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Carbon Capture in the Southeast Asian Market Context

Sorting out the Myths and Realities in Cost-Sensitive Markets

Executive Summary

In recent years, Carbon Capture Utilization and Storage (CCUS) discussions have gained traction in Southeast Asia (SEA). CCUS' strategic value lies in its ability to retrofit existing assets and hard-to-abate sectors. The young fleet of coal and gas power plants in SEA suggests the region may present the right fit for CCUS applications.

It is critical to understand that CCUS is not a monolithic subject. Examples of CCUS applications include gas processing and power generation. Each application primarily runs on separate tracks with their own maturity and costs projections. Three applications currently dominate the discussions in SEA: gas processing, industries/product based CCUS for hydrogen/ammonia, and potential future usage in the power sector. Gas processing CCUS is arguably the lowest cost and most mature application, primarily due to the relative ease of capturing highly concentrated carbon dioxide (CO_2) in its flue gas, compared to the diluted low-pressure CO_2 in power sector applications.

In planning ahead for their respective net zero targets, stakeholders in SEA should clearly understand what CCUS could and could not likely offer – sorting out the myths and realities. The Institute for Energy Economics and Financial Analysis' (IEEFA) summarises the following:

- **Discussions surrounding the need for 'policy support' should not veer from the big questions on CCUS: which CCUS drivers would be present in SEA countries? Carbon emissions valuations, strong public funding support or market drivers?** In IEEFA's view, very few of these drivers exist in SEA, other than Singapore. In a region where a carbon price is practically non-existent and the chance for it to reach more than US\$50/tCO_2 is unlikely in the near future, widespread CCUS use would likely be constrained. Several CCUS cost projections indicate that within the next several decades, the cost of CCUS in the power sector is unlikely to be competitive, particularly in light of the continual decline of renewable energy and storage costs. In 2020, the International Energy Agency (IEA) presented a CCUS cost projection under the Sustainable Development Scenario (SDS), which projects the decline in cost of CO_2 *capture* for coal power from circa US\$65/tCO_2 in 2020 to US\$40/tCO_2 in 2070 – a value likely far from the immediate reach of most SEA nations.

- **Three-quarters of the newly planned CCUS capacity in SEA is for gas**

processing, a 'different' CCUS from the majority of other markets. Gas processing CCUS has been applied since the 1970s to deal with CO_2-rich resources. SEA is home to considerable gas resources which contain large amounts of excess CO_2 when produced. A combination of market drivers and the imperative to raise state revenue have been the most noticeable drivers to adopt CCUS. This CCUS is notably 'different' from other CCUS applications, as it captures the *excess* CO_2 from gas production, not the CO_2 from final use or combustion of the gas, which is more commonly done in other CCUS applications. In evaluating such projects, host countries need to understand the implications of the various CCUS investment drivers, such as the Internal Carbon Pricing (ICP) policies of investing companies. Through ICP, companies voluntarily embed a 'shadow' carbon price into their business decisions, which should have already moved the investors' baseline scenario. Finding a fair share of CCUS cost allocations between the host government and the investor remains crucial.

- **Representing CCUS as 'technologically mature' muddles public understanding as maturity means little when commercial applications remain far off.** A technology can be viable under the right circumstances – high carbon tax, large incentives, and tight emissions regulations – while remaining implausible in countries with no carbon pricing and lax emissions regulations. The United States (US) is home to half of the world's CCUS capacity, and their 45Q Internal Revenue Code currently applies US$35-50 of tax credit for every tonne of CO_2 injected, with CCUS proponents proposing the incentives to be expanded to US$85+/t$CO_2$.

- **The power sector: with the high cost of failure involved and a patchy history, different pathways of scaling up CCUS should be expected compared to other, more nimble technologies such as solar PV and wind energy**. With the CCUS retrofit for a 240 megawatt (MW) coal plant costing US$1bn in 2017, the cost of failure remains high. Government grants 'policy push' have and will likely continue to play a predominant role in influencing CCUS development. For instance, the US Government Accountability Office reported that the US government alone spent US$1.1bn on demonstration projects between 2010 and 2017, with *none* of the eight government-supported coal CCS operational in 2022. The EU has spent at least €424m, with 'intended progress not achieved' as stated by the European Court of Auditors. Due to the high cost of failure, the design-build-prove cycle of CCUS will likely operate on a different time frame. Scaling up CCUS will likely play out differently compared to other technologies, which can make incremental improvements more readily.

  Only one commercial power generation CCUS is operating globally at present. One for coal and none for gas. Claims of a continued cost decline trend have been largely based on feasibility studies instead of empirical evidence and should be evaluated with care. Boundary Dam CCUS in Canada received CAD240m in government funding, while Petra Nova, the only other plant, was shut down indefinitely in 2021 due to 'economic reasons' despite having been supported by a massive US$190m in funding from the US government.

- **CCUS is energy-intensive, and measuring the cost of CO_2 *captured* is insufficient, as the cost of CO2 *avoided* needs to be the measure.** CCUS process consumes significant amounts of energy, of which associated emissions need to be considered. Current CCUS costs in power could easily add 6-9 c/kilowatt-hour (kWh) to the power generation costs. Further, in assessing the full CCUS cost in South East Asia, stakeholders will need to consider the predominance of subcritical coal plants, which generate higher emissions, and the generally lax emissions standards. The latter will potentially add to the cost as CCUS technology typically requires adequate flue gas pre-treatment standards.

- **The three potential leaders for CCUS in Asia are still inching slowly.** China's total CCUS capacity ranges between 2 to 4 Million Tonnes Per Annum (MTPA) CO_2 spread over dozens of small-scale facilities. South Korea's CCUS is largely limited to pilot projects, while Japan's CCUS long-term trial was built with 0.2 MTPA capacity. Compare this with US' Shute Creek plant with 7 MTPA capacity in a single plant. As the traditional leaders in energy technology and investments in the region – how these three countries move forward with CCUS will be important for SEA. It is especially important given the rapid decline of coal power in the US, home to most of the global capacity of CCUS, and potentially, along with it, its attention to coal power CCUS, a dominant part of the SEA power mix. It is notable that while Japan has some forms of regulatory-based emissions control, its carbon pricing remains paltry at best, with a carbon tax of US$3/$tCO_2e$, despite actively promoting CCUS in the SEA region.

- **Bilateral initiatives can be an ally for CCUS deployment in SEA, but the scale and cost intensity of CCUS make it unlikely to promote widespread adoption.** Initiatives such as the Joint Crediting Mechanism (JCM) initiated by Japan have listed more than 200 projects since 2013. The total emissions reduction is about 2.4 million total carbon dioxide (tCO_2) per year, less than half the annual emission of a one-gigawatt (GW) coal plant. Such initiatives should be commended, but the role of CCUS will likely remain limited.

IEEFA believes that the establishment of CCUS in the South East Asian market within the next several decades will likely be limited around gas processing, and some industrial applications which could be supported by concessionary financings or bilateral initiatives.

CCUS in the power sector remains highly unlikely under the anticipated cost scenario projections. Even at US$40/$tCO_2$ cost of capture, the effective total cost of $50 to 60/$tCO_2$, inclusive of transport and storage, will be beyond reach for most countries in the region. While the development of affordable coal power CCUS remains elusive, it is potentially even more so for gas power plants with its even more diluted CO_2 concentration.

The lack of supporting policy, legal, and regulatory framework is often touted as the primary barrier to CCUS applications. Sometimes, this is meant to ensure that CCUS adoption is recognized with supportive regulations. Most of the time, however, this statement alludes to the lack of a sufficient price attached to carbon emissions, and more specifically, that substantial public funding support is required for CCUS to take off.

The wave of enthusiasm of CCUS with the cluster concept, which combines multiple CO_2 sources to reduce cost and risks, should also be contextualized with the public funds attached to it. The UK government provided nearly £100m of funding, further backed by a £1bn CCUS fund to support its CCUS cluster plan, while the Norwegian government funded two-thirds of its planned US$2.7bn CCUS cluster project. These public funds remain a necessity, despite both countries already exhibiting some of the highest carbon prices in the world. Enthusiasm for the cluster as a CCUS-enabler should remain grounded in the projections of CO_2 capture cost and the context of public funding availability.

There is no dodging the big question: which CCUS drivers would be present in SEA countries? *Carbon emission valuation, strong public funding support or market drivers?*

CCUS will undoubtedly remain an important consideration for some hard-to-abate sectors, such as steel and cement. It is nevertheless important for stakeholders to note the dynamics of the drivers behind them to evaluate the likely pathways in SEA.

Singapore remains an exception in the SEA region. The establishment of CCUS projects there remains plausible, given the concentrated industrial base, market drivers from export products and international companies, and more critically, the higher carbon pricing ambition.

SEA countries can use CCUS as a stepping stone to 'learn the ropes' of the technology and to anticipate future developments of carbon-capture based products and other applications. However, it should not distract from the adoption of other lower-cost and proven carbon abatement options in renewable energy and grid integrations, which should remain at the centre of SEA's attention toward decarbonization.

The recent Intergovernmental Panel on Climate Change (IPCC) report, released in April 2022, outlined the challenging costs of CCUS applications in the near future. With limited resources, CCUS is ultimately a question of priorities, as the costs will eventually land somewhere. It is also pertinent to ask whether the CCUS projects planned in the region match the 'intended CCUS' for each country's commitments toward their decarbonization goal.

It is possible that the power generation CCUS cost may decline substantially over the next two decades. However, the long history of its challenges and the factors outlined in this report suggests that this remains an open question, especially for adoption in cost-sensitive markets.

The CCUS train may eventually arrive, but before it does, it will likely need to make a lot of stops before eventually reaching the South East Asian shores. With the clock ticking toward the 2050 decarbonization timeline, SEA policymakers need to look closely at whether this is the right train to rely on.

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Background

Carbon capture, both for utilization and storage, gained substantial attention in recent years, with the rising urgency to mitigate CO_2 emissions. SEA recently noted an uptick in CCUS project plans and public discussions. With strong electricity demand growth and a relatively young coal and gas power plant fleet, the region is often touted as high potential for CCUS application.

The unique nature of CCUS, which can be retrofitted into hard-to-abate and existing assets, means it could play a substantial role in the net-zero pathways. Nevertheless, IEEFA has noted that the vastly diverse applications of CCUS across industrial and energy sectors often muddles the understanding, particularly for inexperienced stakeholders who may mistakenly think of CCUS as a single subject.

While several reports have evaluated CCUS through multiple angles, IEEFA considers it necessary to draw out the key facts for the public and policymakers to comprehend the evolving CCUS landscape and the diverging characteristics of CCUS applications – what it is and what it is not.

This report is the first of a two-part series covering the CCUS landscape of the South East Asian region. This report will focus on the preconditions of CCUS adoption, the predominance of gas processing CCUS in SEA, and the context of CCUS in power generation. The second part will be presented as part of IEEFA's evaluation of hydrogen and ammonia, which could be closely correlated to CCUS. Industrial applications, CO_2 utilization, direct air capture, and carbon storage potentials, are beyond the scope of this paper.

The term 'CCUS' is used as a general reference of carbon capture in this report for the purpose of simplicity. Specifically, Carbon Capture and Storage (CCS) refers to a process which captures carbon solely to be stored, while Carbon Capture and Utilization (CCU) uses the carbon, which at present, is primarily to produce more oil and gas.

This report is not intended to be exhaustive, nor as a 'deep dive' into CCUS technology options – but rather to provide a conceptual primer for the public, policymakers, and stakeholders to comprehend the ongoing development and context of CCUS in South East Asia.

A Very Brief Introduction to CCUS

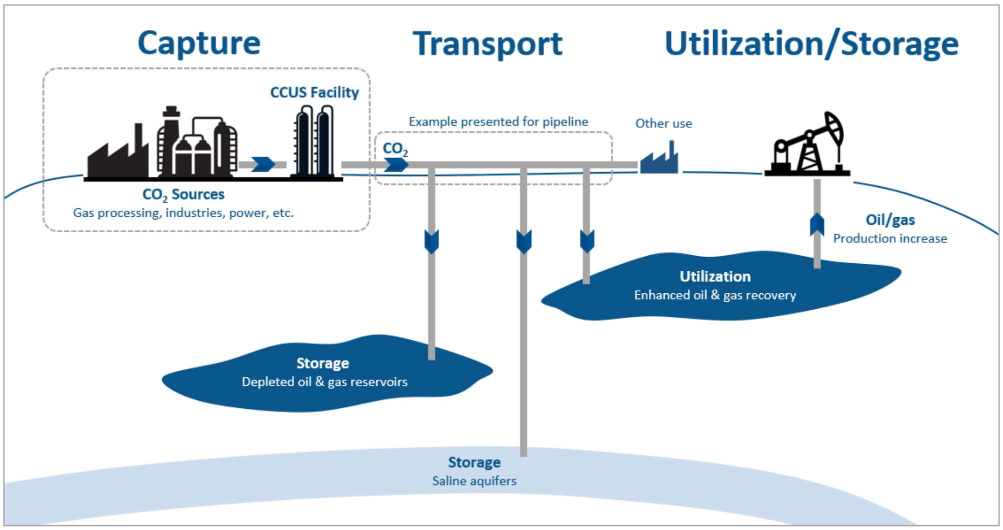
The global CCUS capacity currently stands at around 40 MTPA of CO_2 captured, with about half of the global capacity residing in the US.[1] This existing global capacity is comparable to about 7GW of coal power plant annual emissions. CCUS' strategic value lies in its ability to be retrofitted to existing power and industrial plants, applications in hard-to-abate sectors such as iron, steel, or chemicals, and for low-

[1] Global Carbon Capture Storage Institute (GCCSI). Global status of CCS 2021. 2021.

carbon hydrogen production.[2]

CCUS encompasses three distinct parts: capture, transport, and storage or utilization, as depicted in Figure 1 below. CO_2, which is captured from various stationary sources such as gas processing, chemical process, and power generation plants, are transported to suitable sites, and stored or utilized, mainly underground. Often (in more than 60% of deployed CCUS facilities) these CO_2 are sold as a commodity to oil and gas companies that use it to enhance their production, hence the term: Enhanced Oil/Gas Recovery (EOR/EGR).[3] On other occasions, the CO_2 is permanently stored underground in saline aquifers or other underground deposits.

Figure 1: CCUS Schematics



CCUS terminology is evolving, and there are some terms and concepts that need to be clarified to contextualize and categorize different types of CCUS. Pre- and post-combustion capture describes at what stage the CO_2 is captured, whether before or after fuel is burned.[4] Other technologies are also in development, such as oxyfuel, which uses pure oxygen instead of air to increase CO_2 capture efficiency. Capturing CO_2 in higher concentrations is easier and cheaper than capturing it in more diluted forms commonly encountered in power plant exhaust gas.[5]

While various technologies have been applied in carbon capture, they are primarily a variation of solvent-based, physical-adsorption or membrane-based capture. New

[2] International Energy Agency (IEA). IEA Energy technology perspectives 2020 – Special report on CCUS. 2020.
[3] Global Carbon Capture Storage Institute (GCCSI). Global status of CCS 2021. 2021.
[4] Pre-and post- combustion are relatively new terminology attributed to the growing interest in capturing CO_2 from fossil fuels combustion. The chemical and gas industry has been capturing CO_2 for decades as part of their business process.
[5] The ease of capture is affected by a multitude of factors, primarily the concentration of CO_2 and the pressure of CO_2 the gas stream - the 'partial pressure'. For the benefit of non-technical readers, this paper will primarily refer to these factors as 'CO_2 concentration'.

designs, such as the Allam-cycle, are also undergoing development, although the nature of its design will likely not allow it to be retrofitted into existing assets.[6]

Amine solvent-based capture is arguably the most mature application for CO_2 capture. Its applications originated as early as the 1930s with various developments along the way to help mitigate its associated key challenges, energy penalty and degradations.[7] Energy penalty is associated with the energy required to use and reuse the solvent while degradation expresses the degrading of amine over time due to exposure to heat, O_2, CO_2 and impurities such as NO_x and SO_x.[8] The latter impurities are prevalent in power plant flue gas, and are a crucial consideration for evaluating SEA CCUS application, which will be discussed further in the report.

There are fewer variations in the transport and storage stage of CCUS. In transportation, CO_2 is most commonly transported by CO_2 pipelines. 85% of all CO_2 pipelines reside in the US, although this constitutes only 0.2% of the US pipeline infrastructure.[9] CO_2 transportation by ship is currently in the nascent stage and is starting to be explored in the Norwegian Langskip project.[10] While applications of small-scale CO_2 shipping have existed for decades, several shipping industry giants have only recently begun to explore its wider applications.[11]

Drawing Distinctions Between the Variety of CCUS Applications

As opposed to being a monolithic subject, CCUS is an aggregate of technology applications across varying sectors, each largely running in its own development tracks, drivers, and maturity level. While technology similarities may exist among different CCUS applications, they may involve different technicalities and approaches. Figure 2 illustrates the varying costs of CCUS applications, with the notable disparity between the lowest cost CCUS (gas processing) and the highest cost applications, from below US$50 to greater than US$130/tCO_2.

