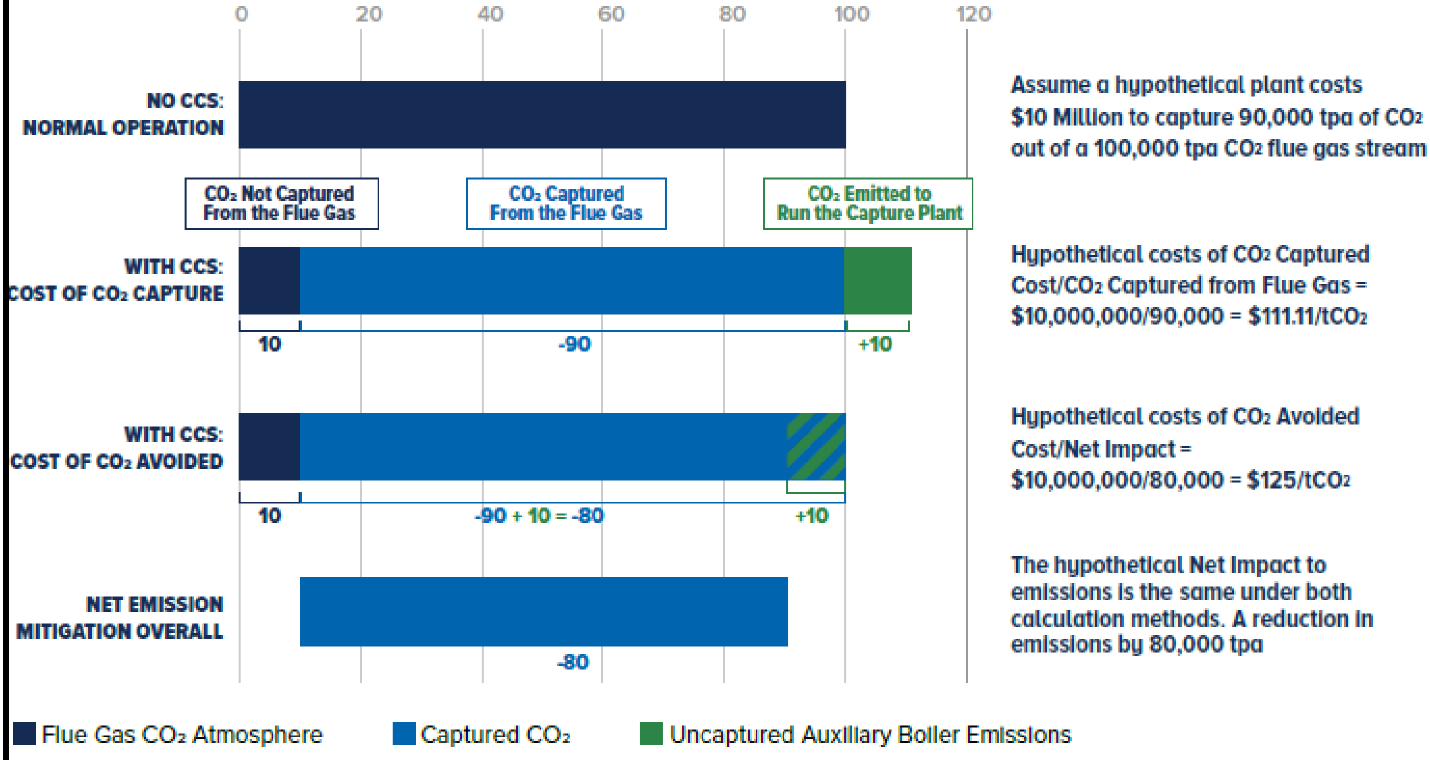
SOURCE: IEA, 2023

Levelised cost of CO2 avoided (LCCA)

- LCCA quantifies the investment and operational costs required to deliver a certain amount of *net* CO2 emissions reduction.
- This metric differs from the LCC by considering any additional CO2 emissions incurred by the implementation of a decarbonisation solution. In the case of CCUS, this can be emissions associated with capturing, transporting or storing CO2.
- Reducing the 'energy penalty' of the CCS process is the key to reducing the gap between the CO2 captured and CO2 avoided, according to DNV.

Because the volume of CO2 avoided will always be smaller than the total capacity of the CO2 capture plant, the levelised cost of CO2 avoided (LCCA) will always be larger than the levelised cost of CO2 captured (LCC) as the total capex and opex costs is spread across a smaller volume of CO2.

Figure 93: The costs of CO2 avoided are always higher than the costs of CO2 captured



SOURCE: GLOBAL CCS INSTITUTE, 2025

As a note, for both the LCC and LCCA metric, capex costs of the CCS facility is factored into the calculation using the "Capital Recovery Factor", which determines the annualised capex costs based on the operating life of the CCS facility and assumed discount rate.

Figure 94: Capital recovery factor calculation

$$\text{Capital Recovery Factor} = \frac{\text{Discount Rate} \times (1 + \text{Discount Rate})^{\text{Plant Operating Life}}}{(1 + \text{Discount Rate})^{\text{Plant Operating Life}} - 1}$$

SOURCE: GLOBAL CCS INSTITUTE, 2025

CO2 transport options

This section is sourced from commentary by DNV (2025).

