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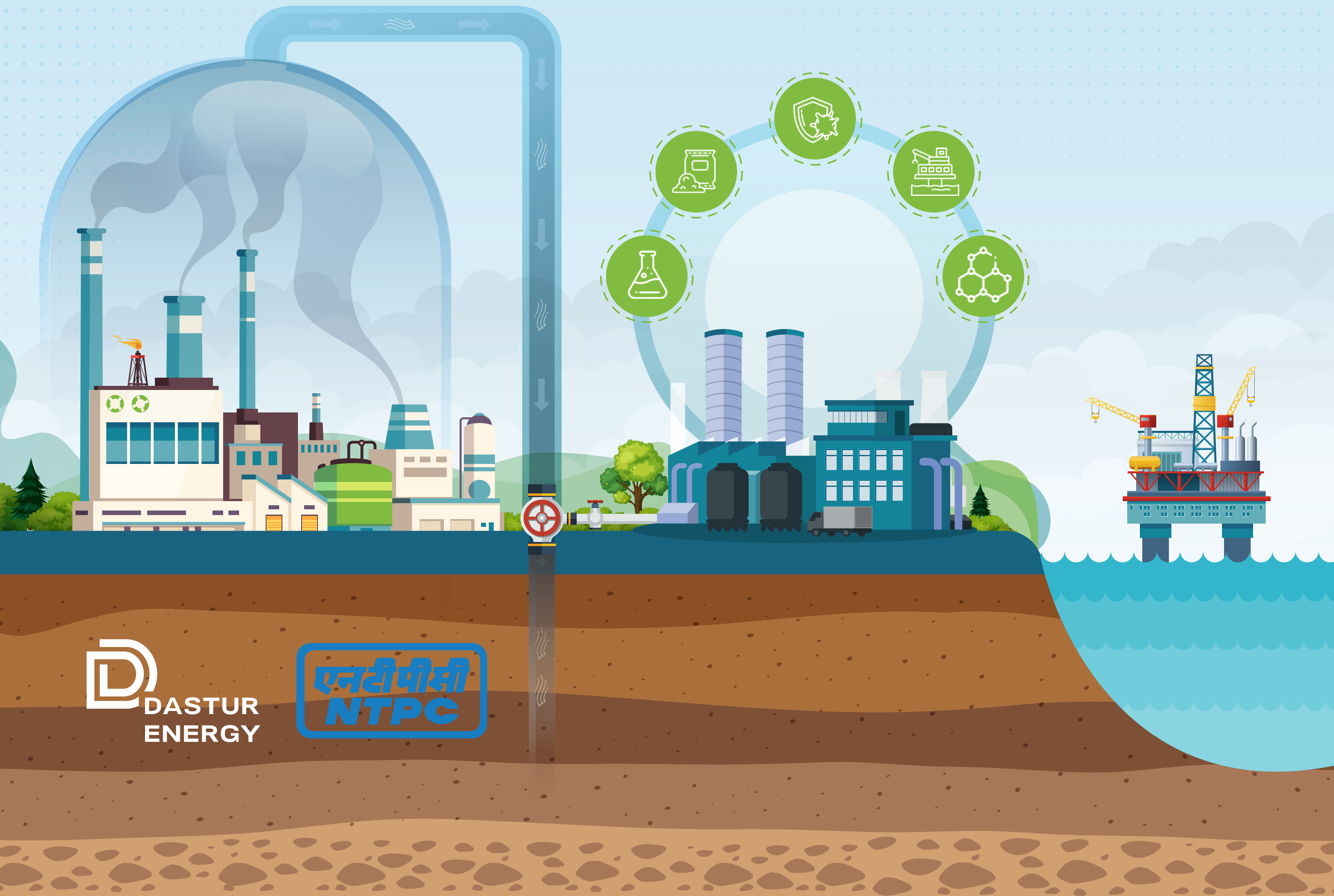
Carbon Capture, Utilization and Storage (CCUS) Technology Gaps and International Collaboration

February 2023



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Foreword

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Foreword

Carbon Capture, Utilization and Storage (CCUS) has a critical role to play in the journey of 'Energy Transition', especially in decarbonizing the hard-to-abate industrial sector and fossil fuel based power generation.

2. Presently, global anthropogenic CO_2 emissions are above 36 giga tonnes per annum. The scale of the decarbonization and 'Net Zero' challenge requires CCUS be scaled manifold to the Gigatonne scale (GT) to make a meaningful contribution to global decarbonization. Decarbonization, at scale, is essential for sectors like steel, cement, oil & gas, fertilizers, chemicals & petrochemicals and fossil based power generation, which are critical to the world economy and form the basic pillars of modern society, ensuring energy, material and food security.

3. One of the key enablers to developing and implementing CCUS technologies & projects is to address the technology gaps across the CCUS value chain - through international cooperation & collaborative efforts, and thus make CCUS technologies and projects cost effective across the G20 countries. The extent of technology maturity and development varies widely across the CCUS value chain - from carbon capture technologies, which are more mature to CO_2 utilization technologies, which are relatively nascent, but are required for achieving 'circular economy'.

4. This report which is outcome of an international study titled 'Carbon Capture, Utilization and Storage – Technology Gaps and International Collaboration' is an important step towards this endeavour. I hope that the report shall provide an insight in technology gaps, measures to bridge them through international collaboration and enablers for scaling up CCUS technology

(Alok Kumar)

RIGHT TO INFORMATION

भारत 2023 INDIA

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एक कदम स्वच्छता की ओर

Preface

The G20 leadership has endorsed the Circular Carbon Economy (CCE) as one of the key approaches to control GHG emissions, mitigate climate change and promote economic development & growth. One of the key components of the CCE framework is Carbon Capture, Utilization, and Sequestration (CCUS). While presently CCUS projects worldwide account for only about 40 mtpa of carbon abatement, the critical and integral role of CCUS in achieving decarbonization of hard-to-abate industrial sectors and reaching net zero is universally accepted.

CCUS consists of many sub-systems which are tightly linked together, and the success of the overall chain depends on the strength and resilience of the weakest link. Hence it is imperative to adopt a holistic approach toward the development of technologies, projects, and enablers across the CCUS value chain.

This study seeks to identify the technology gaps and solutions for the large-scale and cost-effective implementation of CCUS projects across the world and identifies the key areas of international collaboration. This study draws upon the expertise and experience of CCUS technology development & projects across the world and seeks to provide project proponents, policymakers, institutions, investors, and industries across the world with a holistic understanding of the technology gaps that need to be closed for accelerated deployment of CCUS to reach the GigaTonne (GT) scale.

We thank the G20 for giving Dastur Energy the opportunity to undertake this study, which would hopefully shape the trajectory of CCUS technology development and international collaboration going forward. Let me also take this opportunity to place on record our appreciation for the guidance and direction provided by the Ministry of Power, Government of India, NTPC Ltd. and IIT Bombay in shaping this study.

Atanu Mukherjee
Chief Executive Officer
Dastur Energy

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Abbreviations

APCRC	Australian Petroleum Cooperative Research Centre
ARENA	Australia Renewable Energy Agency
ARRA	American Recovery and Reinvestment Act
ASU	Air Separation Unit
ATR	Auto Thermal Refining
BF	Blast Furnace
BFC	Bio-Fuel Cells
BGH	British Geological Survey
BIL	Bipartisan Infrastructure Law
BOF	Basic Oxygen Furnace
BRGM	Bureau de Recherches Géologiques et Minières
BTX	Benzene, Toluene, Xylene
CAGR	Compounded Annual Growth Rate
CaL	Calcium Looping
CBAM	Carbon Border Adjustment Mechanism
CBM	Coal Bed Methane
CCE	Circular Carbon Economy
CCFC	Carbon Capture Finance Corporation
CCT	Carbon Capture Technology
CCUS	Carbon Capture, Utilization and Storage
CDR	Carbon Dioxide Removal
CDU	Crude Distillation Unit
CEFC	Clean Energy Finance Worldwide
CFB	Circulating Fluidized Bed
CNT	Carbon Nano-Tubes
CSP	Concentrated Solar Power
CSRC	CO_2 Storage Resource Catalogue
CVD	Chemical Vapor Decomposition
DAC	Direct Air Capture
DEPG	Dimethyl Ether of Polyethylene Glycols
DGH	Directorate General of Hydrocarbons, Government of India
DOH	Degree of Hydration
DRI	Direct Reduced Iron
EAF	Electric Arc Furnaces
ECBMR	Enhanced Coal Bed Methane Recovery
ECR	Effective Carbon Rate
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
EPBC	Environment Protection and Biodiversity Conservation Act
ETI	Energy Technologies Institute
ETS	Emissions Trading System
EU	European Union

EU ETS	European Union Emissions Trading System
FCC	Fluid Catalytic Cracking
FGD	Flue Gas Desulphurization
FO	Forward Osmosis
FT	Fischer-Tropsch
GCCSI	Global Carbon Capture and Storage Institute
GHG	Greenhouse Gas
GIS	Geographic Information System
HCUs	Hydro Cracking Units
HGU	Hydrogen Generation Unit
HP	High-Pressure
HSE	Health, Safety & Environment
IEA	International Energy Agency
IETF	Industrial Energy Transformation Fund
IF	Induction Furnace
IGCC	Integrated Coal Gasification Combined Cycle
IGV	Inlet Guide Vane
IP	Intermediate Pressure
IPCC	Intergovernmental Panel on Climate Change
JCM	Japan's Joint Crediting Mechanism
JCOP	Japan CO_2 Geo Sequestration in Coal Seams Project
L/S	Liquid-to-Solid
LCA	Life Cycle Analysis
LCFS	Low Carbon Fuel Standard
LNG	Liquified Natural Gas
MCFCs	Molten Carbonate Fuel Cells
METI	Ministry of Economy, Trade and Industry
MF	Micro Filtration
MOF	Metal Organic Framework
MSW	Municipal Solid Waste
MTR	Membrane Technology and Research
MVA	Monitoring, Verification & Accounting
MVR	Monitoring, Verification & Reporting
NCCAP	National Climate Change Action Plan
NCCRP	National Climate Change Response Policy
NCIP	National CO_2 Infrastructure Plan
NCMIP	National Carbon Mapping and Infrastructure Plan
NDCs	Nationally Determined Contributions
NF	Nano Filtration
NGCC	Natural Gas Combined Cycle
NGEU	Next Generation EU
NLECI	National Low Emissions Coal Initiative
O&M	Operation and Maintenance

OGCI	Oil and Gas Climate Initiative
OPC	Ordinary Portland Cement
OPGGSA	Offshore Petroleum and Greenhouse Gas Storage Act
PCOR	Plains CO_2 Reduction Partnership
PCSP	Pilot Carbon Storage Project
PLI	Production-Linked Incentives
PNNL	Pacific Northwest National Laboratory
PP/CGP	Power Plant/ Co-Gen Plant
PPC	Portland Pozzolana Cement
PPMV	Parts Per Million by Volume
PSA	Pressure Swing Adsorption
PSC	Portland Slag Cement
PTP	Point-To-Point
RCSPs	Regional Carbon Sequestration Partnerships
RITE	Research Institute of Innovative Technology for the Earth
RO	Reverse Osmosis
RWGS	Reverse Water Gas Shift
SCCS	Scottish Carbon Capture & Storage
SMR	Steam Methane Reformer
SNBC	Stratégie Nationale Bas Carbone
SPBA	South Permian Basin
SRMS	Society of Petroleum Engineers
STEP	Solar Thermal Electrochemical Process
STP	Standard Temperature and Pressure
TCES	Thermochemical Energy Storage
TDS	Total Dissolved Solid
TEG	Triethylene Glycol
TRL	Technology Readiness Levels
TSA	Temperature Swing Adsorption
TUBITAK	Turkish Scientific and Technical Research Institute
UF	Ultra Filtration
UKSAP	UK Storage Appraisal Project
UNECE	United Nations Economic Commission for Europe
US DOE	US Department of Energy
VDU	Vacuum Distillation
VRE	Variable Renewable Energy

Executive **Summary**

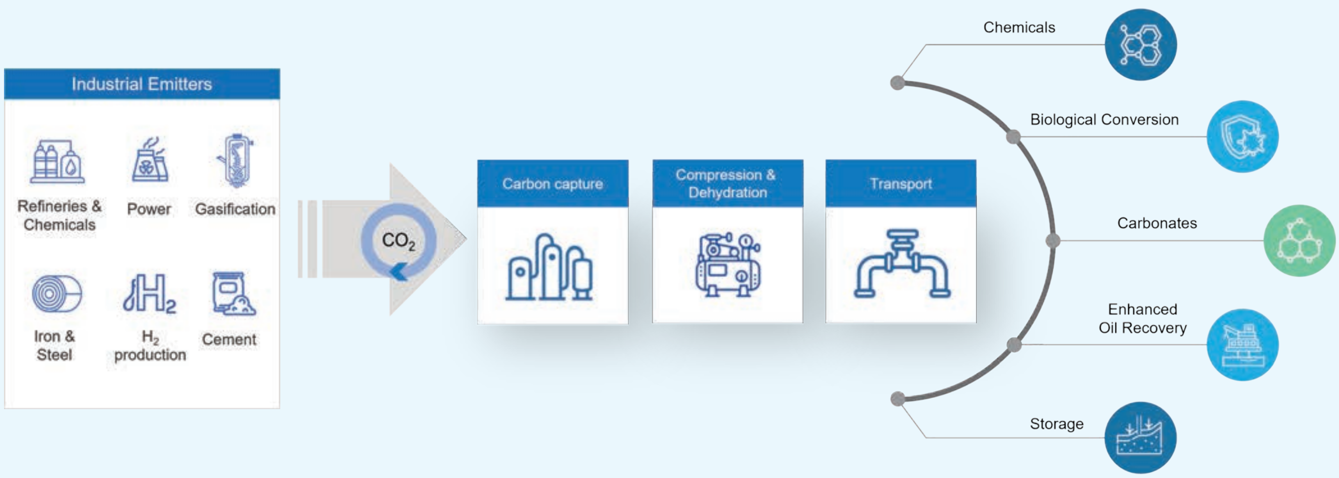
Executive Summary

India, during its presidency of the G20, has commissioned this study titled 'Carbon Capture, Utilization and Storage (CCUS) – Technology Gaps and International Collaborations'. CCUS has a critical role in achieving climate sustainability and the transition to net zero for limiting global temperature rise between 1.5 to 2 °C from pre-industrial levels. CCUS is especially important for decarbonizing the hard to abate industrial sector, as well as large parts of the power generation sector, that will continue to use fossil fuels for at least the next few decades. Leading independent organizations in the energy space, such as the International Energy Agency (IEA) and the Intergovernmental Panel on Climate Change (IPCC) have also concluded that reaching net zero and stabilizing atmospheric CO_2 concentration between 450 – 750 ppmv (parts per million by volume) for limiting global temperature rise between 1.5 to 2 °C is not possible without CCUS.

The global decarbonization challenge is at the gigatonne or GT scale. According to the IEA, the world needs to implement about 6.2 gigatons of CCUS by 2050. However, even 50 years after the first CCUS projects started operating, there are only about 30 CCUS projects around the world capturing only 42 mtpa of CO_2, i.e. about 0.1% of global anthropogenic CO_2 emissions of 36 gtpa. A further 10 mtpa of CCUS capacity is under construction and another 98 mtpa capacity is under advanced development. Given the scale of global CO_2 emissions, CCUS needs to significantly scale up in an accelerated time frame to make a meaningful contribution to global decarbonization.

CCUS is at a nascent stage in most G20 countries, with the notable exceptions of the US and Canada. This is followed by other G20 countries such as Australia, France, Germany, Saudi Arabia, the UK and the EU. To accelerate the rate & scale of adoption and CCUS deployment across the G20, it is critical to address technology gaps across the CCUS value chain through international collaboration across various cross-cutting areas and themes. The CCUS value chain consists of CO_2 capture, processing, transport and disposition/conversion of CO_2 to value-added products. The overall system consists of tightly linked sub-systems and the strength & resilience of the overall CCUS value chain is determined by the weakest link. The level & state of technology readiness, development and deployment widely vary across the CCUS value chain. Hence it is imperative to address technology gaps across the entire value chain.

Figure E-1: The CCUS Value Chain



i. **CO_2 capture:** Many capture technologies are reasonably well developed, with several commercial-scale projects operating across the world. Further developments in mature capture technologies should hence focus on efficiency and cost reduction through innovation in systems engineering, better heat & power integration, development of complements like advanced solvents and solid absorbents, scaling of membranes & cryo-capture technology, and accelerating deployments of industrial scale carbon capture projects across the G20 countries based on these technologies.

ii. **Evolving carbon capture technologies:** New technologies such as Direct Air Capture (DAC) and calcium looping provide the option of being integrated with commercially established capture technologies for creating hybrid and highly scalable capture systems. However, further R&D is required to improve the material chemistry, reaction rates, energy & water usage and bring the costs of these technologies within the realms of economic viability. R&D is also required in new solvent technologies that can yield order-of-magnitude differences in reaction rates and energy use.

iii. **CO_2 transportation:** CO_2 transportation at scale is generally done in the supercritical form (at pressures of 120-150 bar) through pipelines and is essential to connect CO_2 sources to CO_2 storage or utilization and conversion sites. Pipeline CO_2 transport is commercially proven but requires integration with other forms of CO_2 transport, such as ships and tankers in multi-modal scalable architecture of hubs and clusters, to support CO_2 utilization and disposition at scale. The other key research areas in CO_2 transport include developing improved CO_2 flow modelling for phase transitions & offshore CO_2 transport and developing larger CO_2 vessel designs based on lower pressures and temperatures.

iv. **CO_2 utilization:** CO_2 utilization is a critical component of the CCUS value chain and provides a pathway for converting CO_2 into value-added products, creating economic value from waste products and contributing to the circular carbon economy. The most promising areas of CO_2 utilization are building construction materials, fuels & chemicals and carbon nano-materials. The key challenge is that CO_2 is a very low-energy molecule and requires significant energy (either as thermal, chemical or electrical energy) for conversion to other products, leading to high production costs vis-à-vis commercially established routes. Other challenges include low yields, product quality & standards, catalyst quality & degeneration, availability of feedstock and toxicity & biological impact. Hence these challenges need to be addressed through catalyst development, reactor engineering, establishing feedstock quality standards and scaling to commercial scale, as well as creating markets for low-carbon products through supportive policy actions.

v. **Underground CO_2 storage:** Undeground storage of CO_2 is required to complement CO_2 utilization, for the disposition of CO_2 at the GT scale. CO_2 storage options are of two types: enhanced oil recovery & enhanced coal bed methane recovery (which offer certain economic benefits) and sequestration in deep saline aquifers & basalt rock formations along with geomineralization (which offer no apparent direct benefits). However, the suitability assessment and pore space mapping of geo-structures for CO_2 injection are very limited outside the US and the absence of an effective CO_2 sequestration atlas is a key strategic gap for CCUS. Hence, it is critical for G20 countries to invest in the assessment and mapping of CO_2 storage availability within their boundaries. Better pore space mapping also needs to be accompanied by efforts to increase the current understanding and research in the areas of sub-surface geo-mechanical analysis, simulation & modelling of cap-rock integrity, smart well monitoring, well integrity through seismic imaging & machine learning and increasing industry-academia collaboration.

It is critical to understand and address the "Technology Gaps" across the CCUS value chain i.e capture, transport, utilization, storage, as provided in Table E-1.

Given the scale of the net-zero energy transition and decarbonization challenge, scaling up CCUS requires close collaboration between Governments, institutions and industry across the G20 countries to address the identified technology gaps. CCUS also requires large and sustained investments across the value chain, which are only possible through Government support & funding and public policy tools such as carbon incentives and/or carbon pricing mechanisms. International collaboration is also required in the areas of coordinated policy mechanisms to support CCUS, availability of funding & financing for CCUS, technology transfer & deployment, availability & flexibility of options for CO_2 disposition at scale through hub & cluster frameworks, cross-border CCUS value chains, technology support to low per capita emitters, and setting up institutional mechanisms for promoting, facilitating & fast-tracking CCUS-enabled projects.

Table E-1: Summary of Technology Gaps Across the CCUS Value Chain

Technology	Technology Sub-type	Technology Gaps	Potential Solutions
CO_2 Capture Technologies			
Solid Adsorbent	Temperature Swing Adsorption	Poor efficacy with lean CO_2 concentration	Novel adsorbent architecture can accelerate the process by 40-100 times
	Pressure Swing Adsorption	Slow process – cycle time in minutes /hours	Advanced MOF (Metal Organic Framework) – exponentially high surface area
Chemical Solvent	-	• Moderate energy intensity • Solvent life • Tolerance level with industrial SOx & other gaseous effluent	Development of new molecules & chemistry
Membrane	-	Poor 'selectivity' & 'purity'	• New polymeric membranes & electro-chemical membrane • Enhancing 'countercurrent sweep' in polymeric membranes
Direct Air Capture	-	High energy & water intensity, large land requirement and poor life of chemical media	Development of new 'Chemical Loop' and reagents
CO_2 Transport Technologies			
Pipework	-	• Two phase flow of CO_2 • Precipitation of dry ice or hydrate	Development of 'Flow Model' for CO_2 – including trans-critical, super-critical and sub-critical phase – for on/off shore application
CO_2 Utilization Technologies			
CO_2 to Building Construction Materials	-	Limited knowledge of 'process' and quality of product	Development of 'Design Mix' and 'Process'
CO_2 to Hydrocarbon (Chemicals & Fuels)	Chemical Process	Low 'Selectivity' and 'Conversion Efficiency'	• Development of new mechanically and chemically stable catalysts with desired rate of reaction kinetics • Design of efficient reactors
	Electro-chemical Process	Limited knowledge on electro-chemistry	• Development of co-electrlyzer for direct synthesis of chemicals and liquid/gaseous fuel • Development of electrolyzer for sea water and high TDS wastewater

	Biological Process	Limited knowledge on bio-species & bio-chemical process	• Development of bio-catalyst for efficient synthesis of CO_2 & lean syngas • Development of innovative photo-bio-reactor for synthesis of human grade compounds
CO_2 to Carbon Morphology (Carbon Black, Carbon Nano Tubes etc)	-	Shape & structural compatibility	Non-conventional & odd geometrical-shaped CNT membranes require more advanced nano scale fabrication techniques at the atomic level.
	-	Toxicity & environmental impact	Raw CNTs are more toxic than functionalized CNTs because of the existence of metal catalysts. Thorough investigations are required on this subject.
	-	Mechanical resilience & biofouling	Mechanical robustness need to be maintained in dynamic biological environments without triggering any biological growth or degradation.
CO_2 Storage Technologies			
CO_2 Injection Well	-	Limited understanding of CO_2 flow characteristics	Development of modelling tools for understanding multi-phase CO_2 flow in injection wells and geological formations
CO_2 Storage	Basalt and Ultra-Mafic Rocks Abandoned Coal Fields	Assessment of long-term CO_2 storage potential	• Advanced geological modeling alongside specials conditions viz seimic, rock fracture etc • Smart well monitoring techniques

Introduction

1.1 Study Background

The G20 brings together the 20 leading economies of the world, accounting for over 80% of the world GDP, 75% of global trade and 60% of the world's population. Given the leading role of the G20 countries in world affairs and the effects of global warming, climate change and climate events experienced around the world, and the criticality of limiting global temperature increase within 1.5 to 2 ^{o}C, the G20 has recognized "Climate Sustainability and Energy" and energy transition towards net zero as one of its key focus areas.

The G20 Energy Transition and Climate Sustainability Working Group, in its Joint G20 Energy-Climate Ministerial Communiqué of July 2021, has recognized CCUS as a key component in the energy transition journey to a net-zero future. In particular, the communique has stressed **"the use of innovative technologies that will help to abate and remove GHG emissions while also recognizing the efforts made into reducing, reusing, recycling and removing as outlined by the Circular Carbon Economy (CCE) framework"** and also recognized **"the need for investment and financing for advanced and clean technologies, including CCUS/Carbon Recycling"** and **"use the best available technologies and practices in order to address the environmental impacts, including GHG emissions, of their production, transport and consumption."**

The role of CCUS, i.e. Carbon Capture, Utilization and Storage, is pivotal in decarbonizing the hard-to-abate industrial sector, where fossil fuels play an integral role both as a source of energy and in the process, and hence are hard to substitute or electrify. While there is significant interest in CCUS, as of 2022, there are only 30 CCUS projects operating worldwide, contributing to 42 mtpa of CO_2 abatement or about 0.10% of the global annual GHG emissions. While a further 10 mtpa of CCUS capacity is in construction and another 98 mtpa capacity is under advanced development (source: Global CCS Institute 2022 Status Report), it is widely recognized that there is a need to significantly scale up CCUS to gigatonne levels, for CCUS to make a meaningful contribution to global decarbonization.

In this context, the G20, under the leadership of India in 2023, has commissioned this study to identify the technology gaps and propose solutions for the large-scale and viable implementation of CCUS. As outlined in this study, the present status of CCUS varies widely across the G20 countries, especially in the area of carbon capture technologies, CO_2 transportation infrastructure and developmental work undertaken to support the permanent disposition & storage of CO_2.

Given the universal application of CCUS technologies and the global nature of the problem it seeks to solve, i.e. unabated CO_2 emissions and its adverse effects on global climate systems, there is a need to promote international collaboration for addressing technology gaps across the entire CCUS value chain. There should be a collaboration framework for G20 members to assimilate & adopt already commercially proven CCUS technologies rather than reinvent the wheel; collectively address the challenges associated with CCUS; and focus R&D efforts and resources on the most promising & impactful technologies from a time, scale and economic viability point of view.

1.2 Objectives of the Study

The objectives of this study, titled "CCUS Technology Gaps and International Collaboration", are as follows:

a. Profiling emissions in G20 countries, in terms of the sectoral break-up, emission intensity & per capita emissions, the extent of emissions amenable for capture and interventions required to enable CCUS at scale

b. Provide an overview of the current status of CCUS in G20 countries and the role of CCUS in the energy transition journey towards net zero

c. Profiling global CO_2 emissions by source/sector and the scope for CCUS in CO_2 capture and disposition

d. Overview of the present technology landscape across the CCUS value chain of capture, transportation, utilization and storage, as well as evolving nascent technologies across the CCUS value chain

e. Identifying the gaps in CCUS technologies and their likely future development trajectory in terms of scale, time and economic viability

f. Analyze the role of CO_2 storage for carbon abatement and disposition at scale and future developments needed in this area – understand the current status of geological mapping and location of long-term CO_2 storage options

g. Identify the enablers for CCUS to be implemented at scale and contribute to the circular economy – technology development, international cooperation, infrastructure creation, markets, policy frameworks etc.

h. Recommending the technology collaboration framework amongst G20 countries for accelerating CCUS by addressing technology gaps and risks associated with CCUS

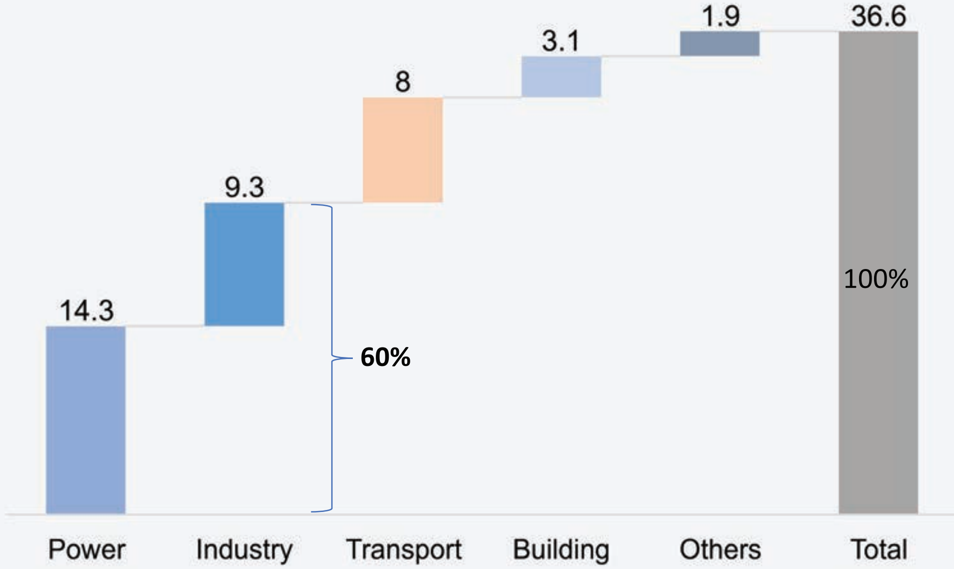
1.3 What is CCUS?

The International Energy Agency (IEA) defines Carbon Capture, Utilization and Storage (CCUS) as a group of technologies for capturing CO_2 from large and stationary CO_2 emitting sources, such as fossil fuel-based power plants and other industries. CCUS also involves the transport of the captured CO_2 (typically by pipeline and also through shipping, rail or trucks) to permanent storage sites such as geological formations, depleted oil & gas fields and facilities for the conversion and utilization of CO_2 for producing value-added products such as chemicals or aggregates.

The sectoral break-up of global CO_2 emissions reveals that even with global renewable capacity crossing 3000 GW in 2021, the replacement of fossil fuel-based power generation by renewables can at most target about 40% of total anthropogenic CO_2 emissions. It is expected that fossil fuels will continue to play a significant role in the global energy mix, both for the hard-to-decarbonize industrial sector and for ensuring affordable & reliable baseload power supply, given the intermittency of renewable sources of power and high costs associated with energy storage. Given this backdrop, CCUS has a critical role to play in the global energy transition journey towards net zero.

In their September 2020 report, the International Energy Agency points out that reaching net zero without CCUS is virtually impossible. The Intergovernmental Panel on Climate Change (IPCC) has also concluded that without CCUS, it would not be possible to stabilize the CO_2 concentration in the atmosphere between 450 – 750 ppmv (parts per million by volume) and limit global temperature rise between 1.5 to 2 degrees Celsius above pre-industrial levels, as per the targets of the Paris Climate Agreement.

Figure 1-1: The 60% Decarbonization Challenge



Source: Dastur analysis; Breakthrough Energy

1.4 Decarbonization Role of CCUS

CCUS can contribute to decarbonization and transition to clean energy systems in various ways:

a. **Hard-to-abate sectors:** CCUS offers the only known technology for the decarbonization of the hard-to-electrify and CO_2-intensive sectors such as steel, cement, oil & gas, petrochemicals & chemicals, and fertilizers. These sectors are very important pillars of the global economy and fundamental to ensuring energy, materials and food security. The nascency of alternative technologies in these sectors indicates that the use of fossil fuels and concomitant CO_2 emissions from these sectors will continue in the foreseeable future, thus making CCUS critical for decarbonizing these sectors.

b. **Low carbon hydrogen economy:** CCUS is expected to play a major role in enabling the future hydrogen economy by enabling the production of blue hydrogen from fossil fuels such as natural gas & coal. Given the current cost structure of green hydrogen of US$ 5-6/kg, cost-competitive blue hydrogen production (i.e. natural gas based or coal gasification based hydrogen production coupled with CCUS) at around US$ 2-3/kg can provide a viable alternative for the hydrogen economy.

c. **Removal of CO_2 stock from the atmosphere:** Achieving the goals of net zero and containing the global temperature to within 1.5 - 2 ^{o}C from pre-industrial levels is not possible without the removal of excess CO_2 stock from the atmosphere through technologies such as Direct Air Capture (DAC). DAC plants are in operation at a small scale today. However, they need to mature significantly on the technology readiness level for implementation at a commercial scale with viable economics. With technological innovation and focused policy interventions, DAC can contribute materially to the net zero transition.

d. **Sustenance of existing emitters:** G20 countries such as China and India have seen significant investments in the last 15-20 years in the expansion of power, steel, cement and oil & gas refining capacities. These capacities are of recent vintage and cannot be just wished away; they need to be made sustainable through the application of CCUS, thus avoiding billions of dollars of economic costs and damages from stranded assets.

e. **Permanent sequestration/utilization of CO_2 :** CCUS can contribute to the permanent sequestration and utilization of CO_2, whether captured from anthropogenic sources or from the CO_2 stock of the atmosphere through DAC. The carbon from fossil fuels extracted from the earth can thus be permanently stored in the earth or be utilized in the form of other products, thus contributing to the circular economy.

1.5 Challenges Associated with CCUS

The key challenges to the growth of CCUS are as follows:

a. **Economics of CCUS:** The cost of carbon capture is high, especially in the case of post-combustion CO_2 capture from CO_2 lean flue gases. Due to the high cost of capture, the overall CO_2 abatement cost on a per tonne or per unit of the saleable product basis is significant for commodities such as steel, cement, power and oil & gas, which have very competitive end-use markets. Whilst costs are expected to fall with the increasing scale of deployment and technology development, enabling policies in terms of CCUS credits or preferential procurement for carbon-abated products are needed to incentivize investments in CCUS.

b. **Absence of downstream CO_2 infrastructure:** Downstream infrastructure for transportation and storage is very nascent, thus requiring emitters to invest not only in capture technologies but also across the entire CCUS value chain. There is a need for policy measures to drive the formation of CCUS clusters with large-scale CO_2 storage sites, with emitters and storage sites being connected through adequately provisioned and shared transport infrastructure. The upfront creation of such downstream infrastructure reduces the risk and costs for new emitters joining the cluster.

c. **CO_2 utilization technologies:** CO_2 utilization technologies are relatively less developed compared to capture technologies and require significant subsidy/market premium to compete with established fossil fuel based production routes. However, it is expected that as CO_2 utilization technologies develop and learning curve effects set in, costs can come down significantly and new industries around carbon utilization will also develop. In particular, for the conversion and utilization of CO_2 to new building materials, there is a requirement for process standardization and defining new standards & specifications.

d. **Lack of pore space and natural resources mapping:** Whilst various CO_2 utilization technologies are in development, CCUS at scale is only possible through the geological storage of CO_2. There is a need to focus and invest in pore space mapping to characterize promising CO_2 storage regions and basins.

e. **Risk management:** There is a need to define robust monitoring, verification & accounting (MVA) and risk management frameworks so that risks and liabilities across the CCUS value chain & project life cycle are managed and limited for participants.

1.6 Global CCUS Landscape

Globally there are 30 operational CCUS facilities, with a capacity of capturing about 42.6 mtpa CO_2 or only 0.1% of the annual global CO_2 emissions. The first CCUS projects started in the 1970s and 1980s in Texas, USA, for capturing CO_2 from natural gas processing plants and supplying it to local oil producers for utilizing the CO_2 for Enhanced Oil Recovery. Since then, CCUS has spread to other regions and countries, viz. Norway, Canada, Australia, Brazil, Canada, China, Saudi Arabia and the United Arab Emirates. A list of the operating CCUS facilities as of 2022 is tabulated in Table 1-1.

Table 1-1: CCUS Facilities in Operation in 2022

Sl. No.	Country	Project	Start Year	CO_2 Source	Capacity (mtpa)	CO_2 Capture Technology	TRL	CO_2 Disposition
1.	USA	Terrell natural gas plants (earlier Val Verde)	1972	Natural gas processing	0.5	Solvent-based physical absorption (Selexol)	9	EOR
2.	USA	Enid Fertilizer	1982	Fertilizer production	0.7	Solvent-based chemical absorption - Benfield process	9	EOR
3.	USA	Shute Creek gas processing facility	1986	Natural gas processing	7.0	Solvent-based physical absorption, Selexol	9	EOR
4.	Hungary	MOL SZANK FIELD CO_2 EOR	1992	Natural gas processing	0.16	Amine	9	EOR
5.	Norway	Sleipner CO_2 storage project	1996	Natural gas processing	1.0	Solvent-based physical absorption, Rectisol	9	Storage
6.	USA/ Canada	Great Plains Synfuels (Weyburn/Midale)	2000	Synthetic natural gas	3.0	Amine	9	EOR
7.	USA	Core Energy CO_2 -EOR	2003	Natural gas processing	0.35	Amine	9	EOR
8.	Norway	Snohvit CO_2 storage project	2008	Natural gas processing	0.7	Collection from fermentation	9	Storage
9.	USA	Arkalan CO_2 Compression Facility	2009	Ethanol production	0.29	Solvent-based physical absorption-Selexol	9	EOR

Sl. No.	Country	Project	Start Year	CO_2 Source	Capacity (mtpa)	CO_2 Capture Technology	TRL	CO_2 Disposition
10.	USA	Century plant	2010	Natural gas processing	8.4	Membrane process	7 to 8	EOR
11.	Brazil	Petrobras Santos Basin pre-salt oilfield CCS	2011	Natural gas processing	7.0	Compression of concentrated fermentation emission	9	EOR
12.	USA	Bonanza Bioenergy CCUS EOR	2012	Ethanol Production	0.1	Vacuum Swing Adsorbers (VSA)	9	EOR
13.	USA	Air Products steam methane reformer	2013	Hydrogen production	1.0	Solvent-based phycical absorption, Selexol	9	EOR
14.	USA	Lost Cabin Gas Plant	2013	Natural gas processing	0.9	Solvent-based physical absorption, Selexol.	9	EOR
15.	USA	Coffeyville Gasification	2013	Fertilizer production	1.0	Amine scrubbing	9	EOR
16.	USA	PCS Nitrogen	2013	Fertilizer production	0.3	Amine	9	EOR
17.	Canada	Boundary Dam CCS	2014	Power generation (coal)	1.0	Post-combustion: AEA Adsorption based capture	N/A	Various
18.	China	Karamay Dunhua Oil Technology CCUS EOR	2015	Methanol production	0.1	Solvent-based chemical absorption, Amine	9	EOR
19.	Saudi Arabia	Uthmaniyah CO_2 - EOR demonstration	2015	Natural gas processing	0.8	Solvent-based chemical absorption - Amine	9	EOR
20.	Canada	Quest	2015	Hydrogen production	1.3	Amine	9	Storage
21.	UAE	Abu Dhabi CCS	2016	Iron and steel production	0.8	Amine	9	EOR
22.	USA	Petra Nova*	2017	Power generation (coal)	1.4	Compression of concentrated fermentation emission	9	EOR

Sl. No.	Country	Project	Start Year	CO_2 Source	Capacity (mtpa)	CO_2 Capture Technology	TRL	CO_2 Disposition
23.	USA	Illinois Industrial	2017	Ethanol production	1.0	Solvent-based chemical absorption, amine	9	Storage
24.	China	Jilin Oilfield CO_2 - EOR	2018	Natural gas processing	0.6	Amine (MDEA solvent)	9	EOR
25.	Australia	Gorgon Carbon Dioxide Injection	2019	Natural gas processing	3.4 - 4.0	Solvent-based chemical absorption, inorganic, Benfield process	9	Storage
26.	Canada	Alberta Carbon TrunkLine (ACTL) with Agrium CO_2 stream	2020	Fertilizer production	0.3 - 0.6	Rectisol process	9	EOR
27.	Canada	ACTL with North West Sturgeon Refinery CO_2 stream	2020	Hydrogen production	1.2 - 1.4	DAC	6 to 7	EOR
28.	Iceland	ORCA	2021	Direct Air Capture	0.004	Chemical solvent based absorption	9	Storage
29.	Canada	Glacier Gas Plant MCCS	2022	Natural gas processing	0.2	Rectisol - solvent based physical absorption	9	Storage
30.	China	SINOPEC Qilu-Shengli CCUS	2022	Chemical production	1	Compression of concentrated fermentation emission	9	EOR
31.	USA	Red Trail Energy CCS	2022	Ethanol production	0.18	Solvent-based physical absorption (Selexol)	9	Storage

Source: International Energy Agency, MIT database, Global CCS Institute and Dastur analysis

1.7 The CCUS Value Chain

For CCUS to be implemented at scale, it is important to focus on the entire CCUS value chain, consisting of the three basic components:

- The capture of carbon dioxide (CO_2) from fuel combustion or industrial gas streams, and compression, dehydration & purification of CO_2 to the desired specifications;
- Transport of the CO_2 (generally via pipeline) to the CO_2 sink
- Disposition of the CO_2, either through utilization in applications such as Enhanced Oil Recovery (EOR), food and beverage applications, or the production of value added products (viz. urea, green methanol, cured concrete) or through sequestration of CO_2 in permanent geological storages

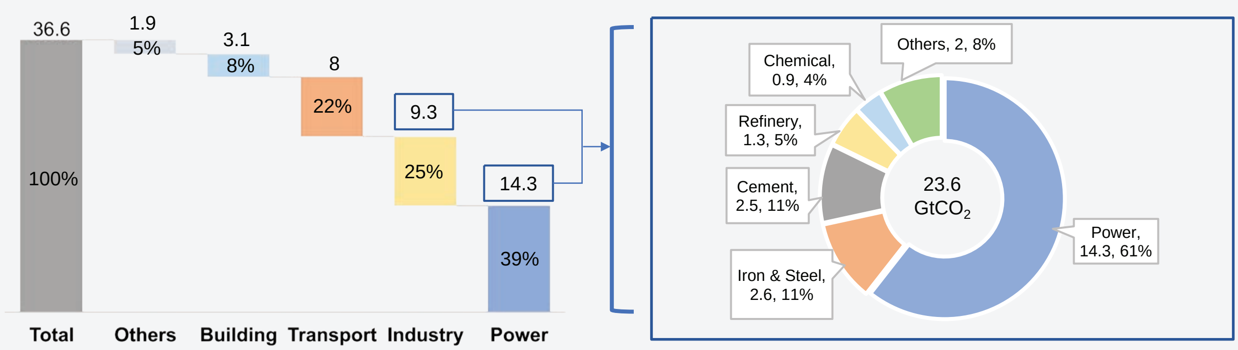
The success of the CCUS value chain depends on the coordination between participants in each part of the CCUS value chain and appropriate policy-enabled business models & market mechanisms which incentivize and enable participants to participate and transact seamlessly across the CCUS value chain.

Analysis of Sector-wise
CO_2 Emissions

2.1 Suitability of CCUS for Various Sectors

CCUS is suitable for large and stationary emission sources, with emissions above a certain threshold level (say 100 ktpa). Hence the target sectors for CCUS projects which meet these criteria are typically coal & gas-based power plants, and industrial facilities such as steel plants, cement plants, chemical & petrochemical plants, fertilizer plants, oil refineries, gasification plants etc. These target sectors contribute around 23.6 Gtpa of CO_2 emissions (around 65%) out of the overall global emissions of 36.6 Gtpa (2021 figures) – see Figure 2-1. Significant anthropogenic CO_2 emissions (35%) also emanate from sectors such as agriculture, transportation and buildings, but these emissions are distributed and are at smaller scales and hence do not merit investment in CCUS projects. The decarbonization initiatives for these sectors include biofuels, electrification & mechanization of processes and increasing thermal & electrical efficiencies.

Figure 2-1: Global CO_2 Emissions in 2021 (36.6 Gt) & CO_2 Emissions from Power and Industrial Sectors in 2021 (23.6 Gt)



Source: IEA World Energy Outlook 2022

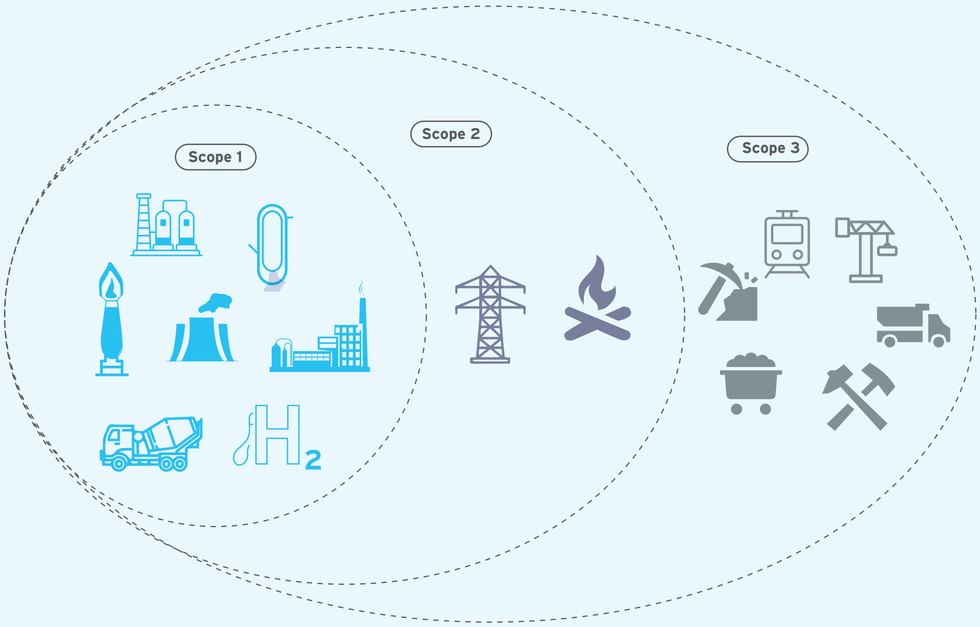
For any typical reference plant in the above CCUS target sectors, the total CO_2 emissions can be categorized into three types (Figure 2-2)

a. **Direct or scope 1 emissions:** Emissions from the production process from the combustion of fuel. This typically occurs within the plant/facility premises.

b. **In-direct or scope 2 emissions:** Emissions associated with the purchase of utilities. These are generally emissions outside the plant boundries.

c. **In-direct or scope 3 emissions:** Indirect emissions associated with the entire value chain, starting from equipment purchase, construction works, raw material sourcing, and product dispatch.

Figure 2-: Illustration of Emission Types and Boundary Consideration



The objective of this chapter is to estimate the aggregate Scope 1 CO_2 emissions from the target sectors, both at the global level and the G20 level. Emissions under Scope 2 and Scope 3 are not assessed, as this chapter gives an aggregate estimate of emissions and considering Scope 2 or Scope 3 emissions would lead to double counting. For example, for a steel plant drawing power from the grid, the CO_2 emissions associated with generating the quantum of power drawn (Scope 2 emissions for the steel plant) is considered when estimating the CO_2 emissions associated with the power sector, i.e. Scope 1 emissions for the power plant. Similarly, for the cement consumed for constructing the steel plant, the CO_2 emitted for producing the cement consumed (Scope 3 emissions for the steel plant) is considered when estimating CO_2 emissions from the cement sector, i.e. Scope 1 emissions for the cement plant.

Based on the aggregate Scope 1 emissions, the extent of CO_2 emissions which are amenable for carbon capture in each sector is also estimated. This estimation is based on a typical reference plant in each sector, and characteristics of the different CO_2 emission sources, in terms of CO_2 concentration in the flue gas stream, and aggregation/distribution of the emissions across different units/facilities and emission sources within the plant. The total sector-wise CO_2 emissions amenable for CCUS is in the Giga-tonne scale; in comparison, the present total volume of CO_2 captured by the operational CCUS plants across the world is less than 50 mtpa. This comparison shows the extent and magnitude of the challenge for CCUS technologies and projects to scale up to make a meaningful contribution towards the decarbonization of the target sectors and the progress towards net zero.