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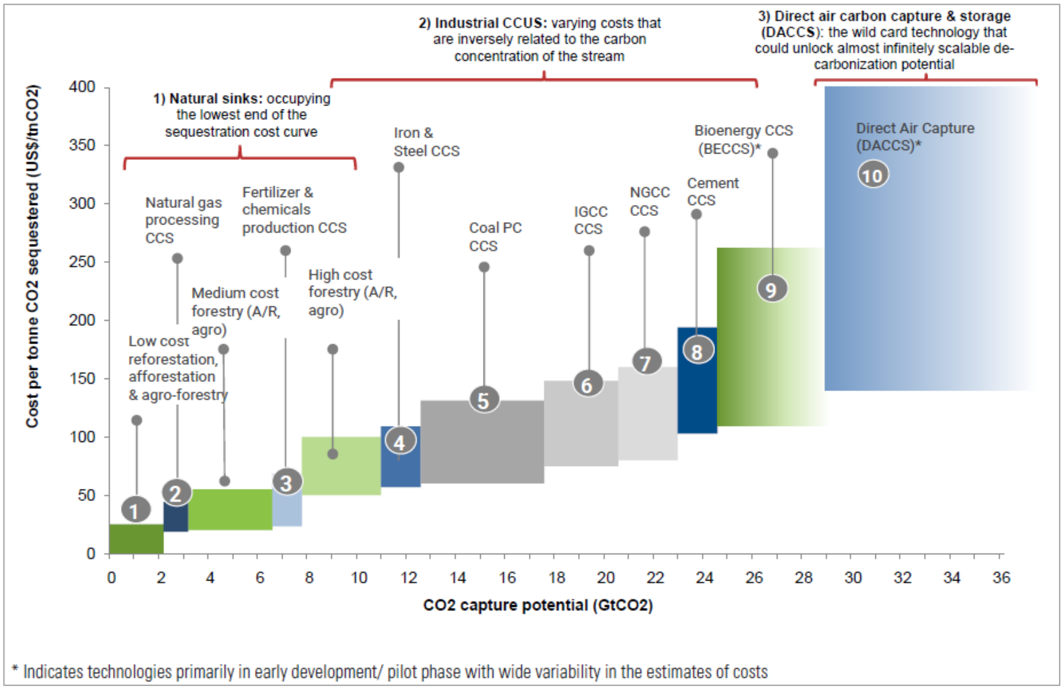
[6] Allam cycle burns gas with pure oxygen in a semi-closed loop system.
[7] Patent Archive. US Patent 1783901 Process for separating acidic gases. 1930.
[8] Gouedard, C. et.al. Amine degradation in CO_2 capture. I.A. review. 2012.
[9] US Department of Transportation. General pipeline FAQs. Accessed on 16 February 2022.
[10] In June 2021 Japan announced a joint research among four companies to explore CO_2 shipping application. The following reference provides a comprehensive summary of existing CCUS shipping literature (Al Baroudi, H. et.al. 2021)
[11] Norwegian Northern Lights CCS project reported plans for 7,500 cu.m CO_2 carriers. In comparison, current LNG carrier fleet capacity typically ranges from 125,000 – 180,000 cu.m. Hyundai Heavy Industries is reported to be exploring 40,000 cu.m CO_2 vessel.
MOL. MOL to Move into Ocean Shipping of Liquefied CO2 Ocean Transport Business through Investment in Norway's Larvik Shipping AS. 2021.
Northern Lights CCS. What it takes to ship CO2. 4 March 2021.
Offshore Energy. HHI's 40,000 cbm LCO2 carrier secures AIP from DNV, LISCR. 24 September 2021.

Figure 2: Carbon Sequestration Cost Curve Across CCUS Applications



Source: Goldman Sachs Equity Research 2021, IPCC, Global CCS Institute.

Readers should be aware that CCUS interests vary significantly across regions with the diverse applications. The European Union (EU) is potentially focusing on CCUS for industries and hydrogen production, while ongoing CCUS discussions in SEA focus largely on three subjects: gas processing, products -hydrogen/ammonia production, and potential future use in the power sector.

Ideally, CCUS should be prioritized toward hard-to-abate sectors such as cement, petrochemicals, iron, and steel. The inherent production processes within these industries and the limited alternatives means that CCUS is likely needed. However, within the South East Asian context, the considerable cost-impact of CCUS on the product price would likely raise the barrier of entry for such applications.

The general characteristics of each category are outlined in Table 1 below. The list is not exhaustive but rather provides a wider view of ongoing plans in South East Asia.

Table 1: Three Distinct CCUS Tracks in South East Asia

CCUS Category	Technology Maturity	Cost of CCUS[12]	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)[14]	**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

Which CCUS Drivers Would Be Present in SEA?

With its high associated costs, both in capital investment and ongoing operations, CCUS essentially represents a 'tax' to continue emitting carbon. Someone in the value chain *will* need to internalize the costs. Ultimately, that added cost will fall to either consumers – in the form of higher tariffs or taxpayers – due to the need for

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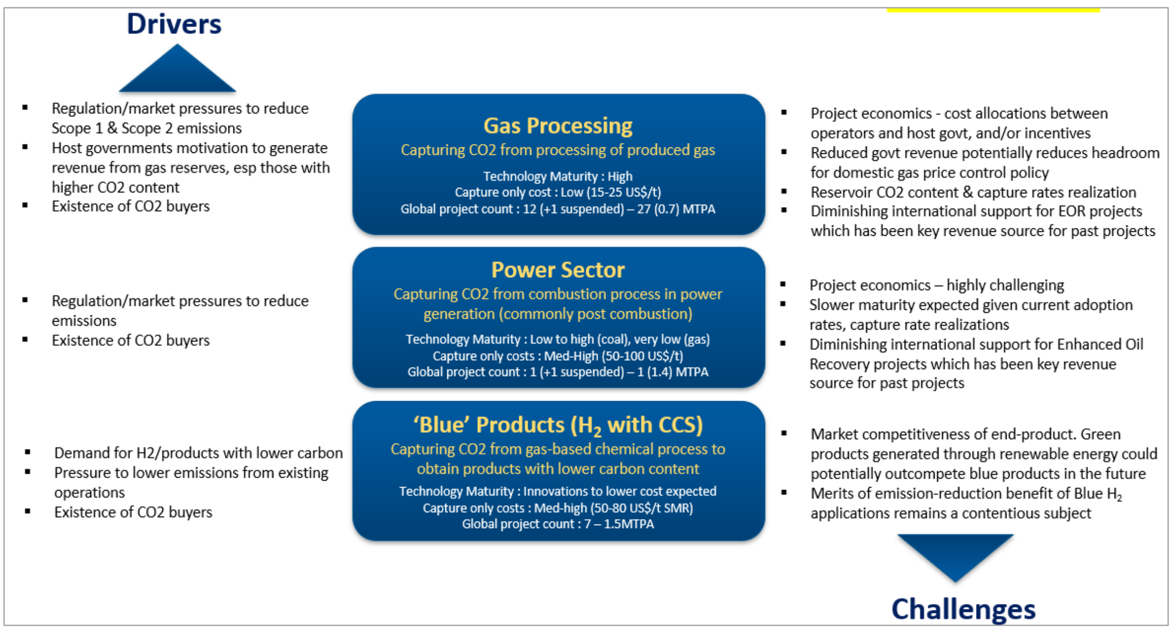
[12] Estimates for Hydrogen is based on Steam Methane Reforming (SMR) process
International Energy Agency. CCUS in clean energy transitions. Page 101, 2020.
[13] 'Blue' products is a term commonly attributed to products which are produced from fossil fuels equipped with CCUS to remove emissions while 'green' products are produced using renewable energy.
[14] National Energy Technology Lab - US Department of Energy. Post combustion CO2 capture. Accessed 20 January 2022.

government to fund subsidies or credits.

Therefore, attaching a high value to the carbon emissions is necessary for CCUS projects to proceed – whether through a carbon tax and credit market, premium low-carbon product prices, or other policy-based incentives. The United States' CCUS establishments were supported by the availability of CO_2 pipeline and CO_2 demand for EOR, but most notably, through generous tax credit incentives and government funding.

Figure 3 outlines the drivers and challenges for CCUS applications. Each category exhibits vastly different market behaviours and technical/cost characteristics, which will dictate their potential pathways in the region. Some lower-cost CCUS applications with strong drivers will likely take off first, but may not necessarily correlate with the likelihood of other CCUS applications.

Figure 3: Diverging Characteristics of SEA Potential CCUS Uses



Globally, the lack of supporting policy, legal, and regulatory frameworks is often touted as the primary barrier of CCUS applications. Sometimes, what this simply means is that supportive regulations should recognize CCUS. Most of the time, however, this statement alludes to a lack of sufficient price attached to carbon emissions, and more specifically, that substantial public funding support will likely be required for CCUS to take off.

Attaching a High Cost to Carbon Emissions

The United States' Section 45Q Tax Credit currently applies US$35 to 50 of tax credit for every tonne of CO_2 captured.[15] The Norwegian Sleipner project has also been established under a strong carbon tax regime, in which by injecting CO_2 the project avoided NOK one million per day in Norwegian CO_2 taxes.[16] Under such conditions, corporations are encouraged to implement CCUS, whether to avoid penalties or gain incremental income.

Table 2 outlines the current state of the carbon pricing mechanism and the ongoing CCUS plans in the SEA region.

Table 2: South East Asia CCUS and the Carbon Pricing Landscape

Country (Population, GDP per Capita Current US$)	**Carbon Tax/Pricing Current State**[17]	**Potential Involvement in CCUS**[18]
Brunei Darussalam 0.44m, $27,443	-	Limited disclosure
Cambodia 16.7m, $1,544	-	Limited disclosure
Indonesia 267.7m, $3,870	**Cap-and-tax scheme with $2.1/CO2e planned** to commence in 2022 potentially starting with the power sector. Ongoing trial of emissions trading for selected coal power plants.	**Gas processing:** BP Tangguh, Repsol Sakakemang, Gundih, Sukowati Pertamina. **Ammonia**: PAU, Jogmec, Mitsubishi. Indonesia/Pertamina is reported to be involved joint evaluation of CCUS with ExxonMobil, Japex, Janus, JGC and J-Power.[19]
Lao PDR 7.1m, $2,630	-	Limited disclosure
Malaysia 31.5m, $10,412	ETS and carbon tax under consideration	**Gas processing**: Petronas Kasawari Petronas reported joint efforts to evaluate CCUS utilization with ExxonMobil. POSCO, and Shell.[20] PTTEP Thailand

[15] Section 45Q of the Internal Revenue Service (IRS) was expanded in 2018 to raise the incentives from US$10 increasing up to US$35/tCO_2 for EOR application, and from US$20 increasing up to US$50/tCO_2 for CO_2 storage application. Certain rules have also been modified such as the claim period, conditions and deadlines for qualifying facilities.
US Congressional Research Service. The tax credit for carbon sequestration (Section 45Q). 2021.
[16] The Norwegian petroleum sector is subject to CO_2 emissions tax which has increased since 1991 to the current tax rate of approximately NOK 500/tCO2e.
OECD. How carbon taxation can help deploy CCS in natural gas production. 2019.
Norwegian Ministry of Climate and Environment submission to UNFCCC. Norway's fourth biennial report. 2020.
[17] State of carbon pricing is based on ICAP and World Bank database
World Bank. Carbon pricing dashboard. Accessed on 14 January 2022.
World Bank. State and trends of carbon pricing 2021. 2021.
[18] Potential involvements in CCUS is based on GCCSI early and advanced stage projects list with additional information from compiled sources.
[19] ExxonMobil. Capturing carbon around the world. Accessed on 14 January 2022.
ExxonMobil. ExxonMobil and Pertamina to evaluate CCS in Indonesia. 2 November 2021.
Jogmec. Signing of MoU regarding CCS joint study for clean fuel ammonia. 24 March 2021.
[20] ExxonMobil. ExxonMobil and Petronas to study carbon capture and storage in Malaysia. 8 November 2021.

		reported plans to evaluate CCUS for its Lang Lebah gas field in Malaysia.[21]
Myanmar 53.7m, $1,468	-	Limited disclosure
Philippines 106.7m, $3,298	ETS under consideration, under low carbon economy act	Limited disclosure
Singapore 5.8m, $59,798	**Carbon tax of US$3.7/t$CO_2$e** since 2019. Planned to be raised to US$ 18/tCO_2e by 2024 and to US$37-60/t$CO_2$e by 2030.	Singapore is reported to be jointly exploring CCS utilization for **industrial emissions** from the region along with ExxonMobil.[22] Aims to have 2MTPA of capture capacity by 2030. Low Carbon Energy Research Funding Initiative was established in 2020 and expanded to S$55m supporting twelve projects (four on hydrogen and eight on CCUS)[23]
Thailand 69.4m, $7,187	ETS under consideration with pilot tests on measurement reporting verification (MRV) mechanisms	PTTEP Thailand evaluating CCUS through involvement in Malaysia gas field
Vietnam 95.5m, $2,786	ETS under consideration, implementation timeline TBC	Limited disclosure

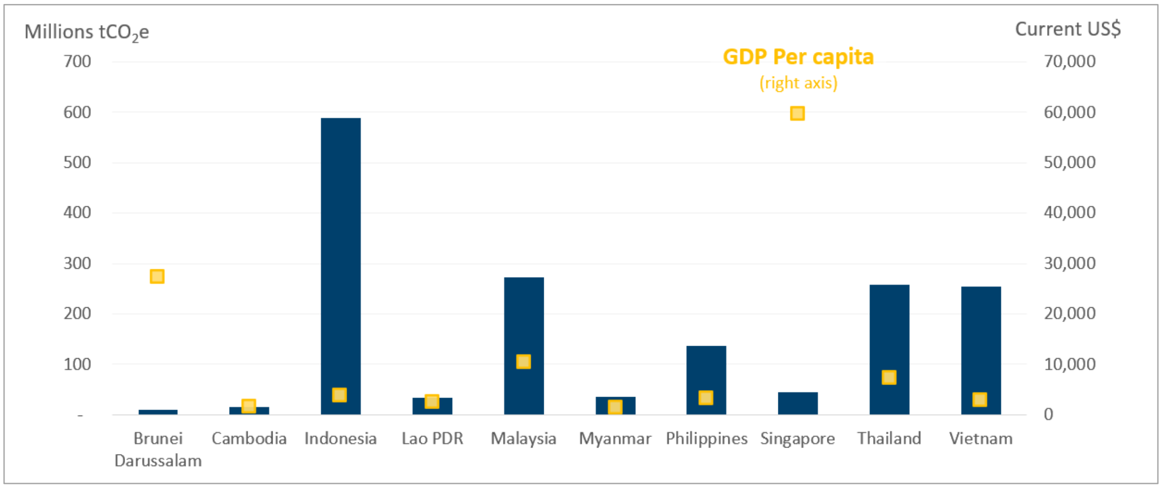
Sources: Compiled, World Bank, International Carbon Action Partnership (ICAP), ASEAN.

In terms of a carbon price as a key driver for CCUS, Singapore is the leader in SEA with a carbon tax of US$ 3.7 set until 2023. The current level still pales in comparison to the carbon price in the EU which hovered more than US$60/t$CO_2$e in recent years, the generous incentives in the US, or even China's emissions trading scheme price which ranges from US$6.5 to 9.7 since it was launched.[24]

In February 2022, Singapore's Finance Minister outlined an aggressive carbon tax hike, rising to US$18/t$CO_2$e by 2024, and potentially reaching a value between US$37 and 60/t$CO_2$e by 2030.[25] This meaningful action will further single out Singapore as the leader in SEA carbon pricing, but one which will need to be placed in the context of other SEA countries' emission scales, carbon pricings, and their GDP per capita, as outlined in Table 2 and Figure 4.

Petronas. Petronas and POSCO to collaborate on CCS value chain. 17 December 2021.
Petronas. Petronas and Shell collaborate on CCS solutions. 11 January 2022.
[21] S&P Global Platts. Thailand proposes carbon neutrality by 2065-2070, bets on CCUS. 27 August 2021.
[22] Reuters. ExxonMobil keen to build carbon storage hubs in SE Asia, similar to Houston project. 25 October 2021.
[23] The Straits Times. S'pore pledges $10m in new funds, making more investments in low-carbon technology. 23 November 2021.
[24] Energy Monitor. Carbon trading the Chinese way. 5 January 2022.
[25] Reuters. Singapore's carbon tax to rise five-fold in 2024. 20 February 2022.
The Straits Times. Budget 2022: Singapore's carbon tax could increase to $80 per tonne of emissions by 2030. 18 February 2022.

Figure 4: SEA Annual Emissions and GDP Per Capita



Source: Our World in Data, World Bank.

With carbon pricing virtually non-existent in most SEA countries, a second CCUS driver will likely dominate in the region – the need to monetize CO_2-rich gas resources.

The dynamics of gas processing CCUS are different from most other CCUS applications, as gas production could be correlated with an urgency to raise state revenue. The value attached to the emission is internalized within the costs – i.e. reduced project revenue – borne by the gas producers and host countries. In the South East Asian market context, this second driver will likely play an important role for earlier CCUS deployment, as we will see in later sections. Table 3 outlines the existing CCUS plans in the region.