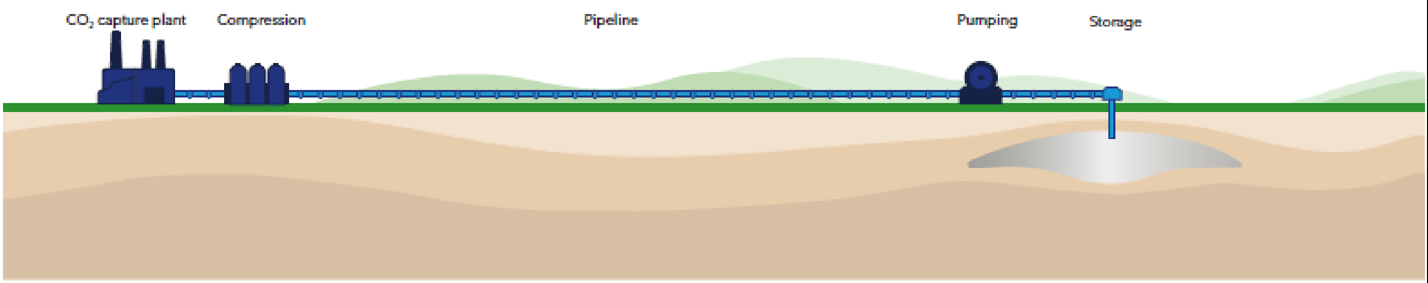
CO2 is typically transported either by pipeline or by ship. Pipeline transport can be used for onshore storage or short-sea offshore storage, while shipping is typically used for offshore sequestration in more distant locations of when the emitters are dispersed.

Pipeline transport

In the US, the availability of vast, non-urbanised, and often flat terrain, as well as cheaper onshore storage options, are resulting in a preference for dense phase CO2 transport through large onshore pipelines and onshore storage, according to DNV.

In Europe, onshore storage is less prevalent, and not allowed in some countries. High population density results in gas phase transport (as opposed to dense phase transport) dominating onshore pipeline development due to safety concerns and stricter regulations, while DNV expects offshore pipelines to mostly operate in dense phase.

Figure 95: Pipeline value chain



SOURCE: DNV, 2025

According to DNV, pipelines have been used to transport CO2 since the 1970s in the US, primarily for EOR purposes. Over 8,000 km of CO2 pipelines are operational in the US today, making this a well-established technology. The typical pipeline value chain is relatively simple, involving the compression of CO2 and the pipeline infrastructure itself.

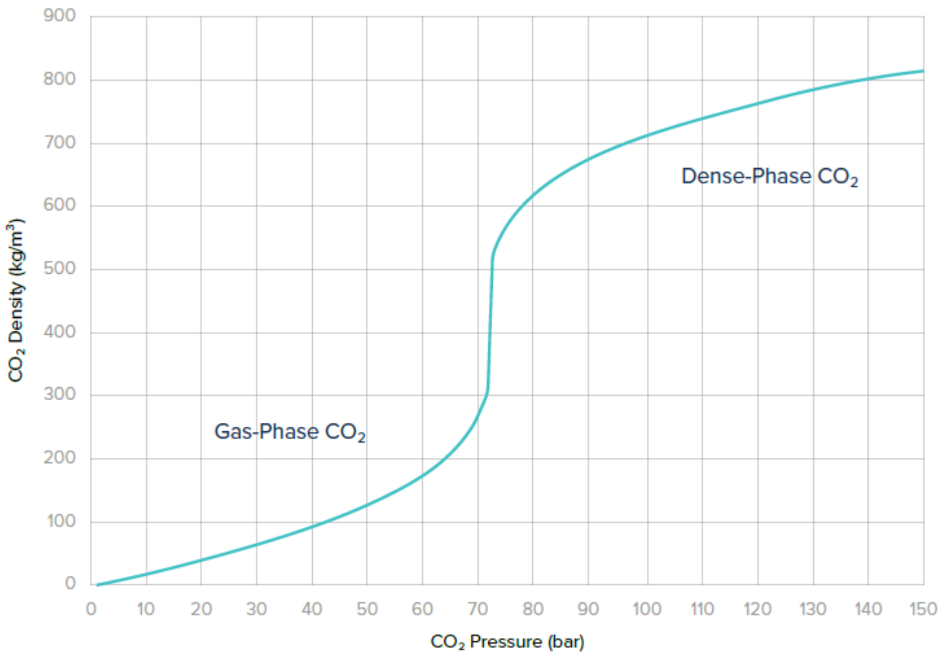
There are two different conditions under which CO2 can be transported: dense phase and gas phase.

- Dense phase transport (where CO2 is maintained either in liquid or supercritical state), is preferred for high-volume, long-distance applications.
- Gas phase transport is generally employed for specific applications, such as repurposed pipelines, early-stage operations with lower volumes, or certain onshore applications like those in urban areas.

International standards generally recommend maintaining CO2 entirely in either dense or gas phase during pipeline transport. Since temperature control is limited, pressure becomes the primary means to achieve the necessary thermodynamic conditions, according to DNV.

Note: According to the US Department of Energy, supercritical CO2 is carbon dioxide in a state above its critical temperature (31.1ºC) and critical pressure (73.9 bar), where it has properties of both a liquid and a gas. This state allows for efficient pipeline transport because the fluid has high density (like a liquid) and low viscosity (like a gas), enabling a high throughput with less drag compared to traditional gas transport.