From a CO_2 emissions point of view, the key sectors are fossil fuel-based power generation, iron & steel, cement, oil refineries, high-value chemicals (ammonia, methanol, petrochemicals) and other sectors like upstream oil & gas exploration, paper, aluminium, textile, glass etc. In certain industries like upstream oil & gas exploration & production, the majority of the emissions consist of methane, with some CO_2 also being released during flaring and captive power generation required to operate drills and other necessary equipment. Methane emissions also have a significant greenhouse warming effect and must be considered along with the CO_2 emissions and are represented in terms of CO_2eq. Thus, to estimate the emissions from the upstream oil & gas operations, an emission intensity factor has been estimated.

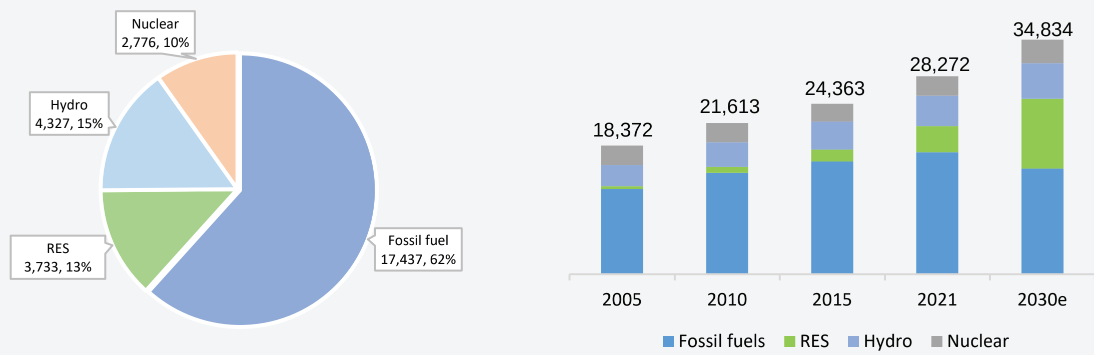
2.2 Analysis of CO_2 Emissions from Sectors (viz. Power, Steel, Cement, Refineries, Chemicals & Fertilizers) Amenable for Carbon Capture

2.2.1 CO_2 Emissions: Global Power Sector

Global power generation has grown at a CAGR of 2.3% in the period of 2005-2021 to meet the growing power demand from rising populations, improving incomes & lifestyles, globalization, and rapid urbanization. Fossil fuel-based power plants are the primary source of power generation to meet the base load demand in developed as well as developing nations. Globally, 28,273 TWh of electricity was generated in 2021 with fossil fuel-based plants having a 62% share in the generation mix, followed by hydropower with a 15% share, renewable energy sources a 13% share, and the rest 10% accounted by nuclear power generation plants. The overall share of fossil fuel-based power plants in the global power generation mix has decreased only marginally from 66% in 2005 to 62% in 2021 as a result of the increase in the share of renewable electricity.

The last 16 years (2005-2021) have seen considerable additions of renewable energy generation capacity to the global energy mix. Renewable sources-based electricity generation has seen a growth of 5.5% CAGR in the period of 2005 to 2021 and the share is expected to grow going forward. However, at the same time, the aggregate energy demand is also expected to increase significantly from the present levels, i.e., ~30% by 2030 and ~60% by 2040 (IEA World Energy Outlook 2022) and the major share of the power demand will continue to be met from fossil fuels in the foreseeable future (Figure 2-3), for ensuring the world's energy security and reliable electricity for every household. Thus, the power sector will continue to be a major source of emissions, and hence CCUS is of prime importance for the abatement of CO_2 from the power sector.

Figure 2-3: Break-up of Generation in 2021 – 28,273 TWh

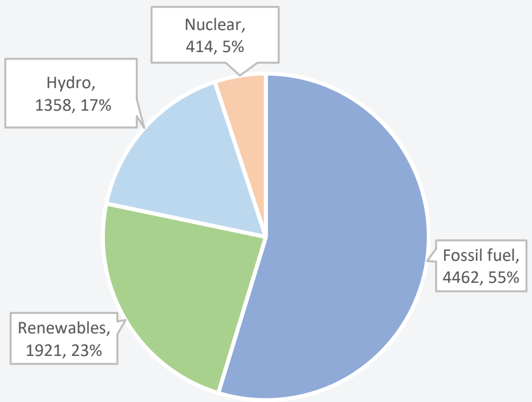


Source: IEA World Energy Outlook 2022

Installed Capacity and Power Generation

The global installed electricity generation capacity for the year 2021 stood at 8.15 TW. The majority of the installed capacity is fossil fuel-based power plants having a share of 55%, followed by RE at 23%, hydropower 17% and the remaining 5% of the capacity being accounted for by nuclear (Figure 2-4). Though renewables contribute to around 23% of the 2021 capacity mix, due to their intermittent and non-dispatchable nature, their share in power generation was only 13%. Going forward also, even as global renewable energy capacity increases by the year 2030, fossil-based power generation will still have an important role to play in the power mix of the world.

Figure 2-4: Break-up of Installed Generation Capacity in 2021 – 8155 GW

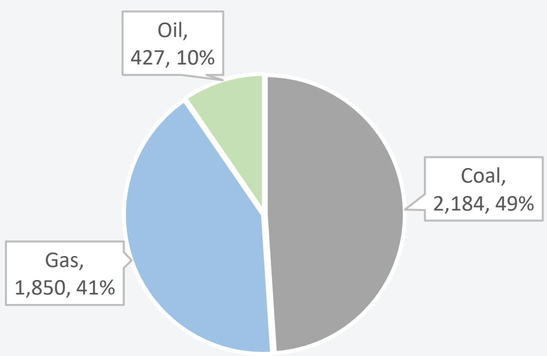


Source: IEA World Energy Outlook 2022

Brief Description of Thermal Power Plants

The basic principle behind the working of a thermal power plant is the generation of electricity using thermal energy from the combustion of fuels. Based on the type of fuel used, thermal power plants can be further divided into three categories, coal, natural gas, and diesel oil. The share of diesel-based power capacity across the globe is minimal; the major share of power capacity is coal-powered thermal power plants, followed by natural gas.

Figure 2-5: Break-up of Thermal Power Plants by Fuel – 4462 GW



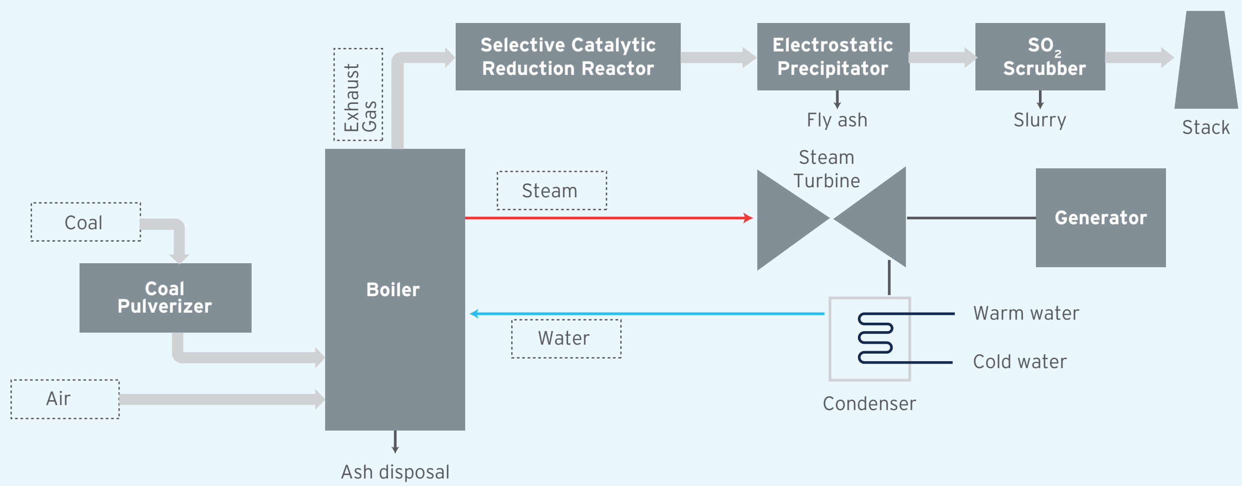
Source: IEA World Energy Outlook 2022

The process flow of power generation from coal and natural gas is described below.

Coal-fired thermal power plant

Coal-fired thermal power plants generate electricity by burning coal as a fuel and use the heat to produce steam from water. The steam is used to generate electricity by passing through a steam turbine generator. The various unit operations involved in this process are illustrated in Figure 2-6.

Figure 2-6: PFD of Coal-fired TPP



Source: Breeze 2019

Coal is received at the material handling yard and thereafter undergoes crushing and beneficiation to reduce the size/moisture/ash content, depending on the quality and size of the coal. The coal is then pulverized to coal fines that can be efficiently combusted in the boiler. This pulverized coal is mixed with air in the combustion chamber and controlled combustion is performed to produce heat energy. After the completion of the combustion process, the ash residue is collected at the bottom of the combustion chamber and is ejected as slag. The combustion chamber and boiler are efficiently integrated to minimize heat loss. The boiler has tubes present in it to carry water. The heat energy released from combustion is absorbed by this water to turn into steam. This steam is passed through steam turbines. A series of high-pressure (HP), intermediate pressure (IP), and low-pressure turbines are present to extract the maximum heat energy from the steam. These steam turbines drive the generators to produce electricity.

The flue gas is subjected to cleaning operations such as a selective catalytic reduction reactor (for NOx), electrostatic precipitator (for fly ash), and sulfur dioxide scrubber. After the flue gas meets the emission norms, it is emitted through flue gas stacks into the atmosphere. The only source of Scope 1 emissions are the flue gas stacks. The rest of the operations have associated Scope 2 emissions only.

Typical flue gas characteristics of a coal-fired thermal power plant are given in Table 2-1. The flue gas characteristics are considering the installation of a Flue Gas Desulphurization (FGD) unit, which is essential to remove SOx from the flue gas before carbon capture, as the presence of SOx will affect the extent of CO_2 absorption by amine based solvents suitable for carbon capture from flue gas.

Table 2-1: Flue Gas Characteristics of Coal-Fired Thermal Power Plants

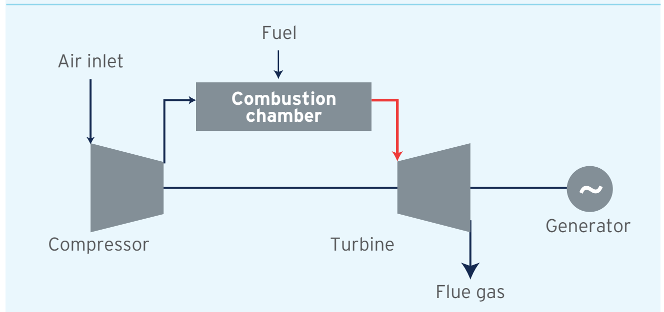
Component	Unit	Value
Temperature	°C	110-120
Pressure	atm	1
Composition		
CO_2	vol%	11
H_2O	vol%	6
O_2	vol%	6
N_2	vol%	76
SO_2	ppmv	-
NOx	ppmv	150-250

Source: https://www.sciencedirect.com/science/article/pii/S030147971930043X

Natural Gas-fired Thermal Power Plant

Natural gas is a relatively cleaner fuel compared to coal and has very few impurities. The gas turbine technology is used to generate power from natural gas (Figure 2-7). Air is sent to the compressor, where it gets pressurized. This high-pressure air is sent to the combustion chamber and mixed with the fuel (natural gas). This mixture is ignited and the combustion of natural gas results in hot flue gases. This flue gas stream then drives the turbine which is connected to the generator that uses the kinetic energy to generate electricity. The turbine and compressor are on the same shaft; thus, the compressor energy requirement also decreases.

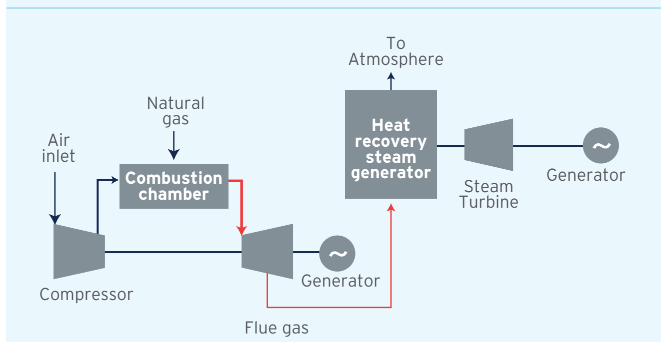
Figure 2-7: Schematic Representation of Gas Turbine



Source: Breeze 2019

The flue gases released are still at a very high temperature, indicating that more heat energy can be extracted from this stream. The flue gases are further fed to a heat recovery steam generator, where the heat energy of the flue gases is used to generate steam from water which drives the steam turbine to generate additional power. This increases the energy conversion efficiency of plants. This type of plant is termed a "combined cycle power plant". Figure 2-8 illustrates a schematic of a natural gas combined cycle (NGCC) power plant.

Figure 2-8: NGCC Power Plant Schematic Diagram



Source: Breeze 2019

The Scope 1 emissions originate from the flue gas emitted into the atmosphere at the end of the process. The rest of the processes involve Scope 2 emissions. Typical flue gas characteristics of natural gas combined cycle (NGCC) power plants are provided in Table 2-2.

Table 2-2: Typical Flue Gas Characteristics of NGCC Power Plants

Component	Unit	Value
Temperature	°C	120-130
Pressure	atm	1
Composition		
CO_2	vol%	4-10 vol%
H_2O	vol%	10-12 vol%
O_2	vol%	8-10 vol%
N_2	vol%	70-75 vol%
SO_2	ppmv	Low
NOx	ppmv	Low

Source: Colin, Minh & Dianne 2016

CO_2 Emissions from the Power Sector

Globally the power sector accounts for the largest share of GHG emissions, emitting about 14.3 Gt of CO_2 in 2021, or about 40% of the total anthropogenic CO_2 emissions of the world. Thus, decarbonization of the power sector is critical to lowering global anthropogenic CO_2 emissions.

The analysis of CO_2 emissions from the power sector has been done for the year 2021 based on the reported electricity generation for the year and suitable grid emission factors (source: IEA, IRENA). An overall analysis is provided in Table 2-3.

Table 2-3: Overall Analysis of CO_2 Emissions from the Global Power Sector

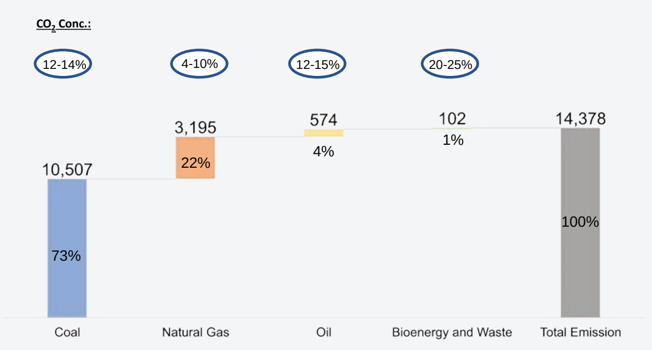
Component	Value
Total installed generation capacity [Non-renewable + Renewable] (GW)	8,155
Total generation (TWh)	28,273
Total emissions (mtpa)	14,378
Total emissions by G20 Countries (mtpa)	10,735
Global weighted average CO_2 emission intensity (t CO_2 / GWh) (greater than 2 mtpa CO_2 emissions)	509

Source: IEA World Energy Outlook 2022, Climate Transparency Reports 2022

CO_2 Emissions by Fuel Source

The CO_2 emission has been analyzed based on the type of fuel used for power generation. The type of fuel used can be of 3 types: coal, natural gas, and oil. Coal has the largest installed generation capacity, followed by natural gas, oil, and a small share of bioenergy and waste. The contribution of each fuel to the total global CO_2 emissions from the power sector is illustrated in Figure 2-9.

Figure 2-9: Share of Total CO_2 Emissions by Each Fuel, mtpa



Source: IEA World Energy Outlook 2022

Note: Bioenergy & waste CO_2 concentration is based on biomass gasification

Coal based power plants have the highest emissions; thus, CCUS projects need to be focused on these plants. Emissions from natural gas based power plants will grow as North American and European countries are phasing out coal-based power plants and shifting toward natural gas-based CCGT plants. Thus, these countries should make early-stage CCUS investments for CO_2 abatement of gas-based CCGT plants to achieve the goal of a carbon-abated power grid and eventual climate neutrality.

CO_2 Emission by Country

The analysis of emission distribution by fuel type gives us an insight into the types of technology to be prioritized for CCUS development. It is also essential to perform a regional analysis to plan the CCUS development, investment and deployment mechanisms to abate CO_2 emissions and simultaneously ensure energy security. While each country may have different metrics to calculate their grid emission intensity, for the sake of uniformity, all the emission intensity factor data has been considered from a common source in this analysis.

Table 2-4: Country-wise Electricity Generation (TWh) in 2021

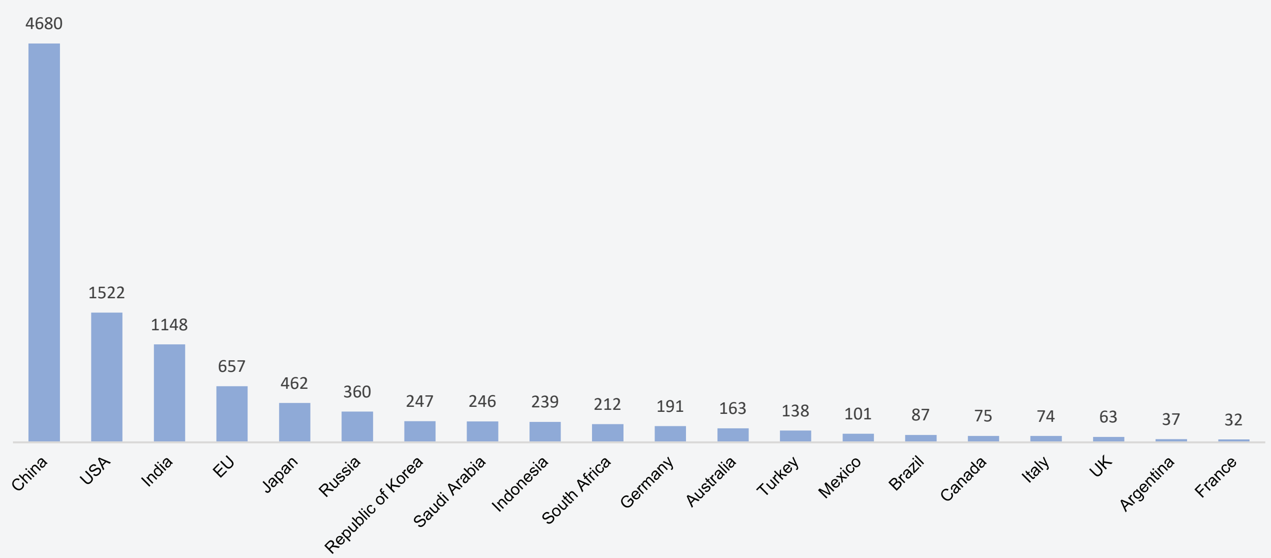
Sl. No.	Country	Total Generation (TWh)	Emission Intensity Factor (tCO_2 / GWh)	Total Emissions (mtpa)	Per Capita Power Sector CO_2 Emissions (tonne)
1.	Argentina	130	288	37.5	0.82
2.	Australia	260	626	162.7	6.33
3.	Brazil	670	130	86.8	0.41
4.	Canada	630	120	75.4	1.97
5.	China	8400	557	4680.5	3.31
6.	France	540	60	32.3	0.48
7.	Germany	580	329	190.7	2.29
8.	India	1610	713	1148.3	0.82
9.	Indonesia	305	785	239.4	0.87
10.	Italy	290	255	73.9	1.25
11.	Japan	1000	462	461.5	3.67
12.	Republic of Korea	600	411	246.8	4.77
13.	Mexico	335	300	100.5	0.77
14.	Russia	1120	322	360.4	2.51
15.	Saudi Arabia	400	614	245.7	6.96

Sl. No.	Country	Total Generation (TWh)	Emission Intensity Factor (tCO2 / GWh)	Total Emissions (mtpa)	Per Capita Power Sector CO_2 Emissions (tonne)
16.	South Africa	245	867	212.3	3.54
17.	Turkey	325	426	138.5	1.63
18.	UK	310	203	63.0	0.94
19.	USA	4252	358	1522.2	4.59
20.	EU	2900	226	656.6	1.47
Total G20 countries		**24,902**	**431**	**10,735**	**2.11**
Rest of the World (Non-G20 Countries)		**3,370**	**1,081**	**3,643.3**	**1.31**
Total		**28,272**	**508.6**	**14,378**	**1.83**

Source: Climate Transparency Reports 2022

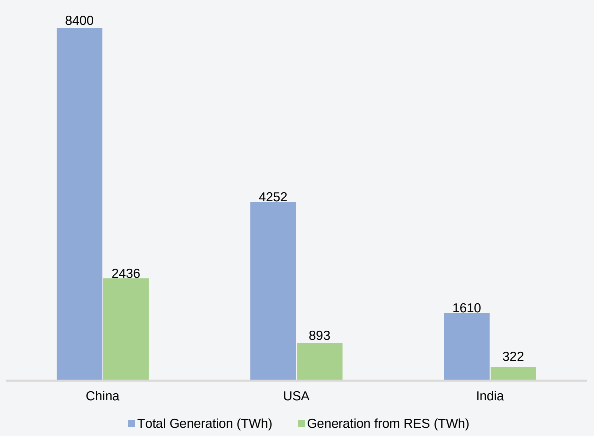
Out of the total power generation in 2021, the G20 countries account for about 88% of the total power generation. The power sector CO_2 emissions for each country have been estimated using the generation values and emission intensity factor. The country-wise analysis (Figure 2-10) indicates the countries to be prioritized for CCUS implementation.

Figure 2-10: G20 Country-Wise Analysis of CO_2 Emissions – 10,735 mtpa



The largest 3 emitters, China, USA and India are investing significantly in renewables as part of their energy transition strategy and goals. From 2016 (i.e. since the COP 21 in Paris) to 2021, the total installed capacity of renewable energy facilities in the world has increased from 2000 GW to over 3200 GW, an increase of about 60%. More than 60% of the incremental capacity has been contributed by China (45%), USA (10%) and India (5%). The trend is expected to continue in the next decade, with China targeting to meet 33% of its electricity consumption from renewables by 2025, USA targeting a net zero electricity sector by 2035 and India looking to almost triple its renewable capacity to 450 GW by 2030. Even with these ambitious RE targets, fossil fuel (coal for China & India and natural gas for USA) based power generation will still have a major role to play during the transition period and to support baseload power, given the intermittent and nondispatchable nature of renewable power and the high costs associated with storage. Thus carbon capture, utilization and storage will have an important role to play in the decarbonization of the fossil fuel based thermal power sector in these countries.

Figure 2-11: Total Power Generation vs Power Generation from RE in 2021



Source: Climate Transparency Reports 2022

CO_2 Emission Projections for the Power sector

According to IEA projections (World Energy Outlook 2022), the global installed capacity is expected to increase by 43% in the next decade and reach 11,673 GW by 2030 from the existing capacity of 8,155 GW. The projection of the power generation capacity by type is given in Table 2-5. Thermal power (coal, gas & oil) capacity of the world is expected to reach 4,495 GW by 2030. Although the share of thermal capacity is expected to drop from the present 55% to 39% in 2030, thermal power generation is still expected to account for 47% of the total electricity generation globally. The drop in the share of installed generation capacity of thermal power plants is an outcome of the increased focus on renewable energy capacity additions across the globe.

However, anthropogenic CO_2 emissions from the power sector will still contribute to the majority of CO_2 emissions in 2030. For estimation purposes, the share of G20 countries in power sector CO_2 emissions in 2021 has also been considered for estimating the power sector CO_2 emissions of 2030.

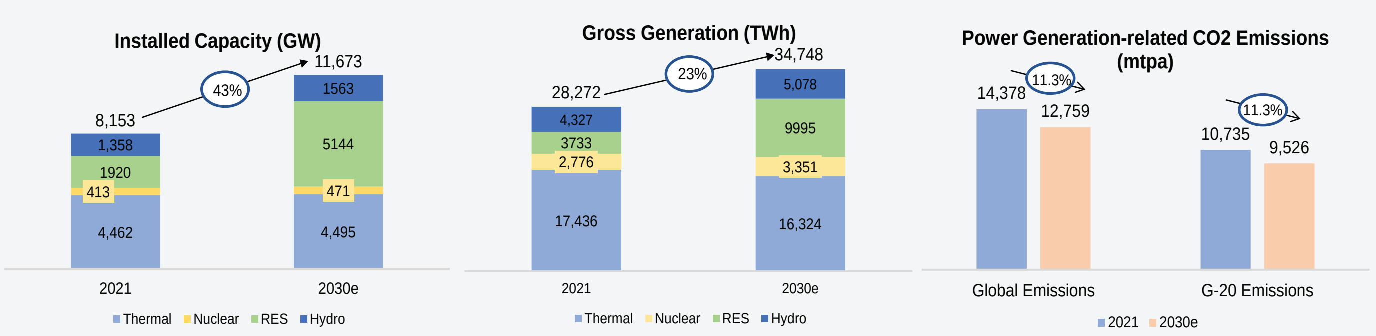
The CO_2 intensity is expected to drop in the future with improved plant performance and more RE in the generation mix. Based on these estimations, the total CO_2 emissions for the power sector is estimated to drop by 11% from the 2021 figure of 14,378 mtpa to 12,759 mtpa in 2030 (Table 2-5). This would still account for the majority 35% share of the total global anthropogenic emissions of CO_2 in 2030.

Table 2-5: Energy & CO_2 Volume Projections for 2030

Component	2021	2030	% Change
Installed Capacity, GW			
Thermal	4,462	4,495	1%
Nuclear	413	471	14%
RES	1921	5144	168%
Hydro	1,358	1563	15%
Total	**8,155**	**11,673**	**43%**
Gross Generation, BU			
Thermal	17,436	16,324	-6%
Nuclear	2,776	3,351	21%
RES	3733	9995	168%
Hydro	4,327	5,078	17%
Total	**28,272**	**34,748**	**23%**
Wtd. avg. CO_2 emission intensity, kg/kWh	**0.508**	**0.367**	**-28%**
Total CO_2 emissions from thermal power plants (mtpa)	**14,378**	**12,759**	**-11%**
G20 countries CO_2 emissions from thermal power plants (mtpa)	**10,735**	**9,526**	**-11%**

Source: IEA World Energy Outlook 2022

Figure 2-12: Energy & CO_2 Emission Projections for 2030

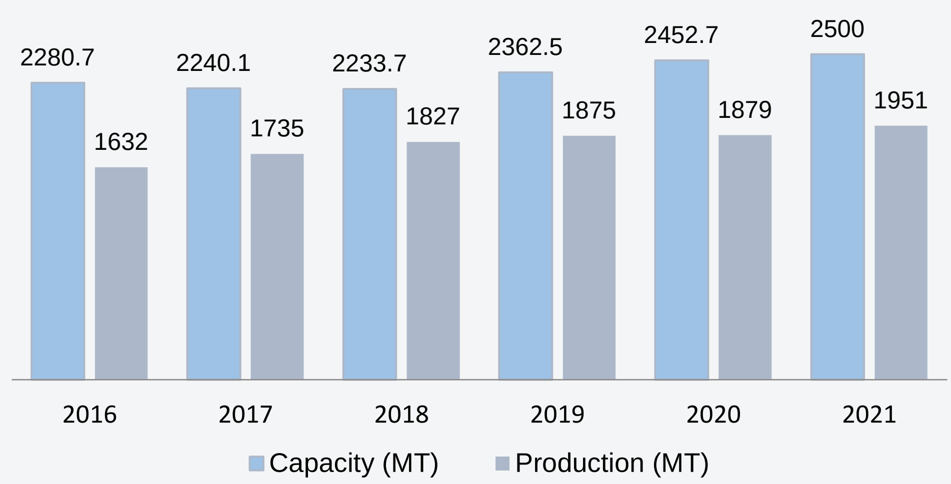


Source: IEA World Energy Outlook 2022

2.2.2 CO_2 Emissions: Global Steel Industry

Globally, the iron and steel industry is primarily based on the processing of virgin materials like iron ore, coal, etc. Steel making is an energy-intensive sector and is responsible for about 7% of global anthropogenic CO_2 emissions. The production of iron is largely through the blast furnace and coal-based DRI route and makes the global steel industry a coal-and CO_2 emission intensive sector, with an estimated 2.6 Gtpa of direct CO_2 emissions for supporting crude steel production of 1860 mtpa in 2020 and 1951 mtpa in 2021. The global crude steel capacity and crude steel production for the last five years are shown in Figure 2-13.

Figure 2-13: Year-wise Crude Steel Capacity & Production in the Last 5 Years (in mtpa)

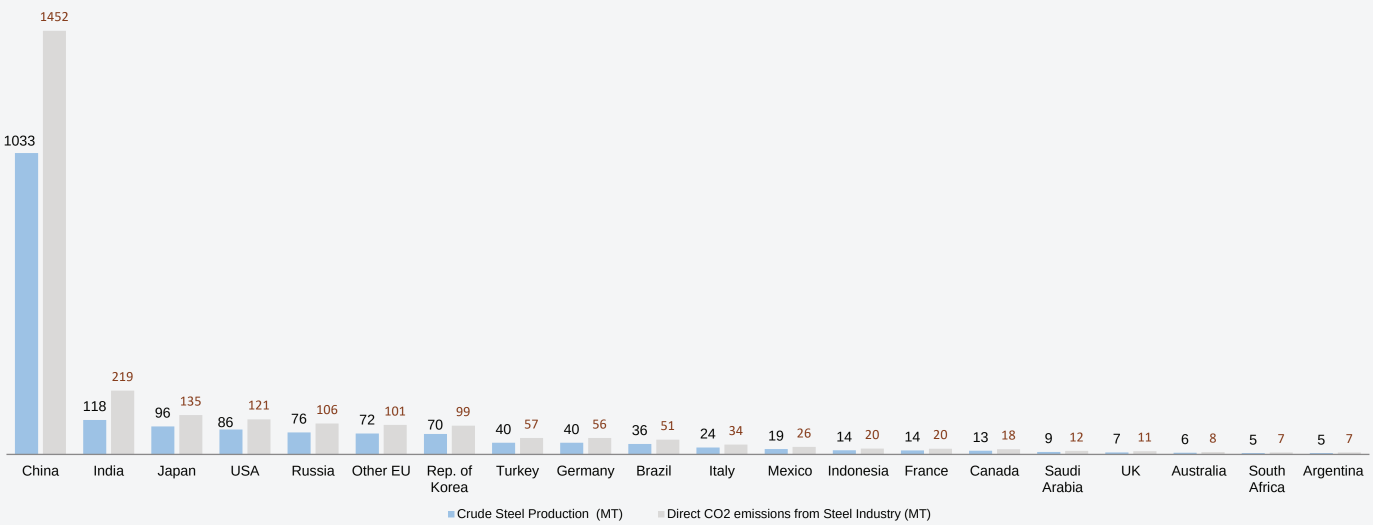


Source: OECD, World Steel Association

Crude steel production has grown at a compounded annual growth rate (CAGR) of around 3.6% from 2016 to 2021, stagnating in 2020 due to the COVID-19 pandemic. The production of 1951 mtpa of crude steel corresponds to about 1834 mtpa of finished steel production, with the remaining crude steel being consumed as intermediates or accounting for losses. Future steel demand growth is likely to be around 1.5% per year up to the year 2030, taking the finished steel demand to 2.1 Gtpa by the year 2030. The trajectory of future demand will be driven by factors such as rising demand in India, technology process & material efficiency improvements leading to reduced specific consumption of steel in end-products and the stagnation/decline of demand in the US and the European region.

The share of different steelmaking routes and dominance of the BF-BOF route (accounting for 70% of global steel production) is unlikely to change significantly till 2030. At the same time, there are likely to be improvements in the efficiency and CO_2 footprint of the steel making process. Based on the above two factors, it is expected that CO_2 emissions from the steel sector will reach 2.8 Gtpa by the year 2030. The top 3 steel producing countries in the world, i.e. China, India and Japan, are part of the G20 – thus, the G20 countries account for a significant share of the CO_2 emissions from the steel sector. The crude steel production and the direct CO_2 emissions from the iron & steel industry of the G20 countries in 2020 are shown in Figure 2-14.

Figure 2-14: Crude Steel Production + Direct CO_2 Emissions from Iron & Steel across G20 Countries in 2020 (in mtpa)

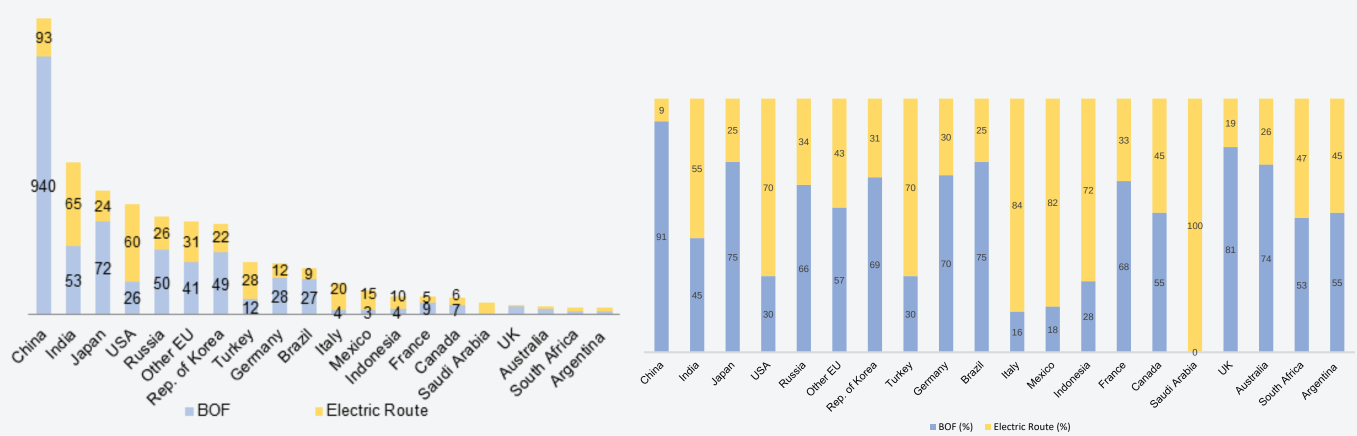


Source: World Steel Association

Routes of Iron and Steelmaking

There are two main steelmaking routes prevalent across the world: the Basic Oxygen Furnace (BOF) route and the Electric Route; the Electric Route consists of steel produced from both Electric Arc Furnaces (EAF) and Induction Furnaces (IF). The contribution of the two routes across G20 nations is shown in Figure 2-15.

Figure 2-15: Process Route Wise Production and Contribution across G20 countries (in mtpa)

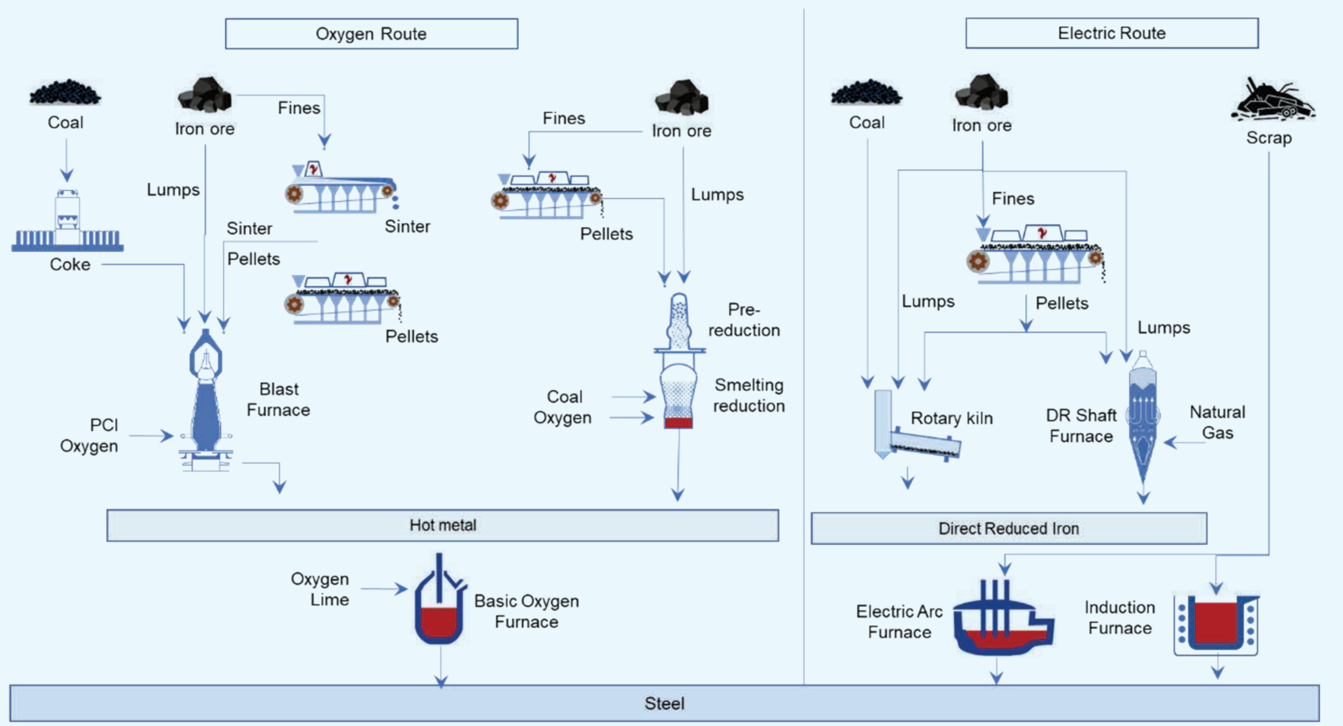


Source: World Steel Association

The majority of large integrated steel plants have adopted the BOF route production because of its robustness, scale, and reliability. The BOF route uses 85-95% hot metal (i.e. iron in molten form) in the charge mix, produced from Blast Furnace/COREX/FINEX iron making facilities. At the other end of the spectrum is the induction furnace route, which is 100% solid-charge based and primarily uses Direct Reduced Iron (DRI or DR), pig iron, and scrap. IF-based production is electric-energy intensive and suitable for small-scale production with typical plant sizes of less than 0.5 mtpa. The EAF route is flexible and ideal for mid-sized plants (0.5 to 1 mtpa) and can be designed to take more than 80% hot metal, whereas the conventional EAF design is based on 100% solid charge. Due to the operational robustness & flexibility and superior techno-economics of upstream Blast Furnaces (BFs), many EAFs across the world and, particularly in India, use a certain percentage of hot metal (obtained from BF) in their charge mix.

In the BF route, iron is produced as a liquid hot metal using sinter, pellet and iron ore lumps, with coke and pulverized coal being used as reductants. In the smelting reduction iron making processes like FINEX & COREX, iron ore fines and coal are used to produce hot metal. The alternative iron making routes consist of the coal-based and gas-based DR processes that produce solid iron known as DRI or sponge iron, which is subsequently melted and refined in the EAF/IF process. The unit processes are described below, including the direct CO_2 emissions from each process. An illustration of the various process routes is given in Figure 2-16.

Figure 2-16: Various Iron and Steel Making Routes



Brief Description of Unit Processes

Coke making

Metallurgical coke is produced at scale (typically 0.5 mtpa and higher capacities) by heating coking coal at a high temperature in the absence of air to expel its volatile matter and obtain a strong porous coke. CO_2 emissions from the coke oven flue stack is estimated at 0.3 tonne of CO_2 per tonne of finished steel.

Sintering

Sintering is a process of agglomeration of iron ore fines along with fluxes to improve the reducibility of the iron ore and decrease coke consumption in the BF. It also has a scavenging function as a unit which consumes different in-plant waste materials like fines and scales. The off-gas from a sinter plant is released into the atmosphere after recovery of the sensible heat. The combustion of coke breeze and fuel gases in the sintering process contributes to about 0.43 tonne of CO_2 per tonne of finished steel.

Pelletization

Pelletization is the process of agglomerating very fine particles of iron ore with fluxes, without any incipient melting. The pelletization process consumes significantly less energy and emits significantly lower CO_2 (0.15 tonne of CO_2 per tonne of finished steel) vis-à-vis sintering.

Ironmaking

The ironmaking process produces hot metal through the Blast Furnace (BF) route; additionally, there are also a few operational COREX plants across the globe. In a BF, iron ore lumps, sinter or pellets are charged from the top of the furnace along with coke, limestone and dolomite along with a hot blast of preheated air (900 ºC) blown from the BF bottom. Coke reduces the iron oxide to metallic iron or hot metal while producing BF gas. BF gas is a low calorific value high volume gas, which is used in other units of the steel plant as a fuel gas and to produce captive power.

The direct CO_2 emissions from the BF stove flue stack account for 0.4 tonne of CO_2 emissions per tonne of finished steel; other units which consume BF gas also emit additional CO_2.

Basic Oxygen Steelmaking (BOF)

The BOF process produces liquid steel by blowing oxygen through the hot metal to remove impurities like carbon, silicon and phosphorous and produce liquid steel. The oxidation of carbon releases CO and CO_2. Due to the high CO concentration, the cooled and cleaned BOF off-gas is used in other units/facilities in an integrated steel plant. The BOF process in itself produces only 0.03 tonne of CO_2 per tonne of finished steel.

Calcining Plant

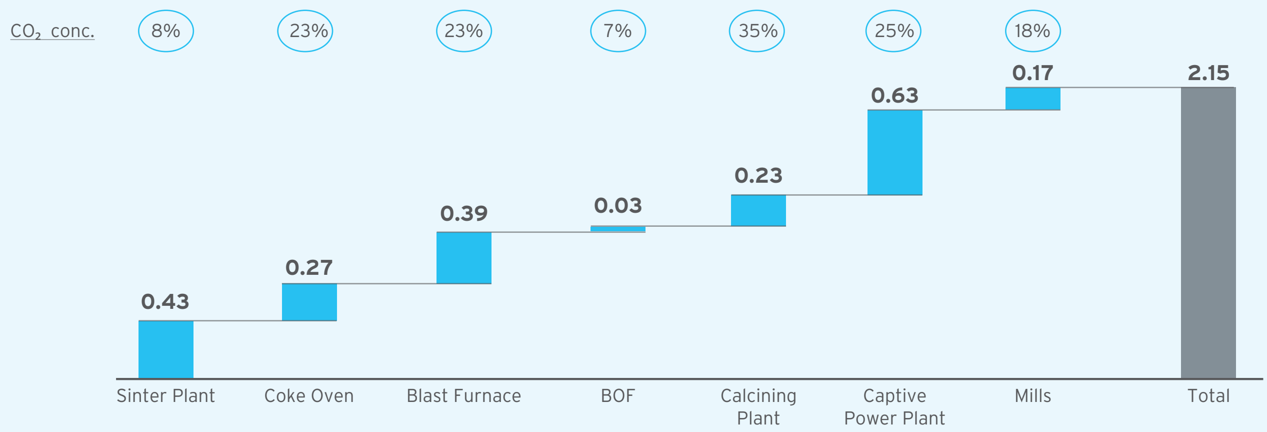
Limestone and dolomite are calcined in kilns at 1000 °C to produce calcined lime and dolo. The use of in-plant fuel gases and decomposition of carbonates ($CaCO_3$ and $MgCO_3$) in the calcining process results in CO_2 emissions of 0.23 tonne of CO_2 per tonne of finished steel.

Rolling Mills

Semis (slabs, billets, blooms) from the steel melt shop are processed/rolled in rolling mills to produce final products like rebars, wire rods, structural sections and hot rolled coils. Rolling mills typically have re-heating furnaces for re-heating the cooled semis before they are rolled. Depending on the plant fuel balance, re-heating furnaces use other steel plant gases (BF gas, CO gas), natural gas and light diesel oil; about 0.17 tonne of CO_2 per tonne of finished steel is emitted by the rolling mill.

The total CO_2 emissions in a typical BF-BOF based integrated steel plant is estimated to be about 2.15 tonne of CO_2 per tonne of finished steel (Figure 2-17). The CO_2 concentration at each unit depends on the fuel consumption and fuel blend.

Figure 2-17: Distribution of CO_2 Emissions per tonne of Steel in a Typical BF-BOF Route based Integrated Steel Plant (tonne of CO_2 per tonne of finished steel)



Source: Dastur reasearch

CCUS is an imperative for the long-term sustainability of the BF-BOF route of steel making due to the following reasons:

i. High CO_2 intensity of the BF-BOF route

ii. Use of fossil fuels not only as a source but also as a reducing agent in the steel making process

iii. Nascency of technology developments for fueling the BF-BOF route with cleaner alternate energy sources like natural gas or hydrogen or electrifying the process

iv. The primacy of the BF-BOF route in the top 3 steel producing countries in the world, all of which are a part of the G20

v. CCUS can also enable the scalable and profitable conversion of waste gases from Blast Furnace, Coke Oven and Basic Oxygen Furnaces to blue hydrogen at a cash cost of less than US$ 2 per kg. Blue hydrogen can be used within the steel plant as a source of clean energy or for producing clean DRI or be sold to external consumers, thus propelling the nascent clean hydrogen economy.

vi. Worldwide there are no operating CCUS facilities associated with BF-BOF based steel plants and hence CCUS technology development & demonstration for BF-BOF steel plants should be one of the key focus areas for the sector

Coal Based DRI Processes (Coal DRI): In a DRI kiln, non-coking/thermal coal is used to reduce iron ore to the solid product of Direct Reduced Iron (DRI) or sponge iron. DRI is a major input raw material to EAFs and IFs for producing steel. Sized lump iron ore or pellets, coal, limestone and dolomite react in the presence of air to produce DRI and release CO_2. The CO_2 emission by the process is about 3.2 tonne of CO_2 per tonne of finished steel. The coal-based DRI process involves solid-solid reactions; it is less efficient and hence requires higher coal quantity (and hence produces higher emissions) compared to the BF route.

Gas Based DR Processes (Gas DR): Natural gas (primarily methane) is reformed using steam to produce hydrogen and carbon monoxide, which is used to produce DRI from lump ore or pellet charge. The reforming of natural gas and reduction of iron ore to DRI produces CO_2 emissions of 1.6 tonne of CO_2 per tonne of DRI.

CO_2 Emissions from the Steel Industry: Based on the emission intensities of the different steel making process, and production data for 2021, the global volume of direct CO_2 emissions from the steel sector is estimated to be 2.6 Gtpa. Based on the current momentum and future outlook of steel demand, it is reasonable to consider that finished steel production will reach around 2.1 Gt per annum by 2030. DRI based production is expected to increase by 25% by 2030 to 150 mtpa, merely by increasing the present low levels of capacity utilization of 70%. The share of gas DR versus coal DR is not expected to change too much, i.e., 20% gas based DR and 80% coal based DR. Scrap usage is expected to rise to 600 mtpa in 2030 from around 70 mtpa in 2020, as many steel plants in Europe and USA look to shift to EAF based steelmaking.