Table 3: South East Asia CCUS Project Plans

Project	CCU/S Type	Country	Production Status	Operating entity	Avg Annual CCU/S capacity (MTPA CO2)	Remarks	*Reported* CCUS commencement plan
Kasawari	Gas processing	Malaysia	New development	Petronas	3.7	FEED contract awarded, expected completed before end of 2022. Kasawari gas field expected on stream by 2023, with CCS onstream by 2025, capacity estimates varies from 3.7-4 MTPA. Malaysia aim to create storage hubs for the region.	2025
Tangguh	Gas processing (EGR)	Indonesia	Tangguh field is in production with expansion plan	BP	2.5	FEED preparation. BP has announced plan of development approval from the Indonesian authority SKK Migas. Current emission estimates 5 MTPA CO2 which will increase to 8 MTPA CO2 with additional LNG Train in absence of CCUS	2026
Gundih	Gas processing (EGR)	Indonesia	In production	Pertamina	0.3	Pre-FEED study, Pertamina supported by various parties & Japan METI. Potential support from Japan JCM.	2024/5
Sukowati	Gas processing (EOR)	Indonesia	In production	Pertamina	0.6	Ongoing studies, Pertamina, Lemigas, Japex, supported by Japan METI. CO2 source 30km away from the target oilfield	2030
Sakakemang	Gas processing	Indonesia	New development	Repsol	2	Under discussion	2027
Banggai-Sulawesi Ammonia	Industry - Ammonia production	Indonesia	In production	Panca Amara Utama	1	Pre-feasibility studies expected completion by mid 2022. Plan to produce 700,000 tonne of clean ammonia annually for export to Japan coal power plants.	TBC
Singapore Hub	Potential focus on industries / products	Singapore	N/A	TBC	2	Potentially focused on industries or lower-emission products. In absence of potential storage sites cooperation with other country storage may be considered. There has also been mentions of plans to explore gas power CCUS.	2030

Source: Compiled.

It should be acknowledged that an explicit valuation of emissions is not the sole determinant of emissions mitigation actions, as other policies and regulations can play an important role.[26] Indeed, improvements have been noted through regulations such as low carbon/clean fuel standards and other legal emissions standards worldwide.[27] However, within the SEA context, there has been limited regulations relating to carbon emissions mitigation, and the future outlook of such regulations remain an open question for the foreseeable future.

In evaluating the likelihood of CCUS adoption, stakeholders are well advised to begin by looking at what drivers will likely be present within a particular market. Most of the time, such drivers may come directly from the state and regulatory domain, but at other times, they may originate from the private sector.

Public Funding Support – Past, Present and Future

Government grants' 'policy push' has played a dominant role in pushing CCUS developments in the past decade. The US government alone has spent US$1.1 bn on

[26] Cullenward, D & Victor, D. Making climate policy work. 2020.
[27] Regulation implementation varies from pure regulatory control to encourage lower emissions to a combination of emission credit issuance/market implementation.

demonstration projects between 2010 and 2017, with at least €424m spent by the EU.[28]

In 2021, the United States Government Accountability Office (GAO) highlighted the 'high-risk selection' of the CCUS projects funded, especially those in the coal power sector. Table 4 outlines some of the findings. Despite the massive public funding, most coal power projects encountered economic issues with only one coal power project, Petra Nova, ever reaching operational stage. The plant later ceased to operate in 2020 due to economic challenges after only three years in operation. Two of the three industrial projects remained in operation and involved the production of hydrogen and ethanol, a lower-cost CCUS application, compared to power generation.

Table 4: US GAO CCUS Public Funding Report Findings

CCS Project	Projects Selected	Project in Operation (2020)	US Department of Energy Funding
Coal Project	8	0	US$ 684 million
Industrial project	3	2	US$ 438 million

Table 1: Coal Carbon Capture and Storage Demonstration Project Outcomes, Final Phase, and Department of Energy (DOE) Funding

Project	Project outcome	Final phase entered	DOE funding totals (dollars)
American Electric Power	Withdrawn	Definition	16,880,268
Basin Electric	Withdrawn	None	0
FutureGen 2.0 Power Plant	Terminated	Design	116,666,759
FutureGen 2.0 Pipeline and Storage	Terminated	Design	83,857,100
Hydrogen Energy California	Terminated	Definition	153,428,898
Petra Nova	Completed	Operations	195,132,425
Southern Company Services	Withdrawn	None	0
Summit Texas Clean Energy	Terminated	Definition	117,876,707
Total			**683,842,157**

Table 2: Industrial Carbon Capture and Storage Demonstration Project Outcomes, Final Phase, and Department of Energy (DOE) Funding

Project	Project outcome	Final phase entered	DOE funding totals (dollars)
Air Products and Chemicals	Completed	Operations	284,012,496
Archer Daniels Midland	Completed	Operations	141,405,945
Leucadia Lake Charles	Withdrawn	Design	12,758,649
Total			**438,177,090**

Source: US Government Accountability Office, Department of Energy.

Plans to attach CCUS to the Integrated Gasification Combined Cycle (IGCC) power plant, which involves gasification of the fuel before being combusted, have also failed to take off. The discussion on IGCC CCUS is outside the scope of this paper, but it is worth noting that its pinnacle IGCC demonstration project in the US, the Kemper

[28] US Government Accountability Office. CCS: Actions needed to improve DOE management of demonstration projects – Report to congressional committees. December 2021.
European Court of Auditors. Special report No 24/2018: Demonstrating CCS and innovative renewables at commercial scale in the EU: intended progress not achieved in the past decade. 2018.

Project, encountered severe problems. The plant was initially touted as a model for the rise of 'clean coal' projects, utilizing lignite coal. Its costs ballooned from an estimated US$3 bn to US$7.5 bn and were later suspended. The US Department of Energy provided more than US$400m of public funding for the project.[29]

A note on the CCUS cluster. In recent years, the revival of global attention on CCUS has been bolstered by the concept of 'CCUS cluster/hub' where the CCUS Transportation and Storage (T&S) plans are based on aggregating multiple CO_2 sources. Clusters are expected to help T&S investors manage their investment risks, rather than rely on a single CO_2 source model.

Table 5: Select CCUS Cluster Plans

Project Hub/Cluster	Stated Objectives	Funding and Supports
UK East Coast Cluster (ECC, combining Teesside and Humber) and HyNet North West	ECC target of 27 MTPA of CO2 emission by 2030 – capturing nearly 50% of all UK industrial cluster CO2 emissions.[30] HyNet 10 MTPA by 2030. Both projects outlined plans for hydrogen production in addition to CCUS.	HyNet supported by **£33m** from UK Research and Innovation (UKRI). UKRI also reported funding awards of **£62m** between Humber and Teesside project.[31] Potentially to be supported by the UK government **£1bn Carbon Capture and Storage Infrastructure Fund** (CIF)
Norway Longship (Langskip)	Capture 1.5 MTPA CO2 by 2024, combining emissions from cement factory, ammonia plant, and waste incineration facility. Further expansion plans are outlined for 5 MTPA.	Norwegian government will be supporting around **US$1.8bn** (NOK 16.8bn) out of the total project cost of US$2.7bn (NOK 25.1bn), about two-thirds of the entire cost.[32]
United States Houston CCUS cluster	Target of 50 MTPA CO_2. Involving 14 companies primarily from industrial applications.[33]	Limited details, ExxonMobil has disclosed the need for "collective support of industry and government, with a combined estimated investment of $100 billion or more"[34]

Source: Compiled, see footnotes.

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[29] IEEFA. Southern Company demolishes part of the $7.5 billion Kemper power plant in Mississippi. 14 October 2021.
US Department of Energy. Southern Company - Kemper County, Mississippi. Accessed on 3 March 2022.
Energy Wire. The Kemper project just collapsed. What it signifies for CCS. 26 October 2021.
IEEFA. Costly and Unreliable, Two Multibillion-Dollar American Coal-Gasification Experiments Prove the Case Against Such Projects. 2017.
[30] East Coast Cluster. East Coast Cluster selected as one of the UK's first two carbon capture and storage projects. 2021.
[31] HyNet. Hynet North West awarded substantial funding. 2021.
UK Research and Innovation. UKRI awards £171m in UK decarbonisation to nine projects. 17 March 2021.
[32] Norwegian Ministry of Petroleun and Energy. Longship. Accessed in 31 January 2022.
Norwegian Ministry of Petroleum and Energy. Questions and answers about the Longship project. 2021.
[33] ExxonMobil. Industry support for large-scale carbon capture and storage continues to gain momentum in Houston. 20 January 2022.
[34] ExxonMobil Energy Factor. The promise of carbon capture and storage, and a Texas-sized call to action. 19 April 2021.

It is notable that despite the new model, the residual investment risks remain significant, and that government support will be crucial. Table 5 outlines some of the most notable CCUS cluster establishment plans, and the significant government backing behind it. Currently, there are limited details on how the Houston CCUS will progress.

The United Kingdom (UK) government clearly stated that part of the motives for their involvement in CCUS cluster developments was first to overcome the coordination failure of private investments, where it is unlikely for private players to coordinate investments for transport and storage of an appropriate size. Secondly, to overcome the first mover disadvantage, earlier developers will likely have to pay higher costs than latecomers.[35]

The prominent role of governments in backstopping CCUS developments remain crucial and unlikely to be afforded by most SEA countries.

In South East Asia, Singapore has envisioned establishing a carbon capture hub, targeting 2MTPA of CO_2 capture capacity by 2030.[36] As home to major refineries and petrochemical complexes, nearly half of Singapore's emissions are concentrated in industrial areas such as Jurong and Bukom. While both Shell and Exxon are exploring the potential of CCUS, an Exxon representative highlighted concerns that in the Asia Pacific, "the value of carbon is relatively low; therefore, it doesn't attract public and private investments."[37]

Enthusiasm in establishing clusters do not negate the fundamental question of potential CCUS drivers in the SEA region. It is also important to note that CCUS applications for many sectors, such as power, are dominated by the *capture costs*, not the latter part of transporting and storing the CO_2. The cluster concept could potentially bring a CCUS project through the last mile, but highly unlikely when there is no solid foundation for it to be built upon.

The high failure rate for CCUS projects is a reminder of the high risks involved in CCUS demonstration projects. The prominent role of governments in backstopping CCUS developments, either through policy intervention or other incentives remains crucial. It is also something which is unlikely to be afforded by most SEA countries. It should also be expected that with a large amount of public money invested, *if and when*, the supported technologies come to fruition, their earlier adoptions will

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[35] UK Department for Business, Energy, & Industrial Strategy. The Carbon Capture and Storage Infrastructure Fund: an update on its design. 2021.
[36] Argus. Singapore targets 2mn t of carbon capture by 2030. 24 November 2021.
[37] Statement from Joe Blommaert, president for low carbon solutions at ExxonMobil to Nikkei. ExxonMobil plans carbon capture network in Southeast Asia. 4 December 2021.
Upstream. Shell mulls Singapore carbon capture hub and biofuels plant. 23 November 2021.
Channel News Asia. Shell Singapore to repurpose core business, downsize Pulau Bukom refinery in low-carbon shift. 10 November 2020.

potentially reside first and foremost in the sponsoring countries.

Market Drivers: Corporations, Internal Carbon Pricing and CO_2 Buyer's Market

International corporations are increasingly under pressure from investors and governments to disclose the effects of their business activities on the climate crisis. These are most commonly presented in the different emission 'scopes' emitted by a company.

At a very broad level, corporations are pressured from both their demand side, the buyers of their products, and the investors.

In 2021, the corporate world saw the establishment of a new International Sustainability Standards Board (ISSB) to develop 'a comprehensive global baseline of high-quality sustainability disclosure standards', a major milestone that exemplifies the growing inertia of corporate scrutiny.[38]

To assess and mitigate future carbon-related risks, a growing number of companies use the Internal Carbon Price (ICP) to incorporate the cost of emissions in their business plans. One common practice is to apply the carbon price as a 'shadow' theoretical price in their decision-making process or applied as a fee to entities within the companies based on their respective emissions.[39]

Setting aside the variations in methodology to set the ICP, and that ICPs most commonly only consider Scope 1 and Scope 2 emissions; the involvement of major international companies reflects the trend that carbon-related risks assessments are gaining traction and will likely escalate in the future. Table 6 below illustrates a non-exhaustive list of ICP implementations on

Scope 1, 2 and 3 Emissions

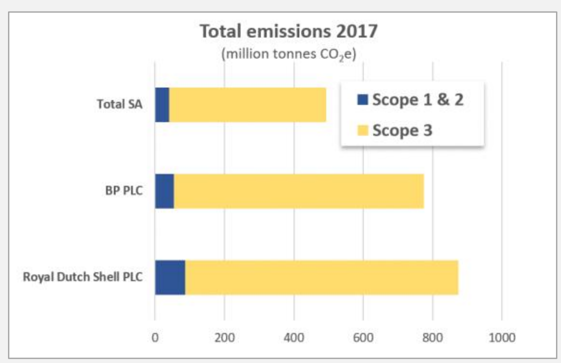
A company's emission is categorized into three different scopes, as outlined by the Green House Gas (GHG) Protocol Corporate Standard.

Scope 1 emissions from sources owned or controlled by the company.

Scope 2 represents indirect emissions from purchased energy inputs such as electricity or heat which are not generated directly by the company.

Scope 3 represents all emissions in the value chain, including those located in the upstream (input) and downstream (output) part of the company's process.

Specific for companies involved in energy *extraction*, it is important to note that the end product emissions (Scope 3) constitute a much greater portion of the overall. Below chart and Figure 6 further illustrates the typical emission scopes for oil and gas companies.



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Source: Trucost, S&P Global Market Intelligence.

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38 IFRS Foundation announces International Sustainability Standards Board, consolidation with CDSB and VRF, and publication of prototype disclosure requirements. IFRS Press release. 3 November 2021.

39 Shadow carbon price can be incorporated to stress-test investment scenarios and in NPV/IRR calculation which should help prioritize lower-carbon investment options.

selected companies that could have potential CCUS involvement in the SEA region.

Table 6: Internal Carbon Price Policy of Select Companies

Select Companies	Internal Carbon Price Policy (US$)
Repsol Scope 1 & 2 Net zero emissions target by 2050[40]	\$25/tCO2e rising to \$40/tCO2e, applied as a shadow price to all investment decisions for new projects, except where a climate regulation is already in place with higher carbon price \$25 (2018), \$30 (2023), \$35 (2024), \$40 (2025)[41]
BP Scope 1 & 2 Net zero by 2050 or sooner[42]	\$50/tCO2e rising to 2050, applied as shadow price for investments above defined thresholds[43] \$100 (2030), \$200 (2040), \$250 (2050) in 2020 real \$
INPEX Scope 1 & 2 Net zero carbon emission by 2050[44]	Adjusted from \$35/tCO2e to \$40/tCO2e in FY2020, applied as a shadow price to all economic evaluations. Internal carbon price is reviewed each year with reference to the carbon prices in the IEA Stated Policies Scenario (STEPS). ICP has been implemented since FY2018 and assumed as base case since FY2021[45]
Petronas, Malaysia Scope 1 & 2 Net zero aspiration by 2050[46]	Petronas 'Assess carbon pricing during project feasibility studies to identify carbon-related risks for new projects', limited disclosure on specificities of ICP values[47]
Pertamina, Indonesia	Limited disclosure on implementation of ICP[48]
PTT, Thailand	Internal carbon price \$7/tCO2, and a shadow carbon price of \$20/tCO2 for investment decisions[49]
Air Products & Chemical, Inc.	Limited disclosure on implementation of ICP[50]
ExxonMobil Announced net-zero target from operations by 2050[51]	Limited disclosure on implementation of ICP[52]

Source: Compiled, see footnotes.

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40 Repsol. Repsol will be a net zero emissions company by 2050. 12 March 2019.
41 CDP. CDP – Repsol climate change 2021 respose C4.3c. 2021.
Repsol. Supporting carbon pricing. Accessed on 10 January 2022.
42 BP. Our sustainability frame. Accessed on 10 January 2022.
43 CDP. CDP – BP Climate change 2021 response C11.3a. 2021.
BP. BP Annual report 2020. Page 30. 2021.
44 INPEX. Business development strategy towards a net zero carbon society by 2050. Accessed on 10 January 2022.
45 CDP. CDP INPEX Climate change 2021 response C4.3c and C11.3a. 2021.
INPEX. Assessment of financial impacts of climate-related risks. Accessed on 10 January 2022.
46 Petronas. PETRONAS sets net zero carbon emissions target by 2050. 2020.
47 Petronas. Petronas sustainability report 2020. 2021.
Reuters. Malaysia's Petronas plans to scale up CCS at Kasawari gas field. 6 October 2021.
48 CDP Climate change 2021 response from PT. Pertamina Persero has been submitted, but not yet publicly accessible.
49 CDP. CDP PTT Climate change 2021 response C11.3a. 2021.
50 CDP. CDP Air Products Climate change 2021 response C11.3. 2021.
51 Reuters. Exxon vows to have net-zero carbon emissions from operations by 2050. 19 January 2022.
52 ExxonMobil. 2020 Annual report. 2021.
ExxonMobil. Our position on climate policy and carbon pricing. Accessed on 10 January 2022.