Figure 96: CO2 density at 30ºC as a function of pressure



SOURCE: GLOBAL CCS INSTITUTE, 2025

Shipping transport

Ship transport, especially in the North Sea or the Mediterranean Sea, will likely play a key role in transporting CO2 between shore terminals or via offshore injection, according to DNV. In Asia, high-emitting countries, such as Korea and Japan, are considering long voyage ship transportation to countries like Malaysia, Indonesia, and Australia, according to the IEA.

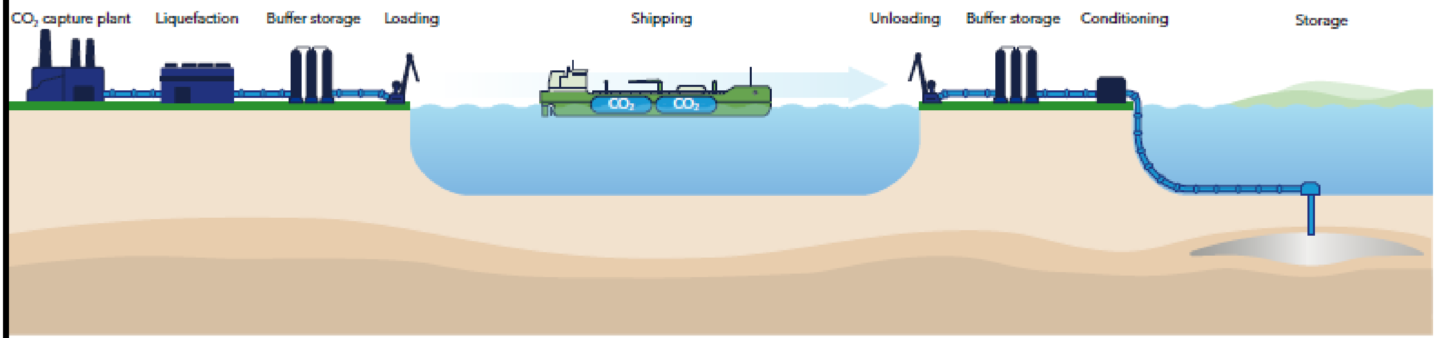
According to DNV, shipping CO2 in the liquid phase for the food and beverage industry has been practiced since the late-1980s, but in considerably smaller volumes than will be relevant for CCS.

A ship-based CCS infrastructure is different to a pipeline infrastructure as ship-based CO2 transport occurs in batches. Hence, buffer storage is essential to accumulate sufficient volumes of CO2 for the ship capacity and logistics. CO2 must also be transported in liquid form to minimise volume and reduce the ship size required.

As a result, the shipping value chain is more complex than pipeline CO2 transport, as it requires a liquefaction unit, buffer storage at both departure and arrival points, specialised vessels, and usually an additional conditioning stage before final storage.

The CO2 can either be transported to a shore-based terminal or to an offshore facility where it is injected either into the reservoir directly from the ship or through a moored or fixed offshore structure.

Figure 97: Shipping value chain (shore-to-shore configuration)



SOURCE: DNV, 2025

Shipping CO2 is often categorised in terms of operating and design pressure — low pressure, medium pressure, and high pressure.

- The pressure regimes have different temperatures, pressures, and density.
- These regimes influence the ship design and liquefaction and conditioning costs, which ultimately impact the overall costs, according to DNV.

Figure 98: Pressure and temperature regimes for LCO2 cargo tank designs

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

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

Source: International Organization for Standardization (2024)

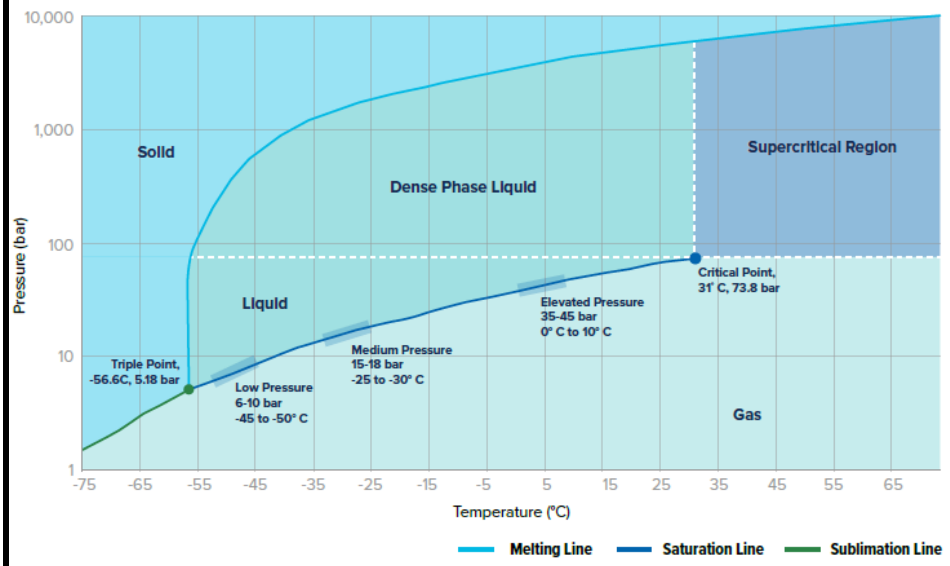
SOURCE: DNV, 2025

Low-pressure LCO2 carriers generally allow for larger cargo tanks and larger vessels, which reduces shipping costs by up to 30% on longer voyages compared to medium pressure, according to a study from public university, ETH Zürich. The main drawback is that it involves storing CO2 closer to its triple point, which increases the risk of dry ice formation and requires more energy for cooling. The CO2 triple point (pressure of 5.18 bar and a temperature of -56.6ºC) is the unique temperature and pressure where solid, liquid, and gas CO2 can all coexist in equilibrium. As a result, low-pressure vessels demand advanced technologies to avoid dry ice formation. However, the economies of scale achieved by transporting larger volumes outweigh these operational complexities, making low-pressure shipping the preferred method for long distances and high-volume projects.