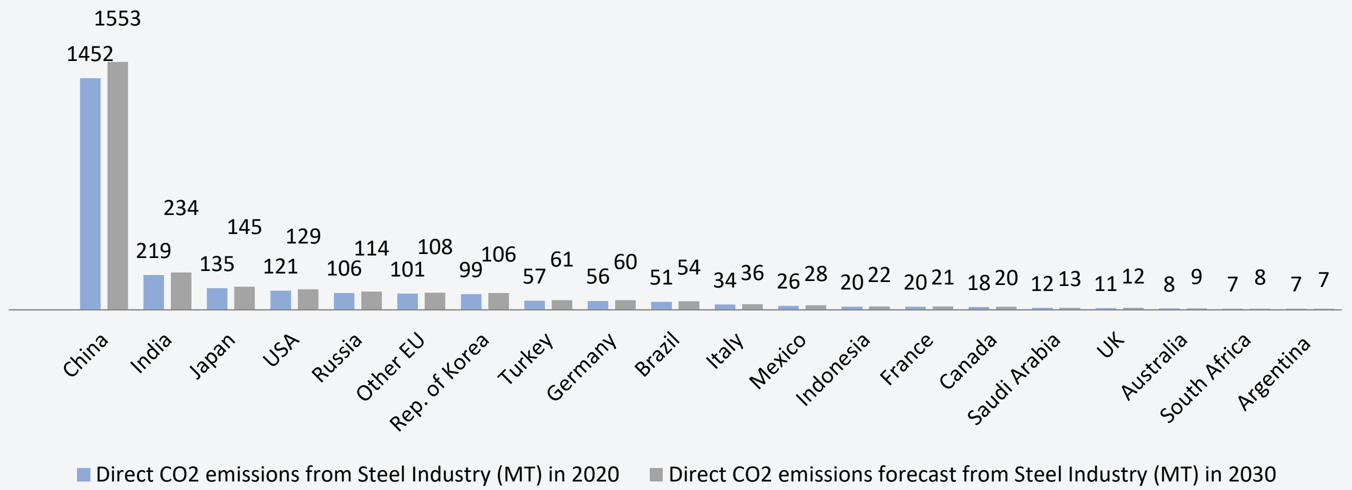
Combining these estimates with the respective CO_2 emission intensities, it is estimated that the total CO_2 emission shall increase to about 2.8 Gtpa by 2030 from the present level of 2.6 Gtpa. Given the uncertainty in the geographical distribution of future capacity additions, it is reasonable to assume that the route-wise distribution of production will not change significantly.

Table 2-6: Steel Production and CO_2 Emissions for Various Steel Making Routes (in Gtpa)

Route	Crude steel production - 2021	Direct CO_2 emission - 2021	Crude steel production - 2030	Direct CO_2 emission - 2030
BF-BOF	1.302	1.85	1.49	2.00
Electric Route	0.53	0.75	0.61	0.80
Total	**1.83**	**2.60**	**2.10**	**2.80**

Source: World Steel Association & Dastur reasearch

Figure 2-18: Direct CO_2 Emissions from Iron & Steel Across G20 Countries in 2021 and Projected Emissions in 2030 (in mtpa) – 2.56 Gtpa in 2021 and 2.74 Gtpa in 2030

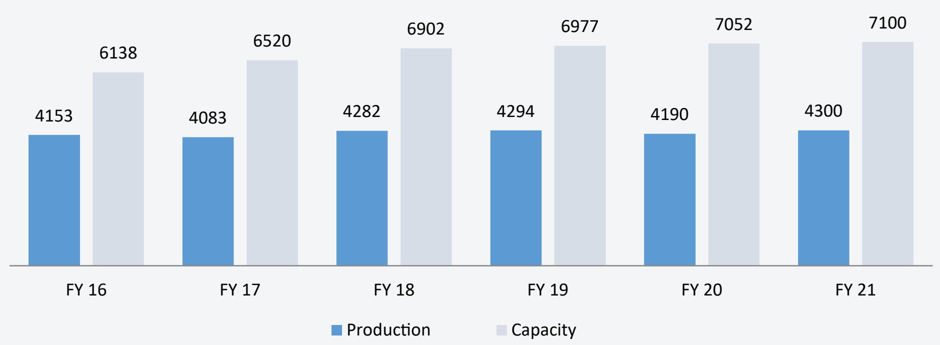


2.2.3 CO_2 Emissions: Global Cement Industry

The cement sector plays a vital role in the overall economic growth of all countries and provides a critical raw material for the construction and infrastructure sectors. Over the last five years, global cement production has remained flat, growing from 4153 mtpa (2016) to 4300 mtpa (2021) at a CAGR of around 1% (Figure 2-19). Global cement demand and production, which were affected in 2020 due to the COVID-19 pandemic, have recovered in 2021.

Currently, cement production across the globe is around 4300 mtpa, implying an average capacity utilization of 60%. The present global per capita cement consumption is around 500 kg. In line with the trend in the last four years, it is expected that the global cement demand will remain largely flat in the next decade, with demand & production likely to decline in China and being offset by increases in India and parts of Asia & Africa, as they embark on their infrastructure growth path.

Figure 2-19: Global Cement Capacity and Production - in mtpa

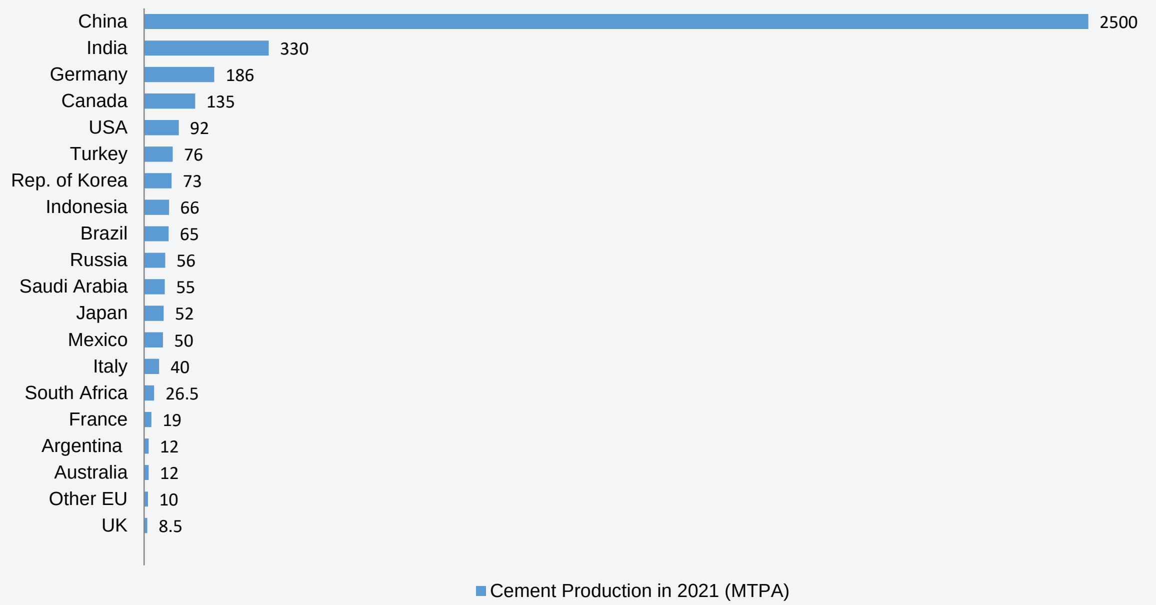


Source: Global Cement Report

Cement Plant Production and Capacity

Limestone is the major feedstock in cement production. Hence most cement plants are built either close to captive limestone quarries or are well connected with limestone quarries. The market for slag and fly ash-based cement has also evolved in the last few years, with blast furnace slag and fly ash-based cement plants expanding in countries where steelmaking is mostly based on the BF-BOF route. Figure 2-20 shows the cement production across G20 countries, which account for 90% of the global cement production.

Figure 2-20: Country-wise Cement Production in G20 Countries in 2021 – 3864 mtpa



Source: Dastur research

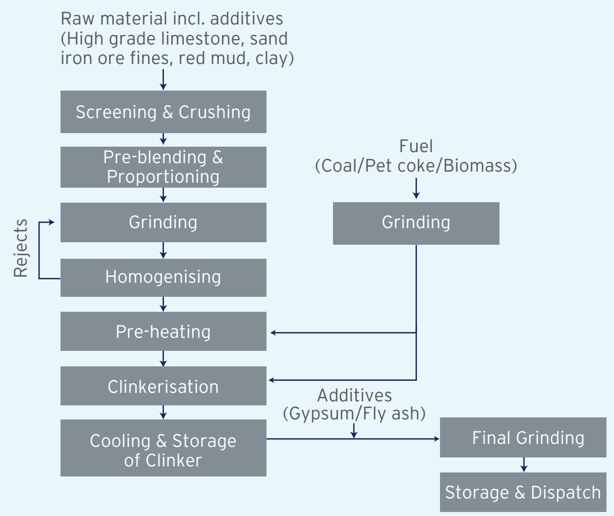
Typical Cement Manufacturing Process

Based on the clinker factor and usage of other ingredients like fly ash or slag, cement can be primarily categorized into three types: Ordinary Portland Cement (OPC), Portland Pozzolana Cement (PPC) & Portland Slag Cement (PSC). The process route for each type of cement production is almost similar, except for the final blending and grinding process steps. The dry-type technology predominant in the cement industry is depicted in Figure 2-21. Clinkerization is the major source of CO_2 generation in cement making. Complete clinkerization is achieved in two stages: preheater and kilns.

Clinkerization: Cement clinker is made by pyro-processing the kiln feed in the preheater kiln system. The preheater-kiln system is a multi-stage (typically more than five), consisting of a cyclone preheater, combustion chamber, riser duct, rotary kiln, and grate cooler.

In the preheater section, heat transfer depends on the number of stages of the preheater. Additionally, coal is also used to provide additional heat. The preheater helps in removing moisture from the feed, as well as raises the temperature of the feed through countercurrent heat transfer with hot flue gas.

Figure 2-21: Typical Process Flow Diagram for Cement Making



The preheated kiln feed is partially calcined in a combustion chamber and riser duct and then completely calcined in a rotary kiln, where it is heated to approximately 1400-1500 °C to form the clinker components. Coal is fed through a burner which is the primary source of heat for the calcination. However, alternative fuels like petcoke, biomass, and other solid waste are also used. Hot clinker is discharged to the grate cooler for cooling from 1350-1450 °C to around 1200 °C with atmospheric air. The cooled clinker is then conveyed to hoppers for clinker storage.

The global average CO_2 emission intensity per tonne of cement was around 576 kg in 2021. The emissions are primarily from three sources:

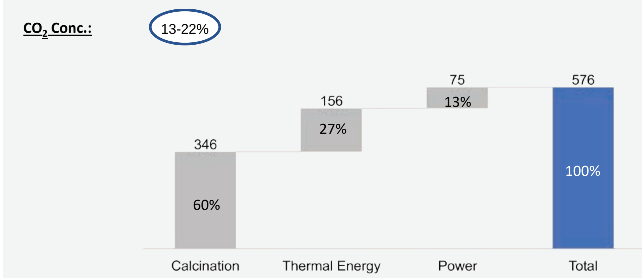
a. Emission from the calcination ($CaCO_3$ to CaO) process accounts for about 60% of the total emissions

b. Emission from process heating contributes around 30%

c. Emission from power usage for grinding, process fans, etc. accounts for the remaining 10%.

A typical CO_2 cascade is shown in Figure 2-22.

Figure 2-22: Typical CO_2 Cascade (in kg of CO_2 per tonne of cement)

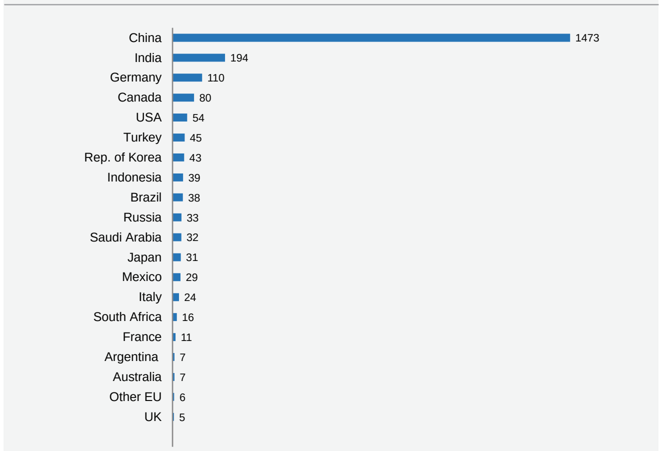


Source: Dastur Research

CO_2 Emissions from Cement Manufacturing

In 2021, global cement production contributed about 7% or 2.5 Gtpa anthropogenic CO_2 emissions across the globe (source: IEA). CO_2 emissions vary widely from plant to plant depending on factors such as product type, plant efficiency, fuel usage, plant capacity etc. Hence an average CO_2 emission per tonne of cement has been used to calculate the total CO_2 emissions at the current and projected level of cement demand and production. CO_2 emissions from cement production within the G20 nations in 2021 are shown in Figure 2-23 below.

Figure 2-23: Country-wise CO_2 Emissions from Cement Production, 2277 mtpa



Source: Global Cement Report, Dastur Research

The CO_2 emission intensity is expected to reduce to 500-520 kg of CO_2 per tonne of cement by 2030, with further improvements in the cement production process, higher production of blended cement, use of vertical roller mills, WHRB installation etc. Thus, with cement production remaining stagnant, total CO_2 emissions from the cement sector is expected to be around 2.24 Gtpa. The share of emissions from the G20 countries is not expected to change from the present 90%; thus, emissions from G20 countries is estimated to be 2 Gtpa.

2.2.4 CO_2 Emissions: Oil & Gas Refineries

The continuous expansion of the fossil fuel-based energy industry is one of the key obstacles to realizing the climate goals of the Paris Climate Agreement. Oil & gas refineries contribute about 14% of overall industrial CO_2 emissions and act as both a consumer and provider of energy. CO_2 emissions from the refinery sector were about 1.3 Gtpa in 2021 and thus, potential CO_2 emissions reductions by the sector will have an important role in meeting future net zero goals.

Refineries can be broadly classified as shallow processing or simple refineries and deep processing or complex refineries. Simple refineries do not have any conversion units and consist of facilities such as tanks, distillation units, recovery facilities, hydro-treating units, and other necessary utility systems. Complex refineries contain a large variety of units, such as catalytic cracking units and hydrocracking units (HCUs), for enabling, treating, and converting heavy crude oil fractions into lighter products. Complex refineries have large capacities, longer service lives and higher CO_2 emissions (about 4X times) than simple refineries; they account for a vast majority of CO_2 emissions vis-à-vis simple refineries, a trend that is expected to continue in the near future.

Process Description of Various CO_2 Sources

A complex refinery has multiple CO_2 emission points such as the Hydrogen Generation Unit (HGU), Power Plant/ Co-Gen Plant (PP/CGP), Fluid Catalytic Cracking (FCC), Crude Distillation Unit (CDU) / Vacuum Distillation Unit (VDU) as well as heaters and boilers. Amongst these, the HGUs generate the highest CO_2 concentration gas streams with CO_2 concentrations of 18-22 vol%, followed by CDU/VDU (8.5-11 vol.%) and FCC (8-10 vol.%) – see Table 2-7. The majority of CO_2 emissions from a typical refinery is contributed by hydrogen generation units, FCC, boilers, and process heaters.

Table 2-7: CO_2 Concentration at Different Refinery Units

Unit	Section	CO_2 vol% (db)
SMR	Reformer Flue	18-22
FCC	FCCU Regenerator	8.5
CDU	Crude Distillation Unit	11
DCU	Coke Heater	8.5
Reformer heater	Reformer Heater	4
VDU	Vacuum Unit	11
Naphtha splitter	Reformer-Naphtha Splitter	8.5

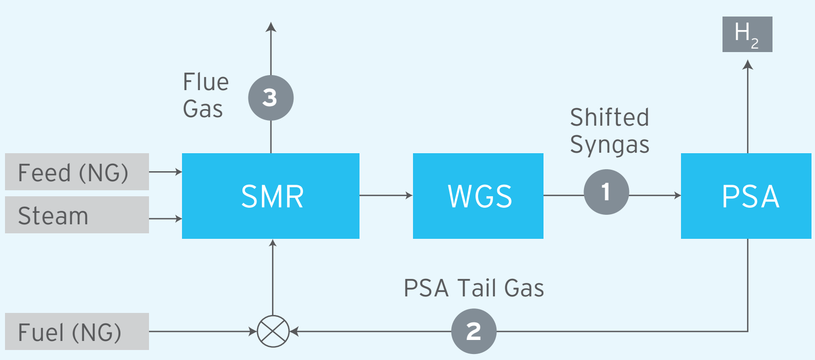
Unit	Section	CO_2 vol% (db)
HC	Hydrocracker	8.5
HC-Heater	Hydrocracker Heater	8.5
HDS	Hydrodesulfurization	8.5
DCU	Coke Heater	8.5
HDS-Heater	HDS- Charge Heater	4
SRU	Sulfur Removal & Tail Gas Treatment	4
FCCU Heater	FCCU Heater	4

Source: Dastur Research

In a complex refinery, the most opportune carbon capture points are the HGU or the SMR and the FCC. Both processes/units are described below.

Hydrogen Generation Unit (HGU): Hydrogen is indispensable in complex refinery operations for handling sour crudes as well as for meeting stringent fuel norms. Globally, almost all refineries produce hydrogen from natural gas (as well as naphtha) through the steam methane reforming (SMR) process. In an SMR, natural gas reacts with steam in the presence of a catalyst to produce hydrogen and carbon monoxide. The SMR output gas stream is passed through a water gas shift reactor to convert the CO to CO_2 and maximize the H_2 recovery. The possible CO_2 capture points and their gas compositions are provided in Figure 2-24 and Table 2-8. While carbon capture from tail gas or syngas (stream 1 & stream 2) ensures the lowest cost of capture because of higher concentration and partial pressure of CO_2, it can capture only 60% of the total direct CO_2 emissions, whereas flue gas capture ensures over 95% direct CO_2 capture.

Figure 2-24: Simplified Block Flow Diagram of Hydrogen Generation Units (HGUs)



NG: Natural Gas; SMR: Steam Methane Reforming;
WGS: Water Gas Shift; PSA: Pressure Swing Adsorption

Table 2-8: Gas Composition at Different CO_2 Emitting Sections in the HGU

Parameter	Shifted syngas (vol.%, db)	PSA tail gas (vol.%, db)	Flue gas, (vol. %, db)
Gas stream	1	2	3
Carbon Dioxide	20	64	18-20
Hydrogen	77	26	
Carbon Monoxide	0.7	7	
Nitrogen			58

Source: Dastur Research

Fluid Catalytic Cracking (FCC): The FCC unit helps in improving the recovery from crude oil by cracking higher hydrocarbons. Crude reacts with steam in a fluidized bed (or fluid-bed) of catalyst particles - cracking begins as the gas oil vapours and the heated catalyst particles migrate upward in the reactor. The catalyst gets coked during the process and is transferred to the regeneration unit, where the deposited coke layer is burnt at around 700-800°C; this is a primary source of CO_2 emission.

CO_2 Emissions from Oil & Gas Refineries

Based on the CO_2 emission intensities for various process units in a refinery, the direct process emissions may be considered for CO_2 capture and further utilization or sequestration. In a refinery, the major sources of CO_2 emissions are the hydrogen production unit and emissions from the production of mid-distillate products from the FCC. Apart from these emissions, CO_2 emissions from utility CPP and boilers associated with a refinery account for the CO_2 volumes that can be captured, due to the possibility of integration with CCU facilities. The country-wise distribution of CO_2 emissions from oil & gas refineries is provided in Table 2-9

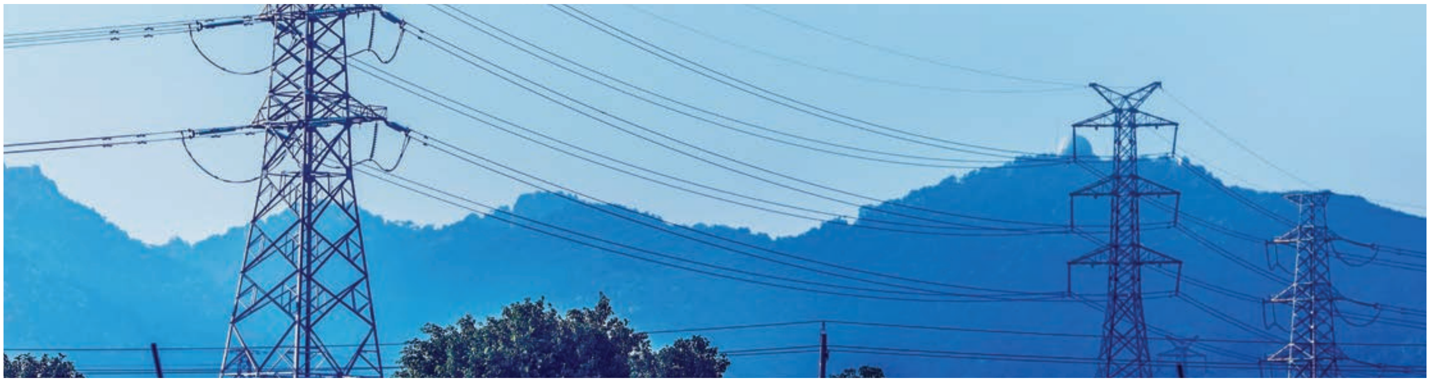
Table 2-9: Total CO_2 Emissions from Refineries

Sl. No.	Country	Capacity in million barrels per day 2021	CO_2 emissions, mtpa
1	Argentina	0.6	7.5
2	Australia	0.46	5.75
3	Brazil	2.1	26.25
4	Canada	1.98	24.75
5	China	16.7	208.75
6	France	1.14	14.25
7	Germany	2.1	26.25
8	India	5.2	65

Sl. No.	Country	Capacity in million barrels per day 2021	CO_2 emissions, mtpa
9	Indonesia	1.1	13.75
10	Italy	1.9	23.75
11	Japan	3.5	43.75
12	Korea	3.5	43.75
13	Mexico	1.64	20.5
14	Russia	6.8	85
15	Saudi Arabia	2.8	35
16	South Africa	2.58	32.25
17	Turkey	0.6	7.5
18	UK	1.2	15
19	USA	18	225
20	EU	3	37.5
Total for G20 countries		**76.90**	**961.25**
Rest of World		**24.3**	**303.75**
Total		**101.2**	**1,265**

Source: Dastur Research

Global refining capacity is expected to reach 105.2 million barrels per day by 2030, with global demand for transportation fuels likely to peak between 2030 to 2035. Considering similar CO_2 intensity factors, the total emissions from oil & gas refineries worldwide is expected to be around 1.32 Gtpa by 2030. About three quarters of these emissions, i.e., about 1 Gtpa of CO_2 , is expected to be emitted from the G20 countries.



2.2.5 CO_2 Emissions: High-value Chemicals Industry

Type of Primary Chemicals

Methanol: Methanol is an essential chemical building block for hundreds of everyday products and applications, including plastics, paints, fibres and construction materials. Methanol is also an alternative clean energy carrier that can be blended in existing fuels and used in cars, trucks, buses, ships, fuel cells, boilers and cooking stoves. The global methanol demand was about 88 mtpa in 2021; global demand is expected to grow strongly at 3%+ per annum to about 111 mtpa by 2030, an increase of 23 mtpa.

Methanol is primarily produced using natural gas (using the SMR process similar to hydrogen production), except in China, where methanol is produced through the gasification of coal. Both processes produce syngas (a mixture of CO_2, CO and H_2) which is conditioned to get the desired H_2/CO ratio of 2.2; the CO_2 is removed from the syngas and the remaining gas (primarily H_2 and CO) is passed through a methanol reactor to produce methanol in the presence of necessary catalysts. The emissions are about 0.4 – 0.5 tonne of CO_2 per tonne of methanol for NG based production and between 5 - 6 tonne of CO_2 per tonne of methanol for the coal gasification-based process used in China.

Ammonia: Ammonia is used as a raw material for the production of different chemical fertilizers, such as urea. The global capacity and supply capability (based on actual utilization) of ammonia production have grown at 0.92% and 1.01% CAGR, respectively, from 2016 to 2021. The installed capacity in 2021 was 189 mtpa, with a supply capability of 162 mtpa. The total production of ammonia in 2021 was 146.5 mtpa. With a growing population and food demand, the demand for urea and ammonia is also expected to grow. The other end uses of ammonia are as a chemical in making refrigerants (driven by growth in urbanization and improving lifestyles) and as a building block for various compounds used in producing household products, cosmetics, pharmaceuticals and metal treatment. Ammonia can also play a role in future energy transitions as a hydrogen carrier for storing and transporting the chemical energy of hydrogen and can be used as a transport fuel, particularly in the shipping industry.

The major end-use of ammonia is in the production of urea, where it is generally produced in situ as part of the urea plant. A typical urea plant uses natural gas as the main feed/raw materials and consists of units for H_2 production, ammonia production and urea production. The H_2 unit is similar to the SMR of refineries and contributes to the majority of the CO_2 emissions. The produced hydrogen and nitrogen (supplied from an air separation unit) combine through the Haber process in the presence of an iron catalyst to produce ammonia, which is pressurized and reacted with CO_2 (captured from the SMR) to produce urea. After taking into account the CO_2 consumed in converting ammonia to urea, the net CO_2 emission is about 1.2 tonne of CO_2 per tonne of ammonia.

Petrochemicals: Petrochemicals are primarily of two types (olefins and aromatics) and provide the basic raw materials for many products of daily use. The source feedstock, i.e., light or heavy hydrocarbons, is used to produce a variety of components such as ethylene, propylene, butadiene, and pyrolysis gasoline through non-catalytic thermal decomposition reaction with steam (thermal cracking). Pyrolysis of hydrocarbons is the most critical process of petrochemical production and presents the main source for most basic organic industrial raw materials: α-olefins (ethylene, propylene, isobutane, butene), butadiene, and aromatic hydrocarbons (BTX = benzene, toluene, xylene).

The most CO_2 emission-intensive process is the production of ethylene through steam cracking. In steam cracking, a gaseous or liquid hydrocarbon feed-like ethane, propane, butane, naphtha, gas or oil is diluted with steam and then heated in a furnace without oxygen at a temperature of 850 °C. The higher cracking temperature favours the production of ethylene and benzene, whereas lower severity produces relatively more elevated amounts of propylene, C4 cuts, and liquid products. The exhaust flue gas is a CO_2 rich product, and depending upon the type of fuel, and is combusted in modern low SOx-NOx burners. Normally the methane content varies from 60-70 vol% in the gaseous fuel. The typical flue gas composition with 10-15 vol% excess air is given in Table 2-10

Table 2-10: Cracker Furnace Flue Gas Composition

Parameter	vol% (db)
CO_2	11-13
H_2	3-4
N_2	85-87
CO	100-200 ppm

Source: Dastur Research

CO_2 Emissions from High-Value Chemicals Industry

Based on the CO_2 emission intensities for various process units in the chemical industry, direct process emissions have been considered for estimating the CO_2 volumes amenable to carbon capture. Based on the production data from various industries and the sector-wise production of different chemicals through various routes, the associated CO_2 emission volumes have been estimated and are tabulated in Table 2-11.

Table 2-11: G20 Country Emissions from High Value Chemical Sector

Products	Production in 2021 (mtpa)	Expected production in 2030 (mtpa)	CO_2 emissions in 2021 (mtpa)	Expected CO_2 emission in 2030 (mtpa)
Methanol*	88	110	319	399
Ammonia	117	142	351	427
Ethylene	182	256	200	282
Propylene	77	113	200	282
BTX	105	140	25	35
Total			**895**	**1143**

Note: About 1/3rd of global capacity is based on the coal gasification route

Source: Dastur Research

2.3 Sector-wise CO_2 Emissions Amenable for Carbon Capture

Based on the sectoral analysis of the total CO_2 emissions across the world and the G20 countries, it is imperative to assess the quantity of CO_2 amenable for capture in different sectors. The extent of CO_2 amenable for capture as a share of total emissions in different sectors depends on the number of sources of CO_2 generation and their concentrations, as well as the availability of suitable technologies for carbon capture. The sector-wise total CO_2 emission quantities across the world, as well as the share of CO_2 emissions amenable for capture, is indicated in Table 2-12.

Table 2-12: Sector-wise CO_2 Volumes Amenable for Capture

Sector	Total CO_2 Emissions in 2021 (Gt)	Total CO_2 Emissions in 2030 (Gt)	Share of Emissions Amenable for Capture (1)	CO_2 Emission Amenable for Capture in 2021 (Gt)	CO_2 Emission Amenable for Capture in 2030 (Gt)
Power	14.3	12.8	90%	12.9	11.5
Iron & Steel	2.6	2.8	60%	1.6	1.7
Cement	2.5	2.2	90%	2.3	2.0
Refineries	1.3	1.3	30%	0.4	0.4
Chemicals & Fertilizers	0.9	1.2	90%	0.8	1.1
Others (2)	2.0	2.5	20%	0.4	0.5
Total (World)	**23.6**	**22.7**	**75 – 77%**	**18.30**	**17.2**
Total (G20 countries)				**14.70**	**13.85**

Note: (1) Based on Dastur's analysis
(2) Includes oil & gas upstream, paper & pulp, other chemicals, aluminium, glass etc.

The share of CO_2 emissions amenable for carbon capture provided above is derived based on the following factors:

i. The lower the number of CO_2 generation sources within a single plant, the greater the possibility of capturing CO_2. Hence substantial capturing of CO_2 is feasible from power plant flue gases or from cement kilns. Refineries and steel plants have a large number of distributed CO_2 emission sources; however, all of them do not have sufficient CO_2 volume or concentration to justify a carbon capture unit installation. Hence the extent of CO_2 emissions amenable for carbon capture for both refineries and steel is lower compared to carbon capture from power plant flue gases or the calcination process in a cement plant.

ii. The extent of CO_2 amenable for capture also depends on other factors, such as the quality of the flue gas. For example, while both the flue gas from coal-based thermal power plants and the calcination unit of cement plants have similar CO_2 concentrations, the quality of the flue gas in the former (due to the installation of pollution control equipment such as Flue Gas Desulphurization unit in many power plants) makes the power plant flue gas more suitable for carbon capture, as SOx presence is likely to affect the extent of CO_2 absorption by amine based solvents suitable for flue gas carbon capture installation.

iii. The actual extent of CO_2 captured would also depend on the CO_2 disposition opportunities available, either in the form of sequestration, EOR or utilization opportunities and the economic viability of the same. In certain cases, carbon capture can also lead to the production of synergetic value-added products, as below:

a. CO_2 utilization for producing aggregates and building materials – offers synergies for cement plants (common end markets) and steel plants (slag availability)

b. CO_2 utilization for producing chemicals such as methanol – offers synergies for refineries and petrochemical plants

c. Steel plants – for integrated steel plants, the post-carbon capture hydrogen rich fuel gas can be purified to produce hydrogen, which can be used to produce DRI with reduced CO_2 emissions. The DRI can be used in both BF and BOF to reduce the coke rate and hot metal requirements, respectively, thus leading to lower CO_2 emissions from the steel sector.

iv. The financial viability of carbon capture and the extent of the "green premium" as a percentag of the overall cost of production of the final product has a significant bearing on the extent of CO_2 emissions captured.

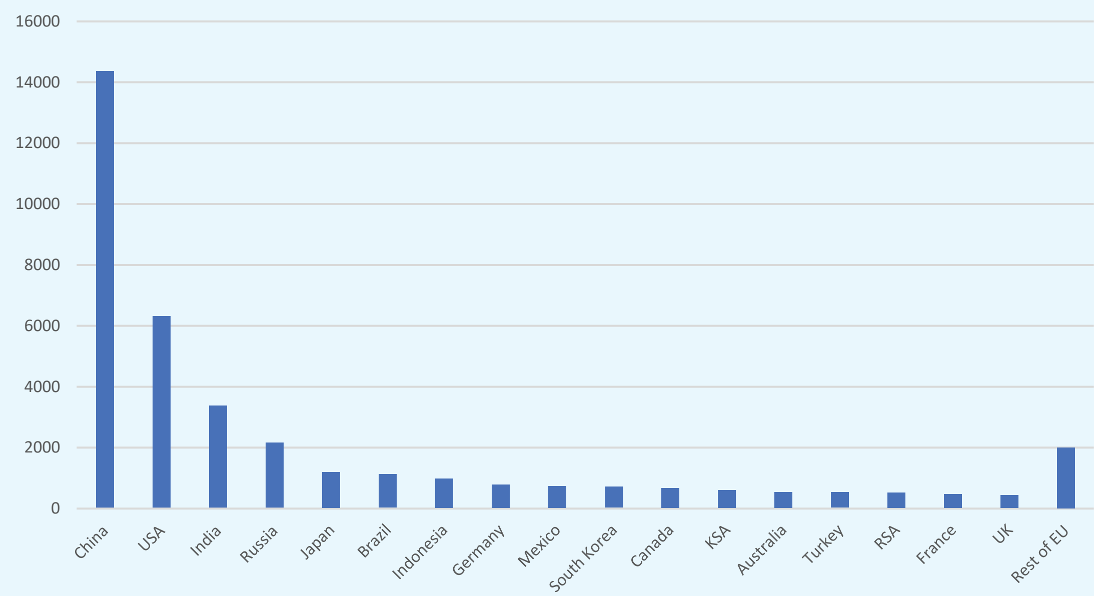
Table 2-12 shows that the aggregate carbon capture opportunity in different sectors is at the giga-tonne scale. In stark contrast, the total volume of CO_2 captured by the 30 CCUS projects operating worldwide is only around 42 mtpa, or less than 1%. Hence there is an urgent need to scale up technology development and project deployment across the entire CCUS value chain, while also addressing the challenges and opportunities listed above. The subsequent chapters of this report provide an overview of the current CCUS technology landscape and the key actions required to address the technology gaps and scale up CCUS.

CCUS in
G20 Countries

3.1 CO_2 Emissions Across the G20 Countries

The amount of anthropogenic CO_2 emissions varies significantly across the G20 countries, as shown in Figure 3-1.

Figure 3-1: Anthropogenic CO_2 Emissions of G20 Countries (in mtpa)



Source: Climate Action Tracker and Climate Transparency Report

Similarly, there is significant variation in the national policy, regulatory environment and long-term strategies for carbon emission abatement among the G20 countries. Analysis and study of the CCUS policy frameworks and project financing mechanisms of the G20 countries reveals that apart from Australia, Canada, France, Germany, Saudi Arabia, the UK, the USA and the EU, CCUS is relatively undeveloped in the other G20 countries. The Government of India policy think tank, the NITI Aayog, has recently released a comprehensive policy report on the likely CCUS policy framework and deployment mechanism for India.

The country-wise analysis of the present status of CCUS in the G20 countries is provided in the Annexure of this report. The analysis reveals that in keeping with the theme of international collaboration for addressing the CCUS technology gaps, enabling CCUS at scale across the G20 also requires collaboration in the following areas:

i) Coordinated policy frameworks and mechanisms

ii) Global financing of CCUS projects

iii) Cross-border CCUS value chains

iv) Accelerating CCUS through new energy carriers like blue hydrogen

These themes are explored in Chapter 7 of this report.

3.2 CCUS Initiatives in India

CCUS is considered critical for transition to a low carbon economy. In India, various academia, R&D institititions and industries are working towards development and demonstration of different type of CCUS technologies, particularly in the area of CO_2 capture and utilization. A brief overview on some of these key initiatives is provided below:

1. Power Sector:

A. CO_2 capture initiatives

I. 20 tpd CO_2 Capture Plant at NTPC Vindhyachal

In the power sector, NTPC has setup and commissioned the first CO_2 capture plant in India. This CO_2 capture plant is connected to a 500 MW fossil fuel fired unit located at Vindhyachal. The Captured CO_2 is regenerated for reuse. Thereafter the CO_2-rich stream is purified, dehydrated, and compressed to raise the pressure to the required level, depending on the end-use or disposition pathway for the captured CO_2.

Figure 3-2: CO_2 Capture Plant at NTPC Vindhyachal

II. R&D Projects for CO_2 Capture

Table 3-1: R&D Projects for CO_2 Capture in Power Sector in India

R&D Project	Technology	Organization
Development of zeolite and 'Pressure Swing Adsorption' process for CO_2 capture	Physical Process	NTPC (collaboration with CSMCRI, NEERI, CSIR-IIP, IITB)
Development of amine and process for CO_2 capture	Chemical Process	NTPC (collaboration with IITG, IITB)
Demonstration of micro algae based CO_2 capture	Biological Process	NTPC (collaboration with IOCL)

B. CO_2 utilization initiatives

I. 10 tpd CO_2 to Green Methanol Plant at NTPC Vindhyachal

NTPC is setting up this plant wherein high purity CO_2 shall be captured from waste flue gas from a fossil fired power plant and thereafter catalytically hydrogenated to produce green methanol. Green hydrogen required for the process shall be produced using a 'Proton Exchange Membrane' electrolyzer.

II. 10 tpd CO_2 to Generation 4 Ethanol Plant at NTPC's Fossil Fired Power Plant

In this plant, a "chemical process" is used to capture CO_2 from power plant flue gas which is converted to Generation 4 ethanol using a combination of "reverse water gas shift" and bio-catalytic processes.

III. Development of CO_2 Based Carbonated Aggregates by NTPC

NTPC, along with CSIR-CBRI Roorke, is developing a "CO_2 based Carbonated Aggregate", using fly ash and CO_2 captured from power plant flue gases. In the domain of CCU technologies, this is perhaps the only technology which is "Carbon Negative".

C. CO_2 Storage Initiatives: Mapping of Geological Storage Potential of CO_2 in Category 1 Field in India

NTPC and the National COE-CCUS of IIT Bombay are working on this project, which is the first of its kind in India.

2. Oil & Gas Sector

Table 3-2: CCUS Initiatives by the Oil & Gas Sector in India

Company	Details
ONGC & IOCL	Feasibility study for the capture of 0.7 mtpa of CO_2 from HGU at IOCL Koyali refinery and utilizing the CO_2 for EOR at ONGC's Gandhar oilfields and F&B grade usage
ONGC	MoU with Shell for cooperation on exploring CO_2 storage and EOR in key basins in India and with Equinor for developing CCUS hubs and projects
BPCL	Feasibility study for gasification of 1.2 mtpa petcoke and conversion to carbon abated chemicals, hydrogen and power

3. Steel Sector

Table 3-3: CCUS Initiatives by the Steel Sector in India

Company	Details
Tata Steel	Commissioned a plant for capture of 5 tpd CO_2 capture from Blast Furnace gases at TSL Jamshedpur, with future plans to re-use the CO_2 within the steel value chain
JSPL	Capture of 2000 tpd concentrated CO_2 from commercial scale coal gasification operations at Angul for enabling carbon abated steel producing using blue hydrogen (as part of syngas). Also exploring CO_2 utilization to bio-ethanol, methanol and soda ash

4. Chemical Sector

Table 3-4: CCUS Initiatives by the Chemical Sector in India

Company	Details
Tuticorin Alkali & Chemicals	Commissioned a 200 tpd carbon capture plant. Captured CO_2 is utilized for the production of baking soda.
BHEL & CSIRCIMFR	Coal to methanol: pilot scale plants for carbon capture and conversion to methanol

Figure 3-3: CO_2 Capture Plant at Tuticorin Alkali & Chemicals

5. Cement Sector

Table 3-4: CCUS Initiatives by the Chemical Sector in India

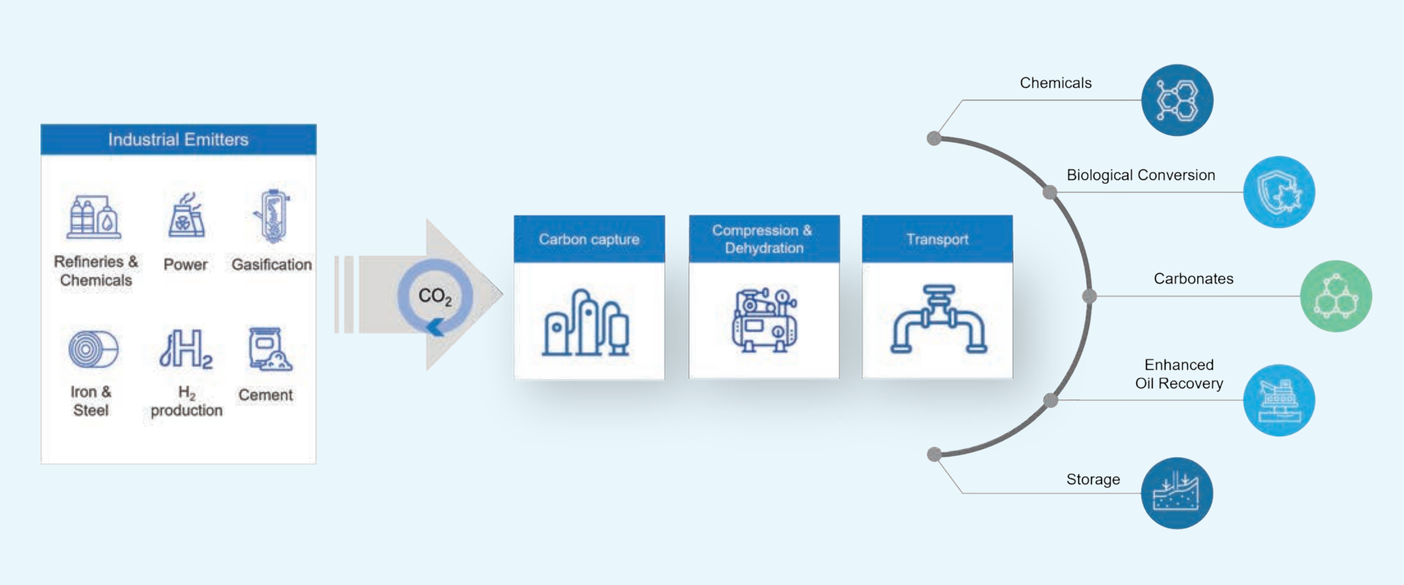
Company	Details
Dalmia Cements	0.5 mtpa carbon capture plant planned at their Tamil Nadu plant – MOU with technology provider

Carbon Capture
Technology Landscape

4.1 CCUS Value Chain

CO_2 capture is the first step in the CCUS value chain of CO_2 capture, processing, transport, disposition and conversion of CO_2. Carbon capture technologies separate carbon dioxide from gas streams released from industrial processes such as power plants, chemical production, cement production or steelmaking as shown in Figure 4-1. This chapter focuses on carbon capture technologies and also covers the related areas of CO_2 compression (and dehydration) and CO_2 transportation. Subsequent chapters of this report deal with CO_2 utilization and storage respectively.

Figure 4-1: CCUS Value Chain



4.2 Categorization of Carbon Capture Technologies Based on Operating Principle

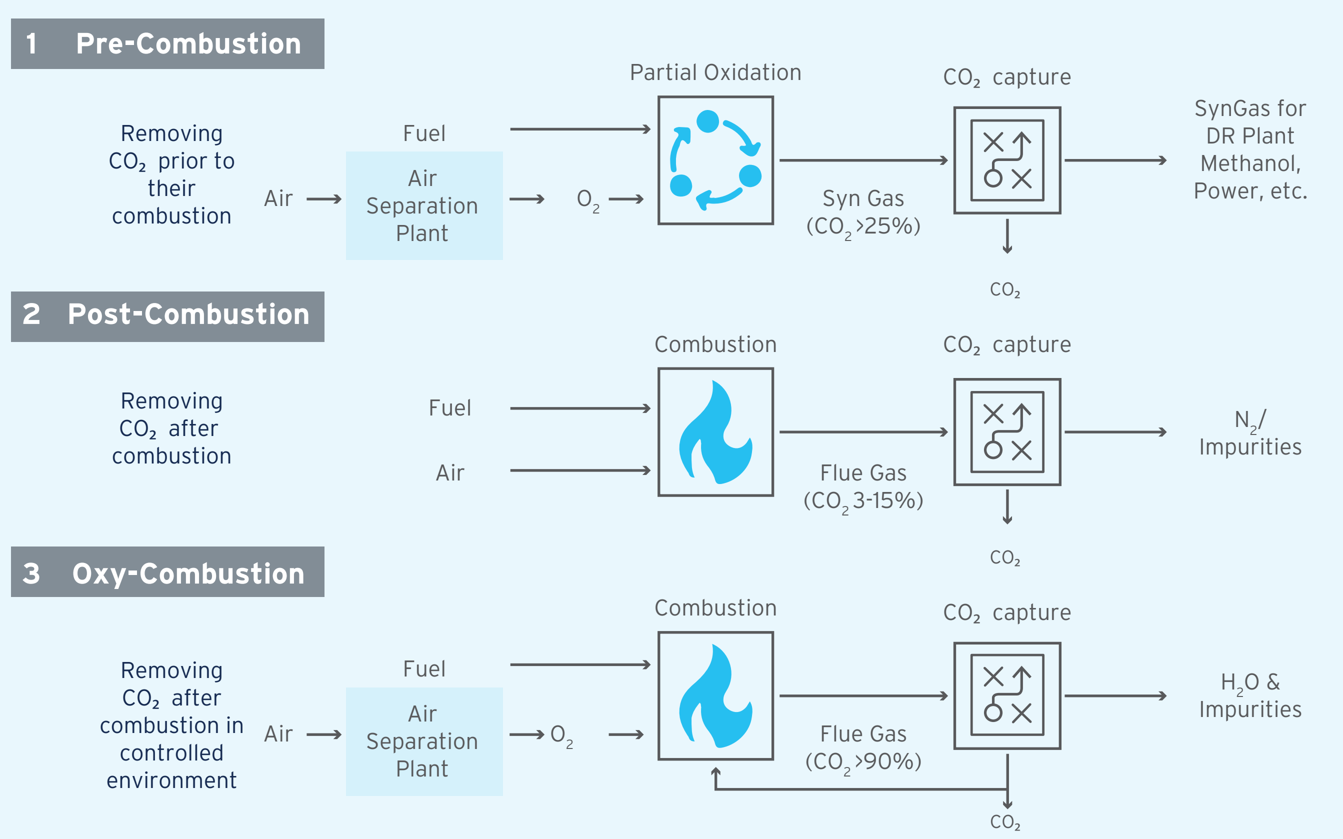
Based on their combustion operating principle, carbon capture technologies can be broadly classified into three categories: post-combustion capture, pre-combustion and oxyfuel combustion. The operating principles of each category are depicted in Figure 4-2.