ICP is not the sole mechanism for corporations to encourage low-carbon investments. It is nevertheless frequently used to translate 'commitments' into more tangible value for their organizations. Moreover, ICP allows companies to transparently display to the public how they incorporate carbon-related future risks in shaping their business decisions.

ICP policies can move 'the goal posts' for corporate investment decisions. Hence, host countries of CCUS projects would be well-served to understand investors' ICP policies to enable a mutual understanding of each party's starting points.

Who will buy the CO2? CCUS involves substantial costs and corporations naturally look for ways to recoup them. A key enabler for past CCUS projects has been to sell the CO_2 as a by-product to external buyers or to use them internally. On both accounts, EOR/EGR applications dominate the landscape. When sold externally, CO_2 provided the revenue stream needed to get past the commercial barriers. Internally, they are commonly used to gain increases in oil and gas production.

It is worth noting that when the CO_2 is used for EOR/EGR, the project will inevitably be exposed typical commodity price cycles. As exemplified in many projects – in times of low oil price, or when competition with other energy sources intensifies, the economics of CCUS projects will likely be affected.

While these models could potentially prevail in some portions of future CCUS plans, including in SEA, it is also increasingly under scrutiny from the international community. While the primary reason for the public to support CCUS through funding and policies is to reduce emissions from fossil fuels, EOR/EGR travels in the opposite direction to facilitate an increase in oil and gas productions.

A policy paper issued by the Asian Development Bank (ADB) in 2021 noted specific exclusions for supporting and financing CCUS associated with EOR.[53] This reinforces the trend that support of CCUS to acquire concessionary funding and international support will likely be targeted to specific applications, with CCUS related to hydrocarbon extraction likely to continue under scrutiny in the future.

In addition to the state and corporate drivers, when domestic drivers may not be sufficient to support CCUS, international support may present the next best alternatives to increase the value of carbon emissions.

External Drivers: Valuing Emissions Through International Agreements and Supports

Bilateral agreements. In the absence of a strong regulation or high carbon valuations in domestic SEA markets, bilateral agreements have been noted in cases such as the 0.3 MTPA CO_2 Gundih project in Indonesia, which aims to be supported

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[53] Asian Development Bank. New ADB Energy Policy to Support Energy Access and Low-Carbon Transition in Asia and Pacific. 20 October 2021.
Asian Development Bank. Energy Policy: Supporting Low-Carbon Transition in Asia and the Pacific. September 2021.

by the Joint Crediting Mechanism (JCM) as the first SEA CCUS demonstration project.[54]

JCM is a bilateral agreement initiated in 2013 between Japan and partner countries to develop carbon mitigation projects in developing countries. A combination of concessionary funding, grants and technology support from Japan is given in exchange for recognizing a portion of the realized emission reductions to satisfy Japan's emission reduction target.[55]

International carbon credits. In addition to bilateral initiatives, international trading of carbon credits provides another potential avenue. While the recent United Nations Conference of the Parties 26 (COP26) provided a new footing, its historical implementation has seen a fair a number of challenges, as exemplified in the Clean Development Mechanism (CDM) initiative under the Kyoto Protocol.[56] Taking lessons from past challenges, project environmental integrity, loopholes, and supply-demand balance in the international carbon market will undoubtedly be on the priority watch list for international stakeholders.

Among this myriad of international support avenues, bilateral agreements such as the JCM, could be the most likely ally for CCUS establishment in SEA. Nevertheless, the prospect for large-scale deployment of CCUS under such a scheme will likely be limited, given the scale of the current JCM scheme. As of December 2021, 205 JCM projects have been listed since 2013, with a total expected GHG emission reduction of 2.4 MTPA CO_2 – less than half the annual emissions of a 1GW coal power plant.[57]

Establishing such programs is commendable as it has been a key enabler of many emissions-reduction projects. Nevertheless, considering Japan's raised JCM ambitions, the capital-intensive nature of CCUS means that the role of such a scheme as the backbone of a widespread CCUS adoption in SEA remains an open question.[58]

SEA CCUS Plans Are Dominated by Gas Processing CCUS, a 'Different' Kind of CCUS

More than 60% of the current CCUS capacity deployed globally is applied for gas processing. With three quarters of SEA's CCUS plans geared for gas processing, the recent uptick in SEA's CCUS discussions is largely a form of catching up on this past trend (Figure 5 and 6), CCUS for gas processing mainly serves to separate the excess 'reservoir-associated CO_2' from the useful components of the gas. It has been

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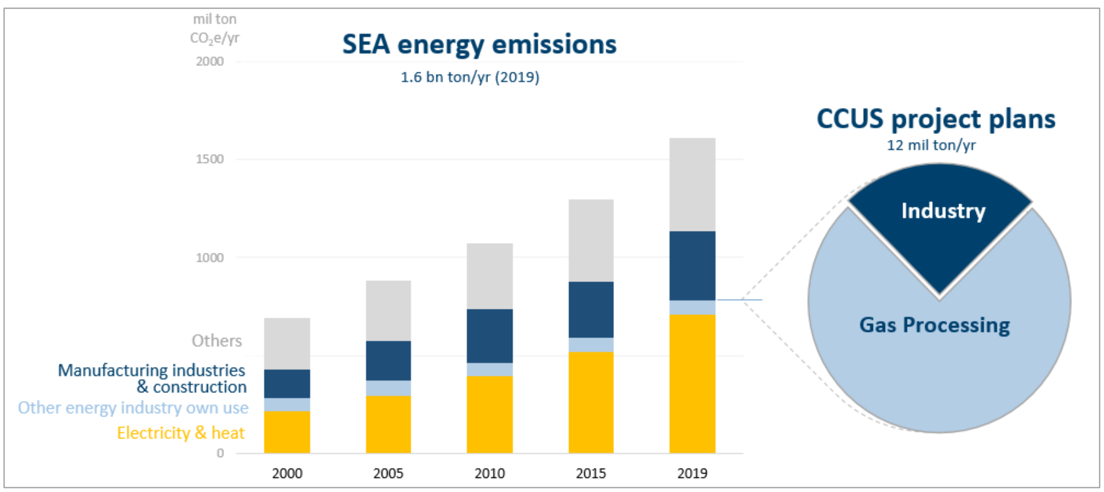
[54] J-Power. Commencement of feasibility study for the first SEA CCS demonstration project. 19 July 2021.
[55] JCM. Basic concept of the JCM. Accessed on 2 February 2022.
[56] CDM allows emission-reduction activities in developing countries to earn certified emission reduction credits (CER) which can be traded, sold, and used by industrialized countries to meet their emissions target under the Kyoto protocol.
UNFCCC. UNFCCC website. Accessed on 2 February 2022.
[57] Global Environment Centre Foundation. List of projects under JCM financing programme by MOEJ. 2021.
[58] The Energy Conservation Centre - Japan. Ministry of Environment to raise the JCM target. 13 July 2021.

adopted since the 1970s and is arguably one of the lowest-cost and most mature variety of CCUS applications.

As gas is produced, impurities such as CO_2 could be present in the gas stream at varying proportions. They will need to be separated to meet required specifications before the gas is distributed and utilized. Consumers have little use of the CO_2 content, which can also complicate various processes in transporting the gas in the value chain. CO_2 content is commonly required to be below the 2-4% range for pipeline transport and end use, with a much more stringent limit of 0.005% CO_2 (50 parts per million volume, ppmv) prior to being liquefied into LNG.[59]

With three-quarters of South East Asia's CCUS plans geared for gas processing, the recent uptick in these CCUS discussions is largely a form of catching up on this past trend.

Figure 5: SEA CCUS Is Dominated by Gas Processing



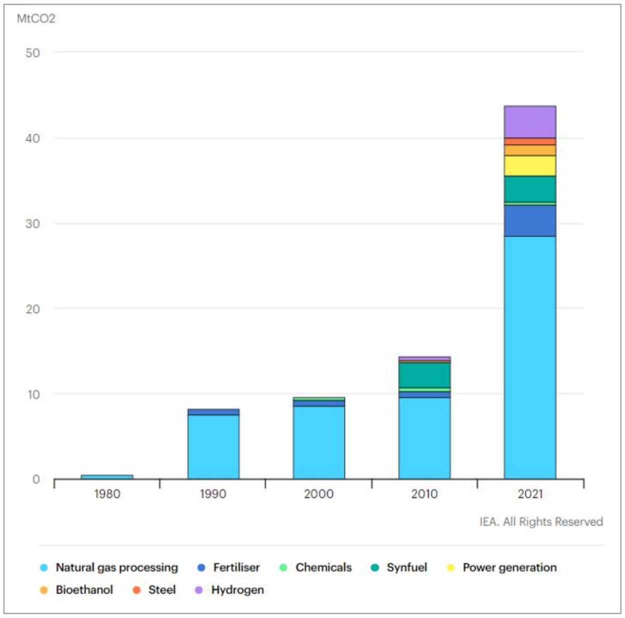
Source: IEEFA, ASEAN, IEA.

The separation of excessive CO_2 from the gas stream is therefore a necessary step in processing marketable gas, regardless of the final destination of the separated CO_2. Gas producers voluntarily embed the process and its costs as part of its revenue-generating activities. In the absence of tight emissions regulations, the captured excess CO_2 are often vented into the atmosphere. In other cases, the gas producers look for ways to use or sell the CO_2, primarily for EOR/EGR. Lastly, the CO_2 is stored permanently underground to a lesser extent.

[59] International Gas Union. Guidebook to gas interchangeability and gas quality page 64-65. 2011.
API. LNG Operations – Consistent Methodology for estimating GHG emissions. 2015.
KBR. Natural gas specification challenges in the LNG industry. 2012.

In certain parts of the world, the excess CO_2 within the gas reservoir can become a prohibitive factor in commercializing the gas. Higher CO_2 content, particularly in the range of 15% to 80% can significantly impact the commerciality and environmental viability of these 'CO_2-rich' resources – this consideration, as we will later see, plays an important role for CCUS in SEA.[60] The challenges primarily lie in two aspects, the need to handle large amounts of CO_2 and the lower volume of useful fuel in gas production, which raises the unit cost of gas production.

Figure 6: Gas Processing Dominates Deployed CCUS Capacity



Source: IEA, CCUS facilities in operation by application, 1980-2021.

A Different CCUS: Gas Processing CCUS Is Covering a Different Emission Scope Compared to Other CCUS

As gas processing CCUS is mainly about 'capturing *excess* CO_2', CCUS in gas processing is not about reducing Scope 3 emissions due to the final combustion/use of gas, but rather to minimize production-related Scope 1 emissions from gas with excessive CO_2 content. This contrasts with other CCUS applications in the industrial and power sector, which aims to minimize the emissions coming from the *end consumption* of fossil fuels, whether by combustion or as feedstock materials.

The touting of gas as a 'clean fuel' with an emissions advantage over coal diminishes when the gas production is accompanied by the venting of millions of tonnes of CO_2 into the atmosphere. In gas production, emissions also come from other processes besides those captured excess CO_2, such as the liquefaction process in LNG plants.

To put the scale into perspective, in the absence of CCUS, Australia's Barossa LNG

[60] Burgers et.al. Worldwide development potential for sour gas. 2011.

project (16-18% CO_2) will, from its production and venting activities, potentially emit more CO_2 compared to the amount of LNG produced.[61]

The necessity of CCUS is further exemplified in Australia's Gorgon LNG project. With 14% CO_2 reservoir content, the plant would emit more than four million tonnes of CO_2 annually. A A$3.1bn CCS facility was deployed as part of the government project sanctioning requirements.[62]

The Gorgon CCS project has failed to deliver, underperforming its self-set targets for the first five years by around 50%. To offset its target, Gorgon has recently agreed to acquire and surrender credible greenhouse gas (GHG) offsets recognised by the Western Australian government. The shortfall amounts to 5.23 million tonnes of CO_2, with cost estimates varying from US$100 million to US$184 million. A report made public by the Australian government in 2022 further outlined that the CCS plant injected 2.26m tonnes of CO_2 over a one-year period, significantly below its targeted 4 MTPA capacity.[63]

CCUS in gas processing is *not* about reducing Scope 3 emissions resulting from the final combustion/use of gas, but rather to minimize *production-related* Scope 1 emissions from gas with excessive CO2 content.

A Quick Look at the Global Gas Processing CCUS Landscape

CCUS for gas processing has been around since the 1970s, with the most notable plants in Sleipner (Norway) and LaBarge (US). In the latter, CO_2 comprised up to 65% of the gas produced from the reservoir.[64]

The higher CO_2 concentration and partial pressure in gas processing emissions

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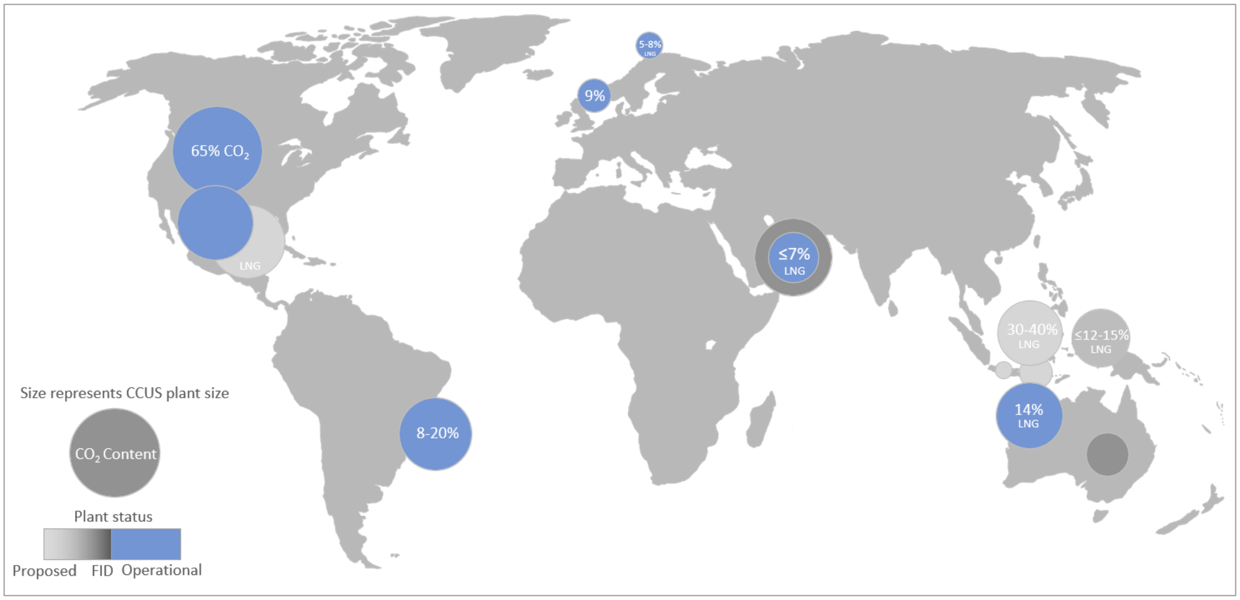
[61] IEEFA. Santos' Barossa gas field emissions create major risks for shareholders. 2021.
[62] Gorgon CCS is based on at least 80% capture and storage requirement from the reservoir CO_2 and has been supported by A$60m of Australian federal government funds. It is also notable that the CCS project only started in 2019 while the first LNG shipment commenced in 2016.
Sydney Morning Herald. Chevron's five years of Gorgon carbon storage failure could cost $230 million. 11 November 2021.
Reuters. Chevron, partners to fork out for carbon offsets for Gorgon LNG carbon capture shortfall. 11 November 2021.
[63] Upstream. Chevron's flagship Gorgon CCS project still failing to live up to expectations. 10 February 2022.
Chevron. Gorgon Project CO2 injection project Annual Report. 2021.
[64] LaBarge facility can capture 7 MTPA CO_2 and is the largest industrial capture facility in the world.
US Environmental Protection Agency. ExxonMobil Shute Creek Treating facility subpart RR monitoring reporting and verification plan. Accessed on 2 February 2022.
Natural gas world. ExxonMobil plans $400mn Wyoming CCS expansion. 21 October 2021.
MIT CCS database. LaBarge fact sheet. Accessed on 2 February 2022.

allows for a lower cost of capture compared to other CO_2 emissions.[65] While the cost of capture is fairly low at below US$30/t$CO_2$, the cost for transport and storage can vary widely from US$10 to more than $40/t$CO_2$ and can be the dominant determinant in CCUS implementation.