Medium-pressure LCO2 transport is the current standard used in smaller CO2 applications like food-grade CO2 transport, and used for small-scale and early CCS commercial projects, according to IEAGHG, the CCUS research team of the IEA. It avoids the operational complexity of low-pressure systems and is less prone to dry ice formation, points out GCMD. However, it is less cost-effective for large volumes over long distances due to limitations on vessel size. The medium-pressure ships are limited to about 10,000 tCO2 per vessel, smaller than for low-pressure LCO2 carriers because the former's cargo containment systems are heavier as they must be built with thicker walls and stronger materials to withstand the greater force from the higher pressure, according to shipbroker Clarksons. Consequently, there is less economics of scale, and more ships are required to transport the same volume of CO2 as compared to low-pressure vessels.

The main benefit of **high-pressure LCO2 vessels** is the reduced cost for liquefaction and conditioning. With a high-pressure vessel, however, the cargo containment system will be even heavier, and the density of the CO2 is even lower. It necessitates thick-walled vessels to withstand the high CO2 pressures, which requires advanced materials and engineering, significantly increasing the capital costs. As a result, it is not considered cost-efficient for long-distance maritime transport compared to low-pressure systems, according to GCCSI.

Figure 99: CO_2 pressure-temperature phase diagram



SOURCE: GLOBAL CCS INSTITUTE, 2025

Storage of CO_2

This section is sourced from commentary by DNV (2025).

The most common method of permanent CO_2 storage is within basins comprised of sedimentary rocks, i.e. depleted oil and gas fields, or deep saline aquifers.

Saline aquifers are underground formations of porous and permeable rocks saturated with very salty water. Saline aquifers make up 80% of the US CO_2 geologic storage capacity. In European CCS projects, there is preference for the use of saline aquifers.

Depleted oil and gas fields for CO_2 storage

Advantages

- The depleted oil and gas fields are proven subsurface traps and seals that have retained hydrocarbon accumulations for millions of years.
- These fields are also well characterised after years of exploration, appraisal and operations by oil and gas companies.
- The repurposing of existing wells for CCS purposes can help to reduce the costs of the CCS projects.

Disadvantages

- The storage capacity of individual depleted fields may generally be more limited compared to saline aquifers.
- Years of hydrocarbon production may have negatively impacted the reservoirs' sealing formations and suitability for CO_2 storage, with potential leakage paths.
- The residual hydrocarbons within the depleted field may inhibit the effectiveness of seismic surveys for the purposes of monitoring the injected CO_2.

Saline aquifers for CO_2 storage

Advantages

- These saline aquifers have not been used for fossil fuel extraction, and hence have fewer number of wellbore penetrations, thereby reducing the number of potential leakage pathways.
- The saline aquifers also have much larger pore space compared to oil and gas reservoirs, thereby increasing the potential CO_2 storage capacity.
- It is also easier to monitor injected CO_2 using seismic surveys in the absence of residual hydrocarbons.

Disadvantages

- New infrastructure and storage wells will be necessary when using saline aquifers for CO_2 storage, which may increase costs compared with depleted field projects that repurpose existing infrastructure.
- The storage performance of saline aquifers is initially less technically certain compared to depleted oil and gas wells, due to limited data availability from fewer wellbore penetrations and the lack of evidence that the intended trap and seal is viable.

CO_2 storage via EOR/EGR

EOR/EGR has been carried out mostly in the US and the Middle East since the 1970s. The produced CO_2 can then be separated from the oil and either recycled for continued EOR or vented.

Advantages

- CO_2 storage via injection into existing producing oil and gas wells for EOR/EGR purposes is a form of utilisation that conveys economic benefits.
- CO_2 storage via EOR/EGR is effective in keeping c.99% of the injected CO_2 trapped in the reservoir and permanently stored in the subsurface, according to IEA.

Disadvantages

- The injected CO_2 can react with formation water to create carbonic acid, which can interact with the reservoir and caprock minerals. This can lead to mineral dissolution (potentially creating new leakage pathways), or mineral precipitation (which can reduce injectivity/permeability), according to an academic study by the China University of Petroleum.

APPENDIX 3: CCUS BUSINESS MODELS

This section is sourced from commentary by The Oxford Institute for Energy Studies (2024).