(i) Pre-combustion technologies:

Pre-combustion carbon capture technologies focus on extracting carbon dioxide from fossil fuel or biomass fuel before the combustion processes generate energy. Pre-combustion carbon capture technologies typically extract the CO_2 from the energy rich gas stream of a gasification process, natural gas processing systems, or energy rich waste gas stream operating at high pressure with a high concentration of CO_2 (typically between 30% – 90%). The elevated partial pressure of the CO_2 stream enables the selective absorption of the CO_2 in a physical solvent, rather than through chemical binding, which is used in post-combustion carbon capture technologies.

Pre-combustion technologies are favoured in cases where the gas stream has a higher partial pressure of CO_2 , such as in the gasification of fossil fuels, NG based H_2 production or sour gas processing. Since no chemical bonds need to be broken for solvent regeneration, the thermal energy penalty is much lower vis-à-vis post-combustion technologies. The regeneration of the physical solvent is achieved mainly by reducing pressure. Pre-combustion capture technologies are scaleable for large-scale CO_2 capture, and are economically & operationally efficient for high pressure and high CO_2 concentration gas streams.

Figure 4-2: Scheme of Post-combustion, Pre-combustion & Oxy-fuel Combustion



(ii) Post-combustion technologies:

Post-combustion capture is useful for separating CO_2 from exhaust gases produced by burning fossil fuels. The exhaust gases, a mixture of CO_2, nitrogen and some oxygenated compounds, are first treated to remove particulate matter and the oxides of nitrogen and sulphur. The treated exhaust gases are then contacted with a liquid solvent, typically an aqueous amine solution. The amine selectively absorbs the CO_2 in an absorber column, capturing more than 85% of the CO_2 and enabling the nitrogen rich flue gas to be released into the atmosphere. The CO_2-rich amine solution is then regenerated by stripping the CO_2 out of the liquid with steam, allowing the lean amine to be recycled to the absorber while producing a concentrated CO_2 stream. The CO_2 is compressed and cooled in liquid form for further processing and disposition.

Fossil fuels like coal, oil, natural gas (NG) are burnt in the presence of air, hence the flue gas is rich in N_2, and the CO_2 percentage typically varies between 3% to 15%. Since the partial pressure of CO_2 in the flue gas is quite low, very high-volume chemical solvent (amine) circulation is required for CO_2 capture. Further, the enthalpy of binding of post-capture amine bases solvents is high, and hence the energy requirements for stripping the CO_2 is relatively high. This makes post-combustion technologies energy and cost-intensive. However, amine-based carbon capture solvents scale very well to millions of tonne of CO_2 capture and can be typically retro-fitted into existing industrial plants and power stations without significant modifications to the original plant.

(iii)Oxyfuel combustion technologies:

While post-combustion and pre-combustion carbon capture technologies have been commercially established, oxyfuel combustion technologies are still in the developmental stage. Oxyfuel combustion represents an emerging novel approach to achieving near zero emissions. Oxyfuel combustion involves burning the fuel in pure oxygen (O_2) instead of air (N_2 and O_2). The flue gas stream is thus composed mainly of water and CO_2 , rather than N_2. High purity CO_2 can be recovered by the condensation of water.

4.3 Categorization of Commercially Proven CO_2 Capture Technologies Based on Process

Mature and commercially proven CO_2 capture technologies (i.e. Technology Readiness Levels or TRL 8 and 9) can be broadly classified into three categories based on the process of CO_2 capture.

i) Solvent-based absorption
   a) Physical solvent based absorption
   b) Chemical solvent based absorption
ii) Adsorption
iii) Cryogenic separation

These carbon capture technologies can be applied to pre-combustion, post-combustion or oxyfuel combustion capture. However, for carbon capture at the pre-combustion stage, the most suitable carbon capture technologies are physical solvent based absorption, adsorption or cryogenic separation - this is due to the high concentration and high partial pressure of CO_2 at the pre-combustion stage. The precombustion stage involves partial combustion in a controlled flow of air, resulting in higher concentration and partial pressure of CO_2 in the resultant gas stream. Typical scenarios include gasifier operations and steam methane reformer (SMR) operations for producing hydrogen.

On the other hand, most post-combustion capture scenarios adopt chemical solvent based absorption. Post-combustion gas streams (viz. flue gas streams from coal or natural gas based power plants) typically have low concentration and low partial pressure of CO_2 due to the high amount of nitrogen in the flue gas because of complete combustion. Such gas streams are most suited for chemical solvents which can achieve high absorption capacity at low partial pressures of CO_2 due to the high chemical affinity of CO_2 to amine-/carbonate-based chemical solvents as well as the faster rate kinetics.

However, with a change in CO_2 concentration through appropriate gas conditioning as well as pressure boosting, post-combustion capture scenarios can also adopt physical solvent absorption or adsorption or cryogenic separation-based technologies and vice-versa. This choice is governed by the availability and cost of utilities required for gas conditioning (steam) & pressure boosting (power) as well as the pressure, temperature and purity requirements of the product CO_2 obtained through the capture process. Prima facie, the application of physical solvents, adsorbents or cryogenic technologies in a post-combustion capture setting or the application of chemical based solvents for pre-combustion carbon capture may adversely affect the carbon capture economics. However, the same can be offset through the appropriate scale of operations and the low-cost availability of utilities required for gas conditioning & compression.

4.4 Commercially Proven CO_2 Capture Technologies

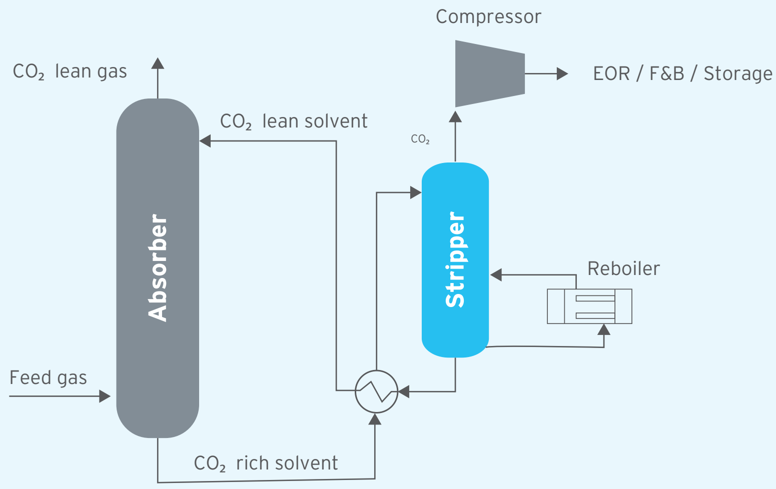
Brief descriptions of the commercially proven and matured carbon capture technologies are provided below.

4.4.1 Solvent-Based Absorption Process

Solvent-based CO_2 capture processes have been used for over half a century for processing natural (sour) gas, combustion flue gas and Fischer-Tropsch (FT) synthesis products. The fundamental principle on which solvent-based CO_2 capture technologies work is the “selective absorption” of CO_2 over the other gaseous constituents. The working principle of solvent-based CO_2 capture is depicted in Figure 4-3.

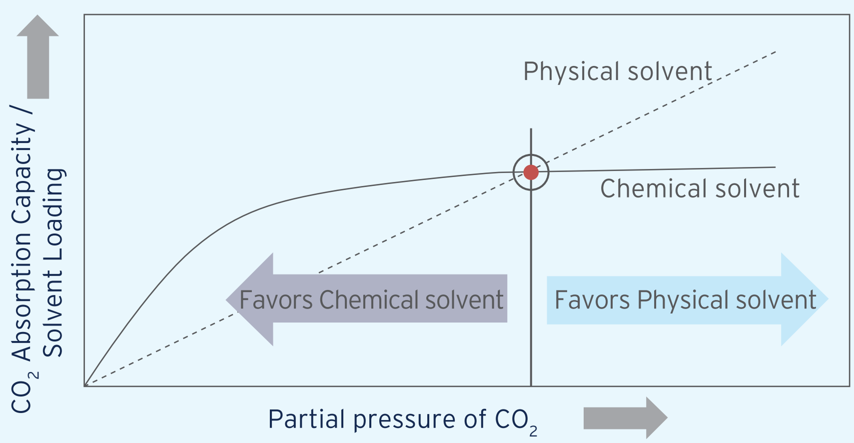
The CO_2 present in the feed/process gas is first selectively absorbed in an absorber using a solvent (physical or chemical); the CO_2 lean gas exits the absorber. Next, the CO_2-rich solvent is sent to a stripper-type configuration where the CO_2 is released from the solvent and the lean solvent is regenerated for reuse. Thereafter the CO_2-rich stream is purified, dehydrated, and compressed to raise the pressure to the required level, depending on the end-use or disposition pathway for the captured CO_2 .

Figure 4-3: Schematic Representation of Working Principle of Solvent-Based CO_2 Capture



Solvent-based CO_2 capture technologies are further categorized based on whether the CO_2 reacts with the solvent chemically (chemical solvents and chemical absorption) or dissolved physically (physical solvents and physical absorption). A schematic depiction of the relationship between the CO_2 absorption capacities of chemical and physical solvents (known as "solvent loading") and the partial pressure of CO_2 in the gas stream is provided in Figure 4-4.

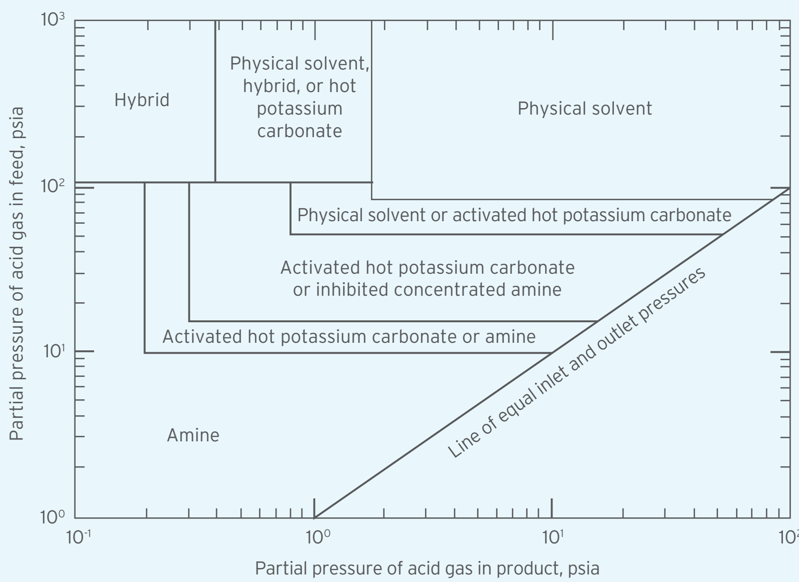
Figure 4-4: Schematic Representation of CO_2 Absorption Capacity of Chemical and Physical Solvents as a Function of the Partial Pressure of CO_2



Chemical absorption based CO_2 capture is better suited for gas streams having a low concentration and partial pressure of CO_2 due to the high chemical affinity of CO_2 to amine-/carbonate-based chemical solvents as well as faster rate kinetics. While chemical solvents can achieve high absorption capacity at low partial pressures of CO_2, a non-reactive or physical solvent performs well at higher partial pressures of CO_2. As shown in Figure 4-4, the solubility curve for a physical solvent typically follows Henry's law, i.e., a linear relationship with the partial pressure of CO_2.

Figure 4-5 depicts the operating ranges of various solvents for CO_2 capture and forms the basis for selecting suitable CO_2 solvents. The low CO_2 partial pressures in the flue gas of coal-fired power plants make amine-based chemical absorption the preferred technology/solvent. However, for relatively higher gas stream pressure and CO_2 concentration, such as in the syngas of gasifiers and SMRs, physical absorption-based capture is more suitable.

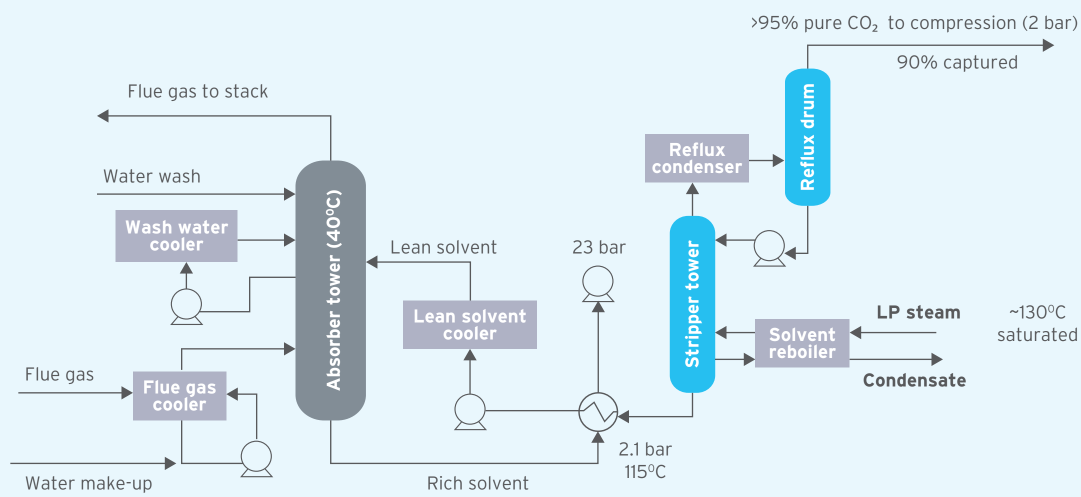
Figure 4-5: Operating Regimes of Various Solvents for CO_2 Capture



Chemical Solvent-Based Absorption Process

A basic flow diagram for a chemical solvent-based CO_2 capture is depicted in Figure 4-6. The chemical reaction between CO_2 and the chemical solvent is an exothermic reaction and hence favoured at lower temperatures. Hence it is necessary to pre-cool the feed gas. During the cooling of the feed gas, water condenses out of the wet gas.

Figure 4-6: Typical Flow Diagram of Chemical Solvent Based CO_2 Capture



The cooled gas stream reacts with the amine-based solvent at 40-60°C via a countercurrent flow reaction within the absorber column, resulting in:

(a) CO_2 free gas stream; and

(b) Solvent with chemically bound CO_2

The major process units include:

Absorber: Multiple stages of structured packing in the absorber columns maximizes the contacting surface area and mass transfer rate of CO_2 in the solvent during the countercurrent flow. While the CO_2 -depleted gas stream leaves the absorber from its top stage, the CO_2 -rich solvent stream exits the absorber column from its bottom stage and is pumped to the stripper/regenerator.

Stripper /Regenerator: At the stripper, the application of higher temperatures (100-140°C) results in the regeneration of the solvent by breaking the chemical bonds between CO_2 and the chemical solvent. The heat required for the regeneration of the solvent is provided by a reboiler, supplied with steam extracted from captive CHPs/CGPs. Such a heat and strip operation for the regeneration of the solvent leads to a high thermal energy penalty. Depending on the solvent used and system configuration, the steam consumption for solvent regeneration can range from 1.1 to 1.5 tonne of steam/tonne of CO_2 .

While the dense CO_2 stream exits the stripper from its top stage, the CO_2 -lean solution is cooled and recirculated to the absorber. Typically, the absorber and stripper's operating pressures for chemical solvent-based capture are low, ranging from 1 – 4 bar(a). The primary characteristics of a solvent which determine its efficacy are as follows:

a. **Rate kinetics:** Faster rates of reaction between the solvent and CO_2 ensure better mass transfer performance at the gas-liquid interface, thus facilitating a smaller absorber volume and a lower cost of capture.

b. **CO_2 carrying capacity:** A higher CO_2 carrying capacity of the solvent reduces the regeneration load, auxiliary unit costs and energy requirements.

c. **Reaction enthalpy:** A lower enthalpy for the reaction between the solvent and CO_2 transpires into lower energy requirements to break the solvent-CO_2 bond during desorption.

d. **Water content:** A decrease in water content in the solvent (aqueous solution) decreases the energy loss associated with vaporizing water (during CO_2 stripping at high temperatures) and increases the CO_2 carrying capacity of the solvent.

e. **Other desirable characteristics of the solvent:**

- Low CO_2 equilibrium backpressures at absorption conditions
- Easy reversible reactions at regeneration temperatures
- Low volatility of the solvent
- High resistance of solvent to oxidative and thermal degradation

A multitude of chemical solvents have shown varying degrees of success, including amine based (primary/secondary/tertiary/hindered), non-aqueous (NASS), carbonate-based and phase change based solvents. While primary and secondary amines (such as MEA, DGA, AEE, DEA) have higher reaction rates and lower CO_2 carrying capacities, tertiary amines and polyamines (such as MDEA and piperazine) have lower reaction kinetics and higher CO_2 carrying capacities. Due to competing characteristics, often blends of varying solvent compositions are used to exploit high reaction rates and CO_2 carrying capacity along with lower regeneration loads. Specifically, for MEA based systems, the steam (LP steam at ~3 bar(a)) energy requirement for solvent regeneration can range from 3.6 to 7 GJ/t CO_2 , depending on the system configuration and heat integration. A few of the proven and emerging solvent-based technologies are tabulated below:

Table 4-1: Commercially Proven Chemical Solvent Based Capture Technologies

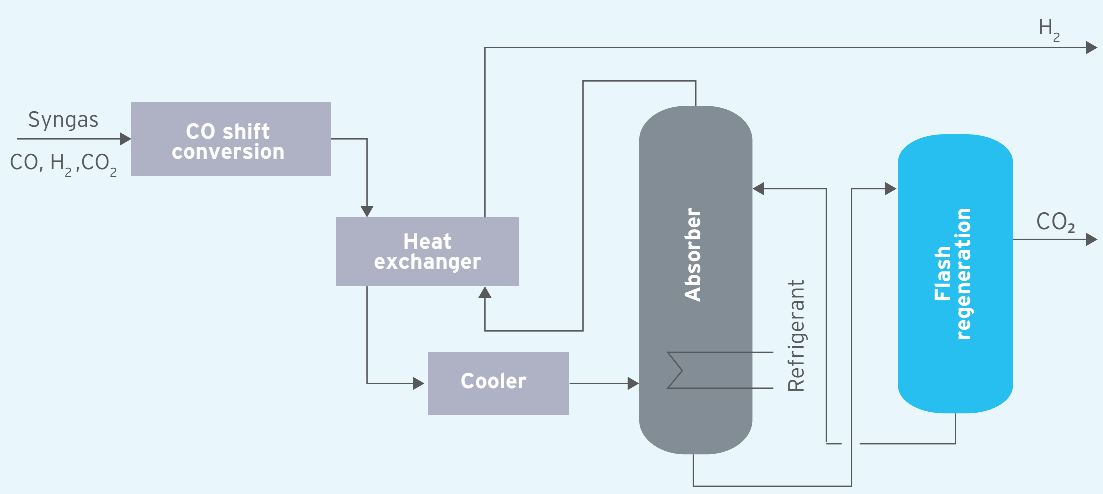
Sl. No.	Technology Supplier	Solvent	Special Features	TRL
1	Air Liquide	Proprietary blends of amines (primary/secondary/tertiary/hindered) and activators (heterocycles, primary or secondary alkanolamines, alkylenediamines or polyamines) having higher stability than MEA	Low energy requirement of 2.5 to 2.6 GJ/t CO_2	9
2	ION Clean Energy	Proprietary ICE-21 solvent which is an amine with an organic solvent; low water content	Low energy requirement of 2.5 to 2.6 GJ/t CO_2	6
3	Kansai Mitsubishi	KM CDR KS-21TM solvent having proprietary composition: sterically hindered amine, low volatility,	Capture with 99.9% purity	5 – 6

Sl. No.	Technology Supplier	Solvent	Special Features	TRL
4	Carbon Clean Solutions	Proprietary solvent CDRMax®	Lowers solvent degradation and solvent emissions	8
5	Honeywell UOP	Several types of proprietary solvents viz. Amine Guard™ FS, Benfield™ and SeparALL™. Amine Guard is the most popular.	High thermal and chemical stability	9
6	Baker Hughes	An ammonia-based solvent; ammonium carbonate solution	High pressure stripping possible	7

Physical Solvent-Based Absorption Process

The major difference between chemical solvent-based capture and physical solvent-based capture is that the latter is favoured in cases where the gas stream has a high partial pressure of CO_2 , such as in gasification, sour gas processing or syngas from SMRs. There is no chemical reaction involved, and the capture process is guided purely by physisorption. Since no chemical bonds need to be broken for solvent regeneration, the thermal energy penalty is much lower. The regeneration of the physical solvent is achieved mainly by reducing pressure. However, the operating temperatures of physical solvent-based capture processes are much lower (ranging from -70 °C to +20°C) compared to chemisorption based capture, thus necessitating high power consumption. The typical process flow diagram is depicted in Figure 4-7 below.

Figure 4-7: Basic Process Flow Diagram of the Physical Solvent Based Absorption Process



The two major commercially available physical absorption-based technologies are Rectisol® (offered by Linde and Air Liquide) and Selexol™ (offered by Honeywell UOP). In the Rectisol® process, the physical solvent used for CO_2 absorption is chilled methanol (at sub-zero temperatures), whereas the Selexol™ process uses a mixture of dimethyl ether of polyethylene glycols (DEPG). The regenerated solvent is recycled and reused in the absorption unit.

4.4.2 Adsorption Process

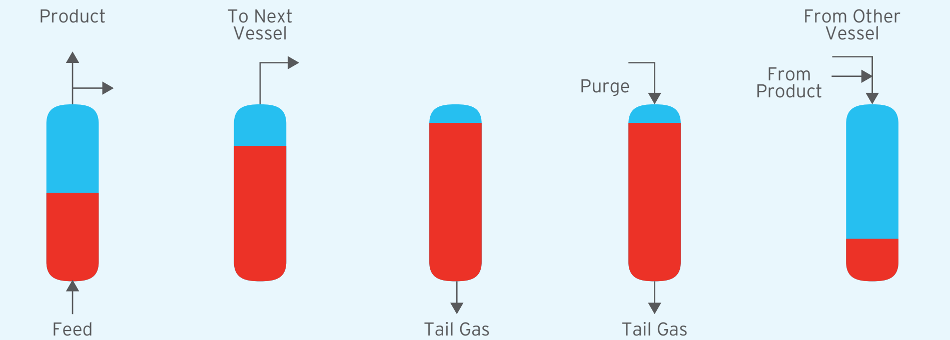
In the adsorption-based CO_2 capture process, the CO_2 molecules selectively adhere to the surface of the adsorbent material and form a film. This is possible because of the difference in diffusivities and heat of adsorption values for the feed gas stream components. The working principle of adsorption-based CO_2 capture can be described in three primary steps:

- CO_2 adsorption on the surface of the adsorbent material
- Diffusion of other gaseous molecules through the adsorbent material and exit from the system
- CO_2 desorption by either decreasing pressure or increasing temperature. While the former is known as Pressure Swing Adsorption (PSA), the latter is called Temperature Swing Adsorption (TSA).

TSA operations involve high temperatures, which may lead to the degradation of the desired products and reduce the life of the adsorbent material. In the PSA route, there is no need for heating/cooling and hence the cycle time is significantly reduced to the order of a few minutes. Hence, adsorption through the PSA route is the preferred choice, allowing the economical removal of a large number of impurities. The typical process flow of the PSA technology is depicted in Figure 4-8.

The PSA route comprises timed cycles of adsorption, pressure equalization, depressurization, blowdown, purge and re-pressurization across multiple fixed beds. These beds consist of different types of adsorbent materials, such as activated alumina, silica gel, activated carbon or molecular sieves. Air Products and Honeywell UOP both offer the PSA carbon capture technology.

Figure 4-8: Five-step Pressure-swing Cycle of UOP's Polybed™ PSA System



Step 1: Adsorption	Step 2: Co-current depressurization	Step 3: Counter current depressurization	Step 4: Purge	Step 5: Re-pressurization

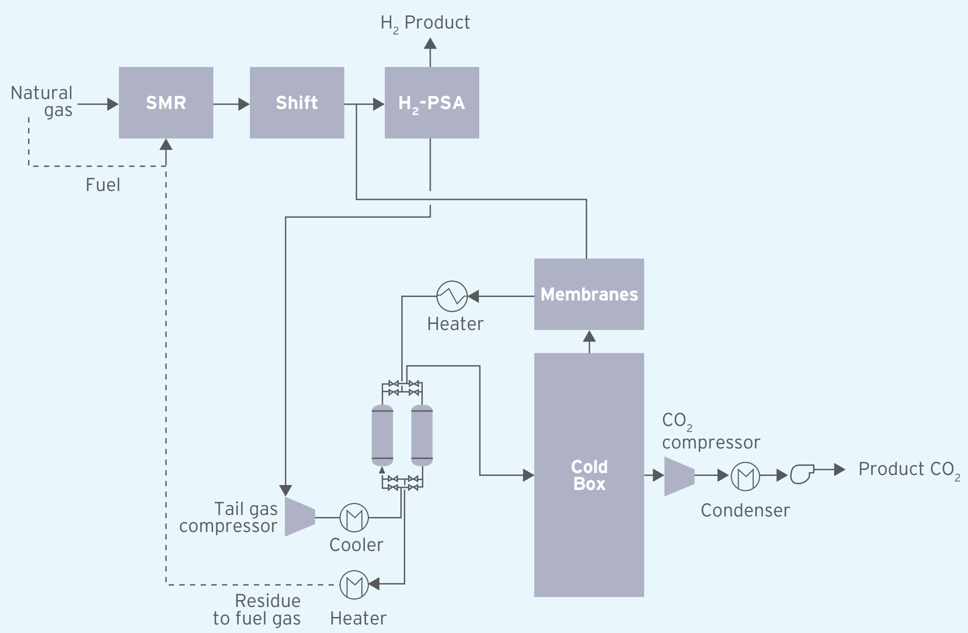
Red: impurity | **Blue:** product

Source: UOP

4.4.3 Cryogenic Separation Process

Cryogenic separation for CO_2 capture is similar to the conventional distillation process, except that it involves the separation of components from a gaseous mixture (instead of liquid) based on the difference in their boiling points. A simple schematic illustration (based on the cryogenic capture technology offered by Air Liquide) is provided in Figure 4-9.

Figure 4-9: Process Flow Diagram of the Cryogenic Separation by Air Liquide (Cryocap™ H_2 Technology)



Source: Air Liquide Technology Handbook 2018

The first step of the process is to compress and dehydrate the feed gas. The feed gas is compressed to about 10 bar(a) and cooled with chilled water before drying to reduce the size of the dehydration unit. There are two parallelly placed dryers – one operates in an adsorption mode and the other in a regeneration mode. The dry gas from the regeneration gas separator is rich in CO and CH_4 and is transferred back to the SMR. After drying and purification, the gas is again compressed to about 40 bar(a) pressure before entering the cold box.

The cold box section aims to separate CO_2 from the remaining components. The gas is cooled down in the main heat exchanger to perform the first separation after partial condensation. The vapor phase of the 1st separator is then sent back to the main heat exchanger and then to the membrane skid for further processing. The liquid phase from the first separator containing the majority of CO_2 is sent to a distillation column to purify the CO_2 from the remaining CH_4 and CO. The first membrane system aims at separating the bulk of the hydrogen from the rest of the components.

The hydrogen-rich stream is recycled back to the SMR. The second membrane system will allow the recovery of a rich CO_2 stream. This stream is recycled to the feed compressor. The remaining stream, rich in CO and CH_4, is regenerated in the dryers before sending to the SMR. The final CO_2 compression aims to achieve the required pressure for CO_2 based on the downstream product CO_2 requirements and specifications.

Due to the extreme operating conditions of high pressure and low temperature, it is an energy-intensive process. The energy consumption can range from 600-660 kWh/tonne of CO_2 recovered in liquid form. Both Air Liquide and Honeywell UOP offer the cryogenic carbon capture technology with different names.

4.5 Comparative Analysis of Various Commercial Scale CO_2 Capture Technologies

Table 4-2: Comparative Analysis of Various Commercial Scale CO_2 Capture Technologies

Process	Working Principle	Advantages	Limitations	Examples
Chemical Solvent	• Chemical reaction between CO_2 and solvent • Governed by rate kinetics & thermodynamics	• High absorption at a low partial pressure of CO_2 • Selective capture and high purity CO_2 product	High energy (steam) required for solvent regeneration	• BASF / OASE® • ICE-21, ICE- 31 • KS-1™, KS-21TM • UCARSOL™ • CAP
Physical Solvent	• Absorption due to CO_2 solubility in the solvent • Governed by Henry's Law	• Suitable for gas streams with a high partial pressure of CO_2 • Regeneration through low temperature flashing or pressure reduction • High absorption capacity & lower solvent recirculation rates	• Low energy efficiency for low partial pressure of CO_2 • High compression requirement for low pressure feed gas • H_2S is often absorbed more effectively than CO_2	• Rectisol™ • Selexol™
Adsorption	• Selective adsorption due to difference in diffusivity & heat of adsorption • Governed by pressure change	• Selective capture • Can be performed at normal temperatures	• Batch process • Complex pressure balancing management system • High electrical energy consumption	• PSA • VSA • TSA

Process	Working Principle	Advantages	Limitations	Examples
Cryogenic Separation	• Low-temperature separation through liquefaction • Governed by temperature change	• Selective capture • Generates high purity CO_2 • Liquefied CO_2 product can be used for F&B grade CO_2 • Almost no steam consumption • Low area footprint	• High energy requirement • High operating pressure	• Cryocap™ • Ortloff Dual Refrigerant CO_2 Fractionation (DRCF)

Summary of the CO_2 capture technology types and applicability

i) **Chemical solvent-based CO_2 capture technologies:** preferred when dealing with gas streams that are lean in CO_2 and have relatively lower pressures, such as flue gases. The cost and availability of steam are key factors, as regenerating the solvent requires large quantities of steam.

ii) **Physical solvent-based CO_2 capture technologies:** these work well on gas streams with relatively higher CO_2 concentration and pressure.

iii) **Adsorption-based CO_2 capture:** they are suitable for pre-combustion capture, where the gas stream has high pressure and a high CO_2 concentration.

iv) **Cryogenic CO_2 capture:** preferred in cases where the cost of power is low. This technology also provides a unique advantage by generating additional hydrogen without increasing the amount of feedstock (natural gas)/ producing the same quantity of hydrogen with lower natural gas consumption.

The applicability of the various CO_2 capture technologies viz., physical solvent, chemical solvent, adsorption and cryogenic, also depends on the project objectives and gas stream characteristics, including:

- CO_2 capture volumes targeted/desired
- CO_2 end usages and CO_2 purity required
- Source gas characteristics (CO_2 concentration, pressure and volumes)
- Availability and cost of utilities such as steam, power, water, fuel, etc.
- Plot availability and space constraints

4.6 Relative Cost Economics of Commercially Proven Carbon Capture Technologies

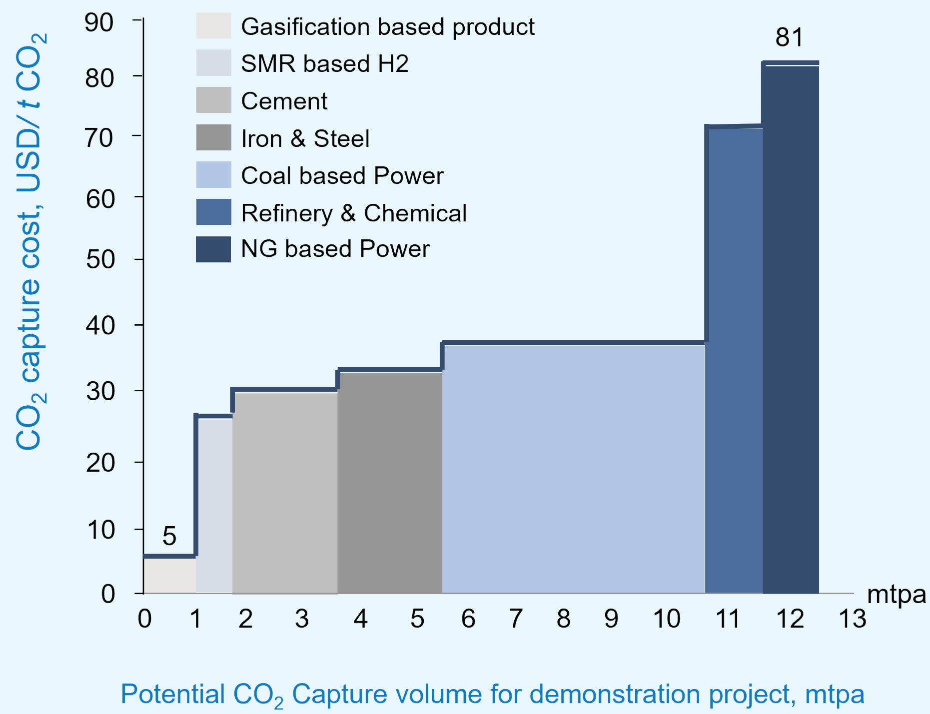
The capital costs and cash costs of different carbon capture technologies depend on the CO_2 source characteristics, i.e. pressure & CO_2 concentration, which mainly determine the carbon capture technology choice. Other key factors are the power & steam sourcing costs. Figure 4-10 provides a relative cost curve for carbon capture projects in the different target sectors, considering a typical reference plant size in each sector. CO_2 delivery from the plant gate has been assumed at 100 bar (a). The key assumptions are provided in Table 4-3.

Table 4-3: Key Assumptions for the Relative Cost Curve of Different Carbon Capture Technologies

Target Sector	CO_2 Stream Source	CO_2 stream specifications	Envisaged Capture Technology	Ref. CCU capacity (mtpa)
Gasification of solid fuels	Gasification/Water gas shift reactor outlet	25-40% CO_2 conc. & 20-50 bar (a)	Physical solvent	1 mtpa
SMR based H_2 production	Tail gas from PSA/ Flue gas	~66%/20% CO_2 conc. & near atm. pressure	Cryogenic/ PSA + Cryogenic hybrid	0.7 - 1.0 mtpa
Refinery and chemicals	Water-gas shift reactor outlet	~35%+ CO_2 conc. & 20-30 bar (a)	Physical solvent	2 mtpa
Cement	Flue gas	15-20% CO_2 conc. & near atm. pressure	Amine/ PSA & Cryogenic hybrid	2 mtpa
Iron and steel	BF gas + flue gas from sinter plant/BF stoves + CPP	~20% CO_2 conc. & near atm. pressure	Amine/ PSA & Cryogenic hybrid + Amine	1 mtpa
Coal-based power	Flue gas	7-20% CO_2 conc. & near atm. pressure	Amine	5 mtpa
Natural gas-based power	Flue gas	3-5% CO_2 conc. & near atm. pressure	Amine	0.7 mtpa

CO_2 capture cost is the lowest for the gasification process, as carbon capture is already integrated within the plant design. So, only an incremental additional cost is required for the purification and compression of the CO_2 stream. The capture costs for other production processes like SMR-based H_2 production, iron & steel, cement, power etc., include the costs for gas processing, carbon capture, and compression and are hence higher. The cost of capture will be lower where steam can be sourced from a coal-based boiler. But, the cost of capture for "refinery & chemical" and "NG based power" is significantly higher due to NG based steam production. Additionally, CO_2 concentration is the lowest for natural gas-based power plants, which makes the capture cost the highest out of all major industries.

Figure 4-10: Cost Curve for CO_2 Capture Across Processes/Industries



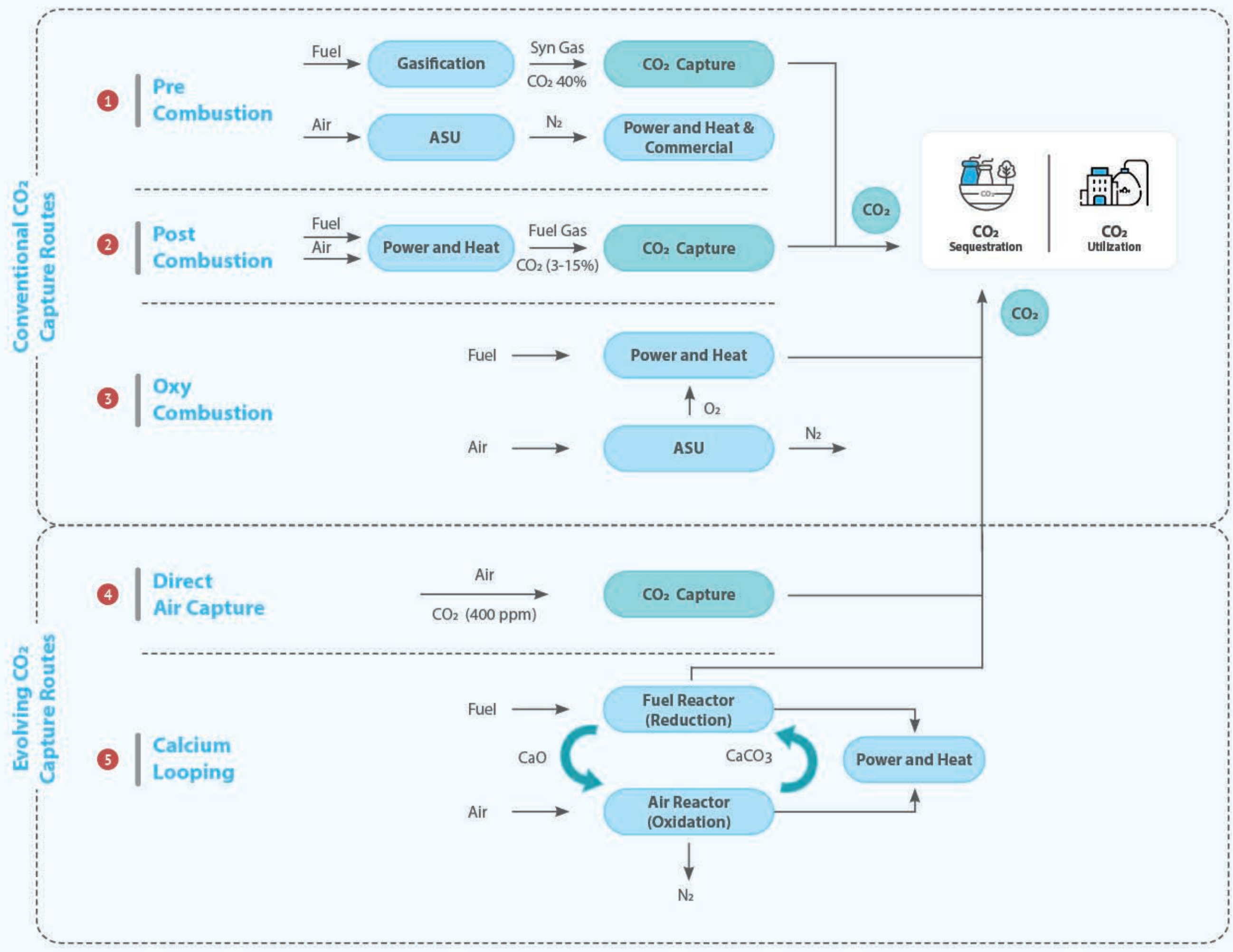
Source: Dastur Analysis

4.7 Evolving CO_2 Capture Technologies

Carbon capture technologies and projects have been operating commercially since the 1970s. The commercially established capture technologies have significant steam and power duties, leading to significant regeneration energy requirements and secondary emissions. Thus there is ample opportunity for further research and development of newer carbon capture technologies and even deploying a hybrid of traditional and emerging methods of carbon capture. The evolving carbon capture technologies have challenges with respect to selectivity, absorbing capacity, energy, new material development, demonstrability and scalability, but they still offer significant potential with respect to their decarbonization impact.

CO_2 capture technologies differ widely; apart from pre-combustion and post-combustion based technologies, there exists the potential to use ionic liquids for carbon capture from power plants and industrial facilities while enhancing the CO_2 capture ability and reducing the carbon capture costs & energy requirements. The various types/routes of CO_2 capture are provided in Figure 4-10 and discussed below. The most promising newer/evolving carbon capture technologies are DAC and calcium looping.

Figure 4-11: Various Carbon Capture Routes



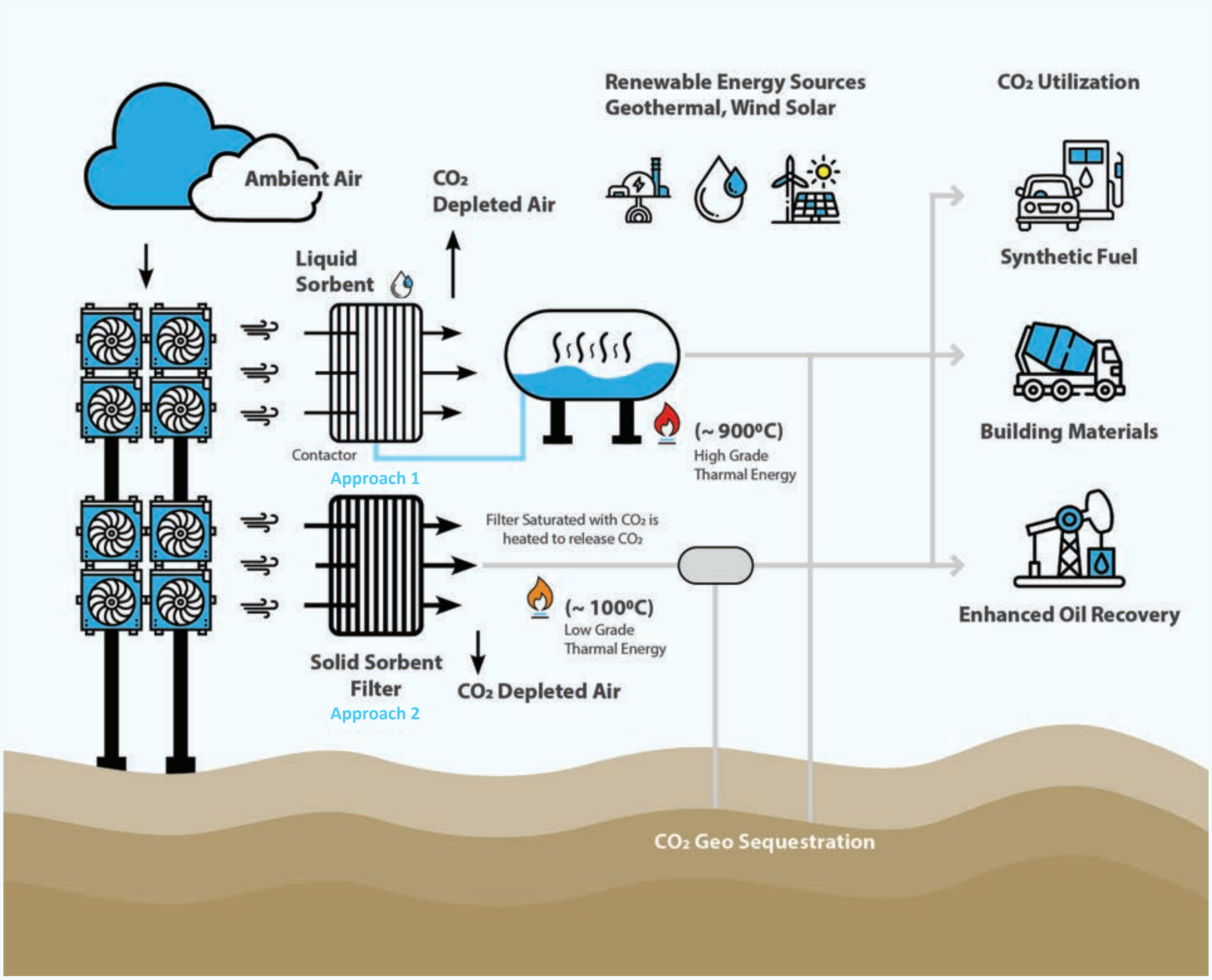
4.7.1 Direct Air Capture

Over 175 nations of the world are signatories of the Paris Climate Agreement, which calls for formulating strategies for deep decarbonization and long-term net zero targets. Against this backdrop, Carbon Dioxide Removal (CDR) from the atmosphere is likely to play a major role as a component of global climate strategies. CDR refers to a range of approaches for the removal of CO_2 from the atmosphere using biological, engineered or hybrid approaches. CDR can play an important role in climate change mitigation and thus supplement existing carbon capture technologies, which reduce and prevent emissions of carbon dioxide from source points.

CO_2 removal from the atmosphere can be done using chemicals, refrigeration or membranes. These approaches are similar to industrial applications such as air separation units for producing oxygen and CO_2 as a by-product for the food & beverage industry or atmospheric CO_2 scrubbers which are used in submarines and spaceships.

Direct Air Capture (DAC) can play a vital role in emission reduction using decentralized mobile units for capturing low-concentration CO_2 from the atmosphere. DAC needs a large flow of air and hence requires significant mechanical and thermal energy for the air to pass through the capture system and the separation of CO_2 from the capture medium, making the DAC process very energy and cost intensive. Figure 4-11 shows two technological approaches: (a) passing air through solutions (hydroxide solution /amine /amino acid) and (b) use of solid sorbent filters to reduce the cost.

Figure 4-12: Basic Technical Schematic of Direct Air Capture Technology



The minimum energy required for capturing CO_2 from the atmospheric air at 400 ppm has been reported as 19-22 kJ/mol CO_2, which is almost 4 times than the energy requirements of the post combustion process containing 10-15% CO_2 concentration in the flue gas of a coal-fired power plant (4.6-5.6 kJ/molCO_2). DAC is distinct from "point-source" carbon capture technologies because it removes CO_2 from ambient air, not from the flue gases, through physical or chemical separation processes. There are three categories of approaches towards the separation of CO_2 from the air.

Table 4-4: Various DAC Approaches

Sl. No.	Approach of Separation	Description
1	Chemical	In this category of separation, CO_2 in the air reacts with liquid solvents or solid sorbents, temporarily binding to them. The solvent or sorbent is then heated or subjected to a vacuum, releasing the CO_2 for further concentration. This approach is similar to point-source carbon capture systems that remove CO_2 from flue gas. The solvents/sorbents used are aqueous hydroxides, solid-supported amines and solid alkali carbonates etc.
2	Membranes	CO_2 can be separated from air and seawater using membranes, including ionic exchange and reverse osmosis membranes. This mimics the way plants and animals separate CO_2.
3	Cryogenic	CO_2 has a relatively high freezing temperature among gases, and can be frozen out of the air. Currently, CO_2 is recovered from the air by freezing it as a by-product of cryogenic oxygen separation.

Most companies developing DAC projects prefer the chemical approach, using either liquid solvents or solid sorbents, as the heat and power required to regenerate the key chemical reagents are easier to handle and manage. Hence mainstream DAC technologies are based on reversible chemical sorbents that can be recycled multiple times to capture and release CO_2. This process tends to degrade the material, reducing CO_2 capture capacity and making its replacement necessary from time to time. The choice of the appropriate chemical materials is an important part of DAC system design since it determines the overall system design.

There is also ongoing research in the development of various physio-sorbent materials, such as zeolites and metal-organic frameworks (MOFs), which typically bind CO_2 much more weakly than chemical sorbents. So far, the experimental results are not very encouraging as they perform inefficiently at the very low CO_2 concentrations of ambient air and are also inhibited by the presence of atmospheric moisture. Therefore, no company or developmental group has yet used these physio-sorbent materials as primary capture materials for any DAC project. The major design challenges for the efficient and economical operation of DAC plants and possible suggested mechanisms to address the same are summarized in Table 4-5.