Figure 7: Global Landscape of Gas Processing CCUS

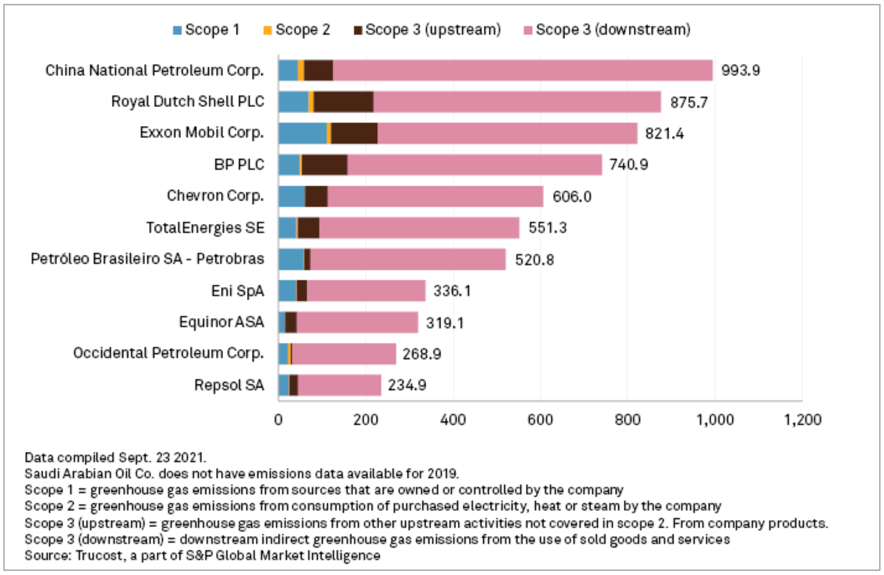


Source: Compiled, see Appendix A for details. CCUS facility size is influenced by the level of CO_2 and the volume of gas production.

Emissions associated with gas processing directly impact the highly visible Scope 1 & 2 emissions, and companies bound by emissions reduction commitments will tread carefully. A single gas processing plant in CO_2-rich resources could easily emit more than 3 MTPA CO_2, a figure that would cause notable emissions' rise in even the largest oil and gas companies (Figure 8). CCUS has, therefore, increasingly become imperative in developing CO_2-rich resources**.**

[65] Partial pressure expresses the pressure of CO_2 in the gas stream, which, in tandem with CO_2 concentration plays a large role on determining the ease of carbon capture process.

Figure 8: GHG Emission Scope of Select Oil & Gas Companies in 2019 ($mtCO_2e$)



Source: S&P Global Market Intelligence.

SEA Gas and CCUS: The Rush to the Door

LNG has historically been a critical enabler for South East Asian gas to reach the east Asian consumer markets. However, SEA has been facing a steady decline in its LNG exports in recent years (Figure 9). With maturing gas fields and persistent under-investments, countries such as Malaysia and Indonesia now must grapple with more challenging gas assets, some of which contain high levels of CO_2 impurities.[66] With international companies, financing, and gas consumers involved, CCUS is now becoming an imperative.

In August 2021, INPEX, which operates Indonesia's undeveloped Masela gas field, announced a potential delay in the project's development and slated the potential need for CCS or CCUS.[67] This tendency is mirrored in the company's recent announcement for CCUS deployment in Australia, with capacity planned up to 7MTPA.[68] CCUS potential developments have also been reported in Petronas Kasawari, BP Tangguh, and Repsol Sakakemang, all located in Malaysia and Indonesia.

Globally, the concentration of underdeveloped gas fields with high CO_2 content appears to be concentrated in South East Asia and Australia (Figure 10).[69] From the

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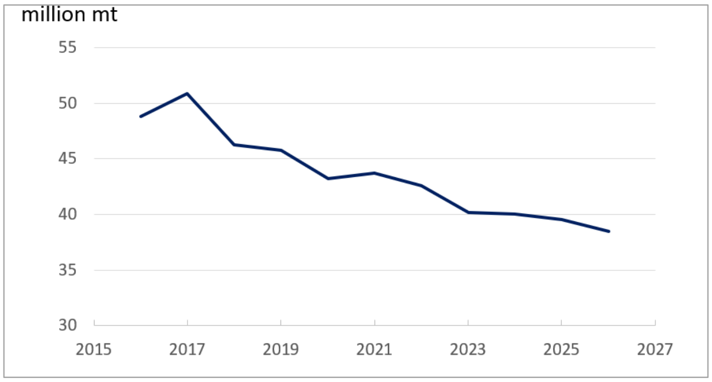
[66] In certain countries this is further coupled with increasing focus to use gas for domestic demand, as observed in Indonesia.
[67] Reuters. Inpex to delay investment decision on Indonesia's Abadi LNG project due to pandemic, climate change. 10 August 2021
[68] Nikkei. Japan's Inpex to spearhead carbon capture at Australian gas field. 9 February 2022.
[69] Changes to developments of these resources may have taken place since 2009, however the map outlines the general landscape of CO_2-rich gas reserves.
Burgers et al. Worldwide development potential for sour gas. 2011.

potential list of gas processing CCUS projects planned globally, nearly half of the capacity is located in the South East Asian region.[70] While many of these projects are still in the early development stages, this trend likely reflects the push to develop gas fields with higher CO_2 content as soon as possible, anticipating potential changes in market attitude.

Figure 9: South East Asia Declining LNG Exports and Outlook



Source: S&P Global Platts Analytics. LNG exports from Malaysia, Indonesia and Brunei. 2021 onwards are estimates.

Equipping CO_2-rich gas resources with CCUS does not necessarily bring a premium price. The prime objective is to reduce emissions to compete with other gas resources with less reservoir CO_2. With the LNG value chain already embedded with higher emissions than pipeline transport, the stake is even higher for LNG-based project development.

In recent years, several long-term LNG sales purchase agreements (SPAs) have been signed between Singapore's Pavilion Energy, Qatar Petroleum and Chevron, which mandated the reporting of emissions for each LNG cargo. 2021 saw the establishment of the Carbon Neutral LNG Buyers Alliance in Japan comprised of 15 companies with notable leadership from Tokyo Gas.[71]

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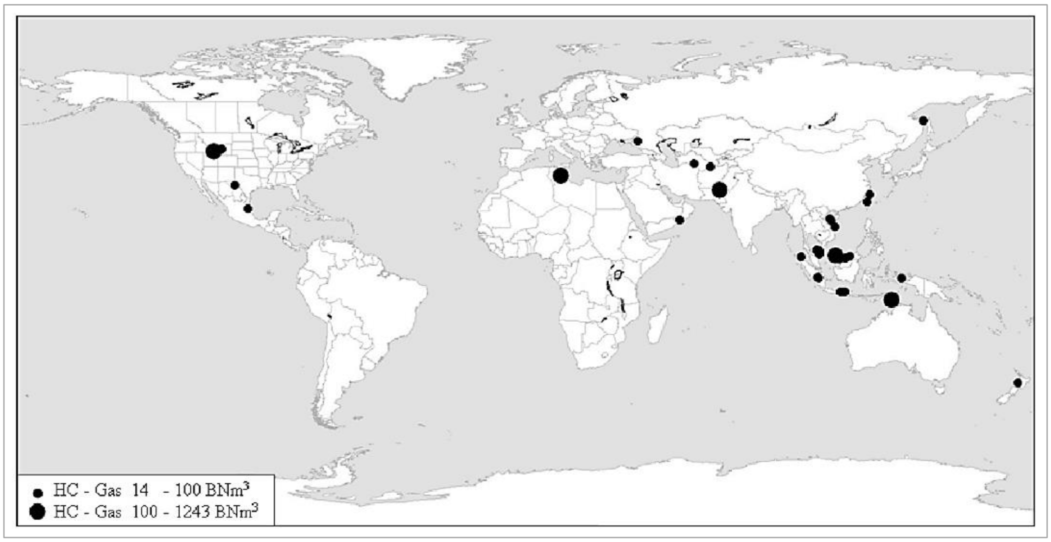
[70] Based on IEEFA market estimates. Indonesian Government approval for BP Tangguh Vorwata CCS plan of development was reported on August 2021.
Global CCS Institute. Global status of CCS 2021. 2021.
[71] Tokyo Gas. Establishment of a Carbon Neutral LNG Buyers Alliance. 9 March 2021.

Figure 10: Indicative Map of Undeveloped and Underdeveloped CO_2-rich (15-80%) Oil and Gas Fields



Source: WFJ Burgers, et.al., IHS.

LNG trade accounts for a sizeable portion of cross-border gas trades. Given the rising rates of imports led by countries such as China and India, the CO_2 content of LNG supply sources will become a highly material consideration. Couple these factors with net zero pledges in importer countries, such as European countries and Japan. These trends likely indicate that disclosure of associated emissions of LNG cargoes and competition to lower emissions will continue to intensify.

In the future, host countries with CO_2-rich gas reserves will likely be persuaded further by oil and gas companies to accommodate the use of CCUS. Given that CO_2 removal is an integral part of gas production, it is imperative that host governments clearly understand the baseline investment scenario without CCUS, and other influencing factors such as the ICP, to comprehensively evaluate cost allocations and to avoid the public bearing more than the fair share.

The additional cost of CCUS would also be particularly salient for countries with domestic gas price control policies. CCUS costs would reduce the state revenue opportunity, which could be used as a hedge against price fluctuations and would likely lower the headroom to maintain price control.

Power Sector – Different Pathways for CCUS Cost Decline

People often confuse CCUS as ‘a mature technology in need of policy support’, while at other times as ‘a technology in great need of innovation to lower the cost’. These confusions likely arise due to the diverse CCUS applications, each with distinct characteristics and maturity. Therefore, it is worthwhile to revisit the discussion surrounding its application maturity and particularly to flesh out the two measures of readiness – technical and commercial readiness.

Power Generation CCUS Is a Different Game Altogether – Energy Penalties, Application Maturity and Cost Projections

Power plants inherently emit large volumes of CO_2. A 1GW coal plant could emit 5 to 7 million tonnes of CO_2 annually.[72] Combined cycle gas power plant would emit less CO_2, but the lower concentration of CO_2 in its exhaust gas means that the capture cost would likely be higher.

South East Asian countries have been more conservative in forecasting the role of CCUS in their mid-term power sector projections, as observed in various national planning documents. Malaysia's Tenaga Nasional Berhad and Indonesia's PLN have expressed longer-term interest in exploring the subject, with PLN stating the potential use of CCUS post-2035, after the technology is commercially mature.[73]

Countries such as Vietnam have limited disclosure of their expectation of CCUS for the power sector, while Singapore appears to be more inclined to explore CCUS for industrial applications.[74] Cost-sensitive markets, especially those with rigid power purchase agreements, are bound to be more cautious in implementing CCUS, given its renowned commercial challenges.

It is interesting to note that Indonesia has listed CCUS in its long-term low-carbon strategy document submitted to the United Nations Framework Convention on Climate Change (UNFCCC). The country stipulated that by 2050, the role of coal power will remain significant, with a scenario outlining that '76% of the coal power plants are equipped with CCS to achieve *zero* emissions in coal power plants'.[75]

Current State of Power Generation CCUS

Globally, there is only one operating power generation CCUS, located in Boundary Dam, Canada. A second CCUS plant, Petra Nova in the US, was operational between 2017 and 2020. It was later reported to be 'shut down indefinitely', at only four years old.[76]

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[72] Global Energy Monitor. Estimating carbon dioxide emissions from coal plants. Accessed on 3 February 2022.
[73] TNBR reported ongoing R&D on carbon capture since 2011 with limited disclosure on project plans. Separately, PLN stated that CCUS will potentially be utilized in fully-depreciated plants.
Tenaga Nasional Berhad. Investor Presentation. 2021.
Bisnis. Indonesia-Japan cooperation for CCUS, economics is still a challenge. 10 January 2022.
PLN. RUPTL 2021-2030 Electricity procurement plan. 2021.
PLN. PLN decarbonization strategy to reach 2060 carbon neutral. 31 October 2021.
[74] Energy Market Authority - Singapore. Singapore Looks to develop and deploy low-carbon technological solutions. 23 June 2021.
[75] See box in page 34 on CCUS capture rates
Government of Indonesia. Long-Term Strategy for Low Carbon and Climate Resilience 2050 page 58. 2021.
[76] Reuters. Problems plagued US CO2 capture project before shutdown: document. 7 August 2020.

Both coal and gas power are prevalent in SEA. The average age of existing coal power plants in SEA is 11 years (coal power plants' average lifespan is 30 to 40 years), and CCUS offers a potential lifeline to be retrofitted into existing power plants.[77] However, the pertinent questions pertain to the projection of its application maturity and the rate at which its cost can be driven down.

CCUS for the power sector is more costly and complex due to the diluted CO_2 in the flue gas stream, as evidenced in the string of historical issues in retrofitting CCUS into power plants. In contrast to gas processing and certain chemical processes, which could generate exhaust gas in relatively high CO_2 concentrations, coal plants' exhaust gas typically contains 12-14% of CO_2 while gas turbine power plants generate 3-4% CO_2.[78] Small in concentration, but large in terms of absolute volume globally.

It is worth noting that CCUS is an inherent part of revenue-generating activities to produce marketable gas in gas processing. In power generation, in the absence of strong drivers, such as a high carbon price or massive subsidies, CCUS could be seen solely as costs that will be passed on to someone, whether to corporations, the government, or the ratepayers.

Over the years, IEEFA has published a comprehensive body of knowledge in assessing the economics and viability of CCUS projects, particularly in the North American region. Table 7 outlines the two CCUS power generations projects, which came into operation, both supported by generous government grants.

Yahoo finance. Power plant linked to idled US carbon capture project will shut down indefinitely – NRG. 30 January 2021.
[77] International Energy Agency. Average age of existing coal power plants in selected regions in 2020. 8 October 2021.
International Energy Agency. CCUS in power. 2021.
[78] IPCC. Carbon capture utilization and storage. 2005.
Konthadaraman, A. et.al. Energy procedia. Comparison of solvents for post-combustion capture of CO2 by chemical absorption. 2009.

Table 7: Power Generation CCUS Projects

Facility	Power Generating Capacity	Plant Capacity	Project Costs	CO2 usage	Realization & Remarks
Boundary Dam Unit 3, Canada. Coal Power Plant	115MW power generation (retrofit from 150MW)[79]	1 MTPA[80] 2014	CAD 1.5 bn [81] US$800m for CCUS[82]	EOR & Storage	Received CAD 240M funding from Canadian Government[83] Power plant was repowered to adopt CCUS. CCUS is powered by coal plant steam. CCUS technology: Cansolv solvent
Petra Nova, US. Coal Power Plant Operation suspended in 2020 (Startup in 2017). Notable issues reported by US DOE. Shut down indefinitely in 2021[84]	240MW slipstream from WA Parish Unit 8 610MW plant	1.4 MTPA CO2[85] 2017	USD 1bn CCS Retrofit[86]	EOR	Received US$190M funding from the US Department of Energy[87] CCS powered by gas cogeneration. CCS technology: MHI KS-1 Solvent

Source: Compiled.

It is also important to note that while the development of affordable coal power CCUS remains elusive, the development of gas power CCUS is potentially even more challenging given the more diluted CO_2 concentrations (~3-4%) compared to coal plants (12-14%).

It is generally expected that as more CCUS projects in the power sector develop, lessons learned will reduce the cost over time. While the timeframe of such progress remains an open question, SEA policymakers should remain aware of the following key subjects in evaluating and planning for power generation CCUS.

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79 International CCS Knowledge Centre. Boundary Dam 3 Carbon Capture and Storage (CCS) Facility. Accessed on 11 April 2022.
80 Global CCS Institute. Global status of CCUS 2020. 2020.
81 EU CCUS Projects Network. Current and emerging industrial-scale CO_2 capture. 2019.
82 IEA International Centre for Sustainable Carbon. CCUS Status, barriers, and potential. 2020.
83 Government of Canada. Boundary Dam integrated CCS demonstration project. Accessed on 11 April 2022.
84 Plant owner NRG stated that the project suspension was due to pandemic and low oil price. US Department of Energy reported significant problems with the plant operation, with reported outages encountered on 367 days during the plant operations in 2017-2020.
Reuters. Problems plagued US CO2 capture project before shutdown: document. 7 August 2020.
US Department of Energy. Petra Nova DOE NETL Report. 2020.
Yahoo finance. Power plant linked to idled US carbon capture project will shut down indefinitely – NRG. 30 January 2021.
85 Global CCS Institute. Global status of CCUS 2020. 2020.
86 US Energy Information Administration. Petra Nova is one of two CCS power plants in the world. 31 October 2013.
87 US Department of Energy. Petra Nova – W.A. Parish Project. Accessed on 11 April 2022.

Who Will Pay for the Energy to Run CCUS?

Capturing CO_2 consumes a large amount of energy, which effectively reduces the amount of electricity that can be delivered to consumers.[88] Under regular operations, power plants already consume a portion of the power they generate for self-consumption. CCUS imposes additional energy penalties into the mix, typically by drawing steam or power to operate the capture process.

CCUS could consume up to 20% to 30% of the power generated by the plant, with an expected net efficiency reduction of 6 to 12 percentage points.[89] Decades of technological progress have been devoted to increasing coal power plant efficiency by a mere 7%, from the sub-38% of subcritical plants to the ~45% of Ultra Super Critical (USC) plants.[90] Therefore, a loss of 6 to 12% due to increased self-consumption poses a substantial barrier for many CCUS applications.