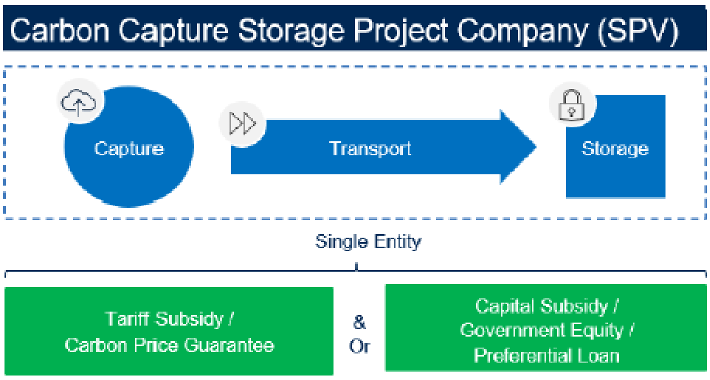
In the full chain CCS business model, a single company undertakes the capture, transport and storage of CO2. In the partial chain model, a few separate companies break up the value chain; typically with emitters on one side of the equation and with another company providing the transport and storage (T&S) service to the emitters.

Full chain model

A full chain model may also be either state-owned or privately-owned or consisting of a public-private partnership (PPP), dependent on the approach a government has taken to establish a viable and sustainable market for CCS.

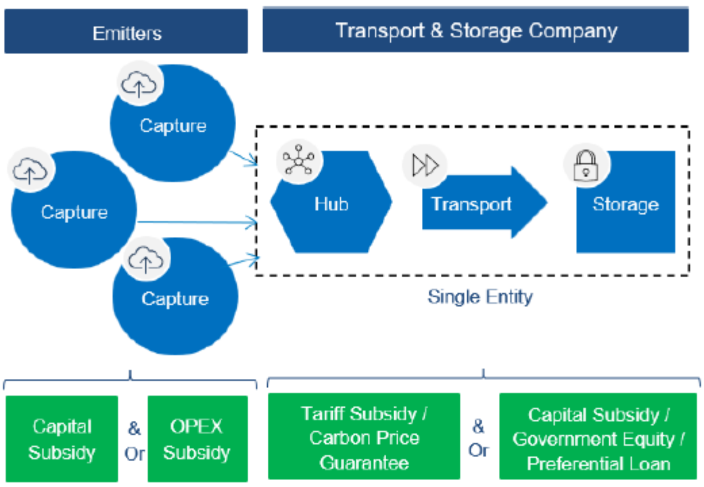
- In China, NOCs such as Sinopec, PetroChina, and CNOOC dominate nearly all CCS projects, except for the Karamay methanol plant, operated by the private Dunhua Oil Company.
- In the Middle East, NOCs such as Saudi Aramco, QatarEnergy (in collaboration with ExxonMobil) and ADNOC hold sway over the regional operational of CCS projects.
- Examples of public-private partnerships include Norway. The Norwegian government is the majority shareholder in Equinor, which boasts almost three decades of experience operating commercial CCS projects.

Figure 100: Full chain model concept



SOURCE: THE OXFORD INSTITUTE FOR ENERGY STUDIES, 2024

Figure 101: Partial chain model – single hub concept



SOURCE: THE OXFORD INSTITUTE FOR ENERGY STUDIES, 2024

The majority of CCS projects currently in operation adopt the full chain model, whereby the captured CO2 is transported from one capture facility to one injection site. The project is usually developed, owned and operated by a single entity. It is commonly adopted for EOR projects and for demonstration sequestration projects where the operator is able to control the development, execution and operation of full value chain from emissions to storage site.

This is a natural model for a first-of-a-kind (FOAK) project to prove the concept with capture-ready emitters and is usually accompanied by government subsidies to bridge the funding gap.

The advantages of such a model are the limited development and coordination risks, due to one entity operating the entire chain, although the operator bears all the liabilities and must possess the technical and operational expertise in all areas of the CCS chain.

Examples of full chain model projects include:

- Gorgon CCS, Australia – for natural gas processing
- Qatar LNG, Qatar – for natural gas processing
- Sleipner CCS, Norway – for natural gas processing
- Snohvit CCS, Norway – for natural gas processing
- Uthmaniyah CCS, Saudi Arabia – for natural gas processing
- Al-Reyadah CCS, UAE – for steel production

Partial chain model

Partial chain models offer a strategic advantage by enabling emitters to delegate the expertise in T&S to specialised companies, including the establishment of CCS hubs that facilitates the connection between more dispersed and smaller emitters and T&S providers.

The risks associated with partial chain models include increased cross-chain and coordination risks since multiple entities are involved. This describes a 'chicken and egg' situation whereby emitters are reluctant to invest in capture facilities unless they have certainty on where the captured CO2 will be taken and stored, and T&S operators will not invest in T&S infrastructure unless there is a critical mass of customers (emitters) who have committed to investing in capture plants. This is where some governments have stepped in with financial and regulatory support.

The partial chain, single hub model is currently adopted by many European countries developing CCS, including:

- UK's 'Track-1' and 'Track-2' CCUS clusters
- Denmark's Project Greensand Phase 1 and Bifrost
- Norway's Longship and Northern Lights CCS, and the Havstjerne CCS projects
- Netherlands' Aramis and Porthos CCS projects
- Saudi Arabia's Jubail CCS hub

Several emitters would all feed into the shared T&S infrastructure of the CCS hub. Ownership and operation of the T&S infrastructure is carried out by a single entity (or a consortium of companies potentially including SOEs), forming a natural monopoly and therefore requiring regulation of fees and access. This model relies on substantial government participation, as the case with Denmark, or via a Regulatory Asset Base (RAB) model, such as the case with the UK.