Table 4-5: Design & Operational Issues of DAC Plants

Sl. No.	Design and Operational Issues	Possible Suggested Solutions
1	Minimize exhaustion of sorbent-liquid/solid materials while being regenerated, releasing the adsorbed CO_2 .	Use of a combinational process of Temperature-Swing Adsorption (TSA) [heating the sorbent material, whether solid or liquid], Moisture-Swing Adsorption (MSA) [by changing the amount of ambient moisture/humidity] and Pressure-Swing Adsorption (PSA) [changing the ambient pressure of the air], depending on the properties of the sorbent material.
2	Maximization of the area & contact timing of air with the sorbent	Better design of the air contactor to handle both large volumes of air throughput and also the flow of a liquid sorbent or the structural support of a solid sorbent, considering the structural materials, geometric design, pressure drop and other features.
3	Minimization of the thermal and electrical energy requirement for regeneration of sorbent and pushing air through the system	Usage of waste heat and renewable energy to compensate for the thermal and electrical energy load. Use blended sorbents to achieve the desired level of thermal performance.

There are presently 19 DAC plants operating worldwide, cumulatively capturing about 0.01 mtpa CO_2. DAC plants are still in their infancy and are very expensive. The key improvement areas for DAC technologies to drive down costs to below US$ 100 per tonne of CO_2 are improvement in contactor, sorbent and regeneration. The current DAC costs are about 2X to 6X times the desired levels, and depends largely on the source of energy being used.

Table 4-6: DAC Plants Worldwide

SL No.	Name Of Company	Location	Plant Type/Status	CO_2 Removal Capacity (Metric tonne/ yr)	Date of Operation	Type Of Solvent/Sorbent	Source Of Thermal Energy	Utilization of Captured CO2
1	**Carbon Engineering**	Squamish, British Columbia (Canada)	Pilot plant/ Operational	350	2015	Liquid Solvent	Natural Gas	Carbon natural fuel
		Squamish, British Columbia (Canada)	Innovation center/ Under construction	1,500	2022			CO_2 capture and storage for shopify and vergin
		Permian basin, Texas (USA)	Commercial plant/ Under construction	1,000,000	Mid-2020s			Enhanced oil recovery and carbon sequestration
2	**Climeworks**	Across Europe	14 Pilot & Commercial Plants/ Operational	2,0000	2015	Solid Sorbent + Contactor	Geothermal, Waste heat etc.	Renewable fuels, food, brevrages, and agriculture
		Kanton Zurich (Switzerland)	Pilot plant/ Operational	900	2017		Waste Incineration	Greenhouse
		Hellisheidi (Iceland)	1 Commercial plant/ Operational	4,000	2021-2022		Geotharmal	CDR services-Microsoft, Shopify, Audi & Storage by mineralization

SL No.	Name Of Company	Location	Plant Type/Status	CO_2 Removal Capacity (Metric tonne/ yr)	Date of Operation	Type Of Solvent/Sorbent	Source Of Thermal Energy	Utilization of Captured CO2
3	**Global Thaemostat**	Menlo Park, California (USA)	Pilot plant (DAC + Flue)/ Non-operating	10,0000	2013	Direct CO_2 Capture From Air	Residual heat from industry	Not for commercial use
		Huntsville, Alabama (USA)	Pilot plant/ Non-operating	4,000	2019			Not for commercial use
		Magallanes (Chile)	Pilot plant/planning	250kg/h	2022		Wind power	Synthetic gasoline
		Sapulpa, Oklahoma (USA)	2 commercial plants / Under construction	2,000/plant	2021		Natural gas	CO_2 based fuel, CO_2 as industrial gas
4	**Infinitree**	New York (USA)	Pilot Plant/Operating	100	2014-2018	Ion exchange sorbent material	Humidity Swing mechanism	Greenhouse application
5	**Mechanical Tree**	Arizona (USA)	Prototype/ Under construction	30 tons from a single tree	2022-2023	Moisture driven CO_2 sorbents	None, passive DAC	Agriculture, CO_2 based fuel, building materials, sequestration
		Global	Commercial Farms/Planning	4 million/farm	Second half of 2020s			

The key strengths and advantages of DAC technologies vis-à-vis other CDR approaches are as follows:

a) The cumulative removal potential of DAC is very large in relation to other CDR pathways. The CO_2 removal can be permanent when coupled with geological storage or mineralization.

b) Water requirements for DAC are far lower than other pathways that harness bioenergy crops for carbon removal.

c) High annual rates of CO_2 removal by DAC could be sustained for centuries at the global level, based on the CO_2 storage capacity of geological reservoirs that can serve as sinks for the captured CO_2 .

d) DAC has no direct impacts on nutrient cycling and requires no application of additional nutrients (such as nitrogen or phosphorous fertilizers) in contrast to biomass crop based pathways, ocean fertilization and enhanced weathering.

The key challenges of DAC are as follows:

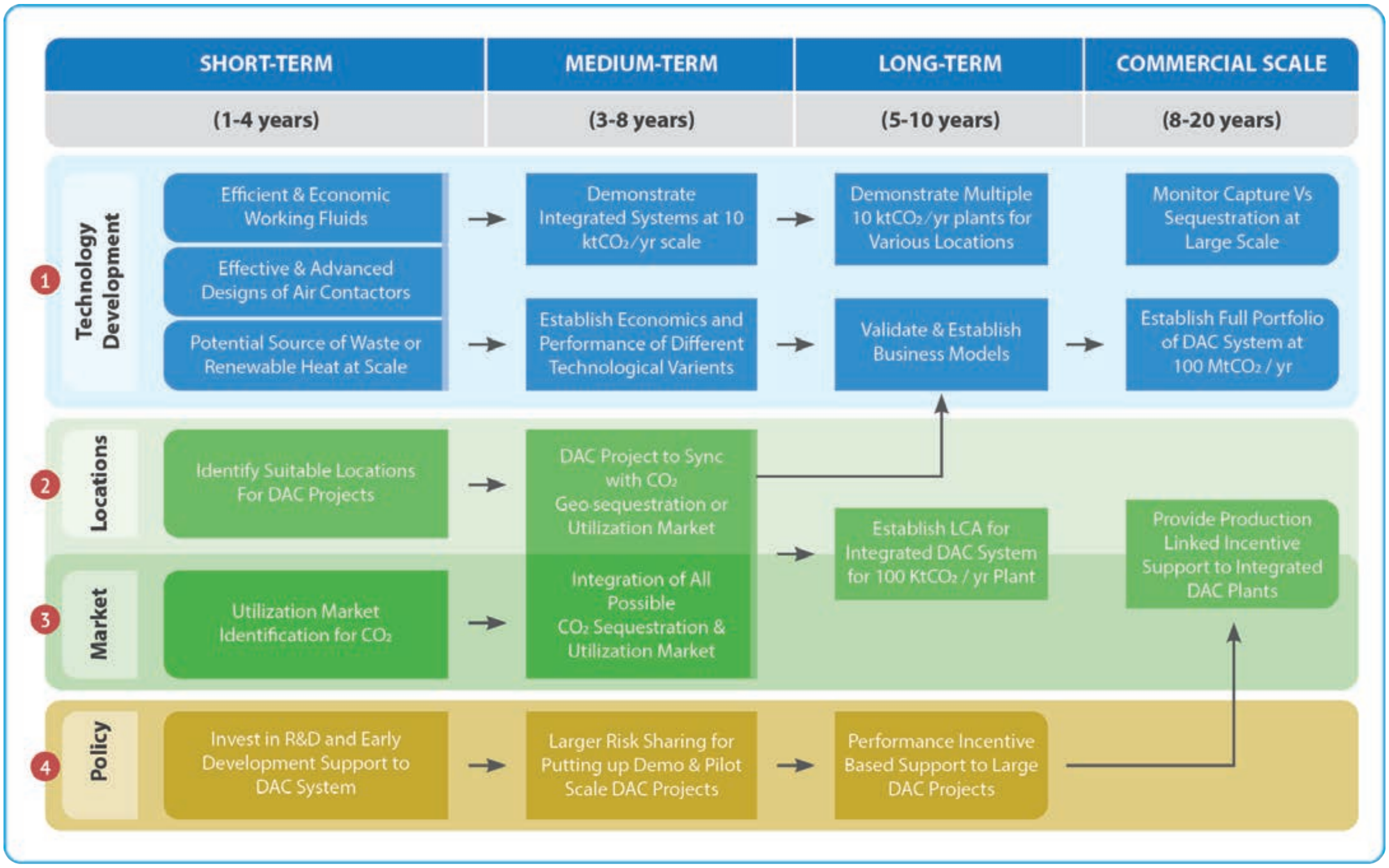
a) DAC is more expensive than other CDR options. The reported cost of DAC ranges from US$ 300-600/tonne of CO_2, with a predictive estimation that the costs will go down to US$ 100/tonne of CO_2 in the future, which is higher than the average carbon market prices. Thus DAC needs strong policy support for the developmental roadmap towards deployment and scaling up. The high costs of DAC are due to CO_2 being much more dilute in the atmosphere (0.04%) vis-à-vis industrial sources such as power plant flue gases (5% in NG based power plants and 12% in coal based power plants). As a result, the theoretical minimum energy needed to separate CO_2 from air is approximately three times higher than flue gas from industrial sources. This is one of the strongest challenges for DAC to be competitive vis-à-vis industrial scale carbon capture from sources such as flue gases.

b) Other CDR pathways provide concomitant benefits such as improving biodiversity and agricultural practices. DAC does not provide any such co-benefits, although DAC could be incorporated into a system where DAC provides CO_2 as a feedstock for downstream CO_2 utilization.

c) DAC requires a large quantum of energy per tonne of CO_2 removed and hence requires cheaper and larger waste-based or renewable sources of energy to make it competitive or at par with the other CDR approaches.

DAC technology needs to simultaneously achieve much lower total costs (both capital and operating costs) and higher net (lifecycle) CO_2 removal. It is important to understand, explore and therefore formulate the possible "Technology & Developmental Pathway for DAC" (Figure 4-13) to achieve these goals and make DAC a mainstream and scalable CDR solution.

Figure 4-13: Technology & Developmental Pathway for DAC



4.7.2 Calcium Looping

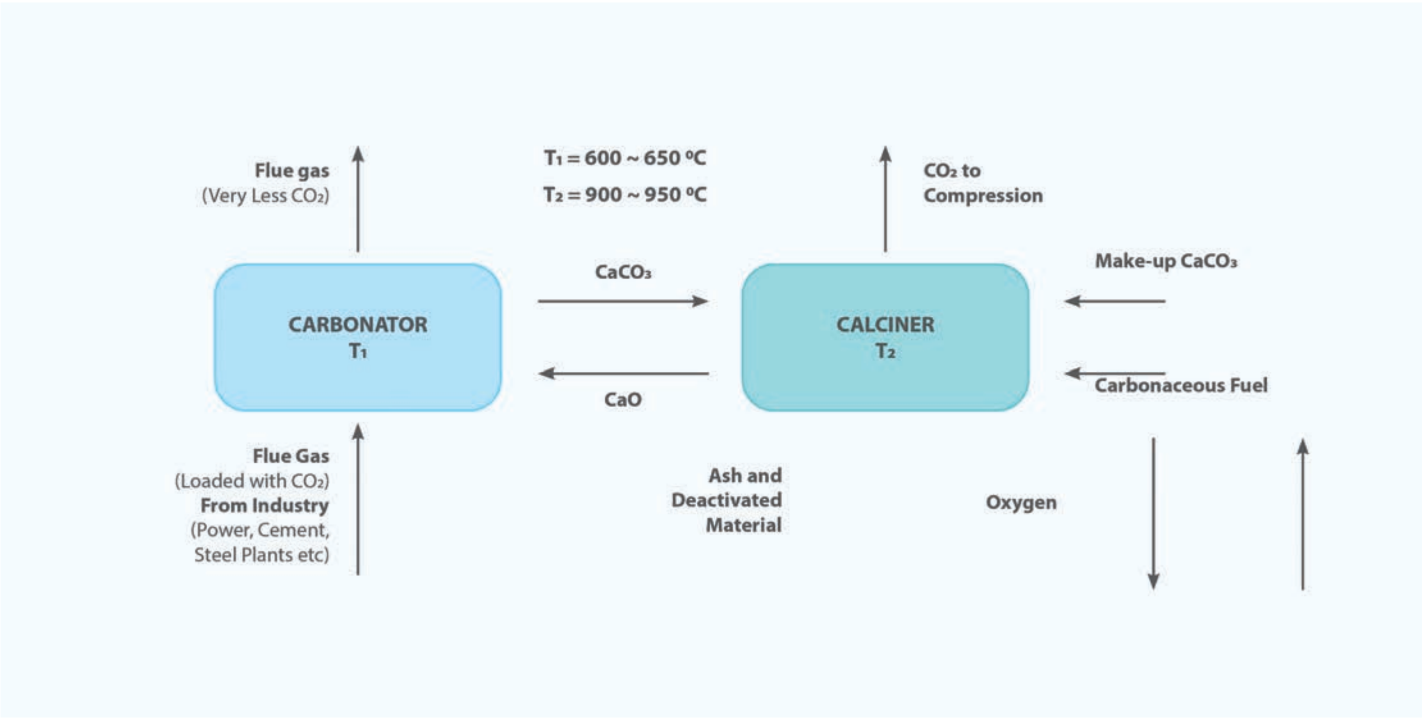
Calcium Looping (CaL) capture can either be classified as a pre-combustion method or as an alternative to the emerging early-stage oxyfuel combustion technology. The CaL process is based on the multicyclic calcination–carbonation of $CaCO_3$, which can be obtained from limestone, a cheap and abundantly available material. The key reactions are:

Calciner Reaction:
$CaCO_3 \rightarrow CaO + CO_2$ Delta H = 182.1 kJ/mol (1)

Carbonator Reaction:
$CaO + CO_2 \rightarrow CaCO_3$ Delta H = -182.1 kJ/mol (2)

The CaL process was first introduced in the 19th century in the context of sorption-enhanced hydrogen production. However, the first instance of using the CaL process as a carbon capture scheme in power generation systems was introduced by Shimizu, who proposed two interconnected circulating fluidized bed (CFB) reactors for the carbonation and calcination reactions (Figure 4-14).

Figure 4-14: Basic Schematic of Calcination and Carbonation Reaction in Calcium Looping



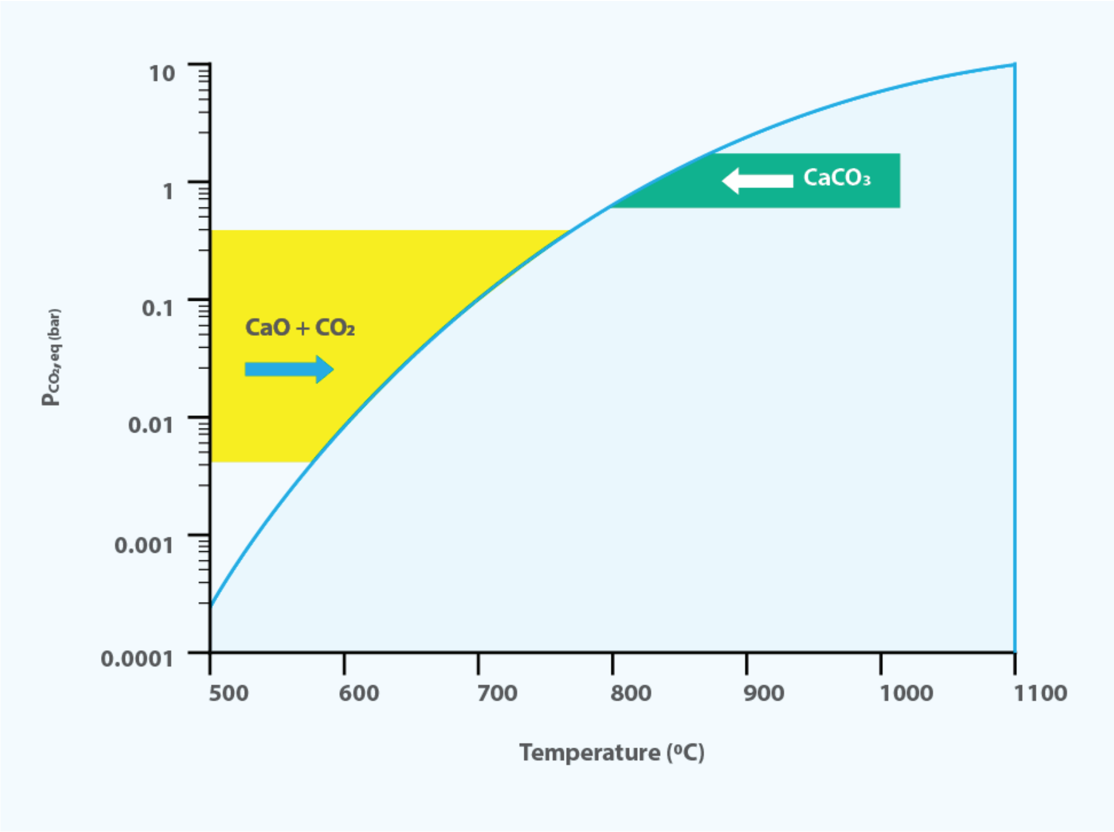
The CaL process is based on the reversible gas-solid reaction between calcium oxide and carbon dioxide to form calcium carbonate. The carbonation reaction involves the reaction of sorbents with CO_2 in the flue gas.

The typical CO_2 concentration varies in the range of 3–30 vol.% depending on the flue gas source. The forward reaction occurs in the carbonator exothermically at a temperature range of 600 - 700 ºC, at which the equilibrium CO_2 partial pressure is below 0.001 bar, such that most of the CO_2 in the gas stream can be captured by the sorbent. Then, the sorbent is regenerated by the reverse endothermic reaction, which includes the decomposition of calcium carbonate. Noting that the goal of the CaL process is to produce a pure stream of CO_2 , the calciner must be purged with either pure CO_2 or the CO_2 has to be diluted with steam, which can be readily separated by condensation. With these restrictions, thermodynamic limitations require the calciner reactor to be operated above 900 ºC, which is the equilibrium temperature of equation (2) at a CO_2 partial pressure of about 1 bar. Calcination can be achieved at a temperature lower than 900 ºC, provided that the purge gas is diluted with steam.

Figure 4-15 shows the carbonation and calcination operating conditions regions according to the thermodynamic equilibrium of the reaction (1) and (2). The high-operating temperature of the calciner usually requires oxyfuel combustion in the calciner, which necessitates an air separation unit (ASU). However, the size of the ASU for this process is estimated to be one-third of the size of the ASU required for an oxyfuel fired power plant. Moreover, the energy penalty of the ASU is partially recuperated by the recovery of the high-grade heat available in the CaL process.

Unlike amine scrubbing systems, the flue gas is not required to be pre-cooled since the CaL operates at high temperatures. The high-grade heat available from the hot CaO and CO_2 streams, as well as the heat from the exothermic carbonation reaction can be used to generate additional steam, owing to their high temperature. As a result, the efficiency penalty of the CaL process (6%–8%) is lower than that of traditional amine scrubbing systems (9.5%–12.5%).

Figure 4-15: Equilibrium of CO_2 Partial Pressure vs. Temperature in Calcium Looping Reaction



The techno-economic aspects of the CaL process have been reviewed by several researchers, and it is reported that CaL offers significant advantages over conventional amine processes with respect to the cost per tonne of CO_2 captured - less than US$ 20 per tonne CO_2 for CaL, compared with approximately US$ 30 per tonne CO_2 for amine-based processes. The CO_2 capture process accounts for 2%–3% of the efficiency penalty, which is comparable to the penalty of a desulphurization unit (0.5%–4%).

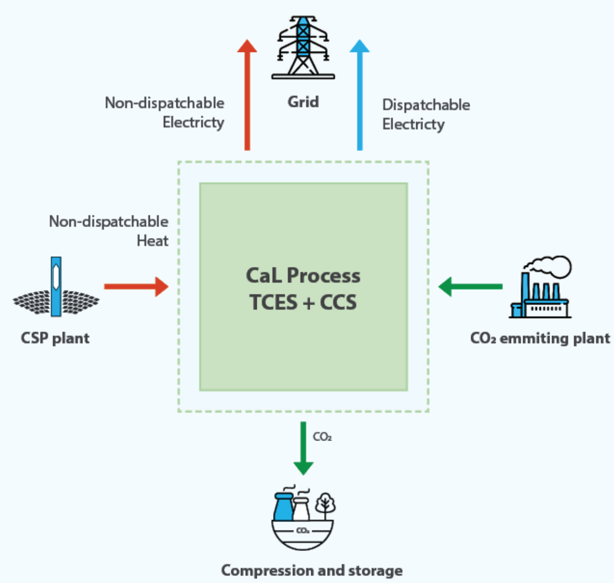
The kinetics of the carbonation reaction and the non-catalytic gas–solid heterogeneous reactions play a significant role in various industrial applications, including lime sulphation, desulphurization of waste gas, and chemical-looping combustion. Moreover, the CaO + CO_2 carbonation reaction has gained attention for the CaL process. It is well-accepted that the carbonation reaction is initially rapid and kinetically controlled, followed by a considerably slower diffusion-controlled stage.

During the two stages of the carbonation reaction, the kinetically controlled stage, which prevails during the first minute of the reaction, the free surface of CaO is available with which the CO_2 can react. In this initial stage, the reaction rate is fast since there is no diffusion resistance and the reaction is only limited by the reaction kinetics. As the reaction evolves, diffusion takes over as the limiting factor due to the formation of a product layer of $CaCO_3$ on the surface of CaO. The product layer restricts access of CO_2 to the surface of CaO, inhibiting the complete conversion of the CaO sorbent.

The cyclic carbonation-calcination of $CaCO_3$ in fluidized bed reactors not only offers a possibility for CO_2 capture but can at the same time, be implemented for Thermochemical Energy Storage (TCES), a feature which will play an important role in the future, due to the increasing share of non-dispatchable variable electricity generation (e.g., from wind and solar power). The CaL process is considered both a Carbon Capture Technology (CCT) and a Thermo-chemical Energy Storage (TCES) technology, as well as an integrated dual use system in energy transitions.

For CO_2 capture, it has been industrially experimented and established that the CaL process represents a competitive capture technology in terms of both efficiency and costs. If implemented as TCES, it increases the dispatchability of renewable energy facilities that are able to provide high-temperature streams, such as Concentrated Solar Power (CSP) plants or be used in any industry where surplus waste heat can be made available. Integrating both applications, the CaL process can turn Variable Renewable Energy (VRE) into dispatchable electricity while at the same time mitigating atmospheric CO_2 emissions from a nearby emitting plant. In summary, it is important to consider the economic feasibility of the CaL process at different scales when it is deployed for TCES in a concentrated solar plant (CSP) as a renewable non-dispatchable energy source combined with capture of the CO_2 from a nearby emitter (i.e., not accounting for the transportation and storage of CO_2) as depicted in Figure 4-17. Thus the CaL process can actually be deployed to make a profit from the sale of dispatchable renewable electricity and from the CO_2 capture services provided to a nearby emitting plant.

Figure 4-16: Schematic of Calcium Looping Capture for both CCS & TCES



A comparison between pre-combustion capture technologies and CaL technologies employed to capture CO_2 in gas fired plants reveals that a plant integrated with CaL technology has 2.8% higher efficiency than the pre-combustion technology. The CaL process has been found to be promising, similar to oxyfuel combustion and more cost effective due to the elimination of the air separation unit, but not suited to high CO_2 concentrations. The oxygen carriers should have high oxygen capacity, thermodynamic and kinetic stability, be environmentally friendly, have high mechanical strength, and be cost effective.

Solid sorbents have been investigated as promising materials for CO_2 mitigation. Solid sorbents of different types with a wide range of operating conditions have been developed and tested for carbon capture. Among various solid oxide sorbents, CaO based materials have emerged as promising sorbents owing to the abundance and low price of calcium sources, fast sorption kinetics, high-temperature operation, and synergy with various industrial processes such as cement. Various methods have been employed by researchers to optimize and enhance the materials and process conditions of the calcium looping process.

The high potential of the process for decarbonization of fossil fuel-intensive industries has led to significant investments in scaling-up up this technology and industrial deployment through numerous pilot-scale demonstration projects around the world. Salient details of a few prominent projects are provided in Table 4-7.

Table 4-7: Various Pilot Installations for Experimentation on Calcium Looping

Sl. No.	Name of the Facility	Capacity	Operational Hours (without stopping)	Possible Suggested Solutions
1	Industrial Technology Research Institute, Taiwan	1.9 MWth	600	The flow rate of flue gas from the cement plant was 3400 Nm^3/h with a CO_2 concentration exceeding 15 vol. %. About 15 tonne of sorbent was circulated within the system. A CO_2 capture efficiency of 85% was achieved with a capture rate of more than 1 tph.
2	Institute Nacional del Carbon, Spain	1.7 MWth	1800	La Pereda is a 50 MWe power plant, and the CaL plant was designed to treat about 1% of the flue gas from the power plant (1400 kg/hr of flue gas), corresponding to 1 MWth in the La Pereda power plant. The flue gas composition includes 12.6 vol.% CO_2 , 7.0 vol.% H_2O, 5.5 vol.% O_2, and 700 ppmv SO_2.
3	Darmstadt University of Technology, Germany	1 MWth	3900	A flue gas stream from the combustion of lignite or natural gas containing approximately 9.5 vol.% of CO_2 was supplied to the CaL system for decarbonization. Experimental campaigns adding up to 230 hours of operation in the interconnected CFB mode with firing SRF in the calciner were carried out.
4	University of Stuttgart, Germany	200 KWth	600	The CFB calciner operated in a fast fluidization regime, while the CFB carbonator was able to operate under both turbulent and fast-fluidization regimes. The calciner can operate in both air-blown and oxyfuel modes.

Calcium looping offers significant advantages over conventional post-combustion capture technologies such as amine scrubbing processes. Due to high temperature cyclical operations, the stability and uptake capacity of the CaO-based sorbents decreases, leading to a major hurdle for the large-scale deployment of this technology. In order to overcome these inherent challenges, a two pronged industrial research & developmental strategies may be adopted:

a) Production of synthetic sorbents with enhanced stability and CO_2 uptake capacity for better performance of the materials for cyclical operations. Use of the most efficient techniques eg., flame spray pyrolysis and combustion synthesis for the production of fine particles with high-surface area and porosity, resulting in improved sorbent performance.

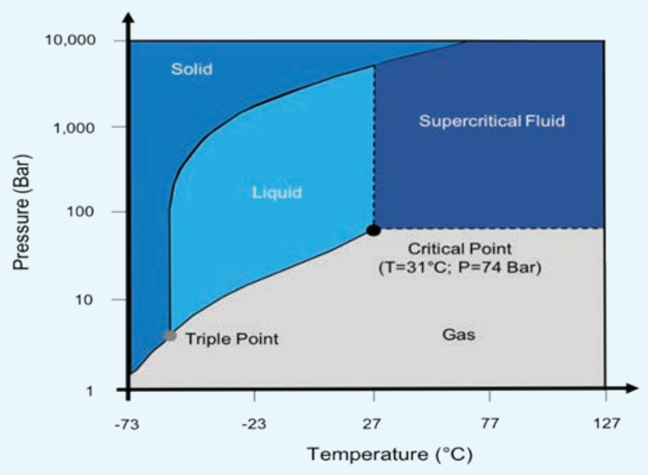
b) Incorporation of inert metals in the structure of the CaO-based sorbent to inhibit the sintering at high-temperature operations, resulting in improved stability over successive cycles of carbonation & calcination, and making these sorbents suitable for decarbonization of carbon-intensive industries e.g., the cement, steel, and power sectors.

4.8 CO_2 Dispatch Requirements

Once CO_2 is captured, it needs to be made ready for transportation for disposition or utilization. The quality and pressure of CO_2 requied for different disposition and utilization applications vary. For example, for utilization in the food and beverage industry, the CO_2 needs to be 99.90% pure and hence a CO_2 purification unit needs to be included in the plant configuration.

For CO_2 sequestration applications, the transportation of CO_2 over long distances is done in its supercritical form as it is the most efficient CO_2 transport mechanism. In its supercritical state, CO_2 has the density of a liquid but the viscosity of a gas. This substantially reduces the required CO_2 volume in comparison to the volume at standard temperature and pressure (STP). The supercritical point of CO_2 is achieved at temperatures greater than 31°C and pressures greater than 74 bar, as shown in Figure 4-18.

Figure 4-17: Phase Diagram of CO_2 Showing the Various Phase Stability Regions



However, there is a substantial risk involved if the operations are carried out at pressures close to the critical point. Under these circumstances, a small change in the operating temperature and pressure can lead to a very large change in the density and viscosity of CO_2 due to the formation of a two-phase (liquid/gas, supercritical fluid/gas or supercritical fluid/liquid) stream. Additionally, the fluid velocity changes, resulting in a slug flow – this negatively impacts the operational aspects as well as increases the chances of pipeline failure.

Thus, it is necessary to maintain a single-phase flow of the CO_2 stream by keeping a wide margin of safety above the rated critical pressure of 74 bar. Sometimes, the reservoir requirements necessitate keeping the CO_2 stream at pressures above 240 bar during the injection. However, accommodating for the volume flow, distance and pressure drops in trunk pipelines, usually 120-150 bar pressure at the carbon capture plant gate boundary is optimal from a design perspective.

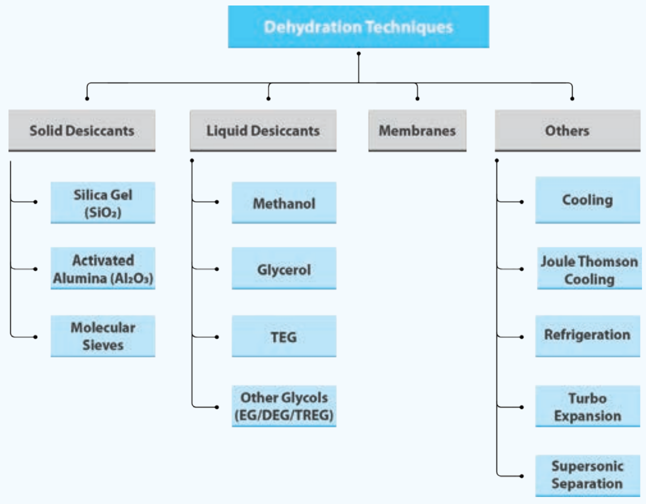
From a flexibility and scaling perspective, supercritical CO_2 is usually distributed through feeder pipelines at 120-150 bar, and the pressure is elevated to the required injection pressure at the sequestration site. The captured CO_2 gas stream needs to be compressed suitably for this purpose at the carbon capture plant end.

Before compression, dehydration of the stream is necessary for the removal of water. Water can form corrosive products such as carbonic acid and sulphuric acid in the presence of CO_2 and sulphur. These acids can corrode the pipeline and result in cracks and leaks. Also, the formation of hydrates (solid ice-like crystals) in the presence of water can cause severe blockages in the compression & dehydration units and transportation pipelines.

4.5.1 CO_2 Dehydration & Compression

Dehydration: Once the CO_2 is captured, it needs to be dehydrated and compressed to the desired pressure at which it will be transported. Under supercritical conditions, dense phase CO_2 stream exhibits retrograde water condensation behaviour, i.e., carrying more water instead of less with increasing pressure. Worldwide CO_2 transportation operations strictly practice the dehydration of the CO_2 stream to minimize its moisture content. Removal of water is necessary to prevent pipeline corrosion and higher injection costs in case of storage of CO_2. Figure 4-19 shows the different dehydration techniques for treating a wet CO_2 stream.

Figure 4-18: Different Dehydration Techniques for Treating Wet CO_2 Stream



A comparative analysis between the molecular sieve and desiccant based dehydration (TEG) is presented in Table 4-8. A lot of variances exist in the available CAPEX and OPEX data mainly because of differences in the use of regeneration techniques, construction materials, number and size of adsorption beds, the number of dehydration trains and compression equipment. While TEG requires relatively lesser absorbent and footprint area, a molecular sieve unit can reduce the moisture content to as low as 1 ppmv and result in no CO_2 loss, unlike TEG.

Table 4-8: Comparative Analysis of Molecular Sieve and Triethylene Glycol (TEG) based Dehydration Techniques.

Parameter	Molecular Sieve	TEG (Triethylene glycol)
Type of desiccant	Solid	Liquid
Life, years	2-4	3-10
Achievable moisture content	1 ppmv	150 ppmv 30 ppmv (by increasing TEG conc.)
Train size, tph of CO_2 rich gas	300-600 (for 30 bar-a & 30 °C) 100-120 (for 5 bar-a & 30 °C)	Up to 3500
Absorbent required for a 265 tph unit	Higher (48-102 t)	Lower (30 t)
Footprint area	High (big bed size for moisture adsorption)	Low (no beds)
CAPEX[1], USD / yr. / t CO_2	Variable	-
OPEX[1], USD / yr. / t CO_2	5-15	8
CAPEX[2], USD / yr. / t NG	3.5	5
OPEX[2], USD / yr. / t NG	0.6	0.8

Source: Kemper et al., 2014; EPA

Notes:

[1] For 265 tph unit processing CO_2 gas stream

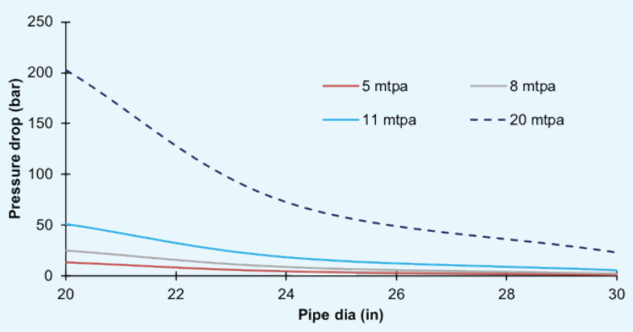
[2] For processing 1 MMCFD Natural Gas (NG) at 31 bar and 8 °C

Compression: The captured CO_2 stream needs to be compressed to facilitate its transportation in the supercritical state to the envisaged disposition location. The pressure to which the CO_2 stream has to be compressed is determined based on: (a) pipeline dimensions; (b) volume of the CO_2 stream; and (c) pressure drops due to frictional losses and the difference in elevation levels throughout the pipeline run. Thus, the design/sizing of the compressors and pipelines is performed based on the phase-wise progression of CO_2 volumes.

Major trunk pipelines are generally envisaged to carry the dense CO_2 stream to a location close to the disposition sink. Pressure drop calculations based on the Darcy-Weisbach equation show a variation in pipeline pressure drop with varying CO_2 volume flow rate and pipeline diameter (Figure 4-20). The pressure drops increase with increasing CO_2 volume flow rates and decrease with increasing pipe diameters.

While a designer may want to opt for a large diameter pipeline to decrease the pressure drops and reduce the compressor load, it would raise the costs of pipeline material and installation. Thus, the pipeline diameter needs to be decided considering an economic trade-off between the costs of the pipeline and compression.

Figure 4-19: Pressure Drop in the CO_2 Pipeline with Volume Flow Rates (5 to 18 mtpa) and Pipeline Diameter (20 to 30 inches). Pipeline Length: 100 km.



Source: Dastur Analysis

Out of the various types of compressors available for CO_2 compression, the traditional approach has been to use high-speed reciprocating compressors. They can handle very high pressures and are a natural choice for high-pressure applications. However, centrifugal-type compressors are also widely used as they can handle high CO_2 volume flows. Multi-stage centrifugal compressors are of two types: (a) Between-bearing designs and (b) Integrally geared designs. The latter has emerged as the more favourable option for CO_2 compression due to the following advantages:

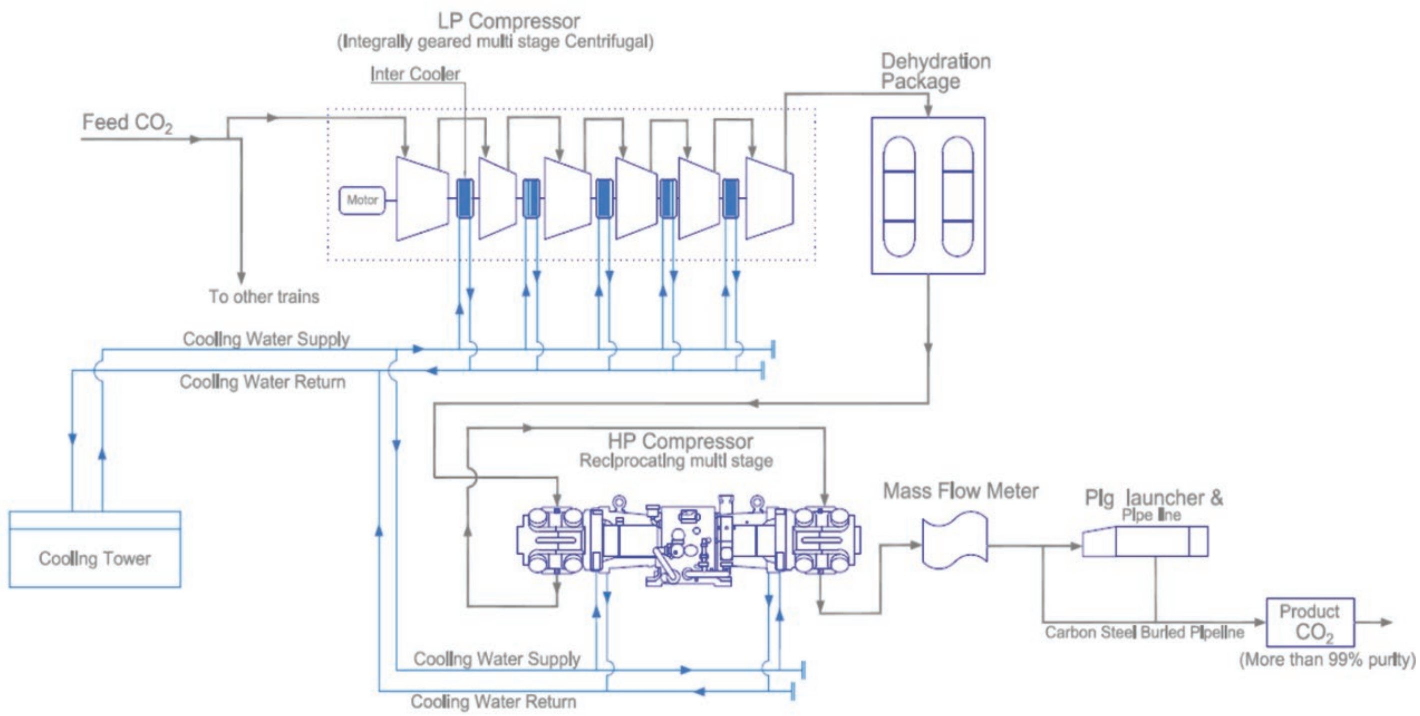
- The number of stages in one machine has no limit: a pressure ratio of even 200 is possible on a single frame
- External connection after each stage results in more flexibility in selecting the pressure level for the dehydration system
- Axial inflow to each stage
- Low hub/tip ratio
- Can be direct-driven by a 4-pole electric motor on the bull-gear, or a steam turbine on one of the pinions
- Shrouded or un-shrouded impellers can be used
- Inlet Guide Vane (IGV) for flow control
- Inter-cooling is possible after each stage (impeller)

Figure 4-21 shows a typical scheme of compression and dehydration facilities of a compressor train. Each train consists of the following major components:

- 1 LP (Low Pressure) compressor: multi-stage integrally geared
- 1 dehydration unit
- Intercoolers
- 1 HP (High Pressure) compressor: multi-stage reciprocating

The LP compressor can handle high volumes of CO_2 and is used to raise the pressure to moderate levels (about 30-40 barg). The dehydrating unit has a lower capex when operated at moderate pressures and hence it is placed after the LP compressor. Next in the train comes the centrifugal/reciprocating compressor, followed by a pump, for raising the pressure to higher levels (about 125-250 barg). Both the compressors in the train are envisaged to be multi-staged, instead of single-staged, as the former results in higher compression efficiency due to inter-cooling.

Figure 4-20: Typical Scheme of Compression and Dehydration Facility



Source: Dastur Research

4.9 CO_2 Transportation

Ships, tanker trucks, rail and pipelines are the possible options for the transportation of dense CO_2 streams from the point of capture to the disposition point. In general, truck and rail transport are feasible options while transporting small volumes, whereas ship transportation only becomes economically feasible when the transportation distance and CO_2 volumes transported are large. These modes of transportation are mainly used in the food and beverage industries.

On the other hand, pipeline transportation can deliver a constant and steady supply of CO_2 without the need for intermediate storage and is the most cost-effective and reliable for onshore transportation of large quantities of CO_2 (Svensson 2004). There exists more than 8000 km of pipelines for CO_2 transportation, mainly in the USA. The choice of mode of transportation depends on the quantity of CO_2 to be transported and the transportation distance, as given in Table 4-9.

Table 4-9: Various Modes of Transport of CO_2

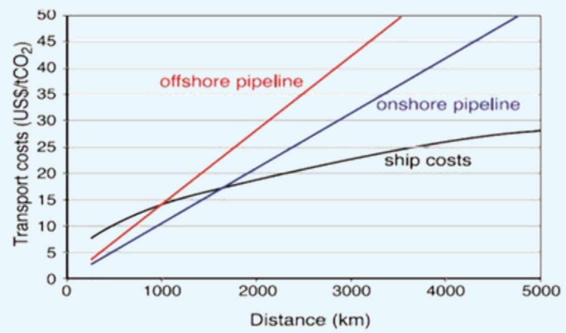
Mode of CO_2 transport	CO_2 volumes	Distance	Land / Water	Suitable CO_2 utilization pathway
Tanker trucks / Rail	Small	Short	Land	Food & Beverage industry
On-shore Pipeline	Large	Short	Land	EOR / Storage
Off-shore Pipeline	Large	Short	Water	EOR / Storage
Ship	Small to Medium	Long	Water	EOR / Storage

Source: Dastur research

For the transport of small volumes of CO_2 , typically associated with utilization opportunities such as food and beverage grade applications, the transportation of purified and liquified CO_2 is done through cryogenic bullet tankers. The transportation regulations and safety norms are the same as those for liquid nitrogen, argon or liquified natural gas (LNG). The road tankers are double-walled vacuum insulated cryogenic vessels suitable for transport while maintaining the cryogenic conditions. Apart from road transport, these tankers also have the flexibility of being useable for ship and rail transportation. The inner vessels and pipework are made of stainless steel and hence the tankers can be used for the multipurpose transportation of various industrial gases such as CO_2, N_2, O_2 and Ar.

In general, ships are better suited for small to medium volumes transportation over long distances, while pipeline transportation is better suited for larger quantities and relatively shorter distances. The variation in the transportation costs via ships along with onshore and offshore pipelines is depicted in Figure 4-20. As seen from the figure, ship transportation becomes economically attractive when the transportation distance is about 2000 km. Moreover, marine transport leads to additional CO_2 emissions, arising from energy usage for CO_2 liquefaction as well as the combustion of fuel.

Figure 4-21: Variation in Transportation Costs of CO_2 as a Function of Distance and Mode (Ship / Pipeline).



Source: IPCC

4.9.1 CO_2 Pipeline Transportation

The key factors to consider for CO_2 pipeline transportation are as follows:

i. **CO_2 flow rate:** It is cheaper to develop "appropriately-sized" CO_2 transportation pipelines without any provisions to handle any additional capacity in the future. However, in case of an increased CO_2 supply in the future, a completely new pipeline architecture and distribution network will be required to transport the additional CO_2. On the contrary, "oversized" pipelines are those that have provisions for transporting additional CO_2 volumes in the future.

ii. **Operating pressure and temperature:** Since the CO_2 stream needs to be in its supercritical state, the operating temperature and pressure should be more than 31 °C and 74 bar (critical point).

iii. **CO_2 stream composition:** The presence of impurities can cause significant operational issues during transportation. Generally it is recommended to limit the impurity levels to: 5-50 ppmv H_2O, 10-100 ppmv O_2, 10 ppmv H_2S and 1 vol% N_2.

iv. **Length of pipeline and route selection:** The pipeline architecture and network distribution are planned to maximize operational flexibility and economical viability while minimizing safety concerns. The initial plans for CO_2 disposition may change over time and hence a CO_2 pipeline network also needs to develop over time to cater to different types of CO_2 disposition projects at different locations. Given the scarcity and difficulty in developing multiple CO_2 sinks, a combination of trunk and feeder pipelines, forming a "hub and spoke" configuration may be appropriate for some projects vis-a-vis "tree and branch" or "point-to-point (PTP)" pipeline configurations.

v. **Trunk pipelines:** These are pipelines of large diameters carrying high volumes of CO_2 at high flow rates for long distances. These pipelines terminate at strategically located "landing points".

vi. **Feeder pipelines:** These pipelines branch out from the larger trunk pipelines. The feeder lines are usually narrower and carry lower volumes of CO_2 for shorter distances into specific disposition sinks. Since each disposition sink/application has a different P&T requirement, the CO_2 stream must be raised to an appropriate pressure by using a booster pump at a booster station.

vii. **Pressure drop:** The variation in frictional pressure drop as a function of CO_2 flow rate and pipe diameter is calculated based on the Darcy-Weisbach equation (Figure 4-18). While the pressure drop is found to be directly proportional to CO_2 flow rates, it decreases with an increase in pipe diameter. The maximum calculated pressure drop is about 15-20 bar for a pipe with an external diameter of 30 inch, carrying 18 mtpa CO_2 . This pressure drop must be accounted for by compressing the CO_2 stream before entering the pipe. Although using a pipe diameter of more than 30 inch can reduce the pressure drop further, it would mean incurring significantly higher pipeline costs.

viii. **Pipeline diameter and thickness:** While a pipeline with a smaller diameter results in higher flow velocities, pressure drops and wall erosion, a pipeline with a larger diameter results in very high costs. Thus, the selection of the right pipeline diameter depends on a trade-off between these two factors. The design should also limit the CO_2 stream velocity below the erosional velocity. The pipeline wall should be thick enough to withstand the high-pressure flow and the generated hoop stress (stress generated in a direction perpendicular both to the axis and to the radius of the cylindrical pipe). The maximum operating pressure defines the selection of the pipeline wall thickness.

ix. **Pipeline material:** The presence of water in the CO_2 stream results in increased susceptibility to corrosion, necessitating the requirement of anti-corrosive materials for the pipeline. Since the allowable water levels are considerably low (<50 ppmv), API 5L GR X52(1500#) carbon steel is recommended as the pipeline material. Although the internal corrosion is taken care of due to low moisture levels, external corrosion needs to be prevented by utilizing the principle of "cathodic protection", in combination with a protective coating.

x. **Other considerations:** High pressure CO_2 pipelines require crack arrestors as they cannot self-arrest longitudinal failures. These arrestors should be installed in intervals of 0.5 to 1 km. Crack arrestors can be of two types:

(a) Pipe joints with greater wall thickness and improved hoop-stress properties

(b) Non-metallic material wrappings

The auxiliary equipment list consists of booster compressors/pumps, control systems, crack arrestors, venting equipment, valves (block valves, check valves and emergency shutdown valves) and flowmeters. Lower inlet and ambient temperatures result in increased CO_2 densities and decreased pressure losses. Burying the pipelines below the surface minimizes temperature variation and prevents temperature rise, thereby aiding efficient transportation.