Based on per-tonnage captured CO_2 basis, current CCUS costs in coal power could easily add 6 to 9 cent/kWh to the power generation costs. Proper assessment should also consider

CO_2 Capture Rates

As reducing emissions is the main goal of CCUS, CO_2 capture rates is a subject of great importance. Capture rates describe the amount of CO_2, described in percentage, which can be captured by CCUS from a process, while the remaining emissions are released into the atmosphere.

Globally, capture rates of 85 to 90% is commonly planned. A study by IEAGHG in 2019 suggests that increasing the capture rate from 90% to 99%+ can be achieved with a modest increase in LCOE (7%) and CO2 avoided costs (3-8%).

These, however, will need to be evaluated against historical realizations. Experiences in projects such as Petra Nova and Gorgon CCUS have all noted challenges in meeting the CO_2 capture targets for various reasons. Researchers at MIT have also noted the rising incremental costs and diminishing returns to achieve higher capture rates.

Petra Nova's actual capture rate averaged 70% from 2017 to 2019, when including the emission from its gas-powered turbine for CCS, the capture rates go down to 58%. Boundary Dam capture rates between October 2014 and December 2021 was 53%. Both projects had promised a 90% capture target.

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[88] Energy consumption can be in the form of drawing steam from the power plant to heat solvent-based CCUS process.

[89] Conservative reduction figures presented. Reductions in output should also incorporate any additional flue gas pre-treatment installations required to accommodate CCUS (see later sections).
Increase in fuel consumption ranges from 24-40% (supercritical coal) and 11-22% (gas), 6 to 9% efficiency reduction on gas and ultra supercritical coal plants, based on *new* plants with 90% capture rate. Existing reports indicated greater efficiency loss in CCUS retrofits.
Working Group III of IPCC. IPCC Special report on carbon dioxide capture and storage. 2005.
Cebruean, D. et al. CO_2 capture and storage from fossil fuel power plants. 2014.
GCCSI. CO_2 capture technologies. 2012.
7 to 22% potential net efficiency reduction in gas power plant. IEAGHG. CO_2 capture at gas fired power plants. 2012.
11 to 12% point efficiency reduction in subcritical coal plant assessment (27 to 31% output reduction). World Bank. CCS for coal-fired power plants in Indonesia page 39. 2015.
Herzog, H.J. & Rubin, E.S. Environmental Science & Technology. Comment on "Reassessing the Efficiency Penalty from Carbon Capture in Coal-Fired Power Plants. 2016.

[90] SEA-based studies on coal capacity suggested average efficiency of 33% for subcritical coal power plant in the South East Asian region.
ASEAN Centre for Energy. ASEAN CO_2 Emissions from Coal-Fired Power Plants: A Baseline Study. 2021.

the impact of emissions generated by the CCUS energy consumption.

To compete in a competitive electricity market, the high cost of CCUS will need to be compensated either by selling the captured CO_2, receipt of government incentives or by charging a premium price to the consumers.

In markets with rigid long-term take-or-pay Power Purchase Agreements (PPA), it is likely that power plant owners expect the utility company, state-owned or private, to pay the full cost of the power generation capacity. In contrast, in competitive markets, the additional cost of CCUS will need to compete head-on with other lower-cost power generation options. For CCUS, that question then becomes – would a consumer pay a premium for CCUS-generated electricity, or would they rather save money by buying from a lower-cost source, such as renewable energy.

Furthermore, in subsidized power markets where there is less chance of increasing electricity prices, the government will likely in the end, bear the full costs of CCUS implementation, with monies sourced from allocations of the national budget. The question for government then becomes, do we allocate a budget for buying CO_2 or do we use that money for investment in cheaper sources of energy or higher priority items?

The Road to Low-Cost CCUS Will Likely Be Plagued With Many Giant Project Casualties

With only one operational power generation CCUS, determining technological maturity could prove challenging. The Global Carbon Capture Institute (GCCSI) has listed nine power generation CCUS projects in the 'advanced development' stage, with an additional two under construction. IEEFA's evaluation of the project list concludes with the following:

- All the projects in the advanced development stage have received various government grants ranging from US$2.8m to $21m, primarily in supporting feasibility studies and Front-End Engineering and Design (FEED).
- Capture capacities vary widely, from 0.12 to 6 MTPA CO_2.
- Nine out of eleven projects plan to retrofit CCUS into existing power plants.
- At least seven different technology provider companies are involved with a variation of amine-based carbon capture dominating the technology class.
- The United States government has been the most dominant public funder, trailed behind by the United Kingdom and Australia.
- Two projects have announced delays in 2021, San Juan and Project Tundra. Both projects outlined the intention to acquire low-interest loans or loan guarantees from the US government to fund the projects.

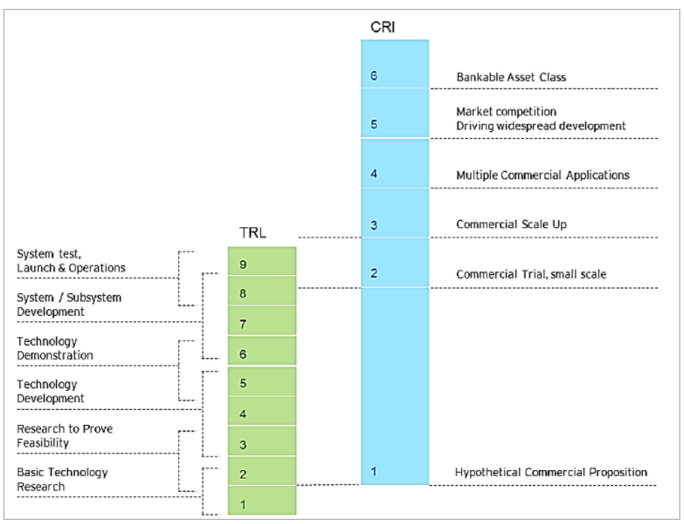
The complete list of power generation CCUS evaluated is enclosed in Appendix B.

In comprehending technological maturity, indicators that can assist include the 1-to-9 scale of the Technology Readiness Level (TRL).[91] A report by GCCSI[92] in 2021 provided a comprehensive list of the various Research & Development (R&D) stages of CCUS technologies and their respective TRLs. In understanding such a concept, however, readers should naturally also incorporate economic and market-related aspects in projecting their potential deployment pathways. Just because a technology solution is feasible, it does not necessarily mean that it is cost-effective compared to alternatives.

The process of technological innovation is inherently associated with uncertainties surrounding the technology's capabilities, limitations, and development trajectory.[93] Nevertheless, stakeholders would be well advised to envisage under what market circumstances such technology would likely thrive, if and when, they scale up.

Frameworks such as the Commercial Readiness Index (CRI) developed by the Australian Renewable Energy Agency (ARENA) could help evaluate the potential commercial readiness of technology as they reach higher TRL levels (Figure 11).[94] While it has its limitations, such a framework would be useful to provide a more comprehensive view.

Figure 11: Commercial Readiness Index (CRI) and Technology Readiness Level (TRL)



Source: Australian Renewable Energy Agency.

[91] Technology readiness levels (TRLs) was initially developed at NASA in the 1970s and was later adopted by various institutions such as the European Commission as a tool to evaluate maturity of a technology. Level 1 indicates initial conception with level 9 being fully in service.
[92] Global CCS Institute (GCCSI). Technology Readiness and Costs of CCS. 29 March 2021
[93] European Commission Directorate general for research and innovation. Technology readiness level: guidance principles for RE technology. 2017.
[94] Australian Renewable Energy Agency. Commercial Readiness Index for renewable energy sectors. 2014.
IEA-RETD. Commercial readiness index assessment. 2017.

The commercial readiness of a technology could further vary based on the regulatory context of its application. A technology may be commercially viable when placed under a certain operational context, such as a high carbon price environment with a strict emissions regulation. The same technology could be far from ready in more cost-sensitive markets with lax emissions regulations.

Stakeholders should note the following points in evaluating the development of CCUS for the power sector, as well as its wider applications.

- **First mover disadvantage – when technology demonstrations typically cost greater than $200M+.** With a large amount of investment required to build CCUS at scale, earlier adopters could be disadvantaged. There will undoubtedly be many projects with challenging economics on the road towards commercial CCUS scale-up. When a medium scale 240MW power plant CCUS retrofit costs US$1bn, the stake is undoubtedly high. While public funding support has seen an increasing trend to support CCUS and CCUS hub development, it remains to be seen whether they will be able to sufficiently entice innovations and spur project developments to drive down the cost fast enough for adoption in emerging markets.

- **Potentially limited future growth potential and useful lifetime in power generation – as the competition continues to drive down cost.** As the cost of renewable and energy storage technology declines, conventional power generation will likely continue to be outcompeted by the cheaper renewable energy power. Battery costs have declined by 97% since 1991.[95] Even with CCUS costs declining in the coming decades, CCUS will face fierce competition. As the current power plant fleets age, coupled with limited new build of coal power plants, uncertainty will likely arise on the useful lifetime of CCUS in the power sector. Furthermore, stakeholders should note that CCUS plant operations largely relies on fossil fuels, exposing it to the typical commodity price cycles, in contrast to the zero marginal costs of renewable energy. These factors, taken together, could have a

On the road towards the commercial scale-up of CCUS, there will be many projects with challenging economics. When a medium-scale 240MW power plant CCUS retrofit costs US$1bn, the stake is certainly high.

[95] MIT News. Study reveals plunge in lithium-ion battery costs. 23 March 2021.

detrimental effect on the potential investment landscape.

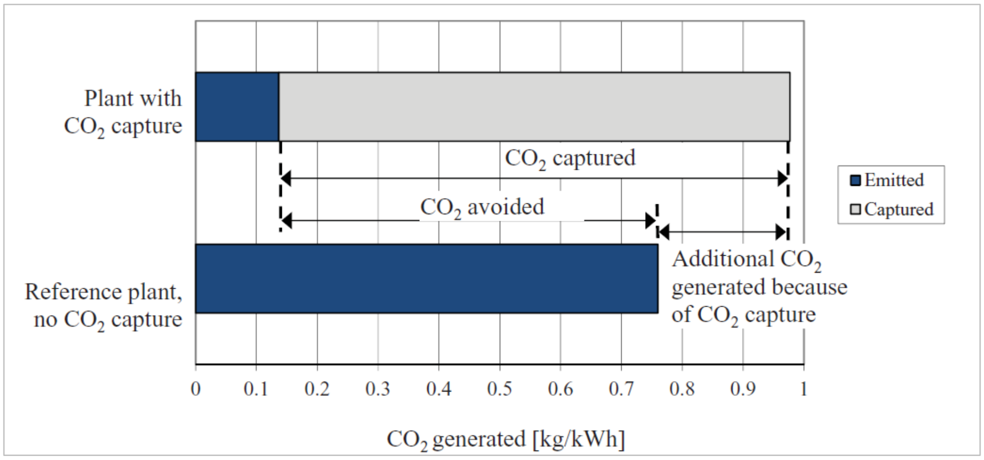
- **Stakeholders should be mindful of past power generation CCUS which stopped short at FEED or pre-FEED stage and are mostly cancelled – nearly fifteen plants with 28 MTPA CO_2 total capacity.**[96] Most of the projects have not seen further developments due to various reasons, largely around economics, lack of established CO_2 buyers and carbon credit markets/incentives. Many of these projects were initially planned to be supported by massive government funding, as exemplified in the initial plan for Longannet (UK, £1bn), Mountaineer (US, US$334m), and Pioneer CCUS projects (Canada, CAD779m). Comprehensive evaluation of these projects could shed more light on the key barriers and the future outlook of power generation CCUS, while paying close attention to the cost and type of technology involved.

- **Cost of CO2 *captured* is insufficient – the cost of CO_2 *avoided* should be the main measure.** The ultimate goal of CCUS will need to be associated with how much CO_2 is being avoided, and not solely captured. The emissions coming from the energy intensive CCUS process will need to be considered in the assessment. While this is a well-known concept for industry insiders, uninitiated unaccustomed stakeholders should also be familiar with the critical difference between the two terms, as illustrated in Figure 12 below. Cost of CO_2 avoided will inherently be higher, as the cost of CCUS will be spread over a smaller amount of CO_2 volume. Readers should also note that the majority of current CCUS facilities employ *planned* capture rates of 85% to 90%. While noting that reaching such planned capture rates has proven challenging in a number of projects, even at such level the process will still leave out considerable CO_2 emissions. Raising the capture bar at 98% – 99% and higher should become the norm.[97]

[96] IEAGHG. Toward zero emissions CCS in power plants using higher capture rates or biomass. 2019

[97] IEA GHG report suggested that increasing capture rates from 90% to 99% increase cost by only 4 to 10% in power generation, for chemical absorption based CCUS.
IEAGHG. Towards zero emissions CCS in power plants using higher capture rates or biomass. 2019.

Figure 12: CO_2 Avoided vs CO_2 Captured for Example Gas Power



Source: Mathieu, P. & Bolland, O., IPCC.[98]

- **Lessons from Petra Nova and Boundary Dam 3 should be placed in the open, disclosing actual costs and operational information.** For a more transparent assessment of past power generation CCUS, it is imperative that associated parties are willing to place the lessons learned from these two power plants in the open. This is especially important after the 'indefinite shutdown' of Petra Nova after only four years in operation, despite being scaffolded by massive US government funding.

- **Readiness of adequate flue (exhaust) gas pre-treatment in existing power plants**. CCUS deployment will likely require considerable exhaust gas pre-treatment prior to the CO_2 capture process. Large amounts of pollutants such as NO_x and SO_2, in the flue gas, will potentially decrease the performance of typical CCUS operations.[99] While pre-treatment equipment is more common in developed countries, a specific assessment of the regulatory and market context in individual SEA countries will be needed. It should be noted that flue gas will also be affected by the power plant characteristics and fuel compositions. Predominance of subcritical coal assets which generates emissions and the use of lower-grade coal would also need to be part of the assessment. In absence of an adequate level of existing flue gas pre-treatment equipment, the costs of pre-treatment equipment retrofit, and its associated energy cost will need to be added to the CCUS cost planning. It can be generally concluded that lax pollution control/air quality standards would likely be a major impediment for CCUS development.

- **Increase in water usage with CCUS deployment** also needs to be considered. CCUS deployment can increase in cooling water usage up to 50%

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[98] Mathieu, P. & Bolland, O. Energy Procedia. Comparison of costs for natural gas power generation with CO2 capture. 2013.
[99] IPCC. Carbon dioxide capture and storage. 2005.
World Bank. CCS for Coal-fired Power Plants in Indonesia page 32. 2015.

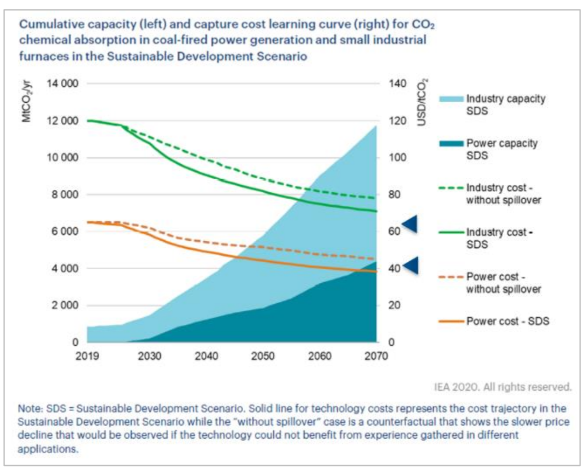
> more, with water withdrawal increase ranging from 25 to 200% higher has been reported. Proper technical and environmental impact assessments will be necessary to mitigate such risks, including incorporating potential associated costs.[100]

IEEFA acknowledges that there are potential strategic roles for CCUS in the path towards a net zero world. Nevertheless, the implementation of CCUS in the power sector in South East Asia is deemed less likely, given the potentially slow trajectory of the carbon pricing regime in the region. When power generation CCUS does become commercially mature, earlier adoption is expected in less cost-sensitive parts of the world.

Cost Projections

A recent report from the Asia Investor Group on Climate Change (AIGCC)[101] incorporated multiple CCUS scenario outlooks developed by Wood Mackenzie in several countries. The projections incorporate a top-down evaluation of the 2040 scenario with current country policies (Energy Transition Outlook) and an aggressive decarbonization scenario with an elevated carbon tax (Accelerated Energy Transition 2). Under such scenarios, both coal power+CCS and gas power+CCS will still be significantly more expensive than solar+storage in China, India, and South Korea, although coal and gas could still be competitive in Japan under the current policy scenario.[102]

Figure 13: IEA Projection of CCUS Capture Costs Under the IEA Sustainable Development Scenario



Source: CCUS in clean energy transitions. IEA. 2020.

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[100] IPCC. Climate Change 2022 – Mitigation of Climate Change page 6-39, 6-75. Accessed 11 April 2022.
[101] AIGCC. Investors should scrutinise Asian CCS plans as new analysis finds large-scaled deployment could fall short. Accessed 11 April 2022.
[102] Note that Wood Mackenzie's scenarios provides a top-down/indicative trend evaluation and not a comprehensive case-specific economic evaluation of CCUS.
AIGCC. CCS in the decisive decade for decarbonization – The case for Asia. 2021.