In the case of the emitter, direct subsidy of both capex and opex is required. Some form of subsidy or equity investment in the T&S infrastructure is required to share the project risks, reduce the WACC and effectively reduce the T&S tariff. A T&S agreement is negotiated directly between the T&S operator and each individual emitter. There is also an option for government to take equity in T&S infrastructure; with state ownership, there is easier access to finance, usually at lower rates than for private enterprises operating alone.

Integrated T&S networks servicing multiple emitters do face significant challenges. Some challenges include flow assurance issues, the need to identify and meet strict CO2 purity specifications (i.e. permitted impurity levels), interdependencies, and overall increased complexity.

APPENDIX 4: PATHWAYS FOR UTILISATION OF CAPTURED CO2

This section is sourced from commentary by DNV (2025).

IEA reported in 2019 that around 230 MtCO2 are used in commercial applications annually, of which c.75 Mtpa (30%) is used in EOR and 130 Mtpa (56%) is used in fertiliser production.

These are some of the key ways that CO2 can be utilised.

1. **Enhanced oil recovery (EOR)**
   - This is a well-established utilisation pathway. EOR involves injecting CO2 into oil reservoirs to increase the extraction of crude oil. CO2 acts as a solvent, reducing the viscosity of the oil and allowing it to flow more easily to production wells. Annual use is c.70-80 MtCO2.
2. **Chemical industry**
   - In the fertiliser industry, CO2 is used as a feedstock that reacts with ammonia to form urea, a nitrogen-based fertiliser. Annual use is c.130 MtCO2.
   - The Solvay process is an industrial method that uses CO2 to produce sodium carbonate (soda ash) (used in glass manufacturing, pulp and paper processing, and other industrial processes).
3. **Welding**
   - CO2 is commonly used in welding as a shielding gas, particularly in gas metal arc welding (GMAW) or metal inert gas (MIG) welding.
4. **Agriculture**
   - CO2 is used in greenhouses to enhance plant growth through a process known as CO2 enrichment. Increasing CO2 levels in a greenhouse can significantly boost photosynthesis, leading to faster and more robust plant growth.
5. **Food and beverage industry**

   CO2 is extensively used in the food and beverage industry for various applications.
   - Carbonation: CO2 is used to carbonate beverages such as beer, soft drinks, and sparkling water, giving them their characteristic fizz and preventing the growth of bacteria and fungi.
   - Preservation: CO2 helps preserve grains, fruits, and vegetables by preventing pest infestation and maintaining freshness through modified atmosphere packaging (MAP) or controlled atmosphere packaging (CAS).
   - Freezing and refrigeration: CO2 is used in cryogenic freezing and as a refrigerant to preserve the taste and texture of food items. Dry ice, a solid form of CO2, is also used for shipping and transporting frozen foods.
   - Solvent: CO2 is used in various industrial processes due to its unique properties. In supercritical form, CO2 acts as an effective solvent for extracting compounds, such as in the decaffeination of coffee and the extraction of essential oils. Its non-toxic nature and ability to operate at relatively low temperatures make it ideal for preserving the integrity of sensitive materials.

Emerging applications are among potential pathways of CO_2 conversion.

6. **Fuels**
   - Synthetic fuels: CO_2 can be converted into synthetic fuels like methanol and ethanol, which can be used in transportation.
   - Sustainable aviation fuel (SAF): CO_2-derived fuels are being developed for use in aviation, offering a greener alternative to traditional jet fuels.
   - The higher cost of these synthetic fuels rely on voluntary demand, unless there is a mandate for such fuels, such as the EU's SAF mandate.
7. **Chemicals**
   - Polymers and plastics: CO_2 can be used as a feedstock to produce various polymers and plastics, reducing reliance on fossil fuels.
8. **Building materials**
   - Concrete: CO_2 can be utilised in the production of concrete, where it is permanently stored, reducing the carbon footprint of construction.
9. **Aggregates**
   - CO_2 can be converted into aggregates used in construction.

Figure 102: The traditional steam methane reforming process for methanol production

Steam methane reforming pathway to producing methanol

Methane gas (CH_4) and steam (H_2O) is passed over a nickel catalyst in the steam reforming process under high temperatures and pressure to create synthesis gas, which is a mixture of carbon monoxide (CO and hydrogen (H_2), and CO_2.

$CH_4 + H_2O \rightarrow$ Synthesis gas ($CO + 3H_2$) + CO_2

The carbon dioxide (CO_2) can be reacted under high temperatures and pressure over a nickel catalyst with more methane (CH_4) and steam (H_2O) to produce more synthesis gas.

$CO_2 + 3CH_4 + 2H_2O \rightarrow$ Synthesis gas ($4CO + 8H_2$)

The synthesis gas is then combined to make methanol (CH_3OH), using a catalytic converter at high pressures and temperatures, with a copper-zinc catalyst.

$CO + 2H_2 \rightleftharpoons CH_3OH$

SOURCE: CGSI RESEARCH

Figure 103: The chemical process for synthetic methanol

Producing synthetic methanol

Green hydrogen (H_2) is produced using the electrolysis of water and renewable energy.

The CO_2 captured from the CCS process and green hydrogen (H_2) is compressed, mixed, and heated. This mixture is fed into a reactor containing a catalyst, most commonly a copper / zinc oxide / aluminum oxide catalyst.

The high temperature and pressure drive the chemical reaction:

$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$

SOURCE: CGSI RESEARCH

Figure 104: The traditional steam methane reforming process for ammonia and urea production

Steam methane reforming pathway to producing ammonia and urea

The hydrogen (H_2) from synthesis gas is combined with nitrogen (N_2) that is derived from the atmosphere via an air separation unit, is passed over an iron catalyst at high temperatures and pressures via the Haber process to derive ammonia (NH_3).