Examples of operating CO_2 pipelines across the world are given in Table 4-10.

Table 4-10: CO_2 Pipelines

Country	Project Name	Length, km	Capacity, mtpa	Onshore/Offshore	Sink
Canada	Weyburn	330	2	Onshore	EOR
USA	Beaver Creek	76	Not known	Onshore	EOR
	Monell	52.6	1.6	Onshore	EOR
	Bairoil	258	23	Onshore	Not known
	Salt Creek	201	4.3	Onshore	EOR
	Sheep Mountain	656	11	Onshore	CO_2 hub
	Slaughter	56	2.6	Onshore	EOR
	Cortez	808	24	Onshore	CO_2 hub
	Central Basin	231.75	27	Onshore	CO_2 hub
	Canyon Reef Carriers	354	Not known	Onshore	Not known
	Choctaw (NEJD)	294	7	Onshore	EOR
	Decatur	1.9	1.1	Onshore	Saline aquifer
Norway	Snøhvit	153	0.7	Both	Porous sandstone formation
Netherlands	OCAP	97	0.4	Onshore	Greenhouses

Source: Noothout, Paul, et al. "CO_2 Pipeline infrastructure–lessons learnt." Energy Procedia 63 (2014): 2481-2492.

Pipeline costs: The three major cost components of pipelines are:

- **Construction costs:** include the costs of materi al/ equipment (pipe, pipe coating, cathodic protection, telecommunication equipment and required booster stations). These vary with the pipeline length, diameter, CO_2 flow rate and stream quality.

- **Operation and maintenance (O&M) costs:** include the costs of maintenance and monitoring

- **Other costs:** includes the costs of design, project management, regulatory filing fees, insurance, right-of-way and contingencies.

The variation in capital cost of pipelines with the type of terrain is shown in Table 4-11.

Table 4-11: Representative Cost Metrics of CO_2 Pipeline Based on Terrain

Terrain	Capital Cost (USD/inch-dia/mile)
Flat and Dry	50,000
Mountainous	85,000
Marsh, Wetland	100,000
River	300,000
High Population	100,000
Offshore (45-60 m deep)	700,000

Source: NETL, Kinder-Morgan

The cost of CO_2 transportation pipelines varies according to the geometry of the pipeline (diameter, thickness), the volume of CO_2 to be transferred and the transportation distance. Depending on the pressure of the CO_2 stream to be transported, the material grade used for pipeline manufacture may vary.

A pipe with a higher yield stress rating would be less thick and light but would be more expensive. CO_2 transportation may also cause mesa corrosion in the pipeline. Thus, the pipeline needs to be suitably coated with protection measures (3 LPE coating and impressed current cathodic protection). The cost of coating will increase with the length of the pipeline. Special care must be taken to ensure that the transportation temperature is maintained above the dew point temperature of CO_2 (at least 10°C more). Thus, suitable thermal insulation needs to be provided to the pipeline to minimize the temperature drop per unit length for CO_2 transportation in the pipeline, thus increasing the cost of CO_2 pipeline.

CO_2 Utilization **Technologies**

5.1 Types of CO_2 Utilization Technologies

CO_2 utilization technologies present the opportunities for converting CO_2 into value-added products; these exclude the storage of CO_2 in geological formations or the injection of CO_2 in depleted oil wells for Enhanced Oil Recovery (EOR). The challenge with utilizing and converting CO_2 to other products is due to the fact that CO_2 is a very low-energy molecule and needs significant energy (either as thermal, chemical or electrical energy) to convert to other products, which contributes to significant Scope 2 emissions when viewed from a CO_2 Life Cycle Analysis (LCA) point of view and also lead to higher costs of production, vis-à-vis the established manufacturing pathways for the same products.

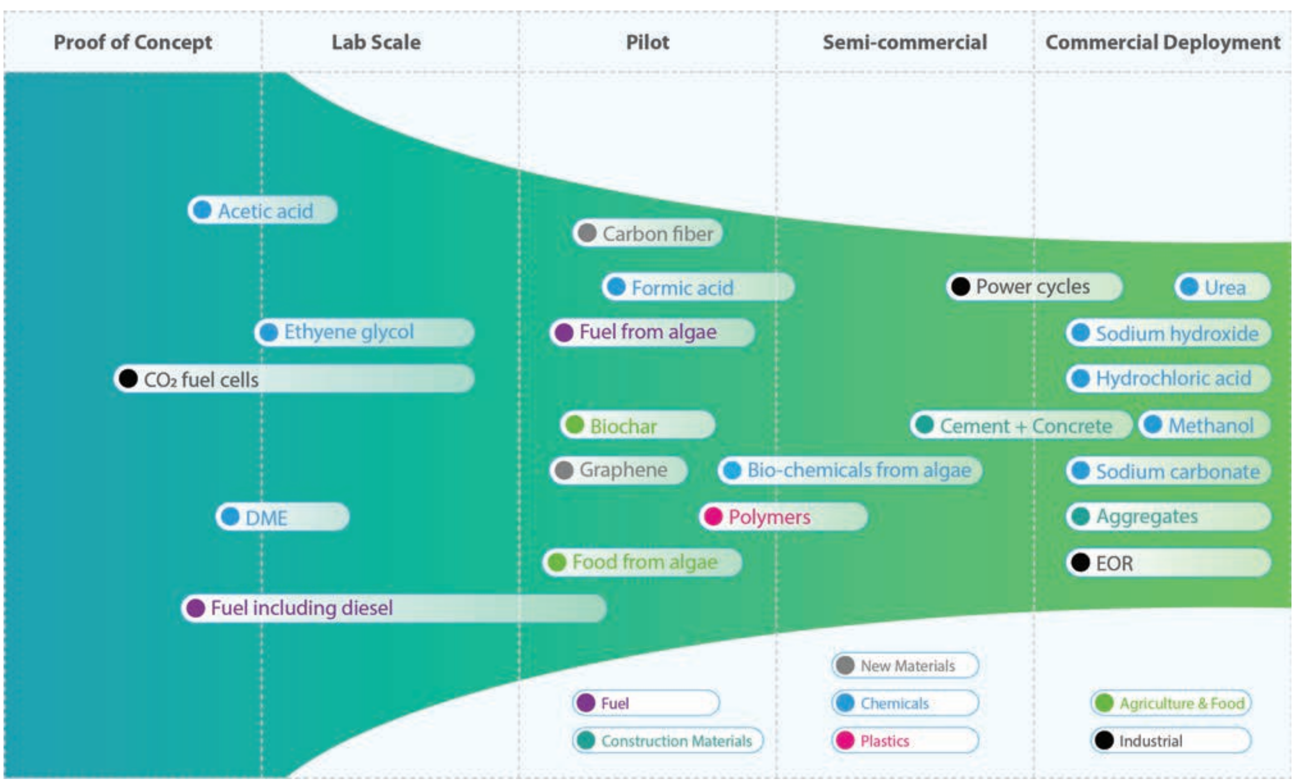
Unlike carbon capture technologies, CO_2 utilization technologies are relatively lesser developed. However, the decarbonization opportunity lies in the fact that CO_2 can be converted into a vast swathe of value-added products, such as fuels, construction materials, new materials, chemicals, plastics, agri & industrial products (Figure 5-1). The conversion of CO_2 into products such as urea is well established at a commercial scale and is not covered in this chapter. Instead, the focus is on the emerging CO_2 utilization technologies, which have been grouped into the following three categories:

i) CO_2 utilization in building construction materials

ii) CO_2 utilization in fuels and chemicals

ii) CO_2 utilization in the form of carbon nanomaterials

Figure 5-1: Maturity of Different CO_2 Utilization Technologies



Source: Dastur analysis

5.2 CO_2 Utilization in Building Construction Materials

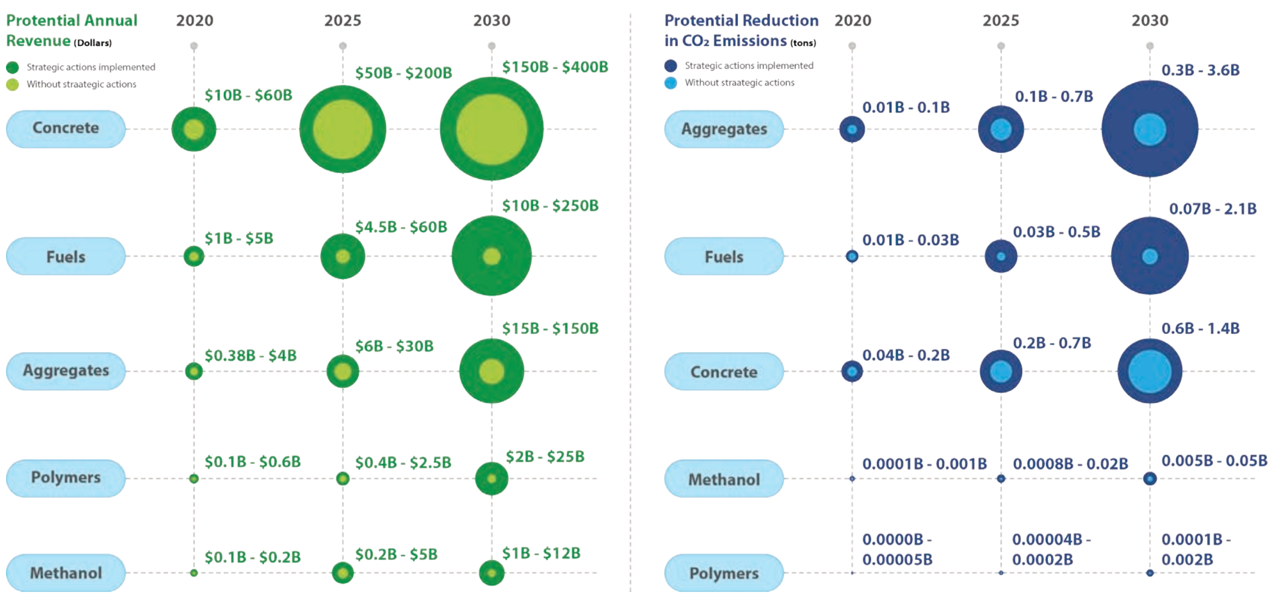
Cement is one of the pillars of modern life; however, the production of cement is an energy-intensive and CO_2 -emitting process that accounts for about 7% of global CO_2 emissions. Thus, the production of low-carbon alternative cement is very important from the point of view of developing sustainable construction materials. Other building construction materials, like pre-casted blocks, aggregates, and concrete, also offer significant potential for CO_2 utilization. In fact, building construction materials present the largest opportunity for CO_2 utilization, leaving aside CO_2 for Enhanced Oil Recovery (EOR), and is projected to grow as a preferred market for low carbon materials.

In these applications, CO_2 is utilized via carbonation curing technology, providing a pathway for integrating the economic, permanent, and safe sequestration of CO_2 and producing low-carbon construction materials. Construction materials represent a potentially large and a low-hanging fruit for CO_2 utilization in the form of various materials such cement, sand and aggregate, which together provide the key raw materials for concrete.

The global market for concrete is around 30 billion tonnes per annum and is estimated to grow to about 40 billion tonnes by 2030. This creates a theoretical CO_2 utilization potential of 1.4 billion tonnes. Likewise, the global aggregates market is about 25 billion to 30 billion tonnes annually and is estimated to grow to about 50 billion tonnes by 2030, providing a CO_2 storage potential of 3.6 billion tonnes (Figure 5-2).

However, the key challenges are the construction standards for products like concrete in different countries and regions and the higher cost of production, thus requiring specific policy and financial support for low carbon materials. The development of CO_2 utilization processes to develop novel building materials should not disturb existing supply chain logistics or impose additional costs due to an increase or changes in existing logistics. New quality tests and standards also need to be defined for the new building materials. Nevertheless, given the large volume of the end markets, low-carbon building construction materials offer the highest CO_2 utilization prospects, both in terms of market value and CO_2 reduction potential.

Figure 5-2: Present & Future Market & Potential of BCM and Other CO_2 Utilization Technologies



Source: https://www.vox.com/energy-and-environment/2019/11/13/20839531/climate-changeindustry-co2-carbon-capture-utilization-storage-ccu

Mineral aggregates are the main ingredients in any typical concrete composition and comprise 60 to 80% of concrete; the rest is a binding phase or a matrix. Mineral aggregates are granular in nature, and their size ranges from millimetres to centimetres. The different types of aggregates used globally are derived from natural sources, viz. sand, gravel, crushed rock and materials mined from quarries, gravel pits, seabeds, and riverbeds. However, the restrictions and regulations on these natural sources of aggregates are growing due to their depletion, contribution to erosion and degradation of various types and concerns about mining activities in proximity to urban areas.

This has led to demand and focus on secondary and manufactured sources of aggregates, like recycled concrete and by-products of industrial processes, like blast furnace slag. Although secondary and manufactured aggregates are still a small portion of the overall mineral aggregates market, they represent an important and growing segment.

Against this backdrop, mineral carbonation is a prospective CO_2 utilization pathway for aggregate production, provided the costs can be competitive within a certain range and the required quality & performance standards are achieved.

Concrete is the key material in the construction industry and consists of a mixture of aggregates (sand and stone), water, chemical additives, and cement. Cement is the binding agent and reacts with water to form the matrix for holding together the solid components of concrete, so that concrete can form a synthetic rock on hardening and can be shaped as per the construction requirements. Ordinary Portland cement (OPC) is the most popular cement type and is produced from limestone and other materials like silica, clay, and iron compounds and additives.

However, the production process of OPC is associated with a large carbon footprint of nearly 0.58 tonne of CO_2 per tonne of cement produced. The sources of CO_2 emissions in the cement-making process are the thermal decomposition of limestone ($CaCO_3$) to lime (CaO) and also from the use of fossil fuels in the clinkerisation phase of the cement manufacturing process. The cement industry has taken several steps to reduce the CO_2 intensity of cement production, viz., improving kiln thermal efficiencies, installation of waste heat boilers and use of waste materials such as fly ash and slags as binding materials. However, the growing demand for construction materials and cement has meant that the aggregate CO_2 emissions from the sector have grown/remained steady even with decreasing CO_2 intensities.

During the concrete production process, calcium oxide present in cement exothermically reacts with water to form calcium hydroxide.

$$CaO + H_2O \rightarrow Ca(OH)_2$$

During the concrete hardening process, calcium hydroxide ($Ca(OH)_2$) reacts with CO_2 to form the calcium carbonate ($CaCO_3$), as per the equation below – this process is called “carbonation”. Calcium carbonate has the lowest solubility among all salts in the H_2O – CO_2 – Ca system.

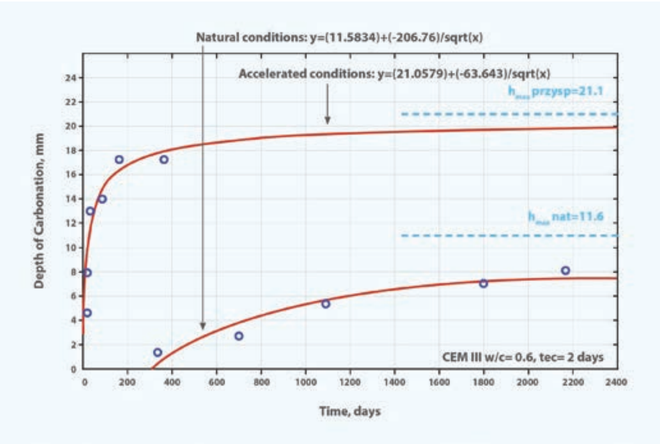
$$Ca(OH)_2 + CO_2 \rightarrow CaCO_3 + H_2O$$

The process of natural “carbonation” is a surface phenomenon for hardened concrete components and is a very slow process which occurs over a lifetime of 80 years. The natural mineral carbonation reaction involves alkaline silicate minerals and atmospheric CO_2, wherein Ca and/or Mg ions from silicate react with dissolved atmospheric CO_2 (HCO_3^-) to form solid carbonates.

$$(Ca,Mg)_x\,Si_y\,O_{(x+2y)} + xCO_2 + H_2O \rightarrow (Ca,Mg)CO_3 + ySiO_2 + H_2O$$

In CO_2 utilization applications involving mineral carbonation, the carbonation process is accelerated to a few hours or by optimizing and improving the reaction parameters, such as concentrated & pressurized CO_2 source, high P&T, liquid-to-solid (L/S) ratio, particle size and other operating conditions. The carbonation process can also reduce cement consumption in the concreting process, leading to a lower CO_2 intensity per tonne of concrete produced.

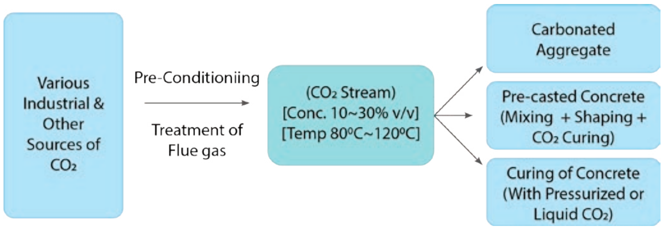
Figure 5-3: Rate of Conventional Carbonation Process and Accelerated Carbonation Process with Captured CO_2



Source: L. Czarnecki and P. Woyciechowski – "Modelling of concrete carbonation; is it a process unlimited in time and restricted in space?"

CO_2 utilization in building construction materials can be threefold - carbonated aggregates, pre-casted & pre-formed sections and the curation of concrete (mineral carbonation); the same is depicted in Figure 5-4.

Figure 5-4: Different Forms of Utilization of CO_2 in Building Construction Materials



Mineral carbonation involves the reaction of CO_2 (in the fluid state or as a solution) with alkaline mineral solids rich in Ca or Mg materials. The carbonation reactions proceed readily, even at ambient conditions of pressure and temperature. Carbonation usually involves dissolution and precipitation reactions, i.e. the dissolution of the elemental species from the reactant solid(s) and the solubilization of CO_2 into the liquid phase (e.g., water) followed by the precipitation of carbonate mineral solids from a supersaturated solution. The reaction of CO_2 to form the cementing can follow two alternative routes:

i) Injecting fresh concrete with CO_2 over a short time period; or

ii) Exposing pre-formed structural components to vapour-phase CO_2 (either dilute or concentrat ed) for hours within reactors

The rate and extent of CO_2 utilization in each pathway are also different. In the first case of injection of fresh concrete with CO_2, the CO_2 utilization is limited by the rate kinetics of the reaction of CO_2 with calcium & magnesium and the CO_2 solubility in the alkaline aqueous solution – the typical CO_2 utilization uptake is ≤ 0.01 g CO_2 per gram of the cementitious components.

In the second pathway, the rate of CO_2 uptake depends on the type of reactant and the shape & geometry of the structural members. However, the CO_2 uptake is higher and ranges between 5 and 50 g CO_2 per 100 gram of the carbonated aggregate. The maximum CO_2 uptake demonstrated till date is 44g CO_2 per 100 gram of carbonated aggregate.

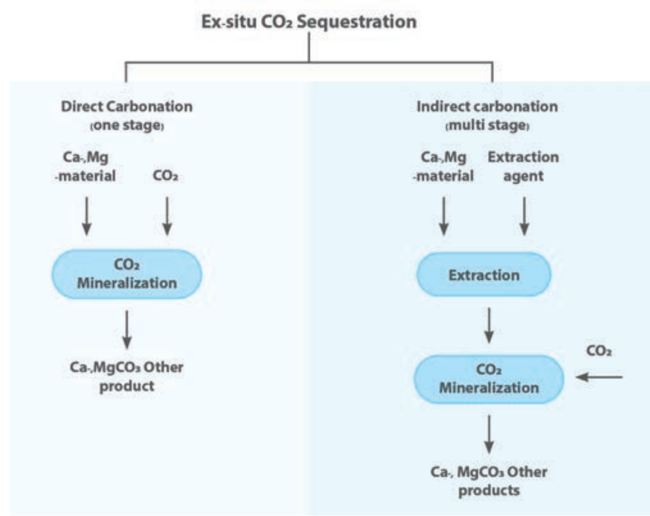
Mineral carbonation technologies can also be divided into two categories: "In-situ" and "Ex-situ". Many research groups at commercial companies and institutions have developed various processes to achieve "ex-situ" mineral carbonation with acceptable kinetics through two different categories of approaches (Figure 5-5)

- Direct carbonation
- Indirect carbonation

Direct carbonation can be accomplished in a single stage via direct gas–solid reactions or mineralization in aqueous solutions. The aqueous route is more efficient and effective than dry processing. CO_2 is sequestered in a recycled product, i.e. concrete aggregates. The concrete aggregates are exposed directly to a gas stream with a high CO_2 concentration in a reactor system at controlled pressure. Calcium hydroxide ($Ca(OH)_2$) and C-S-H present in the concrete react with CO_2 to form a chemically stable calcium carbonate, which is a type of carbonated aggregate (Figure 5-5).

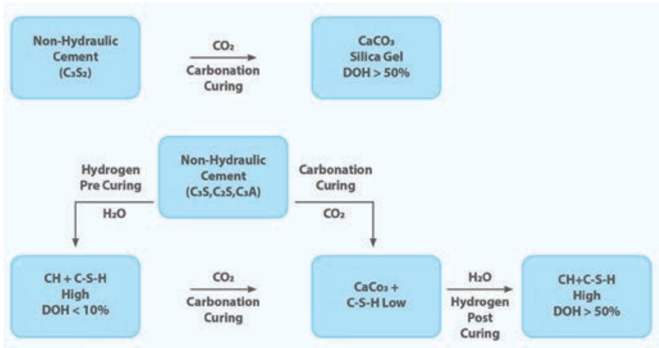
Indirect carbonation involves a multi-stage aqueous process. Concrete aggregates are suspended in a solvent in the dissolution reactor, wherein the solvent selectively extracts the calcium contained in the hydrated cement. In the next step, the inert materials (regenerated sand) are filtered out of the slurry and the calcium-enriched solution is fed to the mineralization reactor. The solution is brought into contact with CO_2, which results in the crystallization of stable calcium carbonate. Indirect carbonation can be through different technologies and process routes, viz. indirect multi-stage gas–solid mineral carbonation, pH swing process, HCl extraction, molten salt process, other acid extractions, bioleaching, ammonia extraction and caustic extraction.

Figure 5-5: Different Types of Mineralization Processes



Carbonation hardening involves more complex reactions compared to hydration. The specific reactivity of the phases and CO_2 availability determine the reactions between the hydration and carbonation process. Figure 5-6 shows the reactions and products involved in the carbonation hardening of hydraulic cement and non-hydraulic cement, the Degree of Hydration (DOH) of the cement/clinker, and the phases (C3S, C2S, C3S2, CS, C3A) of building cement clinker.

Figure 5-6: Carbonation Curing Processes in Hydraulic and Non- Hydraulic Cement



Considering the present success of various commercial and R&D initiatives worldwide in the mineral carbonation process for manufacturing building construction materials, this process is regarded as an achievable and sustainable avenue for CO_2 utilization. A few of the successful ventures and their different TRLs (Technology Readiness Level) are captured in Table 5-1. CO_2 utilization in the form of building construction materials is thus not only a good business proposition but also provides a safe route for CO_2 disposition for decades to come.

Table 5-1: Mapping of Mineral Carbonation Technologies Worldwide

Sl. No	Company	Technology	TRL	Prime Product
1	Alcoa Corporation, USA	Treatment of bauxite waste with CO_2 (from an ammonia plant)	6	Construction fill, soil amendment
2	Carbicrete Technologies, Canada	Carbonation activation of steel slag	6-7	Carbonated "concrete"
3	Carbon8 Systems, UK	Accelerated carbonation technology	9	Aggregates/fill, e.g., for blocks and concrete
4	Orbix, Belgium	Carbonation of steel slag	9	Construction materials, including roofing tiles
5	Blue Planet, USA	Carbonate coating over an alkaline substrate	6-7	Aggregate
6	Carboclave, Canada	Nano-$CaCO_3$ crystals produce a densification effect	7	Concrete blocks
7	Green Minerals, Norway	Carbonation of olivine	3	Building materials
8	Solidia Technologies, US	Concrete & pre-casted curing with liquid CO_2 stream	9	Concrete and re-casted cement blocks
9	CarbonCure, Canada	Concrete & pre-casted curing with liquid CO_2 stream	9	Concrete and re-casted cement blocks

Construction materials provide a large market opportunity for utilizing waste CO_2 for mineral carbonation. Mineral carbonation can be utilized to produce both aggregates and binding agents for displacing currently used natural and existing synthetic sources of these commonly used and vital construction materials. As mentioned in Table 5-1, different organizations across the world are focusing their research in this area and have reported lower comprehensive strengths for concrete, aggregate, pre-casted bricks/blocks cured under moist curing conditions. Also, the efficiency of carbonation and the extent of CO_2 uptake depends on various operational conditions like P&T, CO_2 concentration, gas stream composition, particle size and mineralogy of the ingredients.

The carbonation of CaO-MgO rich raw materials to produce calcium and magnesium carbonate results in improved mechanical strength. Steel slag contains high levels of CaO and MgO and hence its commercial use in carbonation for producing construction materials (supplementary cementitious materials and aggregates) is increasing. However, steel slag has poor hydraulic properties due to a lack of tri-calcium silicates & amorphous SiO_2 content. Hence the replacement of a high proportion of Portland cement with steel slag derived carbonated materials results in concretes of decreased mechanical strength. Also, steel slag containing high levels of free-MgO & CaO can cause excessive expansion, resulting in volume instability in the long term.

Research has also claimed that under moist or hydration curing conditions, the "microstructure" matrix in concrete is generally porous in comparison with the matrix cured through the carbonation process, owing to the formation of calcite as a result of carbonation. Similarly, the hydration curing of concrete, even at elevated temperatures of 60 ^{o}C creates a "volume deformation" due to the expansion of the internal matrix (for inclusion of the water of hydration), which is significantly lower in the case of carbonation curing. However, sources of calcium and magnesium ions are not easily available. The possible sources are seawater, volcanic rocks, slags and alkaline industrial wastes; the key challenge is that there should be a nearby source of CO_2 so that the CO_2 utilization process is economically feasible. The key future research and development areas include making available reliable, sustainable, and low-cost sources of calcium and magnesium for reacting with CO_2 . The key challenges and technology gaps with respect to CO_2 utilization through building construction materials are tabulated below.

Table 5-2: Areas of Challenges & Technology Gap in Carbonated BCM

Sl. No	Areas of Challenge	Technology Gap
1	Poor compressive strength	Compressive strength of various carbonation cured products e.g., concrete, pre-casted bricks/blocks, and aggregates need to meet the desired values as per the regular comparative testing standards of similar categories of products available in the market.
2	Passivation of carbonation curing leading to lesser uptake of CO_2	Optimization of various parameters affecting the CO_2 uptake during mineral carbonation i.e., operational conditions (temperature, pressure, and CO_2 concentration), composition of contaminants in the CO_2 stream, particle size and mineralogy of the ingredients.
3	Availability of abundant and sustainable feedstock	The oxides of alkaline earth metals, essentially CaO, MgO and also silicates, are the prime materials in this mineral carbonation technology and responsible for the CO_2 uptake; unfortunately, the availability of these are finite in nature. Therefore R&D should focus on developing sustainable and cost effective synthetic and/or natural alternatives with optimum performance of CO_2 uptake.

Building Constructional Materials (BCMs) as mentioned in the above paragraphs e.g., concrete, pre-casted blocks or bricks and coarse or fine aggregates, are all critical construction materials and meet the respective recommended manufacturing or testing standards of national and international levels. The carbonated version of all these BCMs therefore, must fulfill the same quality standards as that of the non-carbonated one (without any thermal, chemical or any type of degradations), so as to be treated at par by the customers in the respective markets. However, considering the large carbon utilization benefits of carbonated BCMs, and depending on the specificity and criticality of the applications, respective standards, whether international or specific to the country, may be redefined.

5.3 CO_2 Utilization in Fuels and Chemicals

Fuels and chemicals represent a significant opportunity for CO_2 utilization technologies (Figure 5-1). While fuels and chemicals have different end-use markets, the carbon utilization processes have certain similarities, and hence both opportunities are considered together. As per the Global CO_2 Initiative Roadmap, the estimated market size of the two product categories ranges from US$ 1 BB to more than US$ 2500 BB per year, which corresponds to a CO_2 abatement opportunity of 0.1 mtpa to 2.1 Gtpa of CO_2 (Figure 5-2).

The conversion of CO_2 to fuels and chemicals often involves the addition of hydrogen to the carbon atom in CO_2 . Accordingly, current research in this area is focused on developing catalytic, electro-chemical and photolytic processes to facilitate the reaction for producing useful value-added products in a techno-economically feasible manner and for scaling up the processes to the commercial scale.

One key challenge in this respect in the availability of clean hydrogen at a low cost. Producing low carbon hydrogen (blue hydrogen) from natural gas (through steam methane reforming) or coal, biomass or MSW (through gasification) requires the geo-sequestration of the CO_2 produced through the process, and there are only a handful of such projects across the world. Green hydrogen produced through the electrolysis of water using entirely renewable sources of energy is still very expensive compared to hydrogen produced using the traditional method of SMR. Research in the area of green hydrogen is expected to also benefit CO_2 utilization in fuels and chemicals through the availability of green hydrogen at lower cost points.

Industrial emissions and waste gases containing CO and CO_2 are already being converted to low-carbon fuels at the commercial scale, resulting in fuels which have more than 70% carbon abatement vis-à-vis fossil fuels. Various commercial-scale industrial processes use CO_2 as one of the key raw materials to produce various different high chemicals or fuels (Figure 5-7). However, these processes typically involve significant energy requirements for the conversion process as CO_2 is a very stable compound, requiring significant activation energy for the reaction process. Nevertheless, CO_2 is still being utilized as a carbon source for producing many fuels and chemicals.

The conversion of CO_2 to fuels and chemicals involves adding hydrogen (either in molecular form or from other compounds) to the carbon atom in the CO_2. This is achieved either through the direct hydrogenation of CO_2 or through indirect production methods, which involve the conversion of CO_2 to carbon monoxide (CO), and thereafter synthesis and conversion of the CO to the desired value-added products. Table 5-3 provides the various production routes for converting CO_2 to different chemicals and fuels.

Figure 5-7: Large Scale Utilization of CO_2 for Conventional Chemicals & Fuels Production

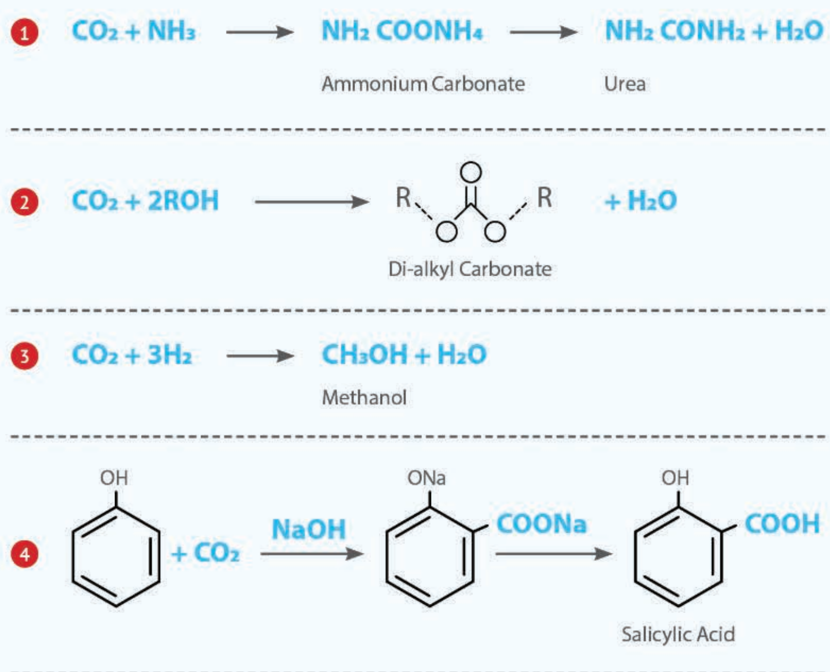


Table 5-3: Various Routes CO_2 Conversion to Synthetic Fuels & Chemicals

Sl. No	Routes of Conversion of CO_2	Basic Description & Focus Areas	Leading Technology Companies	TRL
1	Thermocatalytic	Energy is provided in the form of heat and pressure. Reaction is driven by a catalyst to activate the CO_2 reacting with hydrogen.	• Emission to Liquid Technology (ETLTM) of Carbon Recycling International (CRI) of Iceland • UOP Honeywell of USA	7-8
2	Electrochemical	Energy is provided as electricity; reactions happen in an electrochemical cell.	• INEOS Electro-chemical Solution – UK • Helmholtz Zenturm – Germany • Avantium – The Netherlands	7-8

Sl. No	Routes of Conversation of CO_2	Basic Description & Focus Areas	Leading Technology Companies	TRL
3	Biochemical	Living organisms or bioproducts (e.g., enzymes) convert CO_2 or CO to products.	• Gas Fermentation Technology – LanzaTech • VITO – Belgium	7-8
4	Photochemical	Solar energy provides the heat or electricity for the catalytic conversion reactions	• MAN Energy Solution (MES) –Germany	7-8
5	Hybrid approaches	The above approaches are combined (e.g., electrolysis, thermo-catalytic approaches, electrochemical reactions driven by microbes, etc.).	• Johnson Matthey – UK	7-8

All the CO_2 conversion routes mentioned in Table 5-3 are presently operating at a commercial/ sub-commercial scale. Thus, a TRL of 7-8 may be considered for these process routes. The availability of captured CO_2 in a pure form and the availability of clean and cost-effective sources of hydrogen are key factors in the success of utilizing large quantities of CO_2 in the production of value-added chemicals and fuels, and making them comparable in terms of specifications and performance criteria with the hitherto established and fossil fuel-based production process. Presently the three methods of producing hydrogen are:

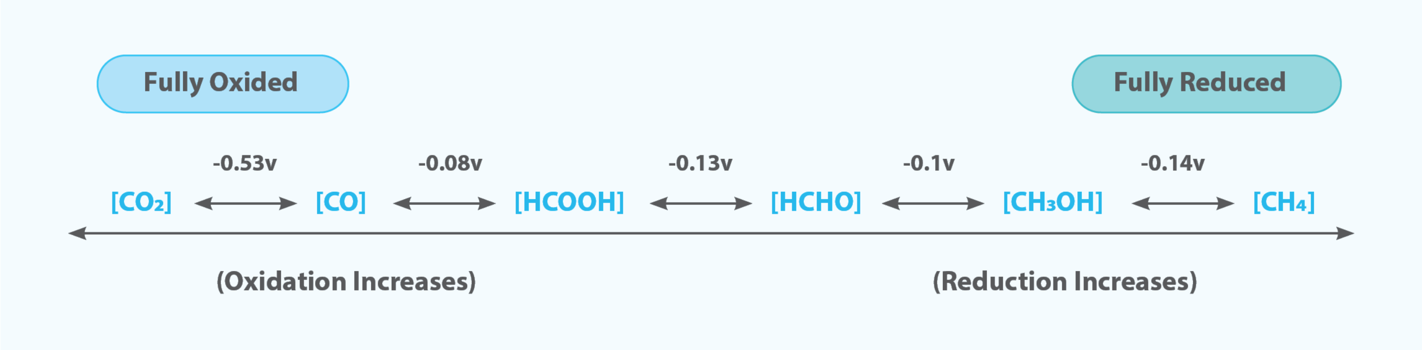
i. Steam Methane Reforming (SMR) or Auto Thermal Refining (ATR) of natural gas

ii. Gasification of coal, petcoke or biomass and municipal solid waste (MSW) etc., coupled with water gas shift reaction and hydrogen separation & purification

iii. Electrolysis of water using cost-effective renewable energy.

From the point of thermodynamics, the high energy requirements for converting CO_2 to other products are due to the fact that CO_2 has the highest level of oxidized state of carbon, compared to methane, which has the highest level of reduced state of carbon (Figure 5-8). Each step of reduction requires significant energy, which should ideally be provided from low-cost renewable energy sources to reduce/minimize Scope 2 emissions and make the CO_2 utilization process techno-economically feasible.

Figure 5-8: Different State of Oxidation and Reduction of CO_2 with 1 Mole of Hydrogen Requirement

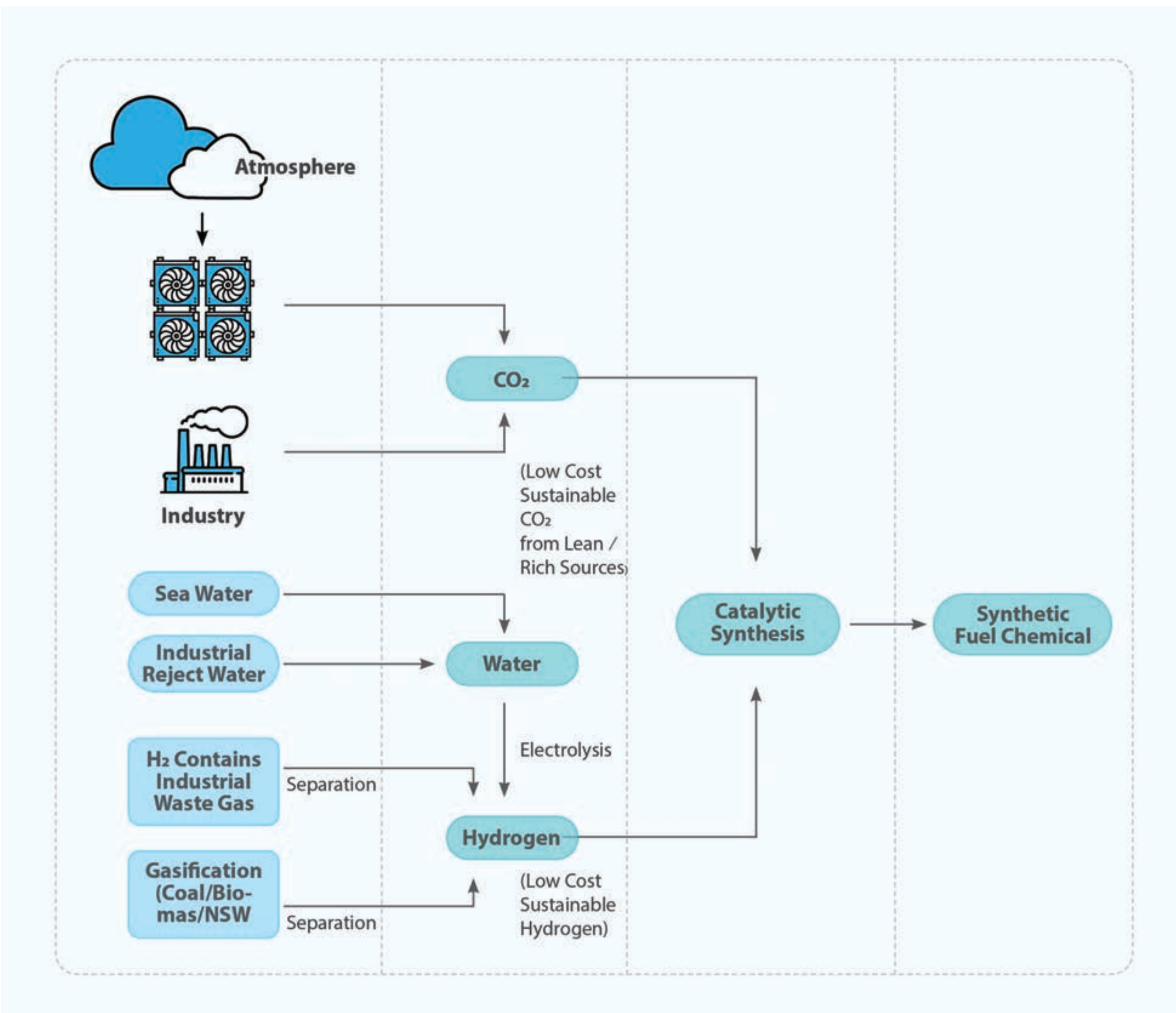


Source: Dastur Research

It is expected that with the increasing greening of the grid using renewables, the production of hydrogen from the electrolysis of seawater or industrial effluents (highly impure water with very high Total Dissolved Solid or TDS) would have a sustainable future. Similarly, the development of low-cost and higher-efficiency electrodes and catalysts for facilitating higher rates of hydrogen generation will also have an important role to play in improving the CO_2 utilization proposition. Present electrolysis-based hydrogen production processes use high cost noble metal electrodes and deionized water, which makes the production of green hydrogen an expensive and resource intensive proposition.

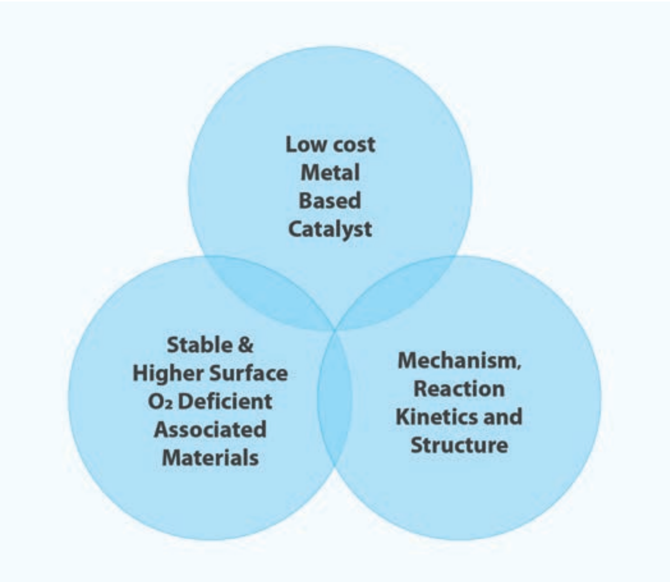
As shown in Figure 5-9, CO_2 can be captured from different types of sources, with varying concentrations, such as lean sources like the atmosphere or rich sources such as industrial waste gases. Similarly, hydrogen can be produced from fossil fuels (viz. steam methane or auto reforming of natural gas or the gasification of coal, petcoke, MSW or biomass), electrolysis of water using renewable power or the low-cost recovery of hydrogen from industrial waste gases such as Blast Furnace gas or Coke Oven gas.

Figure 5-9: A Sustainable Value Chain of Carbon Utilization for Renewable Chemicals & Fuels



Post the mixing of hydrogen with CO_2 at elevated temperature and pressure, the reaction takes place in the presence of the catalyst or combination of catalysts required for the production of the synthetic fuels and chemicals. Here, the selection or development of a low-cost & highly efficient metal-based catalyst (Figure 5-10) with better reaction kinetics, recharge frequency and more efficient separation processes are essential to drive down the costs and should be considered as important areas of further technological interventions.

Figure 5-10: Important Characteristics for Development of a Catalyst Ecosystem



There should also be focus on indirect fuels and chemicals production pathways involving the conversion of CO_2 to CO prior to processing, similar to direct conversion but with a defined CO intermediate product. It is attractive because CO is much more chemically active than CO_2 . The process of converting CO and hydrogen (i.e., syngas) into methanol and into hydrocarbons via Fischer-Tropsch (F-T) synthesis is very well-known, although it also does require hydrogen at an affordable price through a sustainable process.

The principal challenge for this approach is the CO_2 - to-CO conversion step, where the options include catalytically driven processes such as Reverse Water Gas Shift (RWGS) to generate CO from CO_2, various forms of other reforming processes, which use methane (or other light hydrocarbons) to convert CO_2 to CO, and electro-chemical approaches such as polymer electrolyte membranes or solid oxide electro-chemical cells. Fundamental advances, such as catalysts that operate at lower temperatures and advanced gas separations techniques are required to commercialize these processes. A near-term opportunity exists to advance CO_2 conversion technology, that can potentially be overcome through low-pressure and low temperature dry reforming of methane to hydrogen and CO_2 to produce methanol, but only in natural gas producing regions. There are also other technologies under development/ commercialization that appear promising.

One of the important indirect conversion pathways is the “Gas Fermentation” technology developed by LanzaTech; the company has created a process through which engineered microbes convert CO into ethanol and other higher order chemicals. This technology has been demonstrated at a commercial scale using waste gas from steel production, which is high in CO content. The inexpensive and widespread availability of more chemically active CO generated from CO_2 through low cost catalytically assisted processes can actually result in the advancement of multiple technologies to generate fuels and chemicals from CO_2 .

The following are important to make CO_2 to Fuels and Chemicals a sustainable means of CO_2 utilization (Table 5-4)

Table 5-4: Areas of Challenges & Technology Gap in CO_2 to Fuels & Chemicals

Sl. No	Areas of Challenge	Technology Gap
1	Catalysts	• Develop low-cost and mechanically-chemically stable catalysts for meeting the desired rate of reaction kinetics, which can facilitate the reaction at a lower temperature for converting CO_2 to a CO & H_2 mixture, for conversion to chemicals and fuels • Lower temperature and corrosion inhibition for electrolysis of very high TDS water.
2	Electrode Development	• Economically affordable metal based mechanically robust and electro-chemically suitable electrodes for seawater and high TDS industrial wastewater • Electrolysis for green hydrogen generation while withstanding higher current density and corrosion resistance.
3	Reactor Development	• Develop reactor technologies tailored to demands of carbon dioxide (to CO or mixture of CO_2 /CO/H_2 etc.) conversion processes • Systems that integrate capture with conversion.

5.4 CO_2 Utilization in the Form of Carbon Nanomaterials

The two key challenges for capturing and converting atmospheric CO_2 into value-added products are the cost of production and the perceived economic value. These challenges can be addressed by developing technologies for capturing atmospheric CO_2 and synergistically converting them into high-value products in a manner which are

i. sustainable
ii. functional
iii. produce a desired product with lower carbon emission on a Life Cycle Analysis basis vis-à-vis the established processes

The product should be stable, have minimal possibility of re-emission (ideally, the product's functionality should be a shield for collecting the captured carbon) and be sufficiently high value so that the economic benefit from the product outweighs the cost of carbon capture and conversion. One such emerging area for CO_2 utilization is the production of Carbon Nano-tubes (CNT) and Carbon Nano-materials.

The total size of the carbon nano-tubes market has been estimated at US$ 34 BB in the year 2021. The market is expected to reach US$ 105 BB by the year 2030 (Figure 5-11), growing at a staggering compounded annual rate of 13% plus during this period. Carbon nanotubes are attracting significant and continuous R&D efforts focused on bridging the existing technology gaps, driven by demand from multiple applications and sectors such as electrical and electronics, energy, consumer goods, aerospace, automobile, defense sectors, and healthcare. The demand is also driven by the rising application of polymers in the construction and automotive industries.