Separately, the IEA issued a CCUS report in 2020, which presented a CCUS cost projection under the Sustainable Development Scenario (SDS). The scenario featured elevated climate commitments one-notch below the ambitious Net Zero Emissions (NZE) 2050 scenario.[103] Under the scenario, cost of CO_2 *capture* in coal power is projected to decline from ~US$65/t$CO_2$ in 2020 to US$40/t$CO_2$ by 2070, assuming a rapid uptake of CCUS. At a potential price of US$40/t$CO_2$ in 2070 for capture, compounded with additional costs for transportation and storage, the price range of CCUS application will very likely be way outside what emerging markets in SEA could afford in the next couple of decades.

Projecting the future cost and growth rate of developing technologies is inherently full of uncertainty, just as past forecasts on solar PV growth has demonstrated.[104] It is nevertheless an essential exercise to help understand the potential pathways. Notably, the 'learning rate' exhibited by the IEA projection is substantially lower than the path of solar PV. This would likely be related to the slower CCUS adoption due to the high cost and custom-fitted nature of CCUS applications.[105]

Figure 14: The Different Scale of CCUS

Source: Petra Nova, Texas Tribune.

Whereas PV can be scaled up through mass production with incremental improvements at relatively low costs. Lessons from CCUS will likely need to be accumulated one plant at a time, each with considerable associated costs and time.

With the high cost of failure, the design-build-prove cycle of CCUS will potentially operate on a different time scale, and the path for scaling-up CCUS will likely play out differently. It is arguably easier to learn from and incrementally improve a US$3-4m wind turbine than a demonstration project costing hundreds of millions of dollars.

In order to help accelerate the cost decline, some technology proponents have been developing 'modularized' carbon capture plant design with 0.002 to 0.2 MTPA capacity. The standardization of designs is touted to reduce costs more effectively

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[103] Readers are encouraged to be familiar with IEA scenarios, including the Announced Policy Scenarios (APS) and Stated Policy Scenarios (STEPS)
International Energy Agency. Understanding World Energy Outlook scenarios. 2021.
[104] PV-Magazine. IEA versus the reality of solar PV. 20 November 2018
[105] CCUS design will typically need to be customized to the planned facility, this is in contrast to the mass-production model associated with other technologies such as PV.

and allow it to be deployed by many scales. A plausible concept of which results remain to be seen. Nevertheless, the applications of CCUS in tight-space locations, such as offshore gas production platforms, have also been performed in a somewhat similar fashion for decades.[106] It is also noteworthy that these modularized CCUS technology potential applications will likely lean more towards industrial applications and less applicable for power generation plants with multi-million tonnes of annual CO_2 emissions.

With the high cost of failure, the path for scaling-up CCUS will likely play out differently. It is arguably easier to learn from and incrementally improve a US$3-4m wind turbine than a demonstration project costing hundreds of millions of dollars.

Claims of cost projections and decline.

With limited project development in power generation and CCUS Petra Nova's closure, an assessment of the actual cost of CCUS will likely remain ambiguous for the near future. In 2021, an IEEFA report highlighted that the often cited claims of a continual cost decline trend of CCUS could muddle understanding.[107]

In the report, IEEFA emphasized that 'the only potentially accurate capture costs shown in Figure 15 are the US$60 to $65 cost for Petra Nova and the US$100-plus cost for Boundary Dam. We say "potentially actual" because no actual operating costs have been released for Petra Nova or Boundary Dam 3. All the other carbon capture costs shown in the figure are merely estimates for past projects that have not been built, or for future projects that have not been built, and may never be built. It is wise to remain prudent in assessing the actual costs and projected costs of CCUS.

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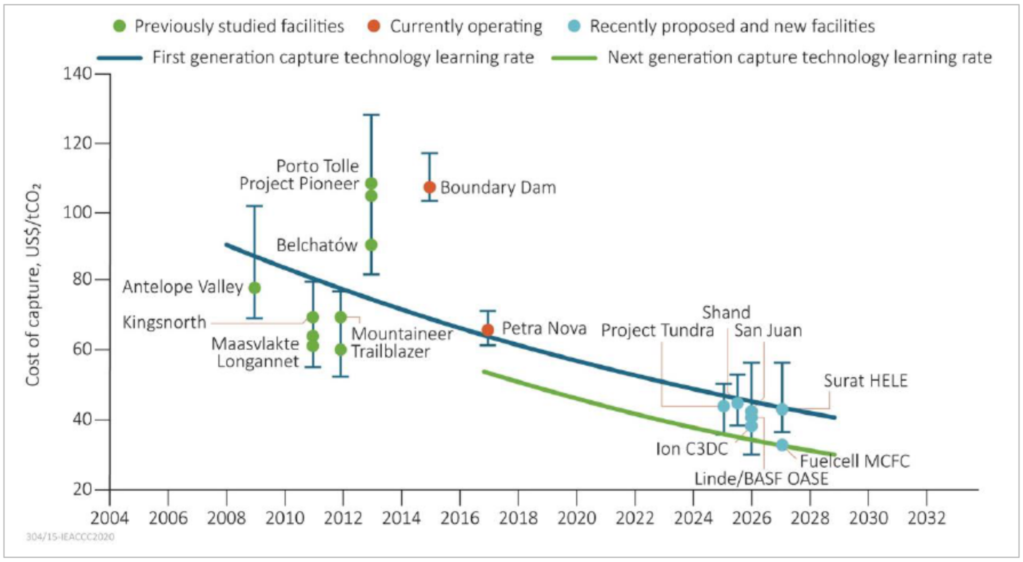
[106] Carbon clean. The future of carbon capture systems. Accessed on 22 February 2022.
Aker carbon capture. Carbon capture made easy. Accessed on 22 February 2022.

[107] IEEFA. Enchant's San Juan Generation Station. CCS Retrofit remains behind schedule, financially unviable. 2020.

Figure 15: Claims and Potentially Proven CCUS Costs



Source: CCUS – Status, barriers, and potential. IEA Clean coal centre. 2020.

CCUS Leadership in Asia

With the technology-intensive nature of CCUS, several countries could provide reference points for the CCUS potential in Asia: China, Japan, and South Korea. All three countries have a long history of technology leadership and energy investments in the region. Their experiences with CCUS can provide a glimpse into the future path of CCUS in SEA.

China

China has been slow in in its development and uptake of CCUS. Most of China's existing CCUS is considered small-scale, with the estimated aggregated capacity ranging from 2 to 4 MTPA CO_2, spread over dozens of small-scale facilities.[108] Compare this with the US' Shute Creek treating plant's 7 MTPA CO_2 capacity (in a single plant). It is clear that China has a lot of catching up to do.

Although most are still in early stages, potential projects are being proposed and prepared. Notable project plans, such as the CNOOC CCUS in the South China Sea (1.5 MTPA CO_2) and the recently established Sinopec's Jiangsu, CCUS (0.2 MTPA CO_2) have been primarily led by Chinese oil and gas companies. It is estimated that more than 70% of the national capacity is operated by Sinopec, CNPC and the CNOOC Group.[109]

[108] Argus. Carbon storage, H2 key to China net-zero goal: Shell. 18 January 2022.
IHSMarkit. China inches forward on CCUS deployment with Sinopec pilot project. 6 January 2022.
South China Morning Post. Climate change: China's plant to double carbon capture capacity by 2025 hinges on securing funding for projects. 14 June 2021.
[109] Reuters. China's CNOOC launches first offshore carbon capture project. 30 August 2021.

In terms of innovations, it is worth noting that between 2020-21, 81% of patents in CCUS filed with the World Intellectual Property Organization (WIPO) were of Chinese origin.[110]

While the development of CCUS and China remains to be seen, it will likely not escape the basic tenet of the CCUS discussion – that attaching a high price to carbon emissions is necessary. A recent report from Shell China suggested that a carbon price of US$47/tCO2 by 2030, and US$205 by 2060, will likely be required to achieve China's 2060 carbon-neutral target, which includes the widespread adoption of CCUS.[111] With China's Emission Trading Scheme's (ETS) carbon price projected to hover around US$10/tCO2 in 2022, there is still some catching up to do.[112]

Japan

With Mitsubishi Heavy Industry (MHI) already playing a prominent role in certain CCUS applications, Japan will likely want to pursue a leading role in CCUS development in Asia. This trend has been displayed in Japan's leadership in a number of CCUS feasibility studies, and in the establishment of the Asia CCUS Network Forum, with member states from Southeast Asia, US, Australia, and India.[113]

While Japan has supported many CCUS initiatives, the plan for CCUS is somewhat less ambitious at home. This is potentially due to the conservative approach in assessing storage in the earthquake-prone region. A long-term CCS trial of 0.2 MTPA capacity has been completed between 2016 and 2019, with further demonstrations planned in power generation applications.

Japan's CCUS goal has likely been spurred by both its significant coal and gas power fleet, as well as an anticipation of the future potential of the hydrogen/ammonia value chain. The country, which will likely leverage its experience in the power and LNG sectors, has also shown particular interest in 'carbon recycling'. This is the utilization of captured carbon, with the ambition to secure 30% of the global market by 2050.[114]

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[110] BDO Research & Consultancy. Carbon capture patents rise for fifth year running as companies race to address climate crisis. 22 November 2021.
[111] Shell China. Shell published report to set out a possible pathway for china to achieve a carbon-neutral energy system by 2060. 17 January 2022.
S&P Global Platts. China to raise hydrogen share to 16%, CCUS capacity by 2060: Shell. 18 January 2022.
[112] South China Morning Post. China's emissions trading market likely to see expansion, rising carbon price in 2022, say analysts. 9 January 2022.
[113] The 1st Asia CCUS Network (ACN) Knowledge sharing conference was held in 2021.
Asia CCUS Network. Asia CCUS Network Members. Accessed on 20 January 2022.
[114] Japan Ministry of Economy, Trade, and Industry. Japan Green Growth Strategy. 2021.

South Korea

South Korea has outlined plans to invest in CCUS, both domestically and overseas.[115]

Early plans have been reported that South Korea is exploring a CCUS collaboration with Malaysia, specifically involving its steel giant POSCO and Petronas.

In 2021, South Korea's utility KEPCO and its six subsidiaries announced an exit from coal by 2050. The company announced plans to commercialize CCUS technology for 500MW of coal power and 150MW of gas power by 2030.[116] The company's current CCUS utilization is largely limited to small-scale pilot installations.[117]

Traditionally, the export of technologies and concessionary financing from these three countries has been vital in promoting various technology applications in SEA. As it stands, all of them are significantly behind in terms of CCUS applications compared to establishments in North America. Despite the growing need to implement CCUS to mitigate emissions, none have yet to develop a commercially viable model for widespread CCUS adoption.

It is also notable that these three countries have varying degrees of CCUS drivers, with South Korea exhibiting the most mature carbon pricing system. Meanwhile, Japan has some form of regulatory emissions control, but the country's carbon pricing remains paltry at best, with a carbon tax of around US3$/t$CO_2$e. This is despite actively promoting CCUS in SEA.

With announced government commitments from all three countries to support net zero targets, the CCUS development in these countries will likely shape the outlook of Asia. This is particularly salient with the US (which is home to most of CCUS' current fleet) rapidly departing from coal. Along with this, so will their focus on coal power CCUS, a dominant part of SEA power mix.[118]

With the US – home for most of the current CCUS fleet – rapidly departing from coal, so will their focus on coal power CCUS, a dominant part of SEA power mix.

Stakeholders in SEA should remain cautious of CCUS' progress in these countries, while also paying attention to

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115 IHSMarkit. South Korea's climate roadmap fails to impress businesses, environmentalists. 21 October 2021.
116 The Korea Herald. Kepco, six subsidiaries announce complete exit from coal by 2050. 10 November 2021.
117 A pilot CCUS plant with amine-based capture is located in the Boryeong power plant with 2 tonnes per *day* capture capacity.
Kepco E&C. Carbon capture & storage: CCUS. Accessed on 3 February 2022.
118 US Energy Information Administration. Renewables became the second-most prevalent U.S. electricity source in 2020. 28 July 2021.

specific policies and public financing support that is attached to such developments.

Where Would the Path of CCUS in South East Asia Lead?

As a concluding remark, IEEFA believes that the establishment and growth of CCUS in the South East Asian market within the next several decades, will likely be limited around gas processing and some stand-alone industrial applications. This could be supported by concessionary financing or bilateral initiatives.

The ongoing CCUS plans are evidence that the region is playing catch up to mature CCUS technologies in the gas sector, potentially anticipating possible changes in market attitudes towards CO_2-rich gas in the future.

Host countries would be well-served to understand the implications of internal carbon pricing for investing companies in finding a fair share of cost allocations, if and when, CCUS is deployed.

IEEFA believes that the widespread adoption of CCUS in SEA's power sector remains highly unlikely within the next several decades. The development of affordable coal power CCUS remains elusive and potentially even more so for gas power. Even at the US$40/t$CO_2$ cost of capture, the effective total cost of US$50 to 60/t$CO_2$, inclusive of transport and storage, will be beyond the reach for most countries in the region.

In assessing the full costs of CCUS in SEA against the alternatives, a multitude of factors will need to be considered, including the predominance of subcritical coal plants, and the costs of flue gas pre-treatment facilities. Further, costs of CO_2 *avoided* should be the main focus to avoid neglecting the emissions resulting from the energy intensive CCUS process.

The establishment of CCUS hubs in locations such as Singapore remains a possibility, given the concentrated industrial base and less cost-sensitive, export-based nature of the market. As mentioned previously, deeper coverage of the potential of CCUS-based products, such as hydrogen and ammonia, is beyond the scope of this paper, but will likely be part of future IEEFA publications.

CCUS will undoubtedly remain key for some hard-to-abate sectors. It is nevertheless important for stakeholders to note that many of the existing, and upcoming, CCUS projects in the US and EU lean heavily on public funding support, which may not be readily available in SEA countries.

The recent IPCC report, issued in 2022, has outlined the challenging costs of CCUS applications in the near future. With limited resouces, CCUS is ultimately a question of priorities, as the costs will eventually land somewhere. It is also pertinent to ask whether the CCUS projects planned in the region match the 'intended CCUS' for each respective country's commitment towards their decarbonization goals.

SEA countries can use CCUS as a stepping stone to 'learn the ropes' of the technology and to anticipate future developments of carbon-capture based export products and other technologies. However, it should not distract from the adoption of other lower-cost options in renewable energy and grid integrations. This should remain at the centre of SEA's attention toward decarbonization.

It is possible that the cost of CCUS in power generation will decline substantially over the next two decades, but historical experience and the factors outlined throughout this report suggest its likelihood remains questionable, especially for adoption in cost-sensitive markets. The CCUS train may eventually arrive, but before it does, it will likely need to make a lot of stops before reaching the South East Asian shores.

Appendix A

Select Gas Processing CCUS Projects

Facility	Reservoir-associated CO_2 Content	**Plant Capacity** Million Tonne Per Annum (MTPA) Start Operation	CO_2 End Use	Realization & Remarks
Shute Creek Treating Facility, LaBarge, US ExxonMobil	~ 65%[119]	7 MTPA CO2 1986, extended in 2010[120]	EOR	Plan for additional 1MTPA capacity has been reported in 2021.[121] ExxonMobil proprietary technology controlled freeze zone was patented in 1986 and demonstrated in LaBarge in 2010 LaBarge facility is also one of the largest helium recovery plants in the world, supplying more than 20% of global capacity.
Century Plant Occidental Petroleum, SandRidge	Up to 65%[122]	5 MTPA CO2 in use [123] 2010	EOR	Facility reported built with 8+ MTPA capacity
Santos basin, Brazil Petrobras	8 – 20% CO2[124]	4.6 MTPA CO2 2013 (Petrobras reported 2008)	EOR	Injected 4.6mT CO2 in 2019. 14.4 miTonne cumulative volume between 2008 and 2019, expected cumulative volume of 40mT by 2025[125]
LNG - Gorgon, Australia Chevron LNG Operation : 15.6 MTPA LNG[126] Chevron (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%), JERA (0.417%)	14%[127]	4 MTPA CO2[128] 2019	Storage	Underperformed its self-set targets for the first five years by around about 50%. Gorgon has recently agreed to acquire and surrender credible greenhouse gas (GHG) offsets recognised by the Western Australian Government to offset its target. The shortfall amounts 5.23 million tonnes of CO_2 with cost estimates vary from US$100 million to US$184 million. A report which was made public by the Australian government in 2022 further outlined that CCS plant has injected 2.26m tonnes of CO_2 over a one-year period, significantly below its targeted 4 MTPA capacity.[129]

[119] Burgers et.al. Worldwide development potential for sour gas. 2011.
ExxonMobil. Utilizing LaBarge experience to support the global developent of CCS. 2009.
[120] MIT CCS database. 2016.
[121] Eurasia review. ExxonMobil plans to increase carbon capture at LaBarge, Wyoming facility. 21 October 2021.
[122] Midland reporter-telegram. SandRidge, Oxy team up to build CO2 extraction plant. 12 July 2008.
[123] MIT. Century plant fact sheet. 2016
[124] Petrobras. Petrobas offshore CO2 management – pre-salt development. 2014.
[125] Petrobras. Petrobras Climate Change Supplement. 2019.
[126] Chevron. Gorgon project overview. 2021.
[127] Reuters. Chevron starts burying CO2 off Australia at huge Gorgon storage. 8 August 2019.
Argus. Chevron misses CCS targets at Australia's Gorgon LNG. 29 July 2021.
[128] Chevron. Gorgon carbon capture and storage fact sheet. 2021.
[129] Upstream. Chevron's flagship Gorgon CCS project still failing to live up to expectations. 10 February 2022.
Chevron. Gorgon Project CO2 injection project Annual Report. 2021.