$3H_2 + N_2 \rightarrow 2NH_3$

Urea [$CO(NH_2)_2$] is manufactured using the Bosch–Meiser urea process. First, liquid ammonia (NH_3) is reacted with carbon dioxide (CO_2) at high temperatures and pressure to form ammonium carbamate (H_2N-$COONH_4$).

$2NH_3 + CO_2 \rightleftharpoons H_2N\text{-}COONH_4$

After that, ammonium carbamate (H_2N-$COONH_4$) into decomposed into urea [$CO(NH_2)_2$] and water (H_2O):

$H_2N\text{-}COONH_4 \rightleftharpoons CO(NH_2)_2 + H_2O$

SOURCE: CGSI RESEARCH

Figure 105: The chemical process for synthetic ammonia and urea

Producing synthetic ammonia and urea

Green hydrogen (H_2) is combined with nitrogen (N_2) that is derived from the atmosphere via an air separation unit, is passed over an iron catalyst at high temperatures and pressures via the Haber process to derive ammonia (NH_3).

$3H_2 + N_2 \rightarrow 2NH_3$

The CO_2 captured from the CCS process is reacted with liquid ammonia (NH_3) using the Bosch–Meiser urea process to produce urea.

SOURCE: CGSI RESEARCH

APPENDIX 5: OTHER COMPANIES MENTIONED IN THIS REPORT

Figure 106: Other companies mentioned in this report

No	Companies mentioned	Bloomberg code	Share price	CGSI Research	
				Recom.	Target price
1	ACWA Power	ACWA AB	SAR192.00	N.A.	N.A.
2	ADNOC	Not listed	N.A.	N.A.	N.A.
3	Aker Solutions	AKSO NO	NOK30.62	Not rated	N.A.
4	Altera Infrastructure	Not listed	N.A.	N.A.	N.A.
5	Andritz AG	ANDR AV	€62.25	Not rated	N.A.
6	Beach Energy	BPT AU	A$1.18	Not rated	N.A.
7	Beijing BBMG Group	Not listed	N.A.	N.A.	N.A.
8	Capital Gas Ship Management	Not listed	N.A.	N.A.	N.A.
9	Carbon Aceh	Not listed	N.A.	N.A.	N.A.
10	China Huaneng Group	Not listed	N.A.	N.A.	N.A.
11	China Resources Building Materials Technology Holdings	1313 HK	HK$1.63	N.A.	N.A.
12	CHN Energy	Not listed	N.A.	N.A.	N.A.
13	China United Cement Group	Not listed	N.A.	N.A.	N.A.
14	Clean Energy Systems Inc	Not listed	N.A.	N.A.	N.A.
15	Climeworks	Not listed	N.A.	N.A.	N.A.
16	Dalian Shipbuilding Offshore Co	Not listed	N.A.	N.A.	N.A.
17	Drax Group	DRX LN	GBp743.00	N.A.	N.A.
18	Dunhua Oil Company	Not listed	N.A.	N.A.	N.A.
19	Emirates Steel	Not listed	N.A.	N.A.	N.A.
20	Energi Mega Persada PT	ENRG IJ	IDR1,000	N.A.	N.A.
21	Eneos Xplora	Not listed	N.A.	N.A.	N.A.
22	Exploration and Production Malaysia Venture (EPMV)	Not listed	N.A.	N.A.	N.A.
23	ExxonMobil Exploration and Production Malaysia	Not listed	N.A.	N.A.	N.A.
24	Gasunie (Nederlandse Gasunie)	Not listed	N.A.	N.A.	N.A.
25	Global Infrastructure Partners (GIP)	Not listed	N.A.	N.A.	N.A.
26	Harbour Energy	HBR LN	GBp208.40	N.A.	N.A.
27	Havstjerne ANS	Not listed	N.A.	N.A.	N.A.
28	Huaneng Power International	902 HK	HK$6.26	N.A.	N.A.
29	HD Hyundai Heavy Industries	329180 KS	Won514,000	Add	Won737,000
30	HD Hyundai Mipo Dockyard	010620 KS	Won223,000	Add	Won249,000
31	Inpex Corp	1605 JP	JPY3,196	N.A.	N.A.
32	IRPC	IRPC TB	THB1.00	Reduce	THB0.78
33	Japan Petroleum Exploration Co (JAPEX)	1662 JP	JPY1,397	N.A.	N.A.
34	JGC Holdings Corp (JGC)	1963 JP	JPY1,874	N.A.	N.A.
35	Jules Nautica	Not listed	N.A.	N.A.	N.A.
36	Kawasaki Kisen Kaisha (K Line)	9107 JP	JPY2,071	N.A.	N.A.
37	Keppel Corp	KEP SP	S$10.25	Add	S$12.71
38	Korea Shipbuilding & Offshore Engineering	009540 KS	Won400,500	Add	Won586,000
39	KUFPEC Malaysia	Not listed	N.A.	N.A.	N.A.
40	Linde	LIN US	US$410.32	N.A.	N.A.
41	Malayan Cement	LMC MK	RM6.65	Add	RM9.00
42	Microsoft	MSFT US	US$492.01	N.A.	N.A.
43	Mitsubishi Shipbuilding	Not listed	N.A.	N.A.	N.A.
44	Mitsui & Co Ltd	8031 JP	JPY4,090	N.A.	N.A.
45	Mitsui OSK Lines	9104 JP	JPY4,398	N.A.	N.A.
46	Malaysia Marine and Heavy Engineering (MMHE)	MMHE MK	RM0.35	N.A.	N.A.
47	Navigator Holdings	NVGS US	US$17.89	N.A.	N.A.