Figure 5-11: Market Potential of CNTs (in USD billions)

Source: https://www.precedenceresearch.com/carbon-nanotubes-market

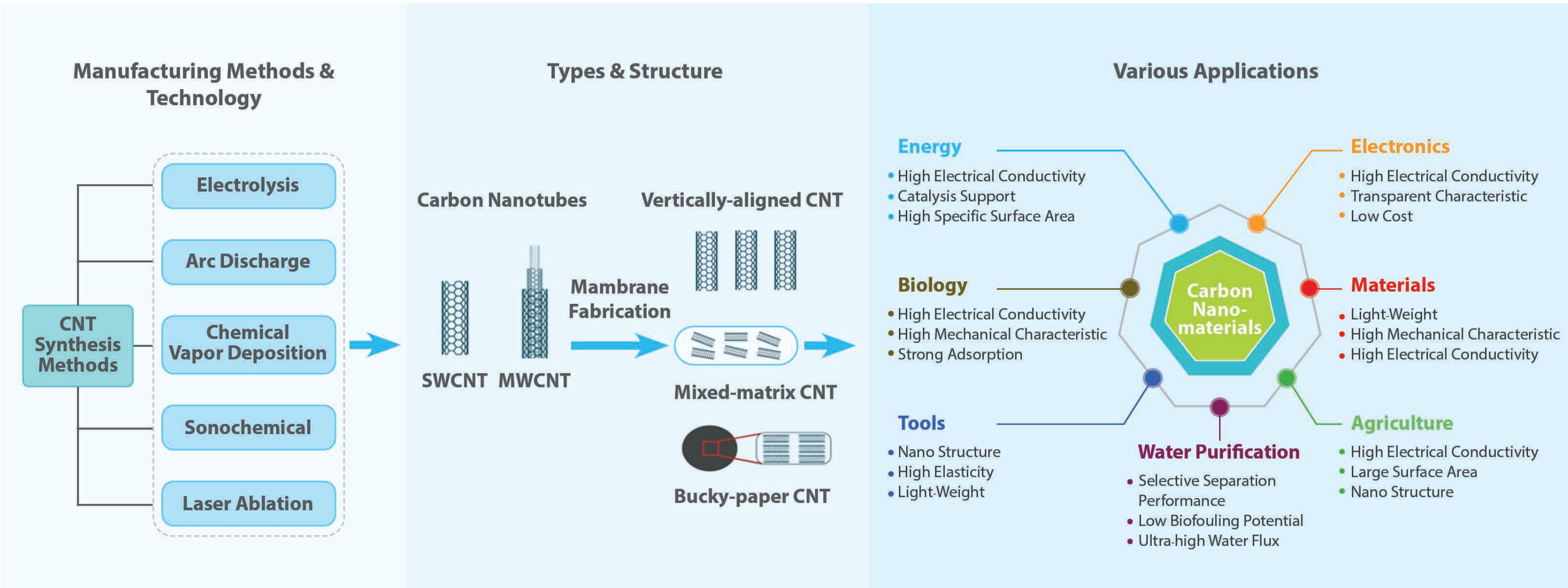
The demand for carbon nanotubes is driven by their simplicity, ease of synthesis and novel properties such as high surface area, good stiffness, and resilience. These reasons are driving the demand for carbon nanotubes in many engineering applications. The commercial application of carbon nanotubes requires large quantities of high-purity carbon carbon nanotubes, which can be synthesized in various ways. The common methods/practices are: arc discharge, laser ablation, and chemical vapor deposition and flame synthesis etc. (Figure 5-12). The subsequent purification is done using oxidation, acid treatment, annealing, sonication, and filtering chemical functionalization.

Concentric multi-walled carbon nanotubes (CNTs) are produced by interconnecting spherical graphene sheets. Carbon nanotubes have several valuable properties, such as high electrical capabilities, high conductivity, versatility, maximum charge storage capabilities and reactivity. The advanced physical and chemical performance drives the demand for carbon nanotubes, especially those produced by utilizing CO_2 , thus enabling effective CO_2 abatement and decarbonization. Carbo nanotubes use molten carbonate electro-chemical reactants and provide a pathway for capturing atmospheric CO_2 to produce valuable products with multiple end-use applications.

The key factor driving the adoption and demand for carbon nanotubes is cost-effective production. As shown in Figure 5-12, the key routes for producing both single-walled andmulti-walled carbon nanotubes are the following:

i. Laser vaporization of metal-doped carbon targets
ii. Arc-discharge of metal-doped carbon elec trodes
iii. Catalytic decomposition of hydrocarbons – also referred to as chemical vapor decomposition or CVD method
iv. The catalytic reduction of carbon monoxide has also been reported as a recent production method

Figure 5-12: Manufacturing Methods, Technology, Types, Structure and Various Applications of Carbon Nanotubes



The arc discharge method involves producing a vapour using an arc discharge plasma between two carbon electrodes, with or without a catalyst. In the laser ablation method, laser irradiation is used to vaporize a graphite target in an inert atmosphere. CVD involves the pyrolysis of gas-phase carbon-rich molecules (e.g., C_2H_2, CH_4) at high temperatures (800–1000 °C) and in the presence of transition metal catalysts and then converting the carbon-fragments into nanotubes.

The CVD method is the most widely used method due to its high product yield and the ability to scale up. However, there are also some disadvantages associated with the pyrolysis of hydrocarbons used in this method. Hydrocarbons used in these methods are generally hazardous and pyrolysis at high temperatures of 1000 °C makes commercial deployment and industrial-scale production impractical. One way to approach this problem is to use CO_2 , which is non-toxic, low energy and abundantly available in the atmosphere at low ppm level concentrations. Also, since CO_2 can be captured from both natural emitters (reservoirs) and industrial processes, there is no need to separately produce CO_2 and thus add to the stock of greenhouse gases. However, the main problem is that the CO_2 molecule is kinetically and thermodynamically very stable and difficult to reduce to elementary carbon.

During the process of synthesizing carbon nanotubes, the carbon nanotubes can be separated from other materials and impurities in the process, such as amorphous carbon, carbon nanoparticles and residual catalyst. The separation requires methods such as gas phase purification, liquid phase purification and intercalation methods.

i) **Gas phase purification:** This is a high-temperature oxidation process in which carbon nanotubes are repeatedly extracted using nitric acid and hydrochloric acid. The carbon nanotubes thus produced have higher purity & stabillity and lower residual catalysts than carbon nanotubes from other processes.

ii) **Liquid phase purification:** This consists of a series of steps such as preliminary filtration (for the removal of bulk graphite particles), dissolution in organic solvents & concentrated acids (for the removal of fullerenes and catalyst), and centrifugal separation of solid carbon nanotubes from the solutions to remove impurities. The other steps are microfiltration and chromatography to separate multi-walled and single-walled carbon nanotubes.

iii) **Intercalation purification:** Nanoparticle impurities are oxidized by metallic copper. Copper is the oxidation catalyst formed by the reduction of copper chloride added during the process. However, this process results in intercalated residues and may damage the carbon nanotubes during the oxidation process.

The demand and production of carbon nanotubes have been limited due to the high production cost. Generally, CNTs are produced using the wet chemical vapour deposition (CVD) process. The decade old technology of the Solar Thermal Electrochemical Process (STEP) of water splitting has also been extended to carbon dioxide splitting, leading to CO_2 splitting at over 50% solar energy efficiency. This process provides a pathway for converting carbon dioxide into useful carbon commodities such as inexpensive electrode materials, varieties of elemental carbon, plastics intermediates, and synthetic methane. However, the market value/prices of such products range from US$ 40 to $400 per tonne, and hence offer limited financial incentives for the capture and conversion of CO_2 .

Carbon nanotubes can also be produced by the direct molten carbonate electrolysis of CO_2 , and thus provide a significant economic value-addition for the entire value-chain of carbon dioxide utilization. In the C2CNT process, the carbonate electrolyte is not consumed, and the net reaction is CO_2 splitting into carbon and O_2, as presented below, using pure Li_2CO_3 as the carbonate electrolyte:

Dissolution:
CO_2 (gas) + Li_2O® (soluble)→ Li_2CO_3 (molten)

Electrolysis:
Li_2CO_3® (molten)→ C(CNT) + Li_2O (soluble) + O_2 (gas)

Net:
CO_2 (gas)→ C(CNT) + O_2 (gas) (1)

In the above net equation 1, the CO_2 gas is entirely transformed into carbon nanotubes (CNTs); 1 tonne of CNT is formed per 3.7 tonne of CO_2 consumed.

The CARGEN™ technology is one of the cutting-edge technologies for converting greenhouse gases such as CO_2 and CH_4 for producing CNTs and syngas (H_2 + CO mixture). The technology provides potential economic value and cost reduction opportunities for converting waste CO_2 emissions to solid products with economic value and potential, thus paving the way for the future production of carbon nanotubes at a commercial scale. Apart from carbon nanotubes, the technology also produces syngas which can be used in downstream processes such as Fischer-Tropsch synthesis and the production of methanol and hydrogen. The proof of concept, scale-up results, and LCA results of the CARGEN™ technology has been demonstrated by various scientific and technical studies, and it is also reported that the technology can reduce the opex and CO_2 emissions of existing Gas to Liquid processes by 40% and 45% respectively.

There are various qualities and grades of carbon nanotubes, with different properties and market prices. At the lowest range are carbon nanotubes with large diameters and poorer properties, with a price range of US$100 to $ 500 per kg. At the top end are single walled carbon nanotubes with diameters less than 5 nm and prices of up to US$ 100,000 per kg and above.

The utilization and conversion of CO_2 into carbon nanotubes provide a unique opportunity of capturing CO_2 and abating climate change by turning the CO_2 into hollow nanofiber products with remarkable performance characteristics in terms of conductivity, nanoelectronics, and flexibility, which open up opportunities to use them for making higher capacity batteries or carbon composite materials, with strengths higher than steel. Carbon composite materials in particular, are lighter alternatives to metals and can be used in highend and value-added applications across multiple sectors, such as electronics, agriculture, biotechnology, tools, water, and energy (Figure 5-12). The development of carbon composite applications is seeing explosive growth, which can be compared to the initial years of the plastics industry. The growth is also fueled by the emergence of more competitive ways of producing carbon nanotubes (viz. from CO_2) vis-à-vis the previously used, more expensive processes of chemical vapour deposition or polymer pulling for producing carbon nanofibers. Table 5-5 summarizes the key developments and innovations in this area of converting CO_2 to carbon nanotubes using low-cost materials and new chemistry.

Table 5-5: Leading Carbon Nanotubes & Nano-Materials Manufacturers & their Specialties

Sl. No	Leaders in CNT	Specialties in CNT Activities
1	Nanocyl, Belgium	High-quality multiwall carbon nanotubes (MWCNTs) and formulated products.
2	Arkema, France	Carbon based coating solutions.
3	Cabot Corporation, US	Carbon nano-structure pallets Graphene based specialty materials Carbon black for reinforcement etc.
4	CHASM Advanced Materials, US	Electronic & battery materials based on carbon, carbon nano hybrid materials etc.
5	Showa Denko, Japan	CNT in composite coating, graphite electrodes etc.
6	Nanoshell, UK	Functional nanomaterials, nanotechnology coatings and impregnators etc.
7	Carbon solutions, US	Single-walled carbon nanotubes for specialty chemical solutions etc.
8	Hyperion Catalysis International, US	Conductive, vapor grown and multi-walled carbon nanotube for special purpose usage in automotive, electronics and other sectors

It is important to develop the sustainable use of carbon nanotubes across various sectors, so that the demand for carbon nanotubes can reach scale, thus creating demand for the conversion of CO_2 to carbon nanotubes. Some of the emerging areas for the deployment of carbon nanotubes is given below:

i) **Water desalination:** Water scarcities have led to the development of desalination technologies, and particularly membrane-based methods, due to advantages such as high-water quality, easy maintenance, compact modular construction, low chemical sludge effluent and excellent separation efficiency. Membranes are of different categories such as microfiltration (MF), ultrafiltration (UF), nanofiltration (NF), reverse osmosis (RO), forward osmosis (FO), pervaporation and membrane distillation.

Typically membranes are made from inorganics and polymeric materials; however, they have disadvantages in terms of high fouling tendency and trade-offs between permeability and selectivity. These problems reduce the permeability and lifespan of membranes due to the increased build-up of trans-membrane pressure. These challenges of desalination can be addressed by developing filtration technologies based on nanotechnology materials such as carbon nanotubes. The advantages offered by carbon nanotubes in such applications include large surface area, ease of functioning, better anti-fouling behaviour, superb mechanical strength, excellent sieving capabilities and exceptional water transport properties. Hence carbon nanotubes can enhance the performance of desalination plants by being applied either as a direct filter or as a filler.

ii) **Electronics-energy market:** This is a growing market where carbon nanotubes and nanomaterials can be used to design and manufacture energy devices on miniaturized platforms. This can result in personalized electronic devices supporting different applications, such as wearable devices, implantable devices, biosensors, bioelectronics, and personalized biomedical devices. In these devices, carbon nanotubes will act as energy-storage devices for delivering optimal power to various biomedical systems for integration with energy-harvesting and energy-converting devices. Additionally, carbon-based energy devices can also power various other biomedical devices such as pacemakers, implantable radio transmitters, gastric stimulators, smart gesture gloves, fitness and motion trackers, and wearable biosensors.

iii) **Energy storage:** Electro-chemical capacitors which use carbon nanotubes can be fully charged in minutes and in some cases, seconds. This ensures fast energy storage, although the quantum of energy stored is lower than conventional batteries. In this regard, new personalized carbon-based supercapacitor systems are being developed, using electrolytes integrated with compliant carbon electrodes. This will lead to better performance in terms of energy storage through the development of new electrolytes which are highly compatible with carbon electrodes.

Another area of development is Bio-Fuel Cells (BFC), which are bio-harvesting energy devices; these enhance energy conversion efficiency by incorporating metal nanoparticles with high catalytic activity and synthesizing redox mediators onto carbon surfaces. Carbon based electrodes are comprised of carbon nanomaterials and nanocomposites, with either conductive polymers or nanometal oxides and are most suited to these applications due to additional retention of high power and energy densities for use in energy-storage devices. Furthermore, these are hybrid systems with various multiple functionalities and capable of incorporating highly flexible BFCs and supercapacitors with other energy devices, such as nano-generators.

Based on the above discussion, it may be concluded that the remarkable properties, performance characteristics and diverse array of applications of carbon nanotubes make these an immensely valuable and worthful pathway to utilize CO_2 as a part of a larger strategy for decarbonization through CO_2 utilization. However, there are a few technology gaps (see Table 5-6) which need strong developmental attention and international cooperation for CO_2 to carbon nanotubes to develop as a technologically superior and economically sustainable solution.

Table 5-6: Technology Gaps in CO_2 to Carbon Nano-Tubes

Sl. No	Areas of Challenges	Technology Gap
1	Stability & Reproducibility	Challenges in controlling CNT size and creating CNT arrays of high pore density while maintaining requisite mechanical properties.
2	Affordability & Sustainability	The cost has to significantly reduce with more focused development on material synthesis for high-quality, purity and efficient CNTs through an energy-efficient conversion process from sustainable sources e.g., CO_2 .
3	Shape & Structural Compatibility	Non-conventional & odd geometrical-shaped CNT membranes require more advanced nanoscale fabrication techniques at the atomic level
4	Toxicity & Environmental Impact	Raw CNTs are more toxic than functionalized CNTs because of the existence of metal catalysts. Thorough investigations are required on this subject.
5	Bio-suitability	Stability of enzymes in carbon-based electrodes and related wiring in the internal structure of nanomaterial walls.
6	Mechanical Resilience & Biofouling	Mechanical robustness to be maintained in dynamic biological environments without triggering any biological growth or degradation

CO_2 Storage Potential

6.1 Necessity of CO_2 Storage

CCUS contributes to the permanent utilization and sequestration of CO_2, irrespective of whether the CO_2 is captured from anthropogenic sources or the CO_2 stock of the atmosphere. Though CO_2 utilization is relatively more nascent compared to the capture and geological storage of CO_2, CO_2 utilization has multiple facets and applications, such as CO_2 to urea, conversion of CO_2 to chemicals such as methanol & ethanol and utilization of CO_2 in producing aggregates and building materials. In terms of technology maturity and commercialization, the production of urea and chemicals using CO_2 is more advanced and offers a pathway to convert CO_2 to value-added products with economic value. In comparison, the use of CO_2 in making cement and building materials is relatively more nascent.

However, only pursuing the utilization of CO_2 is not sufficient to handle the anthropogenic CO_2 volumes from the different target sectors which are amenable to capture. In 2021, the cumulative global demand for urea and the chemicals such as methanol, ethanol (including bioethanol) and downstream chemicals such as ethylene & propylene was about 530 mtpa. Even in the unlikely scenario that the entire urea and chemicals industry shifted to the CO_2-based route of production, the maximum volume of CO_2 that can be utilized would be about 850 mtpa of CO_2. This would, at best, account for only 5% of the global CO_2 emissions amenable for capture, as estimated in Chapter 2. The projected scenario for 2030 is also similar, even as many industries become more energy efficient and reduce their CO_2 intensity and emissions.

Thus for enabling CCUS at the giga-tonne scale (the estimated volume of CO_2 amenable for CCUS is 14-15 Gtpa), it is imperative to seriously look at the options for the permanent storage of CO_2 in deep underground geological formations & reservoirs like depleted oil & gas reservoirs (for enhanced oil recovery or EOR), deep saline aquifers, and basalt rock formations, even if some of these options provide no or lower economic value vis-à-vis CO_2 utilization applications.

6.2 CO_2 Storage Mechanisms, Site Screening Parameters & Site Options

Given the scale of anthropogenic CO_2 emissions and the comparatively limited CO_2 volumes that can be utilized to make value-added products, identifying, exploring and quantifying options for the permanent storage of CO_2 is critical to support CO_2 disposition at the giga-tonne scale.

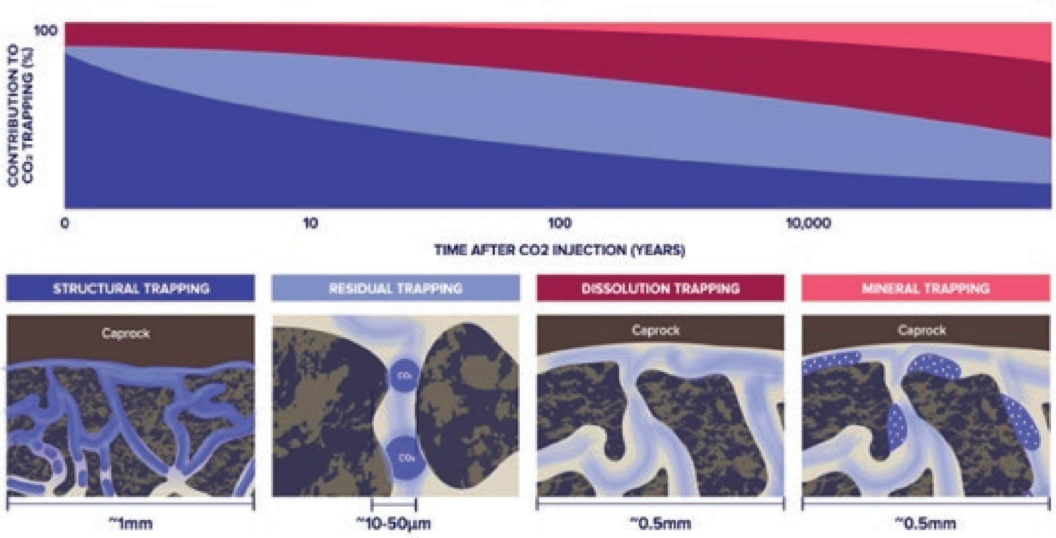
The different CO_2 storage options can be categorized based on the purpose of the CO_2 disposition. The first category consists of two options that also offer an opportunity for CO_2 utilization: Enhanced Oil Recovery (EOR) in depleted oil & gas fields and Enhanced Coal Bed Methane Recovery (ECBMR) in hard-to-mine coal seams. The second category involves only the underground injection & storage of CO_2 and also consists of two options: storage in onshore & offshore saline aquifers and storage in basaltic formations.

Other evolving CO_2 storage-cum-utilization options include the CO_2 battery made by Energy Dome in Italy, for storing CO_2 in large domes and using it in a cyclic manner between a compressor & a turbine set up to generate power. The technology provides a potential option for on-surface CO_2 storage option with an added advantage of power generation – however, the footprint and land requirement of such a project required to store large volumes of CO_2 would be quite high.

6.2.1 CO_2 Storage Mechanisms

When CO_2 is injected into any underground geological formation, it interacts with the formation and elements present in the formation, resulting in 4 types of trapping mechanisms: physical, residual, dissolution, and mineralization. The injected CO_2 is trapped as a result of all the mechanisms, though the rate at which CO_2 trapping is affected by each mechanism varies.

Figure 6-1: Structural CO_2 Trapping Mechanisms



Source: 2022 Status Report, GCCSI

i) **Physical Trapping:** This is the simplest form of trapping mechanism. The injected CO_2 is trapped in the formation due to the absence of any pathways to escape/leave the formation. It is crucial to have a low permeability capping structure above the formation to act as a seal for the formation and trap the injected CO_2. This is considered the predominant storage mechanism in the initial stages of a CO_2 injection operation.

ii) **Residual Trapping:** Geological formations have small pore structures throughout their structure. These pores are connected and generally have an average size of <1mm. These pores make up about 10-30% volume of the formation structure (bulk rock). Residual trapping takes place due to the capillary forces of the pore structure acting on the injected CO_2. A substantial volume of CO_2 is trapped by this mechanism even though the phenomenon takes place at a micro-scale; the CO_2 trapped due to the capillary forces in these pores is held strongly against the surface of mineral grains. The storage of CO_2 is affected by this trapping mechanism in the initial phase (decades) from the time of injection.

iii) Dissolution Trapping: Brine solutions present in the geological formations also contribute to CO_2 storage due to the dissolution of CO_2 in the brine solution. The solubility of CO_2 in the brine solution is determined by various factors, such as the salinity of the brine solution and temperature & pressure at the reservoir. Upon the dissolution of CO_2 in the brine solution, the resulting saturated solution will have a higher density than the unsaturated brine solution. This results in the displacement of CO_2-saturated brine solution to a deeper level below the unsaturated brine solution, thus guaranteeing the permanence of CO_2 storage. The process is relatively slow and may affect CO_2 storage at a much later period from the time of injection (decades to centuries).

iv) Mineral Trapping: The geological formations selected for CO_2 sequestrations have the presence of minerals in their structure. As the CO_2 enters the structure, it interacts with the surroundings. A portion of this CO_2 volume comes in contact with the mineral elements and chemically reacts with the minerals to form carbonate minerals. These carbonate minerals are then deposited and permanently stored in the rock formation. The reaction is slow to progress, so this mechanism traps very small volumes of the injected CO_2 . Basaltic rocks have higher reaction rates for mineral carbonate formation and thus can be considered a viable storage option for mineral trapping mechanisms.

6.2.2 Physical Properties to be Considered for CO_2 Storage Site Selection

For the screening of feasible CO_2 storage sites, various physical and geological properties have to be considered. A preliminary screening of sites can be done based on the properties given in Table 6-1. A comparison of options based on these properties would help in finalizing the site for undertaking detailed studies for the proposed CO_2 injection project.

Table 6-1: Properties for Preliminary Screening of CO_2 Storage Sites

Property	Details
Unit depth	• The selected site must be at a depth much lower than the underground safe drinking water (saline water to 10,000 ppm TDS) to avoid contamination. • Ideal depth of injection zone: > 800 m • Ideal depth of confining system: > 800 m • Closer to the basement increases the risk of microseismic activity
Unit thickness	• Larger thickness of geological formation boundary results in lower chances of CO_2 leakage from the formation. The area of review (AOR) or the area surrounding the injection well for such a site would be less. • Larger thickness can enable higher acceptable CO_2 column height. • Larger thickness may result in lower seismic response on injection

Property	Details
Porosity	• It is the share of void volume in a formation. • Larger porosity is desired for higher storage capacity. • The area under AOR decreases if porosity is high. • Large porosity causes lower pressure increase, therefore lowers the risk of seismic activity
Pressure magnitude	• Critical to assess the pressure elevation and state of stress of all impacted zones to predict the likely seismic response
Permeability	• It is the measure of the ability of the structure of the formation to transmit fluids (dense phase CO_2 in this case) • Large permeability within the formation is desired for the CO_2 to occupy pore spaces with ease. • Larger value means lower pressure increase, therefore lowers the risk of seismic activity
Boundary conditions	• Boundary of the formation may be open or closed. • Closed boundary results in a smaller storage capacity and increased chances of high pressure in the formation, leading to an increased probability of seismic activity.
Mineralogy	• Information required to understand the interaction of injected CO_2. • Fault, fracture and state of stress information is needed to assess the effect of mineralogy on seismic response to CO_2 injection. • It may impact the CO_2 plume area.

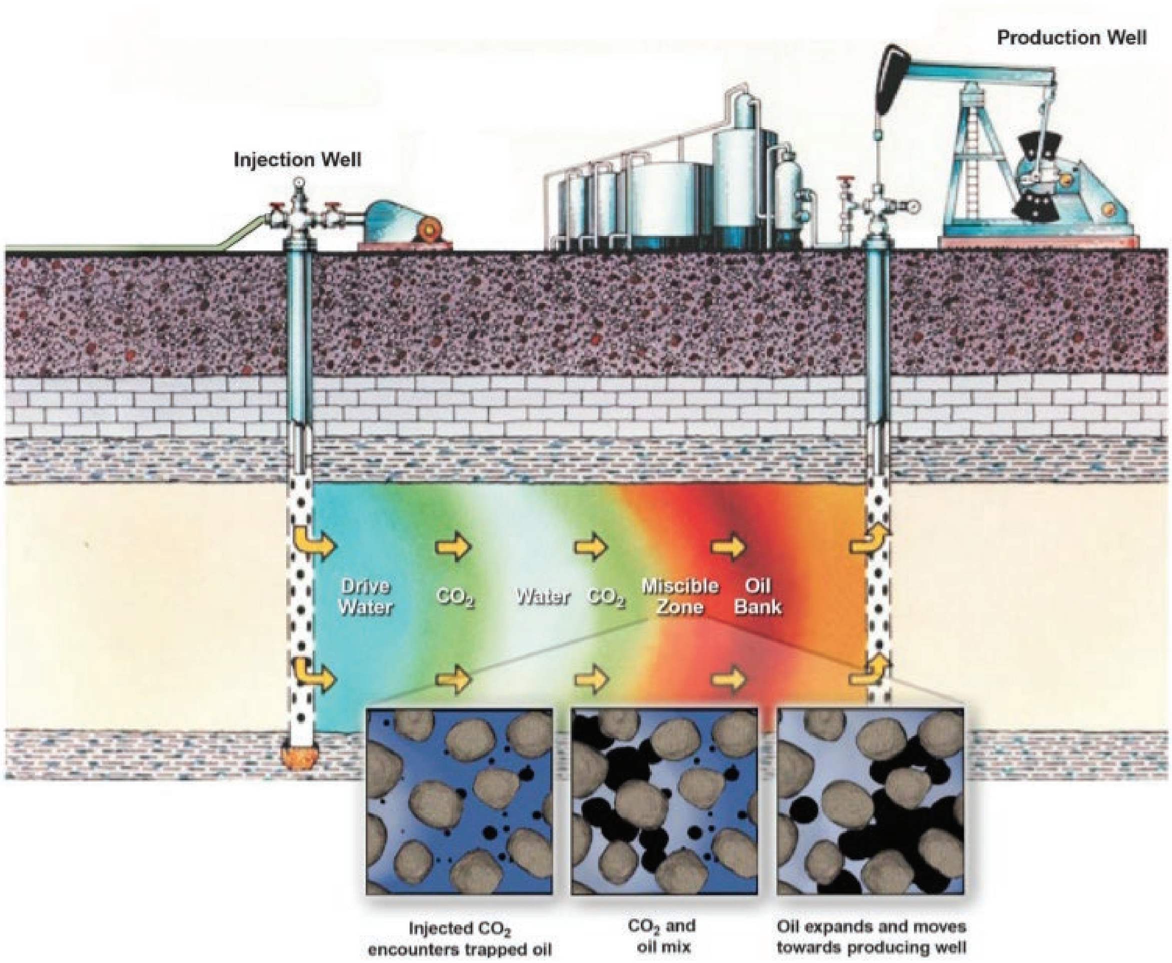
6.2.3 Enhanced Oil Recovery (EOR) in Depleted Oil & Gas Fields

Oil recovery techniques can be categorized as primary, secondary and tertiary recovery techniques. Primary techniques rely on natural reservoir pressure and the use of pumps to bring oil to the surface, but the recovery is only about 10%. Secondary techniques involve the injection of water or gas in the reservoir to drive the oil to the production wellbores. This helps in the recovery of 20-40% of the original oil in place. To further improve the production performance of wells, tertiary techniques are used. Tertiary techniques of recovery include thermal recovery (steam injection), gas injection (CO_2 injection), and chemical injection (use of polymers or surfactants). These help in the production of 30- 60% of the original oil in place.

The injection of CO_2 for EOR has been studied and applied for years, especially in North America. CO_2 is miscible with crude oil, which helps in recovering oil not possible by secondary methods. This also helps in permanently storing CO_2 in oil reservoirs, thus making CO_2 EOR a sustainable option for abating CO_2. In CO_2 EOR, compressed CO_2 is injected into the reservoir. At high densities, CO_2 is readily miscible with oil. It swells the oil and reduces its viscosity, thereby driving it away from rock formations and toward the production wells. A minimum pressure is required for CO_2 and oil to be miscible. To prevent the lower viscosity CO_2 from escaping the reservoir, water and CO_2 are injected alternatively.

The fitness of any oil reservoir to store CO_2 is validated by evaluating various geological parameters. The reservoir under consideration must have suitable sealing mechanisms to prevent any fugitive emissions of CO_2 that will be sequestered in it. It must also have high porosity to store sizable volumes of CO_2. The permeability of the reservoir must be sufficiently high for ease of CO_2 pumping and storage. A detailed geological survey of the reservoir needs to be undertaken to evaluate the storage capacity and risks associated with storing CO_2 in the reservoir.

Figure 6-2: Working of CO_2 EOR



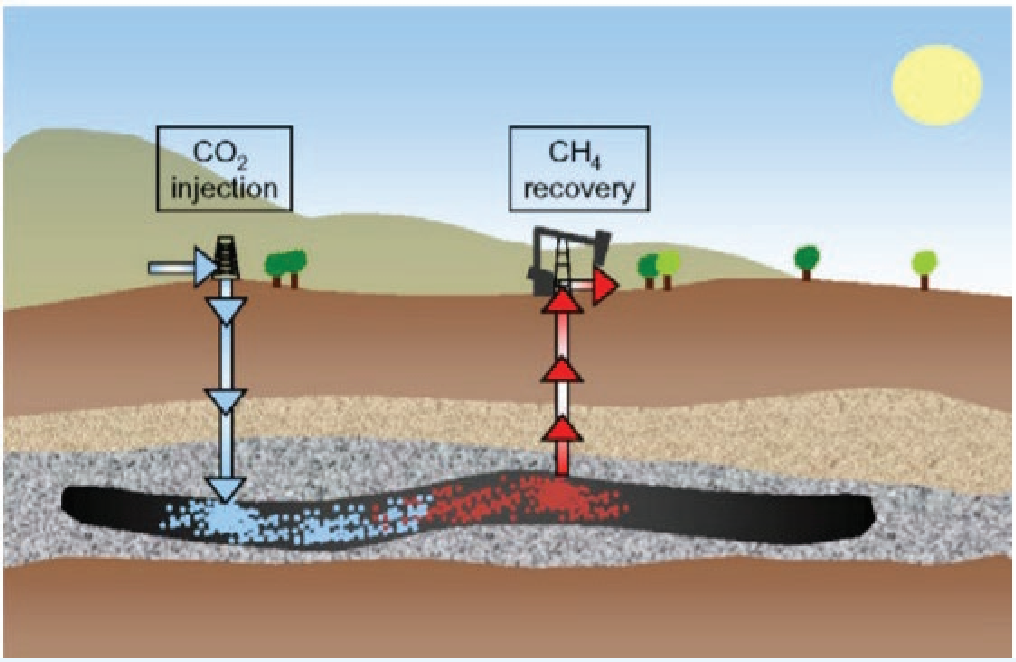
Source: CO_2 EOR primer, NETL

6.2.4 Enhanced Coal Bed Methane Recovery (ECBMR) in Deep Coal Seams

Coal bed methane (CBM) can be produced from coal seams and can contribute to the energy security of countries with rich coal resources. In ECBMR, CO_2 is injected into unmineable coal seams under supercritical conditions. The coal seams present at a certain depth (more than the mining depth) can be considered a suitable option for the storage of CO_2. The injected CO_2 is accumulated in the coal cleats in a dense gas phase. This CO_2 is adsorbed on and absorbed in the coal. Since CO_2 has a higher affinity for coal than CBM, it pushes the coal bed methane towards the production wells, thus enhancing its primary recovery.

Similar to CO_2 EOR, ECBMR can help in permanently storing CO_2 and the recovered methane can also help offset the cost of carbon capture. As noted in the case of sequestration in oil fields, CO_2 storage in coal seams is also affected by several geological parameters and other properties of the coal formation. The permeability of the coal seams must be sufficiently high to allow the injected CO_2 to spread across the maximum part of the coal matrix, which is generally not the case with deep-lying coal seams as they are more compact. It has also been observed that the coal seams tend to swell up upon injecting CO_2, which further reduces the permeability of the coal seam. ECBMR can be a viable option for coal based thermal power plants located near coalfields. Figure 6-3 gives a pictorial representation of the ECBMR process.

Figure 6-3: Working of CO_2 ECBMR



Several pilot tests for ECBMR have been performed across the world, but there is no commercial-scale ECBMR plant (Mazzotti, Pini, & Storti, 2009). Thus, further R&D is required before commercial deployment.

6.2.5 Storage in Deep Saline Aquifers

Captured CO_2 can be permanently stored in deep saline aquifers. Unlike EOR and ECBMR, injection of CO_2 in deep saline aquifers has no economic benefit. Deep saline aquifers are spread across very large areas and, thus, have the potential to store very high quantities of CO_2.

Deep saline aquifers consist of porous rock formations that contain high quantities of unusable salt water. The salt/mineral content is very high in this water, rendering it unusable for human use. The brine water is called formation liquid, and it is trapped by an impermeable rock called the caprock.

Supercritical CO_2 can be injected into saline aquifers. Brine water has a higher density compared to the injected CO_2; thus, CO_2 rises towards the caprock and is trapped in the saline aquifer. This is also termed physical/ structural/ stratigraphic trapping. While injecting, some CO_2 might occupy the pore spaces by displacing the previously present fluid (residual trapping). Some of the injected CO_2 also dissolves into the brine. This mixture is denser than the surrounding brine and settles down (dissolution trapping). CO_2 dissolves into water to form a weak carbonic acid that can react with minerals over time to form solid carbonate minerals. This leads to the storage of some portion of CO_2 through the mineral trapping mechanism.

6.2.6 CO_2 Storage in Basalts

Lately, studies have been carried out to explore the CO_2 storage potential of basaltic rocks. Basaltic rocks are formed from the rapid cooling of basaltic lava from the interior of the earth's crust and are at a depth closer to the surface of the earth. These rocks exhibit high porosity and permeability. Basaltic rocks contain divalent cations of Ca, Mg, and Fe, which react with the CO_2 dissolved in water to form stable carbonate minerals (mineral trapping mechanism) and thus can offer a safe CO_2 sequestration method for an extended period. As a result of the high porosity and permeability, the reactivity of basaltic rocks with CO_2 is high, which makes them an area of interest for research related to CCUS.

Compared to mineralization in saline aquifers, basalt rocks offer faster reaction kinetics due to the abundance of iron, calcium, and magnesium oxides. The abundance of basalts on the earth's surface is also a reason for the rising interest in CO_2 storage research and development programs in basalts. According to previous calculations done by researchers, the global CO_2 storage capacity of basaltic formations is estimated to be around 8,000-41,000 Gt of CO_2 (Vikram, Yashvardhan, Debanjan, & Dhananjayan, 2021).

6.2.7 CO_2 Injection Rates in Different Types of Formations

The CO_2 injection rate is dependent on the site-specific parameters described in Table 6- 1. Broadly, the injectivity of CO_2 can be understood from the thickness of the selected site or formation and the permeability of the formation to the injected supercritical CO_2 . The rate of injection for each site also varies depending on the acceptable number of injection wells such that the reservoir/formation pressure does not exceed the fracture pressure (permissible pressure up to which CO_2 may be injected). Thus, generalizing the rate of injection on the basis of storage site options (oil & gas fields, unminable coal seams, saline aquifers, basaltic rocks) is difficult.

i) **Saline aquifers:** In the US, where CO_2 injection has been studied extensively, the most favourable sedimentary basin formations (sites with high thickness and permeability) are expected to have an injection rate of 0.75 to 1.5 mtpa per injection well; for sites with unfavourable physical properties, the CO_2 injection rate may drop to 75 – 150 ktpa per injection well (a 90% drop in injection rate).

ii) **CO_2 EOR:** In case of EOR, the rate of injection is mainly constrained because the thickness of oil reservoirs is lesser than that of the saline aquifers. In the case of EOR, the injection rate is also lower, as CO_2 and water are often injected in an alternating manner to reduce the cost of purchasing CO_2 for EOR. An injection rate of 0.2 mtpa per injection well is assumed as a rule of thumb for reservoirs with suitable characteristics.

iii) **Basaltic formations:** The CO_2 disposition in basaltic formations is primarily governed by mineral trapping mechanisms. Even though basaltic rocks exhibit faster reaction kinetics, it largely depends on the varying mineral composition. The injection rates in basaltic rock are kept low to avoid excessive pressure build-up in the formation.

iv) **ECBMR:** Unminable coal seams are present at deeper levels resulting in a highly compacted coal bed that offers very low permeability to the injected CO_2. More research needs to be conducted to understand the favourable injection rate for ECBMR.

A comparison between the different storage options is provided in Table 6-2.

Table 6-2: Comparison of different storage options

Storage option	Rate of injection	Economic benefit to storage	Storage potential	Maturity of technique
EOR	Site characteristics dependent	✓	Low	Commercial
ECBMR		✓	Very low	Pilot scale
Saline Aquifer		✗	Very high (Theoretical)	Pilot scale
Basaltic Rocks		✗	High (Speculated)	R&D

6.3 Capacity Assessment for CO_2 Storage – Global and G20 Countries

The efforts to survey and quantify the CO_2 storage potential of various categories of storage sites (as discussed in the previous sections) have increased due to the CCUS policy focus and programs by several countries. This has led to the creation of global storage databases and cyclic assessment of the national reports and research work for updating the global resource base. Geological sequestration mechanisms will be critical to the success of both operational and future carbon capture projects. Further work (discussed in subsequent sections) is required to acquire real-time storage data for the different CO_2 geo-sequestration options.

Based on secondary research (literature and published reports), the global geological CO_2 sequestration capacity considered in the global resource base is about 13,954 Gt of CO_2 (2022 Status Report, GCCSI). The potential and appropriateness for CO_2 sequestration have to be validated with subsequent geological surveys, seismic studies, and pore space mapping.

The resources validated with data from such detailed studies are said to be the discovered resources. According to the GCCSI report, the discovered CO_2 storage resources amount to only 577 Gt out of the total potential resource. The challenge of declaring these as commercial resources requires the formulation of an appropriate legal and regulatory framework around CO_2 sequestration, in-depth techno-commercial analysis of the storage site, and ensuring that there are no obstacles in the process of project development. Currently, the majority of the discovered resources cannot be classified as commercial resources due to a lack of supporting evidence in the form of geotechnical data and the absence of supporting policies and regulations for CO_2 storage. Only 253 mt CO_2 storage resources can be classified as commercial resources.

A theoretical estimation based on validated models needs to be made to quantify the potential of geological sequestration of CO_2 . This kind of estimation will help in forming the basis for more focused studies where the actual capacity can be assessed and validated. This preliminary assessment may also aid in identifying and prioritizing the regions that have generous storage potential compared to others. Published research in this area has utilized established models and base principles (using standard formulae) to estimate the theoretical storage capacity.

In Jordan Kearns' work, the country-wise and global estimation has been made based on the EPPA 6 model - the global storage capacity is estimated to be in the range of 7,910– 55,581 Gt. Almost 70% of the estimated capacity is present in the form of onshore sedimentary basins. Saline aquifers account for a large chunk of this storage capacity. The model also predicts the storage capacity of various nations and regions. With increased hydrocarbon exploration activities in developing nations, the quality of data related to different sedimentary basins has also substantially improved. This data can be utilized in standard formulae and other successful estimation methodologies to estimate the theoretical capacity for the region, as done in the research work of V. Vishal et al. (2021), wherein their team has performed CO_2 capacity estimation for India.
(https://www.sciencedirect.com/science/article/abs/pii/S0921344921004389)

The GCCSI status reports update the global geological storage capacity in collaboration with the Oil and Gas Climate Initiative (OGCI), which maintains the CO_2 Storage Resource Catalogue (CSRC) based on the work of STOREGGA. They maintain a conservative approach towards storage capacity identification as they report only based on the data available in national reports, atlases, or published by international institutions such as the IEA. A comparison of the reported data and data estimated in various research works will help create a roadmap for CO_2 storage capacity assessment by dedicated geological, geo-mechanical, or seismic studies 'focused' on region-wise CO_2 storage. For this purpose, the theoretical estimations from the literature and reported data from GCCSI Status Report 2022 for the G-20 countries and globally have been tabulated in Table 6-3.

Table 6-3: CO_2 EOR Storage Capacity Estimates

Country	Jordan Kearns et al. (2017)[b]		GCCSI Report (2022)			Other Sources (Gt)
	Min. Potential (Gt CO_2)	Max. Potential (Gt CO_2)	Total (Gt)	EOR (Gt)	Saline Aquifer (Gt)	
Argentina	-	-	-	-	-	5.1[d]
Australia	595	4,184	502.40	15.07	487.33	-
Brazil	297	2,087	2.47	2.47	-	-
Canada	318	2,236	404.00	12.12	391.88	-
China	403	2,830	3,077.00	-	3,077.00	-
France	-	-	-	-	-	0.415[e] - 29.04[f]
Germany	-	-	0.11	-	0.11	-
India	99	697	64.00	0.64	63.36	395-614[a]
Indonesia	163	1,184	15.86	1.74	14.12	-
Italy	-	-	-	-	-	5.134[f]
Japan	8	59	152.27	3.05	149.22	-
Republic of Korea	3	24	203.40	0.02	203.38	-
Mexico	138	967	100.80	-	100.8	-
Russia	1,234	8,673	-	-	-	-
Saudi Arabia	-	-	0.74	0.74	-	-
South Africa	-	-	342.93	185.18	157.75	-
Turkey	-	-	-	-	-	0.108[g]
UK	-	-	77.60	7.76	69.84	-
USA	812	5,708	8,061.81	241.85	7,819.96	-
European Union	302	2,120	-	-	-	547.00[f]
G-20 Total	**4,668**	**30,686**	**13,005**	**471**	**12,535**	-
Global Total	**7,910**	**55,581**	**13,954**	**-**	**-**	-

Source:
a) Vishal, Vikram, et al. "Understanding initial opportunities and key challenges for CCUS deployment in India at scale." Resources, Conservation and Recycling 175 (2021): 105829.

Source:
b) Kearns, Jordan, et al. "Developing a consistent database for regional geologic CO_2 storage capacity worldwide." Energy Procedia 114 (2017): 4697-4709.
c) GCCSI Status Report 2022 (CSRC)
d) Pique, Teresa Maria, et al. "Atlas Ar-Co_2. An Argentinean Atlas for Underground Co_2 Storage Potential." An Argentinean Atlas for Underground Co_2 Storage Potential (November 18, 2022) (2022).
e) STRATEGY CCUS
f) "EU Geological CO_2 storage summary (2021)" prepared by the Geological Survey of Denmark and Greenland for Clean Air Task Force
g) "Geologic CO_2 storage in Eastern Europe, Caucasus and Central Asia: An initial analysis of potential and policy", United Nations Economic Commission for Europe (UNECE)

These are the broad storage potential estimates of the respective countries and do not take into account the CO_2 already injected to date. However, given the order of magnitude difference between the scale of the storage opportunity and the volume of CO_2 globally captured and sequestered every year, the extent of the storage opportunity already used up is minuscule.

Nevertheless, at the site level, monitoring the CO_2 plume and the storage space available post-injection is a necessary practice. A general principle followed for determining the maximum limit of CO_2 injection is based on the fracture pressure of the caprock of the geological formation; injection operations are terminated when the reservoir pressure approaches the caprock fracture pressure. Pressure modelling for future injection may give information about the volume of CO_2 that can be further stored in the future in that particular formation/ reservoir. Zhang, Kai et al. (2022) have published their work on reservoir simulation to investigate CO_2 storage in the saline aquifer in Sleipner (Norway) through reservoir pressure management. Their simulation predicts possible CO_2 storage until 2032, when the reservoir pressure will match the caprock fracture pressure limit. They predict a cumulative storage of 32.6 mt of CO_2 by 2032.

6.4 CO_2 Storage Potential Assessment in G20 Countries

The G20 countries cover a large share of the total estimated geological CO_2 sequestration potential. Although efforts have been put in by several countries to analyze their territorial CO_2 storage, a very small share of this estimated capacity has been characterized and classified as commercial storage resources. Thus, it is important to assess the status of storage potential analysis in different countries to identify the gaps and current barriers or shortcomings in the CO_2 storage analysis. This section focuses on reviewing the current assessment stage of the G20 countries.

i) Argentina:

Argentina has hydrocarbon-rich basins and hence the CO_2 storage potential is expected to be good. However, no in-depth storage assessment has been undertaken. The recent work of Pique, Teresa Maria, et al. (2022) has attempted to generate a high level storage potential estimate by applying the US Department of Energy's (US DOE) volumetric method for estimation for the Neuquén (2.1 Gt), Golfo San Jorge (2.3 Gt), and Claromecó Basins (0.7 Gt) in Argentina.

ii) Australia:

The Australian Government has been actively studying and assessing geological CO_2 sequestration potential for the past 20 years through various assessment projects. The project GEODISC was carried out from 1999 to 2003 for the Australian Petroleum Cooperative Research Centre (APCRC). The project was aimed at assessing the national CO_2 storage and the related infrastructure. During the project, all the sedimentary basins were assessed along with characterizing the basins on the basis of several geological parameters and the project concluded with a risk and economic analysis for CO_2 storage along with source-sink mapping. This was followed by the formation of the Cooperative Research Centre for Greenhouse Gas Control Technologies (CO2CRC), which was tasked with the research and demonstration of CCS. Geoscience Australia, a part of this collaboration, was involved in activities like CO_2 geological storage, greenhouse gas monitoring and verification, and the development of a CO_2 injection demonstration site in Australia.