Facility	Reservoir-associated CO_2 Content	Plant Capacity Million Tonne Per Annum (MTPA) Start Operation	CO_2 End Use	Realization & Remarks
LNG - Ras Laffan, Qatar Qatar Petroleum LNG Operation : 77.4 MTPA[130]	Up to 7%[131]	2.2 MTPA CO2[132] 2019	Storage	Total of 2.54 mt of CO2 injected by end of 2020 (starting up on February 2019). Averaged annual realization of 1.38 MTPA CO2 sequestered since Feb 2019 to end of 2020[133] Plan to increase CCS capacity to 5 MTPA by 2025, along with North Field expansion, raising Qatar LNG production from 77 MTPA to 110 MTPA[10]. QP prospectus outlined intention to reach 7-9 MTPA capacity by 2030
Sleipner, Norway Equinor Equinor Energy AS (58.3%), ExxonMobil E&P Norway AS (17.2%), LOTOS E&P Norge AS (15%), KUFPEC NorwaY AS (9.4%)	**~9%[134]**	1 MTPA CO2 1996[135]	Storage	
LNG - Snøhvit, Hammerfest, Norway Equinor LNG Operation : 4.2 MTPA LNG[136]	**5 – 8%** CO2[137]	**0.7 MTPA CO2** Established 2008[138]	Storage	Norwegian state mandated CCS as a condition to operate Snøhvit LNG
Planning – LNG - Kasawari, Sarawak, Malaysia Petronas LNG Operation : 29.3 MTPA LNG	**30 – 40%[139]**	3.7 MTPA CO2 Plan by 2025[140]		3 Tscf estimated recoverable hydrocarbon

130 IHSMarkit. Carbon-neutral and low-emission LNG. 2021.
131 Oil review midde east 2nd Issue 2018. Addressing sour gas processing challenges. 2018
132 In 2019 Qatar produced 78 MTPA of LNG, 1.4 Tcf of gas, and 11 mi mt of condensate and associated products.
IHS Markit. Qatar Petroleum commits to low-carbon LNG in latest expansion. 11 February 2021.
Anatolu energy. Qatar to store more than 5M tons of CO2 a year by 2025. 2019.
Qatar Petroleum. Qatar Petroleum Prospectus. 5 July 2021.
133 Qatar Petroleum. Qatar Petroleum Prospectus page 115. 5 July 2021.
134 IPCC. IPCC Special report on carbon dioxide capture and storage. page 202. 2018.
135 IPCC. IPCC Special report on carbon dioxide capture and storage. 2005.
136 IHSMarkit. 2021.
137 Equinor. Carbon storage started on Snøhvit. 23 April 2008.
138 IHSMarkit. 2021.
139 Upstream. Petronas hits delays over Kasawari gas project. 31 January 2019.
IHSMarkit. Carbon-neutral and low-emission LNG. 2021.
140 Petronas. Getting to know CCUS at Petronas. 17 November 2021.

Facility	Reservoir-associated CO_2 Content	Plant Capacity Million Tonne Per Annum (MTPA) Start Operation	CO_2 End Use	Realization & Remarks
Planning –LNG - Vorwata, Tangguh, Indonesia BP LNG Operation : 7.6 expanding to 11.4 MTPA LNG[141] BP (40.2%), Mitsubishi Inpex (16.3%), JX Nippon (12.2%), KG Mitsui (10%), LNG Japan (7.3%), CNOOC (13.9%)	**Up to 12 to 15%[142]**	3 MTPA CO2[143] Plan by 2026	EGR & storage	Project approval from govt on August 2021 Current emission 5 MTPA will increase to 8 MTPA with Train 3 startup. Estimated 30mi tonne CO2 will be sequestered until 2035.[144] 'The CO2 injection will remove up to 90% of the reservoir-associated CO2 which is currently vented and represents nearly half of the Tangguh LNG emissions'[145]
Planning – Moomba CCS Hub, Cooper Basin, Australia Santos Santos (66.7%), Beach Energy	-	Plan for 1.7 MTPA CO2[146] Plan for 2024	Storage	Project owner claimed acost of $24 to 30/tonne CO2 Supported with Australian Carbon Credit Units for emission reduction.[147]
Planning – LNG - Barossa, Bayu-Undan, **Australia** Santos LNG Operation : 3.7 MTPA LNG[148]	**18%**[149]	TBC		Potential emission without carbon capture at 2.1-3.8 MTPA CO2[150] Argus reported Barossa emission of 3.4+2 (LNG processing) MTPA CO2

[141] BP. BP announces FID to expand Indonesia's Tangguh LNG facility. 1 July 2016.
[142] CNBC. A lineup of Indonesia's oil & gas field with high carbon content. 28 July 2021.
Retrieved from Nippon Export and Investment Insurance (NEXI). Environmental assessment on Tangguh. 2014.
[143] Indonesia Ministry of Energy and Mineral Resources (MEMR). CCUS activities in Indonesia, presented on Japan-Asia CCUS forum 2020. Page 7. 6 October 2020
[144] MEMR. CCUS activities in Indonesia, presented on Japan-Asia CCUS forum 2020. 6 October 2020
[145] BP. SKK Migas approved Plan of Development for Ubadari fieldand Vorwata CCUS. 30 August 2021.
[146] Upstream. Santos betting big on carbon capture in bid to drive down emissions. 18 August 2021.
[147] Santos. Santos announces FID on Moomba CCS project. 1 November 2021.
[148] S&P Global. Australia's Santos takes FID on Darwin LNG Barossa backfill project. 30 March 2021.
[149] IEEFA report in 2021 estimated that without CCS Barossa would emit roughly 5.4 MTPA of CO_2, with emission intensity of 1.47 tonne CO_2 per tonne of LNG.
ABC News. Santos' $4.7 billion Barossa gas field could produce more CO2 than LNG, report says. 24 June 2021.
Argus. Australia's Santos going ahead with Moomba CCS plant. 2 November 2021.
Upstream. CCS may not be enough to save Santos' Barossa LNG development from huge emissions. 21 October 2021.
[150] Upstream. Santos betting big on carbon capture in bid to drive down emissions. 18 August 2021.

Facility	Reservoir-associated CO_2 Content	**Plant Capacity** Million Tonne Per Annum (MTPA) Start Operation	CO_2 End Use	Realization & Remarks
Planning – LNG - RioGrande LNG, US NextDecade LNG LNG Operation : Plan for 27 MTPA LNG[151]	**N/A**	Plan for 5 MTPA CO2 Aim to begin by 2023[152]		FERC application[153]
Planning – Gundih, Java, Indonesia	**21%[154]**	Plan for 0.3 MTPA CO2[155] 2024/25	EGR[156]	Supported by Japan J-Power & Janus Potential supportof Japan's Joint Crediting Mechanism (JCM) scheme
Planning – Sukowati, Indonesia Pertamina	**30%[157]**	Plan estimates vary from 0.6 to 2 MTPA CO2[158]	EOR	Supported by Japex
Planning – Sakakemang, Indonesia Repsol	**26%[159]**	Plan for 2 MTPA CO2[160]	Storage	

[151] NextDecade LNG. Rio Grande LNG. Accessed on 11 April 2022.
[152] Argus. Viewpoint: Biden set to speed regulatory push in 2022. 29 December 2021.
LNG Industry. Nine noteworthy LNG projects by 2027. 23 December 2021.
[153] S&P Global Platts. Rio Grande LNG seeks FERC nod to add carbon capture to project. 18 November 2021.
[154] SEA CCUS Conference. Sequestration & geological opportunities in Indonesia. 7 May 2021.
[155] Pertamina. Advancing CCUS adoption in Indonesia. 15 Dec 2021.
MEMR. CCUS becomes an important part of Indonesia O&G development. 8 September 2021.
[156] Pertamina. Advancing CCUS adoption in Indonesia. 15 Dec 2021.
MEMR. CCUS becomes an important part of Indonesia O&G development. 8 September 2021.
[157] MEMR. CCUS activities in Indonesia, Japan-Asia CCUS forum 2020. 6 October 2020
[158] Pertamina. Advancing CCUS adoption in Indonesia. 15 Dec 2021.
[159] IHS Markit. Repsol project adds to Indonesia's carbon capture ambitions. 19 October 2021.
[160] Repsol. Repsol increases its targets for renewable generation and emission reductions. 5 October 2021.

Appendix B

CCUS Projects Under 'Advanced Development' Status

Status per GCCSI	Brief Status	Project	Country	CCUS Comissioning	Power Plant Type	Newbuild/ Retrofit?	Power Plant Comission.	Power Plant capacity	Capacity (MTPA CO_2)	CO_2 utilization / storage	Technology description	Companies	Remarks
Construction	Limited information on current status. OGCI report suggested commissioning by 2025	**Guodian Taizhou power station**	China	Early 2020s	Coal Supercritical	**Retrofit**	2007, 09, 2015, 16	4 GW (4 Units)	**0.3 - 0.5**	EOR	Limited information	-	No clear information of current status. Potential completion in 2025 (OGCI, Bo Peng white paper)
Construction	Very limited information	**The ZEROS project**	US	2023	Potentially Biomass	**Newbuild, new tech**	N/A	120MW	**1.5**	EOR	**ZEROS Techbology System (System Inc)** Zero emission energy recycling oxidation system. No clear information on prior trials.	Systems International Inc.	Very limited information disclosed. There is reference to plants planned in Chabers County and Liberty County, Texas with 120MW baseload power. (PR Newswire) www.sysii.com www.zerosinc.com www.stevelclark.com.
Advanced Development	Delay reported, see remarks	**San Juan Generating station**	US	2023	Coal Subcritical.	**Retrofit**	1973, 1982	940MW 847MW (nett)	**5.8 - 6.5**	EOR + Storage	**Amine based KM CDR (Mitsubishi Heavy Industries)** 2021 Enchant presentation suggests MHI involvement is being finalized with 95% warranted carbon removal.	Enchant Energy	Delay announced July 2021. Enchant aim to obtain 1bn$ low-interest from DoE for the 1.4bn$ project. . 1.4bn$ for CCUS and pipeline. Announced in 2019, initially planned for 2023, now scheduled for 2024. Funding difficulties, IEEFA foresee timing potential delay 2026-28. Plan to sell CO_2 for EOR and 45Q, noting that the unit will need to operate at 85% capacity compared to64% historical record. IEEFA estimate 2.2-3.3 bn investment is required. Planned to be connected to Kinder Morgan Cortez CO_2 pipeline (20 mile away). The project received $21M of US Government grants (DOE and non DOE) to suppot storage feasibility studies (FOA 1999 in addition to FOA 2058 associated to capture process FEED studies)
Advanced Development	FID planned for 2021	**Coyote Clean Power project**	US	2025	Gas	**Newbuild, new tech**	N/A	280MW each	**0.86**	Under evaluation	**Oxy fuel combustion - Allam Cycle (NET Power)** Combusting gas with pure oxygen, the use of supercritical CO_2 as heat exchange instead of water. Technology trialed on 25MWe (2018) plant in La Porte, Texas	Coyote Energy (8 Rivers, Net Power)	FID planned in 2022. Implementation of new technology (NET power) with semi closed loop system. Aim to access 45Q. Expecting 500M$+ for each plant, with final utilization/storage under evaluation (BBG, April 2021) In 2012 Net Power received a GBP 4.9M grant from UK Department of Energy and Climate Change for the development of the technology.
Advanced Development	Delay reported, see remarks	**Project Tundra**	US	2025-6	Coal	**Retrofit**	1970, 1977	450MW Unit 2	**3.1-3.6**	EOR + Storage	**Econamine FG Plus Amine-based (Fluor Corp)**	Minnkota power cooperative	Delay reported Oct 2021, engineering contractor pulled out in March 2021. Seeking 700M$ DOE loan guarantee (S&P Global) 1bn$ investment required, to tap into Milton R Young station (250 + 455 MW). Project Tundra is reported for Young Unit 2 (up to 90% emission). In advanced stage, construction may commence in 2023. The aim is to proceed before 2023 deadline of 45Q. Minnkota received 9.8M$ grant from DOE in 2019 for front end engineering, total of 43M$.
Advanced Development	FEED expected completion 2023	**Humber Zero VPI Immingham power plant**	UK	2027	Gas turbine	**Retrofit**	2004, expanded 2009	1.2 GW CHP (730MW in 2004, 1.GW in 2009)		Storage	**Amine based** Limited information	Vitol, VPI Immingham, Phillips 66	Power plant provide steam and power to Phillips 66 Humber refinery and Prax Groups' Lindsey refinery (25% of UK capacity). Secured 12.5 mGBP in funding in March 2021 from Innovate UK's industrial strategy challenge fund to develop technology. A combined project between CCS alongside blue and green H_2. Target to remove 8MTPA CO_2 by 2030.
Advanced Development	FEED ongoing (scheduled complete 2021)	**Mustang station of golden spread electric cooperative**	US	mid 2020s	Gas Turbine	**Retrofit**	2000 later OGC 2006/7/13	430MW (UT reported CC capacity)	**1-1.5**	Under evaluation	**PZAS Piperazine Advanced Stripper (Univ of Texas)** Developed with US DOE. Initial research since 2000, pilot for 12% CO_2 coal plant at UT, NCCC (2010-18), for 4% CO_2 NGCC UT NCCC (2016-19)	Golder Spread Electric Cooperative	DOE reported FEED study in 2019 with University of Texas. 4.1 M$ DOE funding scheduled 2019-2021.
Advanced Development	Limited information. FEED ongoing (scheduled complete 2022)	**Plant Daniel**	US	mid 2020s	Gas	**Retrofit**	2001	Minimum 375MWe	**1.6-1.8**	Storage	**Advanced aqueous amine solvent (Linde-BASF)**	Mississippi Power	DOE reported awarding 5.6M$ for FEED scheduled to complete in 2022
Advanced Development	Limited information. FEED ongoing (scheduled complete 2022)	**Gerald gentlemen station**	US	mid 2020s	Coal	**Retrofit**	1982	300 MWe slipstream (up to 700MW (ION))	**4.3**	Under evaluation	**Advanced low-aqueous solvent (ION Engineering).** Lab pilot in 2010 (0.01MW $4M) - 2015 National CC Center (0.5MWe $10M) - 2016/7 Mongstad (12MW $15M) Norway. Reported to be more efficient in 12MWe trial in Mongstand Norway (2016-17). with 30% reduction in parasitic load	Nebraska Public Power District	DOE funding for study reported 2.8M$ (DOE-NETL) with Phase II 5.8M$ reported by NPPD FEED initiated in 2018. Timeline reported by ION suggest FEED will be completed by 2022, with construction in 2023 prior to 45Q deadline
Advanced Development	Limited information. FEED ongoing (scheduled complete 2022)	**Prairies state generating station**	US	mid 2020s	Coal Supercritical	**Retrofit**	2012	816MW (Unit 2)	**5 to 6**	Storage	**Amine based Advanced KM CDR (Misubishi Heavey Industries)** Plan to apply KS-21 solvent with advantage over KS-1 (Petra Nova). R&D began in 1990, KM CDR (Kansai Mitsubishi CO_2 Recovery Process) was developed in 1994, and has been applied globally, including the earlier version (KS-1) in Petra Nova (2016). Water supply highlighted as a key issue.	Prairie state Energy Campus	DOE funding reported 14M$ for a FEED study scheduled 2019-2022. The largest coal plant built in the US in 30 years, mine-mouth power plant. IEEFA has extensive coverage of the development of this power plant and its coal supply chain.
Advanced Development	FEED reported to be completed. FID planned for 2021	**Bridgeport Energy Moonie**	Australia	2023	Coal Supercritical	**Retrofit**	2003	Tapping into 850MW powe plant	**0.12 to 2**	EOR	**China Huaneng's CO_2 technology (limited info).** Partner with China Huaneng Group (CHG, shareholder in Millerman power station). MoU with CTSCo signed in April 2021. In 2009 Huaneng reported the costs was still expensive at ~40$/T (Reuters). Note that Huaneng is also developing CCS for IGCC application	CTSCo (Glencore)	Plan to tap into the Millerman CFPP (850MW total, InterGen, Comissioned 2003). Note that the scale of the capture is very small compared to the 850MW capacity. Received EPQ10 GHG exploration permit in 2019 to assess storage viability. Glencore reported capacity of 0.11 MTPA. Liquefied CO_2 is planned to be trucked 100km away (ABC) Received AU$5M federal funding for CCUS reported in 2018 (ABC) . Received funding from COAL21 fund (LETA) in 2014. Project cost expected A$ 210 (CTSCO fact sheet)

Source: Compiled.

About IEEFA

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

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