SHARE PRICES AS AT 1 DEC 2025
SOURCES: CGSI RESEARCH, BLOOMBERG

Figure 107: Other companies mentioned in this report

No	Companies mentioned	Bloomberg code	Share price	CGSI Research	
				Recom.	Target price
48	Occidental of Oman (Oxy Oman).	Not listed	N.A.	N.A.	N.A.
49	Oman LNG	Not listed	N.A.	N.A.	N.A.
50	OQ	Not listed	N.A.	N.A.	N.A.
51	OQ Gas Networks (OQGN)	OQGN OM	OMR0.19	N.A.	N.A.
52	PacificLight Power	Not listed	N.A.	N.A.	N.A.
53	Panca Amara Utama PT	Not listed	N.A.	N.A.	N.A.
54	Pavilion Energy	Not listed	N.A.	N.A.	N.A.
55	Pema Global Energi PT	Not listed	N.A.	N.A.	N.A.
56	Pembangunan Aceh Perseroda PT	Not listed	N.A.	N.A.	N.A.
57	Pengerang LNG (Two)	Not listed	N.A.	N.A.	N.A.
58	Pertamina	Not listed	N.A.	N.A.	N.A.
59	Pertamina Hulu Energi Jabung PT	Not listed	N.A.	N.A.	N.A.
60	Perusahaan Listrik Negara (Persero) PT	Not listed	N.A.	N.A.	N.A.
61	PetroChina International Jabung	Not listed	N.A.	N.A.	N.A.
62	Petroleum Development Oman (PDO)	Not listed	N.A.	N.A.	N.A.
63	Petroleum Sarawak Berhad (Petros)	Not listed	N.A.	N.A.	N.A.
64	Petroliam Nasional (Petronas)	Not listed	N.A.	N.A.	N.A.
65	Petronas Carigali	Not listed	N.A.	N.A.	N.A.
66	Petronas Carigali (Jabung)	Not listed	N.A.	N.A.	N.A.
67	Petronas CCS Ventures	Not listed	N.A.	N.A.	N.A.
68	Petronas Gas	PTG MK	RM17.50	Hold	RM17.70
69	PetroVietnam	Not listed	N.A.	N.A.	N.A.
70	PetroVietnam Exploration Production Corp	Not listed	N.A.	N.A.	N.A.
71	POSCO International Corp	Not listed	N.A.	N.A.	N.A.
72	POSCO Engineering & Construction	Not listed	N.A.	N.A.	N.A.
73	PTT Global Chemical	PTTGC TB	THB20.40	Reduce	THB19.00
74	QatarEnergy	Not listed	N.A.	N.A.	N.A.
75	Qatar Petroleum	Not listed	N.A.	N.A.	N.A.
76	Repsol	REP SM	€15.98	Not rated	N.A.
77	Samsung Engineering	Not listed	N.A.	N.A.	N.A.
78	Samsung Heavy Industries	010140 KS	Won24,200	Add	Won33,000
79	Santos	STO AU	A$6.37	Not rated	N.A.
80	Saudi Basic Industries Corporation (SABIC)	SABIC AB	SAR54.00	N.A.	N.A.
81	Siam Cement Group	SCC TB	SAR190.50	Reduce	130.00
82	SK Earthon	Not listed	N.A.	N.A.	N.A.
83	SK Energy	Not listed	N.A.	N.A.	N.A.
84	GS Energy Corporation	Not listed	N.A.	N.A.	N.A.
85	Lotte Chemical Corp	011170 KS	Won72,700	Add	Won98,000
86	SLB	SLB US	US$36.24	N.A.	N.A.
87	Stella Maris CCS AS	Not listed	N.A.	N.A.	N.A.
88	Stockholm Exergi	Not listed	N.A.	N.A.	N.A.
89	Storegga	Not listed	N.A.	N.A.	N.A.
90	Tenaga Nasional Bhd	TNB MK	RM13.32	Add	RM18.00
91	Thai Oil	TOP TB	THB36.75	Hold	THB38.00
92	Toshiba Energy Systems & Solutions	Not listed	N.A.	N.A.	N.A.
93	Uniper	UN0 GR	€34.25	Not rated	N.A.
94	Vopak	VPK NA	€39.04	Not rated	N.A.
95	Wintershall Dea	Not listed	N.A.	N.A.	N.A.
96	YTL Power	YTLP MK	RM3.26	Hold	RM3.30
97	YTL PowerSeraya	Not listed	N.A.	N.A.	N.A.

SHARE PRICES AS AT 1 DEC 2025
SOURCES: CGSI RESEARCH, BLOOMBERG

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551 companies under coverage for quarter ended on 30 September 2025		
	Rating Distribution (%)	Investment Banking clients (%)
Add	69.9%	1.3%
Hold	20.7%	0.5%
Reduce	9.4%	0.4%

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Add	The stock's total return is expected to exceed 10% over the next 12 months.
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