A National Carbon Mapping and Infrastructure Plan (NCMIP) was launched and completed in 2009 under the National Low Emissions Coal Initiative (NLECI). A high-level assessment of Australia's potential and capacity to transport and store CO_2 was carried out. The sedimentary basins were ranked according to their potential & capacity and optimized; feasible pipeline routes for CO_2 transportation from emission sources to the sink were mapped using the CO_2 pipeline route planning tool. A program named National CO_2 Infrastructure Plan (NCIP) was launched in 2012 under the NLECI to accelerate the identification and development of CO_2 storage sites close to major emission sources.

The results and proceedings have been made available by Geoscience Australia. The program was focused on a detailed assessment of selective regions and the acquisition of new geological data.

iii) Brazil:

The assessment of the CO_2 geological sequestration potential of Brazil was performed as part of the Brazilian Carbon Geological Sequestration Map (CARBMAP project), initiated in 2006 by the Brazilian Carbon Storage Research Center. The purpose of this project was to generate and maintain a Geographic Information System (GIS) that would store data on CCS and aid in the evaluation of the sequestration potential of Brazil.

The project was executed in 2 phases. The first phase was executed in 2006-2007. A preliminary source-sink mapping was completed in this phase, where stationary CO_2 emission sources were mapped with the sedimentary basins in the country for geological sequestration evaluation. A preliminary theoretical evaluation of CO_2 storage potential was also carried out for the oil & gas fields, saline aquifers, and coal beds. The assessment pointed out the high potential of aquifers to store CO_2 (2035 Gt) compared to the hydrocarbon fields (4 Gt) and the very low storage potential in the coal bed.

Phase 2 of the CARBMAP project commenced in 2008 and was completed in 2010. During this period, the GIS database from phase 1 was updated with more accurate estimations based on the availability of more geological data. Simultaneously the CO_2 sources and the source-sink mapping were also updated in phase 2.

In 2015, as a result of the collaboration of the Centre of Excellence in Research and Innovation in Petroleum, Mineral Resources and Carbon Storage (CEPAC) and the Global Carbon Capture and Storage Institute (GCCSI), a Brazilian Atlas of Carbon Capture and Storage was published and updated in 2016. This atlas evaluated the storage perspective in oil and gas fields, aquifers, coal beds and basalts with a focus on the quantitative evaluation of the Campos basin.

iv) **Canada:**

The assessment of Canada's geological sequestration potential has progressed because of various collaborative projects such as the Regional Carbon Sequestration Partnerships (RCSPs). The North American Carbon Storage Atlas (2008-2012) was developed with the participation of Canada, USA, and Mexico. The atlas evaluates the list of stationary emission sources and the potential geological CO_2 storage reservoirs. This generated high-level data for initial storage potential assessment and a data-based source-sink mapping for CO_2.

The Carbon Storage Atlas V published and maintained by NETL also lists the data on the storage potential of Canadian provinces involved in various RCSPs like the Western Coast Regional Carbon Storage Partnership (WESTCARB) and the Plains CO_2 Reduction Partnership (PCOR). The storage assessment in the province of British Columbia was included in the WESTCARB program, while the PCOR program characterized and evaluated the storage potential of sedimentary basins in the provinces of Alberta, Saskatchewan, and Manitoba. These programs have not only characterized the geological formations but also demonstrated the storage of CO_2. The NATCARB atlas maintains information about the various RCSPs and the active projects in the regions and is available for public access.

v) **China:**

China's potential to store CO_2 in geological formations was assessed in a report published by the Pacific Northwest National Laboratory (PNNL) in 2009. This work evaluated depleted oil & gas basins, saline aquifers and deep unmineable coal seams as potential candidates for long-term CO_2 sequestration. The study prioritized the evaluation of onshore basins but also gathered and reported preliminary data for offshore basins. This report provided a high-level estimation of the storage potential and was intended to be a starting point for more detailed characterization studies.

A more recent geological study is based on the seismic profiling done as part of the CCS demonstration projects in the Shenhua province, where CO_2 is being injected in a saline aquifer and also in cooperation with the Carbon Capture and Storage China-EU (COACH) project, where the geological storage opportunities were investigated in the Bohai basin in China. The focus of the latter was evaluating the storage potential of the Dagang oilfield complex (Tianjin Municipality), deep saline aquifers in the Jiyang depression (Shandong province) and the Kailuan coalfield (Hebei Province).

Wen, Dongguang, et al. (2018) have also evaluated the storage potential in Junggar Basin, located in northern Xinjiang, using static reservoir modelling and dynamic simulations to understand the storage potential and the storage mechanism (residual trapping and CO_2 dissolution into formation water) of CO_2 over a prolonged period. More such work has been carried out as a result of demonstration projects yielding quality data to be applied in static and dynamic modelling.

vi) European Union:

The assessment of CO_2 storage potential for the European countries is drawn from the report "EU Geological CO_2 storage summary (2021)" prepared by the Geological Survey of Denmark and Greenland for the Clean Air Task Force. The assessment across European countries has progressed through various projects and programs, as listed in Table 6-4.

Table 6-4: List of European CO_2 storage assessment projects

Project Name	Year	Remarks
Joule II	1996	• Theoretical CO_2 storage capacity estimated for 13 European countries.
Geological Storage of CO_2 from Combustion of Fossil Fuel (GESTCO)	2004	• Conducted for 7 north-western European countries and Greece. • Mapped storage options such as regional saline aquifers, storage reservoirs (geological structures), oil/gas fields and coal beds. • The efficient storage capacity was calculated and updated in the GIS database.
CO_2 from Capture to Storage (Castor WP 1.2)	2006	• Mapped and integrated storage capacity data for 8 additional Eastern Europe countries in the GESTCO GIS.
EU GeoCapacity	2009	• GESTCO database updated for 25 European countries and 2 provinces of China • Results provide an efficient CO_2 storage capacity
Nordic CO_2 storage Atlas	2014	• Focus countries: Denmark, Finland, Iceland, Norway, Sweden • Evaluated storage capacity in saline aquifers, storage reservoirs (geological structures), hydrocarbon fields, porous basalts and ultramafic rocks.
CO2StoP	2015	• Harmonized the GIS-database from EU GeoCapacity. • Includes publicly available data from 27 European countries. • A revised approach towards categorizing potential geological storage formation was introduced.

Source: EU Geological CO_2 storage summary (2021)

Other regional studies have also contributed to the storage capacity estimations. The high-level estimate is available for all the countries, while some research bodies are also involved in demonstration projects, 2D & 3D static modelling and dynamic modelling for CO_2 injection, Individual levels of storage assessment have not been explored in this report. The assessment data available for the EU countries are as follows:

a) **Austria:** A total of 6 saline aquifers have been mapped within Austria. The theoretical storage potential is estimated at about 20 Gt (Poulsen et al. 2014), but the estimate is tentative. The Austrian Government's Federal ministry, in their long term strategy for 2050 has stated a storage capacity of only 400-510 mt of CO_2 .

b) **Belgium:** A total of 6 saline aquifers and 2 storage reservoirs have been identified as suitable for CO_2 injection and storage. The cumulative capacity for these formations amounts to 260 - 282 mt. Due to the lower coverage of sedimentary basins suitable for CO_2 storage, the estimations for Belgium are on the lower side.

c) **Bulgaria:** Potential CO_2 storage sites have been identified in the eastern parts of Bulgaria. The theoretical storage capacity is estimated to be 2-3 Gt in 11 saline aquifers and 4-6 Gt in the hydrocarbon fields.

d) **Croatia:** The EU Geological Storage Summary considers storage opportunities in the Adriatic Sea and the eastern part of Croatia. The estimated total capacity is 4 Gt in 14 saline aquifers and 175 mt in 17 hydrocarbon fields. The STRATEGY CCUS group estimates a total storage capacity of 2.7 Gt; 2.6 Gt is from five different deep saline aquifers and 14 exhausted oil & gas fields account for the remaining storage (144 mt). However, it's possible that the exhausted hydrocarbon resources will be the first to be used for the storage of CO_2 through EOR.

e) **Cyprus:** No information or estimate is available on the potential CO_2 storage capacity in Cyrus. A study was planned to be conducted by the University of Nicosia's Centre for Green Development and Energy Policy (CGD) and Scottish Carbon Capture & Storage (SCCS) to understand and evaluate the likely geological CO_2 storage sites beneath the Mediterranean Sea, to the south of Cyprus.

f) **Czech Republic:** A few saline aquifers and basins located in the eastern parts of the country offer potential storage opportunities for the emission sources located in the northeastern part of the Czech Republic. The estimated storage capacity is quite moderate: 400 mt in saline aquifers, 190 mt in storage reservoirs and 18 mt in hydrocarbon fields.

g) **Denmark:** Based on the most recent evaluation of the Danish storage capacity in 2020, it was determined that the capacity in storage reservoirs and hydrocarbon fields ranges from 12 to 25 Gt (as per an unpublished internal memorandum). This capacity is consistent with earlier European evaluations.

h) **Estonia:** According to the available sedimentary basin mapping, no storage options are available in Estonia.

i) **Finland:** Finland lacks any potential for geological CO_2 storage; any CO_2 captured in Finland would need to be transported and stored outside Finland's borders. The Baltic Sea has some theoretical capacities, but as per studies done so far, the formations have poor injectivity.

j) **France:** The estimates for the CO_2 storage potential in France are provided by the Bureau de Recherches Géologiques et Minières (BRGM) in the European Horizon 2020 STRATEGY CCUS project. The study focussed on the Paris basin and the Rhone Valley, which have sedimentary basins consisting of depleted oil fields. The Paris basin had a better collection of data on the geological profiling due to geothermal activity and former oil & gas exploitation.

A lack of data availability was noted for the Rhone Valley basin due to fewer studies being carried out in the region. The study assessed the storage capacity to be 0.085 Gt for the Rhone Valley and 0.33 Gt for the Paris Basin and also identified the lack of maturity of these sources.

According to the GIS database in EU GeoCapacity and the CO2StoP project, France has three major basins with five mapped saline aquifers and a total estimated storage capacity of 29 Gt. Although the capacity of storage reservoirs is not specified, the Paris Basin's hydrocarbon fields have been estimated to have a storage capacity of only 39 mt.

k) **Germany:** Underground CO_2 storage has gained public attention in Germany as the country is pursuing ambitious CO_2 reduction targets of minus 40 per cent until 2030 and at least minus 80 to 95 per cent until 2050. A methodology was applied to gain an understanding of the effective storage capacity of onshore aquifers in Germany. The estimate is based on the averaged values from site-specific investigations.

The South Permian Basin (SPBA) covering most of northern Germany offers CO_2 storage options and together with basins south of SPBA, Germany has several storage possibilities, but only a few close to the regions with the highest emissions. Storage capacities for saline aquifers are not included in the CO2StoP, but for Germany as a whole, 24 storage reservoirs are reported in CO2StoP, with a total capacity of 1 – 3 Gt and an additional 2 Gt storage capacity in hydrocarbon fields. A conservative estimate from EU GeoCapacity mapped almost 15 Gt storage capacity in saline aquifers.

i) **Greece:** Theoretical storage capacity estimation has been undertaken for the geological formations in Greece. The prospective storage sites are situated in the northern part of Greece. Three saline aquifers have a total storage capacity of 1 – 2 Gt and 5 storage reservoirs have a mean capacity of 2 Gt. The storage capacity in 3 hydrocarbon fields is estimated to be around 37 mt.

m) **Hungary:** Storage regions are located in western and south-eastern Hungary. The storage capacity estimated for 16 mapped saline aquifers is 311 mt. A further 450 mt of storage capacity is reported in 5 storage reservoirs and 100 mt in 14 hydrocarbon fields.

n) **Ireland:** Nine saline aquifers are mapped in Ireland with a total capacity of 500 mt (Poulsen et al. 2014). One hydrocarbon field has a reported storage capacity of 332 mt, while one storage reservoir has a 40 mt storage capacity.

o) **Italy:** The storage area extends southward from Italy's mid-north region along the country's eastern coast. There are 26 identified saline aquifers with a combined capacity of 5 Gt. Although storage reservoirs are not mentioned, it is estimated that hydrocarbon fields have around 134 mt of storage capacity.

p) **Latvia:** Latvia has storage options in storage reservoirs and the total capacity is estimated to be 340 – 930 mt in 18 reservoirs; however, for saline aquifers, the capacity is estimated to be between 1 and 46 Gt.

p) **Lithuania:** Lithuania has storage options in both storage reservoirs (80 mt) and hydrocarbon fields (7 mt).

r) **Netherlands:** The entire storage capacity of the Netherlands's hydrocarbon fields is estimated to be 10 Gt, while storage capacity is 1.4 Gt for the 18 saline aquifers that are included in the assessment for potential CO_2 storage sites. The coastal regions have the highest concentration of emission sources, making offshore depleted hydrocarbon fields an excellent option for storage.

s) **Poland:** The majority of Poland's geology is dominated by the South Permian Basin, which is also present in the northern parts of Germany. The basin presents a good opportunity for CO_2 sequestration in Poland, with 4 saline aquifers mapped with a theoretical storage potential of about 200 Gt; within the basin, 33 storage reservoirs (geological structures) are mapped and can accommodate an estimated 4 to 7 Gt of CO_2 .

t) **Portugal:** The STRATEGY CCUS has stated that the Lusitanian basin in Portugal has the potential to store CO_2 in its geological formations, both onshore and offshore. The onshore formations offer low storage potential with an estimated theoretical CO_2 storage capacity of 340 mt compared to 1.6 Gt of offshore storage capacity (theoretical). There is limited characterization data on the geological formations, but some data is available due to the 3D seismic survey carried out as a part of oil exploration activities in 2012, which can be used for estimations and preliminary simulations.

u) **Romania:** Numerous studies and stakeholder involvement in the CCS4CEE project have underlined Romania's substantial theoretical capacity for CO_2 storage. Deep saline aquifers form the majority of the storage capacity, with depleted hydrocarbon reservoirs (mainly onshore) making up the remaining portion. Based on the assumption that the majority of Romania's remaining hydrocarbons will be extracted in 20 to 30 years and the resulting depleted fields will be available for CO_2 storage, the most thorough estimate (EU GeoCapacity) of Romania's storage capacity found a total theoretical capacity of 22.6 Gt, with 18.6 Gt in deep saline aquifers and 4.0 Gt in depleted hydrocarbon fields, considering both enhanced oil recovery (EOR) and enhanced gas recovery (EGR).

Two suitable sites in the Sarmatian reservoirs (tertiary deposits) of the Getica Depression and the sedimentary basin between the South Carpathians and the Moesian Platform were found to have a storage capacity of about 100 mt each in a feasibility study for the Getica CCS Demonstration Project (2011), which is the only existing CCS proposal in Romania. There is no potential to store CO_2 in unmineable coal seams in Romania.

v) **Slovakia:** The potential CO_2 storage sites are distributed in the western and eastern parts of the country. The majority of the CO_2 storage capacity is offered by 37 saline aquifers and the capacity is expected to be in the range of 2 to 13 Gt, while the hydrocarbon fields offer a very small storage capacity of only 1 mt.

w) **Slovenia:** The country has a number of storage possibilities that have been mapped. 37 saline aquifers are mapped and estimated to have a combined CO_2 storage capacity of 154 mt.

x) **Spain:** A total of 45 saline aquifers with a combined capacity of about 6 Gt CO_2 have been mapped in Spain. These storage facilities are distributed across the northern and eastern regions of the country.

y) **Sweden:** The potential CO_2 storage capacity in Sweden has been published in the CO_2 storage atlas of Sweden based on a study carried out by the Nordic Competence Centre for CCS (NORDICCS). The south-east Baltic Sea and southwest Scania in southern Sweden have been identified as two regions with potential for geological storage of CO_2 , based on screening the data on deep well logs and seismic data. There are a total of eight storage formations and one geological trap identified for CO_2 storage. The combined theoretical capacity for these formations is estimated to be around 3.4 Gt.

vii) India:

The Directorate General of Hydrocarbons (DGH) in India is the authority for managing the survey of sedimentary basins. Their current work focuses on generating geo-scientific data related to the 26 sedimentary basins in India to support hydrocarbon E&P activities. While no country-level mapping of sedimentary basins has been done for CO_2 sequestration, the geological profiling of these basins has generated good quality data to form preliminary estimates of the CO_2 storage potential.

A report published by the British Geological Survey (BGS) and IEAGHG for the Indian subcontinent evaluated a high-level storage potential for the oilfields, unmineable coal beds and deep saline aquifers. The improvement in the availability of geo-scientific data has been instrumental in updating this high-level storage potential assessment. In this regard, the work of Vishal, Vikram, et al. (2021) evaluates the storage potential for oil and gas reservoirs, coal formations, deep saline aquifers and basalt formations using the data available for each of the basins provided by DGH based on the current exploration assessment.

viii) Indonesia:

Indonesia has initiated research on Carbon Capture and Sequestration technologies as part of efforts to reduce increasing atmospheric CO_2 concentrations. There are 33 sites with storage resource potential in both saline aquifers and oil & gas fields, with saline aquifers accounting for 89% of Indonesia's storage resource. Indonesia has several high CO_2 gas fields, many of which were studied in the CO2CRC (2010) report, with their associated saline aquifers proposed for CO_2 injection sites. Indonesia has evaluated 11 sedimentary basins, which have been identified as having storage potential and are included in the CSRC.

One known pilot project in Indonesia is the Gundih CCS Pilot. This project aims to be the first in Southeast Asia to research and develop technology for CCS along with management and leakage monitoring.

ix) Japan:

The Japanese Government has stated its objective to develop commercially viable CCS technology by around 2020 and introduce CCS in the coal-fired power sector by 2030. In February 2012, Japan CCS Co, a collaboration created in 2008 of about thirty Japanese companies specializing in CCS technologies, was chosen to oversee the CCS Project. It has been conducting R&D and feasibility studies to enable large-scale testing of CCS technology.

Japan is also conducting a thorough seismic survey of subsea storage potential. It has set a target for storing 100 mtpa of CO_2 . The Research Institute of Innovative Technology for the Earth (RITE) has been subsidized by the Energy Ministry to test CO_2 injection and storage in Iwanohara, Nagaoka city, in cooperation with Inpex Corporation. The Japan CO_2 Geo sequestration in Coal Seams Project (JCOP) at the Ishikari coalfield of Hokkaido is funded by the government and is Japan's first CO_2 storage field trial in coal seams. Also, a CO_2 storage demonstration project was conducted in the south-west of Nagaoka City to obtain data on the behaviour of CO_2 in an onshore aquifer. The project was carried out by the Japanese research agency, RITE.

x) Republic of Korea:

Published literature by Huh, Dae-Gee, et al. (2011) and others consider the onshore basins in Korea to be unfit for CO_2 storage as the geological parameters (porosity, permeability) of the formations in onshore basins are unlikely to support a successful injection project.

The seismic activity in onshore basins is also a major concern - in 2017, a 5.4 magnitude earthquake (induced by water injection in an enhanced geothermal system) in Pohang City (in the largest onshore basin) caused cessation of all fluid injection activities (both CO_2 and geothermal).

Three offshore basins have been identified as potential candidates for CO_2 storage; the Ulleung basin is the most feasible due to the presence of gas-bearing structures. A better quality of geo-scientific data may be rendered from the recent exploration activities in the Ulleung Basin in 2019 by KNOC and Woodside and a new drilling contract awarded in February 2021.

xi) Mexico:

In 2012, the Federal government included Carbon Capture, Use, and Storage as a topic in the National Energy Strategy 2012-2026, with specific tasks and goals for the next 5 years, which include the development of a national atlas, a GIS on CCS, and a national strategy to be developed by the end of 2012. 13 geological provinces were identified with CO_2 storage potential in saline formations deeper than 800 meters. Nine of these geological formations were assessed, and an estimate was generated for their CO_2 storage resource. These evaluations were conducted in two phases: In the first phase, the basins were separated into exclusion or inclusion zones, where excluded basins exhibited high seismicity, geothermal or volcanic activity and thus were not recommended for geological storage. In the second phase, a theoretical storage resource was calculated for prospective sectors within basins in the inclusion zone.

xii) Russia:

A report by Shogenova et al. (2011) included north-western Russia in aquifer storage capacity estimates. The data availability was a critical barrier in forming preliminary estimates; consequently, the storage capacity for the entire country could not be estimated. According to the study, the Tiskre Formation's Middle Cambrian sandstones are the most promising aquifer in the European part of Russia, despite the fact that many of its sites are too shallow. Only in the south-east of the Novgorod Region, within the Moscow Syneclise, a site with a depth of more than 800 m is observed.

xiii) Saudi Arabia:

Saudi Arabia is expected to have a very high potential of CO_2 storage due to the large volume of proven crude oil reserves. Even so, the subsurface data is highly restricted. A large share of work published on CO_2 storage potential is based on high-level estimates, while some 3D modelling has been carried out to acquire a better understanding of the storage potential of the basins.

Corrales Guerrero, M. A. (2021) have assessed the CO_2 storage potential in the Unayzah formation. This was done by creating a dynamic simulation for the identified storage site using publicly available data and dominant mechanisms influencing storage efficiency. The simulation was also used to study continuous injection of CO_2 in the formation for 40 years, followed by another 20 years of monitoring. Mantilla Salas, Sofia, et al. (2021) have also investigated the storage potential for the Unayzah formation using geological data to generate probabilistic models and 3D static and dynamic simulation to understand the storage mechanisms as well.

xiv) South Africa:

South Africa does not have any CO_2 storage specific regulatory or legal framework. The evaluation of potential storage sites began in 2010. An atlas and a detailed report on the geological storage of CO_2 in South Africa was published. The atlas indicated a theoretical geological storage capacity of 150 Gt. The majority of the work undertaken for evaluating the storage potential in South Africa has focused on saline aquifers as it has the highest potential as a storage resource. A pilot project named "South Africa Pilot Carbon Storage Project (PCSP)" was established to carry out 10,000-50,000 tonne of CO_2 injection over a two-year period. The potential storage sites in South Africa are located in the Onshore Algoa basin, Onshore Gamtoos basin, Onshore Zululand basin, Offshore Orange basin, Offshore East Coast basin and the Offshore Outeniqua Basin.

xv) Turkey:

The assessment of storage potential in Turkey has focussed mainly on depleting oil and gas fields. The deep saline aquifers in the Thrace region, Central Anatolia and Southeastern Turkey and the salt caverns of soda mines have also been identified as potential candidates for CO_2 storage. In 2013, the Turkish Ministry of Environment and Urbanization Capacity undertook estimation work for the potential CO_2 -EOR projects and the associated storage in the fields in Batman, Adıyaman and Thrace regions. The study reported the storage potential in these fields to be 108 mt, but to date no nation-wide survey for CO_2 storage potential has been carried out.

xvi) United Kingdom:

The CO2Stored (CO_2 storage evaluation database) is the official database on the CO_2 storage potential of the United Kingdom. This was developed under the UK Storage Appraisal Project (UKSAP) and is maintained by the British Geological Survey and the Crown Estate and under license from the Energy Technologies Institute (ETI). The database provides insights on 500 potential CO_2 storage sites. The database reports an estimated 78 Gt of CO_2 storage potential for sedimentary basins, oil & gas fields present in the UK territory, with the majority of the storage potential (68 Gt) in saline aquifers.

xvii) United States of America:

The USA has rich experience in terms of operating EOR projects (the first being in 1972) and has been assessing the storage potential of geological formations for years. Through various programs and RCSPs, the US DOE has studied the potential storage sites and has generated high-level estimates for CO_2 storage potential. The data from different programs, DOE's carbon storage activities and field projects is represented in the Carbon Storage Atlas – Fifth Edition (Atlas V). The data from large-scale field projects executed under various RSCPs, small-scale field projects and American Recovery and Reinvestment Act (ARRA) site characterization projects is included in this atlas. The GIS created under NATCARB is the basis for the atlas. The US DOE has classified types of waste storage wells into 6 classes and also follows a standard of permitting for Class VI wells (for CO_2 storage) permits. The regulatory framework for CO_2 sequestration is well established.

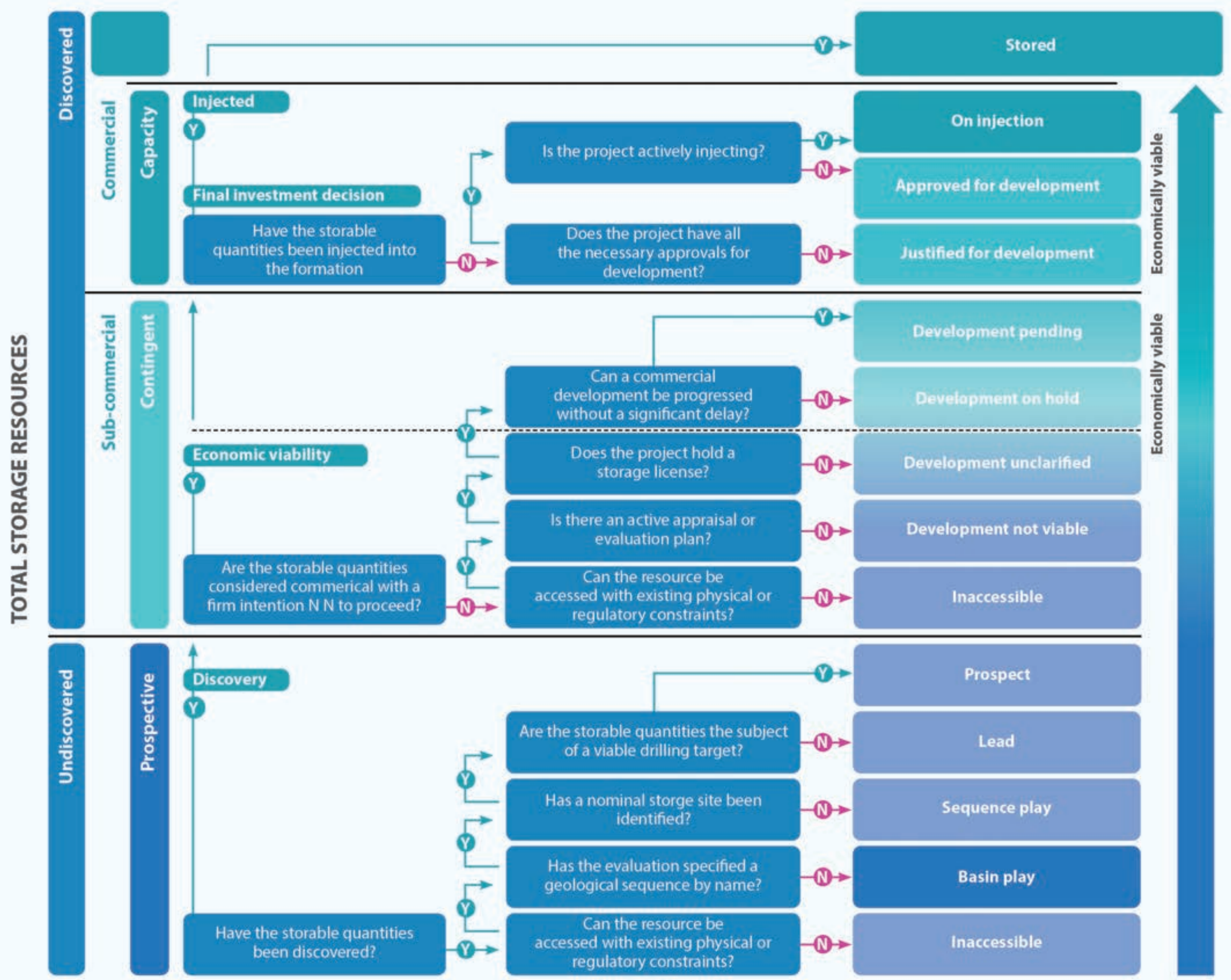
6.5 Storage Resource Management System (SRMS)

Estimated theoretical capacities represent the potential for CO_2 storage, but they do not give the actual storage capacity. In order to provide a robust database for CO_2 storage capacity and to accelerate commercial deployment of CCUS at scale, it is imperative to categorize the CO_2 storage capacity as theoretical (prospective) or commercial. The GCCSI, in collaboration with OGCI and Storegga, has created a system for the classification of CO_2 storage sites into three categories: prospective, sub-commercial and commercial categories.

Similarly, the CO_2 Storage Resource Catalogue (CSRC), published by OGCI and developed by GCCSI and Storegga identifies storage resources in various categories following the SRMS guidelines of the Society of Petroleum Engineers SRMS. The CSRC aims to aid countries track the progression of storage resource maturity, and provide a common resource terminology for better communications within international bodies and divulge reliable data pertaining to storage capacities for different stakeholders and facilitate data driven business decisions.

There were various stages involved in the classification of the CO_2 storage resource to get better clarity on the types of storage resources (undiscovered/ discovered) and further analyze their commercial readiness (sub-commercial/ commercial). The flowchart followed to build the CSRC has been illustrated in Figure 6-4. The flowschart takes the user through a set of questions that would enable the user to categorize their storage resource and also create a plan of action for upgrading the status of the storage resource.

Figure 6-4: CO_2 Storage Resource Classification Flowchart based on SRMS guidelines



Source: 2022 Status Report, GCCSI

6.6 Gaps in Characterization of CO_2 Storage Potential

Sequestration of CO_2 in geological formations dates back to 1972 when the first EOR project commenced operations in North America. This was possible due to the availability of good quality data for the selected storage site (oil field) because of the operational expertise of oil & gas exploration and production (E&P) activities. This explains why a large share of existing CO_2 capture projects has developed with EOR as the preferred mode of CO_2 disposition. Although the knowledge and technology have matured a lot over the years, assessing CO_2 storage potential and setting up a CO_2 storage project is still quite challenging. The broader challenges encountered in a CO_2 storage project are site selection, development of the storage resource, and identification of technical risk factors associated with CO_2 injection & storage. The gaps in the site specific characterization and potential assessment are listed below:

i) **EOR:** The primary gap in the assessment and characterization of the CO_2 storage potential exists at the database creation stage and updating of existing databases. Due to efforts made by E&P activities, oil well characteristics data is available for hydrocarbon-producing fields, but most of these formations are not explored with CO_2 storage as the primary target. Thus, keeping this in mind, the geological formations need to be studied and required data needs to be generated from a CO_2 storage perspective.

ii) **ECBMR:** ECBMR is still in its nascent stages, with only operational pilot plants. Significant R&D work is needed for the maturity of the concept. This technique does not offer a sizable share of sequestration capacity and thus, there is very little data available for it. Thus, keeping this in mind, the geological formations need to be studied and required data needs to be generated from a CO_2 storage perspective.

iii) **Sedimentary basins or saline aquifers:** These form a large share of the estimated global CO_2 storage capacity. But due to the very low possibility of hydrocarbon production and no economic benefit or returns, these formations have not seen focused geological studies and characterization. This has resulted in poor quality of the database with tentative results. The lack of site-specific data makes it difficult to even generate a theoretical estimation. In cases where data is available, there exists a risk of double counting the capacity, as the storage capacities are considered both in the national atlas/ publication as well as studies that estimate the theoretical capacity based on the injection into structures in the aquifers.

Based on high-level estimations, potential sites need to be explored and studied for CO_2 injection and storage. A profiling of potential sites needs to be completed by generating well-log study data, seismic study data, dynamic modelling, pore space mapping, and other relevant techniques. These will help in understanding the geophysical properties of the site. The data and methodologies for such tests and studies need to be shared in the public domain to enhance the database and resources, which may benefit other nations that may be at an initial stage of site characterization. This is a key area for promoting international collaboration and would make permit generation for storage an easier task. Finally, field experimentation and testing data of pilot sequestration projects need to be made available in the public domain to support further research and development of concepts and technologies and risk assessment related to CO_2 sequestration and to make CO_2 storage a more economically viable solution.

iv) **Basaltic formations:** Carbon mineralization is in its development phase, with an operational pilot plant in Iceland sequestering 4,000 tpa of CO_2 in basalt formations. Since it presents a huge potential for permanent CO_2 sequestration with little or no identified risks of fugitive CO_2 leakage, there is a lot of scope for process improvement. Thus it is crucial to understand and eliminate any research gaps related to the technology or the process to scale up the capacity. Other than research, the main gap is the characterization of the basalt formations, as different types of minerals are present in different basalt formations. This would impact the mineralization process of CO_2 and hence is crucial for project site selection. The CO_2 dissolution in pore water also needs to be researched thoroughly for the possibility of contamination of nearby aquifers.

v) **Reservoir quality:** It is also important to assess the site/reservoir quality, uncertainties arising from structural faults, site performance under varying injection conditions and health, safety & environment (HSE) related issues for the project site. Injection of CO_2 leads to seismic response (maybe at a microscale), which must be addressed before commencing injection operations. The absence of policy and regulatory frameworks related to CO_2 storage in many countries also poses a barrier to progressing and developing storage resources at the commercial level. Sealing the geological formation at the end of the injection project is necessary to prevent the CO_2 from migrating out of the storage site. The required action for closure of the site may vary with the geological characteristics of the site. Thus, site specific studies need to be carried out to formulate a sealing strategy for the selected storage site.

vi) **Data & information sharing:** Generating and publishing pilot data for reference (like CO_2 DataShare) is a necessity to support the global research community and other stakeholders (governments and industries) to work together and create a Gigaton scale infrastructure for CO_2 disposition.

6.7 Risk Monitoring Framework for CO_2 Storage

The geological formations discussed in the previous sections have the potential to store CO_2 at the giga-tonne scale. This comes with its own set of risks, thus mandating standardization of suitable risk monitoring frameworks. In this context, it is also important to understand the risks associated with geological sequestration. Based on the risk assessment for each site, risk monitoring guidelines need to be followed.

All gas transportation systems (whether pipeline or shipping based) have the inevitable risk of a fugitive emission or leakage due to structural failure or accidental events (e.g., corrosion for pipes and collision, foundering, stranding, and fire for ships).

Since a very high concentration of supercritical CO_2 (typically > 98-99 wt%) is transported for sequestration projects, CO_2 leakage poses a high probability of hazardous impact on humans as well as animals and plants.

Another possible risk associated with the CO_2 storage site boundary is CO_2 leakage from the geological formation. The hazard due to leakage from geological formations can be classified based on the rate of leakage. When the rate is slow, the hazard will be localized but may still lead to loss of life. For leakage at rapid rates, the hazard could be fatal and can cause loss of lives.

The leaked CO_2 from the geological formations can also rise and get dissolved in potable water bodies (shallow groundwater). This will lead to the formation of carbonic acid, thereby altering the pH of the water and rendering it unfit for consumption, agricultural, and industrial use. There is also a chance of leaked storage entering a hydrocarbon reservoir and reducing the economic value of fuel by contaminating it.

CO_2 storage in geological formations is being explored as a long-term solution for CO_2 disposition. Leakage of CO_2 in any of the above cases may lead to CO_2 escaping back to the atmosphere and thus negating all the efforts to capture and store it. Pilot tests in certain sedimentary basins have revealed that CO_2 injection can also cause micro-seismic activity. This may lead to the fracturing of the proposed formation. Rapid CO_2 leakage can also cause fault activation, which may result in earthquakes on a large scale.

A well-defined monitoring framework is very crucial for the safe and successful operation of CO_2 sequestration. A monitoring framework would help the creation and maintenance of CO_2 injection data in a particular geological formation. A better understanding of different CO_2 storage mechanisms can be developed with the aid of the required monitoring setup. It would also help in studying the storage status of CO_2 i.e., whether it is present in the same formation where it was intended to be stored, or has migrated to a different site (maybe to a neighbouring field, other rock formation, or underground potable water reserves). Injection monitoring subsystems are needed to supervise injection activities to ensure the injection pressures are in the required range and to assess the need to drill new wells. Specific monitoring systems are required for monitoring the integrity of the well as well as the possibility of any leakage from it. The monitoring systems would also add a set of operational data which can support the R&D behind 3D simulations for performance modelling of the CO_2 injection. As CO_2 injection may cause micro-seismic activities, it is important to have a monitoring system to predict the possibility of any future hazard due to continued operations at the selected site. Thus, all these reasons necessitate a risk monitoring frame work for the geological sequestration of CO_2 .

MVA (Monitoring Verification and Accounting): One of the key risk management frameworks used for CO_2 geo-sequestration projects is the MVA framework. The MVA framework provides the tools, techniques and frameworks to monitor and manage risks across the lifecycle of geosequestration projects. MVA activities are typically carried out in four phases:

i) **Pre-Operation Phase:** Project design, estab--lishing baseline conditions, characterization of the site geology and identification of risks.

ii) **Operation Phase:** Period of CO_2 injection in the storage site.

iii) **Closure Phase:** Period of closing and plugging the sites, removal of equipment and facilities and undertaking site restoration. However, necessary monitoring equipment is retained at the site.

iv) **Post-Closure Phase:** Ongoing monitoring is undertaken before making a decision that further monitoring is not required, except in case of any incidents like leakage, or legal cases, for which new information is required about the storage project/site.

CO_2 storage in geological formations (both sequestration and EOR to a limited extent) is imperative for the disposition of CO_2 at scale, and hence critical to the implementation of CCUS at Gt scale, especially for the decarbonization of large industrial scale emitters of CO_2. Given the safety concerns about underground CO_2 storage as well as for accounting CO_2 volumes eligible for credits/incentives, it is necessary to develop CO_2 storage demonstration projects and develop robust MVA programs for them. In order to develop a holistic perspective, it is also important to implement projects at different types of CO_2 storage sites, such as saline aquifers, basaltic traps, and oilfields amenable for EOR. The MVA programs and best practices developed by the US DOE provide a good starting point based on which site-specific MVA programs can be developed and implemented.

6.8 CO_2 Storage - Key Areas of Research & Development

With respect to CO_2 storage, the key focus areas for future research & development are as follows:

i) Cap rock fracture

Sequestration sites should have a sealing structure called cap rock, to limit the injected CO_2 within the reservoir boundary. A pressure differential between the inside and outside of the cap rock is formed. This differential keeps on increasing, and on reaching a certain pressure drop, the cap rock may fracture, and the injected CO_2 may escape the reservoir. This phenomenon needs to be accounted for while considering a site for CO_2 sequestration. Presently research is being carried out to assess the long-term cap rock integrity for the ongoing CO_2 sequestration projects with the help of scenario-based simulations and modelling cap rock fracture scenarios to develop fugitive emission prevention/remediation strategies. Research work has also been carried out for the development of remediation measures in case of CO_2 leakage.

Few recent investigations have focussed on the sealing of fractures in a representative CO_2 reservoir caprock by migration of fines (source: Rod, Kenton A., et al. "Sealing of fractures in a representative CO_2 reservoir caprock by migration offines." Greenhouse Gases: Science and Technology 11.3 (2021): 483-492), use of chemical sealants (source: Moneke, Kenechukwu. Gel reaction and permeability modification for CO_2 leakage remediation and flood conformance. Diss. 2020), and injection of solution reactive with CO_2 in the micro annulus of well to induce calcite precipitation and block the leak path (source: Wasch, Laura, and Mariëlle Koenen. "Injection of a CO_2 -reactive solution for wellbore annulus leakage remediation.: Minerals 9.10 (2019): 645). The development of such techniques would further eliminate the risk of leakage.

ii) Smart well monitoring techniques

The development of well monitoring technologies has enabled researchers to access real-time data sets to study the behaviour of the injected CO_2 and to carry out further research towards the enhancement/ development of well monitoring technologies. Different types of logs and profiles can be generated: leak detection log, cement bound logs, tubular inspection, production (injection) profile, beutron, and spectral. These can be used to validate the well integrity, pressure isolation, corrosion, and injection profile.

Pressure Down-hole Gauges (PDG) can be employed to understand the flow behaviour of CO_2 in the subsurface and generate real-time data for different parameters. To visualize fluid movement in the reservoir and detect signs of CO_2 migration, real-time pressure data obtained from PDGs can be used.

Research undertaken to develop seismic imaging technology has assisted the development of time-lapse seismic imaging or 4-D seismic models for monitoring injected CO_2 movements in the subsurface at different intervals during injection projects. The database generated from these real-time monitoring data can be used to train a machine learning algo-

-rithm which can be used as an Intelligent Leakage Detection System (ILDS) to identify potential leakage hazards prior to the occurrence of the event (source: Haghighat, S. A. (2014). Monitoring the Integrity of CO_2 Storage Sites Using Smart Field Technology. West Virginia University). The application of artificial intelligence in smart well systems is still also being developed for smart well monitoring systems. A few areas of research include proxy model development, artificial intelligence assisted history matching, project design, and optimization. These have an immense potential towards enabling intelligent well monitoring and eliminating the risks associated with CO_2 sequestration by assisting in the formulation of mitigation strategies in case of CO_2 leakage from the reservoir.

iii) Well integrity

Well integrity of an injection well is the ability to inject the CO_2 in the reservoir without any leakage throughout the project life. The oil & gas industry has been developing well integrity monitoring techniques as it is crucial to their operations. Similar techniques can be employed to monitor the well integrity of CO_2 sequestration wells. Recent research has also focussed on monitoring the integrity of plugged and abandoned wells for CO_2 storage purposes. Some research works have also employed artificial intelligence-based approaches to detect anomalies or defects when monitoring permanently plugged wells (source: Hosseini, Seyed Ehsan, et al. "Artificial Intelligence for Well Integrity Monitoring Based on EM Data." TCCS–11. CO_2 Capture, Transport and Storage. Trondheim 22nd–23rd June 2021. Short Papers from the 11th International Trondheim CCS Conference. SINTEF Academic Press, 2021).

iv) Seismic studies

Seismic survey techniques are applied for the characterization and imaging of the reservoir area. These studies can also be used for monitoring and detection of CO_2 leakage from the formation. A time-lapse seismic imaging or 4 D seismic that captures the area occupied by the injected CO_2 at different intervals reveals the movement of CO_2 in the subsurface over time. The CO_2 migration path coupled with a machine learning algorithm could help in predicting the future size of the CO_2 plume and possible leakage points.

v) Role of academia and industry in further development of CO_2 sequestration

To further develop CO_2 sequestration, preliminary basis must be set based on the geophysical properties and seismic data for the selected storage site. Academic institutions with state-of-the-art simulation tools and labs can help in generating the basis for sequestration projects by forming a group dedicated to these types of projects. They can also develop lab scale solutions for the mitigation of risks related to the CO_2 sequestration. This work can then be supported by the industry participants in the field of CO_2 sequestration.

The basis for the projects developed by academic institutions can be used to generate more detailed project designs required for clearances and project execution & completion. The industry can aid academic institutions by collaborating to provide operational expertise to further improve the research work carried out at lab scale. The stakeholders from the industry can also support the research and development of nascent technologies and monitoring techniques by undertaking pilot plants/ demonstration projects to validate the applicability of technology and demonstrate the viability of leakage mitigation technology/well monitoring technique, thereby enhancing its TRL. The data generated from the operation of sequestration projects and pilot demonstration projects need to be published in the public domain to provide real-time data for the research community to further develop concepts.

CCUS Technology
Gaps and International Collaboration

7.1 Closing the Technology Gap in CCUS

Implementing CCUS for giga-tonne scale deployment in G20 countries requires that technology gaps across the various technologies in the CCUS value chain are closed in a reasonable time horizon from the perspective of progressive commercial-scale deployment across all the G20 nations. A broad indicator of such gaps is the Technology Readiness Level (TRL) of various technologies in the CCUS value chain. The key levers of the TRL level that needs to be addressed to close the gaps involve the advancement of science, the attractiveness of the economics, and the deployability (availability, scale, reliability and learning curve) of relevant technologies across the value chain. The general description of TRL levels in the attached Table 7-1 helps to characterize the level of maturity of the relevant technology and the trajectory that the relevant technology has to take to move it from TRL 5/6 to TRL 7/8/9 from the perspective of achievability of scalable commercial deployment.

Table 7-1: Description of Technology Readiness Levels (TRL)

Category	TRL	Description
Demonstration	9	Operations of the technology in its final form, under the full range of conditions.
	8	Commercial demonstration, full-scale deployment in final form
	7	Sub-scale demonstration, fully functional prototype
Development	6	Fully integrated pilot tested in a relevant environment
	5	Sub-system validation in a relevant environment
	4	System validation in a laboratory environment
Research	3	Proof-of-concept tests, component level
	2	Formulation of the application
	1	Basic principles, observed, initial concept

7.2 Technology Readiness of Carbon Capture Technologies

A major part of the carbon emissions in the industrial and power sector are stack or post-combustion emissions with relatively dilute CO_2 concentrations ranging from 4% to 15%. Most applicable capture technologies in this area are chemical solvent-based, sorbent-based, adsorption-based, membrane or cryogenic separation-based technologies and are at different TRL levels of maturity.

Post Combustion and Chemical/Liquid Solvent-based Capture Technology Gaps

Most amine-based chemical solvent capture technologies that are applied towards post-combustion and lean CO_2 stack capture have reached commercial scale operations, exhibiting TRL 8/9 levels of operation and should be applied at scale for deployability. However, the advancement of the science of alternative chemical solvents offers significant opportunities for superior economics and scale of liquid solvent-based capture, which can supplant and complement existing amine-based chemical solvents for lean CO_2 capture at a deployable scale. Many such transformational technologies are targeted to reduce costs by up to 30 percent (i.e. less than US$ 30/tonne of CO_2 captured) from the first-of-a-kind technology (TRL 5/6) and be available for demonstration in the 2030 timeframe by reaching TRL 7/8/9.

To close the technology gaps in such additional liquid solvent types for achieving superior economics at scale, there are two key levers in the liquid/chemical solvent space that need to be actively addressed through enhanced and shared R&D, G20 inter-country collaboration and progressive scaled pilots, demonstration and deployment:

i) Further reduction in the cost of CO_2 separation from gas mixtures, which can be highly energy intensive. Current CO_2 solvents either have high rate constants and high binding enthalpy, and thereby high energy costs; or low rate constants and low enthalpy, and thereby high capital costs. Collaborative research and deployment are needed to develop low-cost CO_2 solvents that have sufficiently low binding enthalpy (<70 kJ/mol) and high binding rate constant (>12,000 $M^{-1} S^{-1}$).

ii) Collaborative research to develop and deploy low-cost, non-corrosive, low-viscosity liquid solutions with lower heat capacity than water and which selectively bind CO_2 with the above characteristics. Furthermore, new materials and processes to separate miscible liquid mixtures are also needed.

Several liquid solvents that share some of the above characteristics, like sterically hindered amines (eg. from MHI, Toshiba, CSIRO at TRL 6-8), chilled ammonia process (eg. Baker Hughes at TRL 6-7), water-lean solvents (eg. Ion Clean Energy at TRL 6), phase change solvents (eg. IFPEN/Axens 5-6 DMX™ at TRL 6) can be quickly taken through the development and deployment trajectory in the G20 countries to close the technology gap in liquid solvents for complementing amine based solvents.

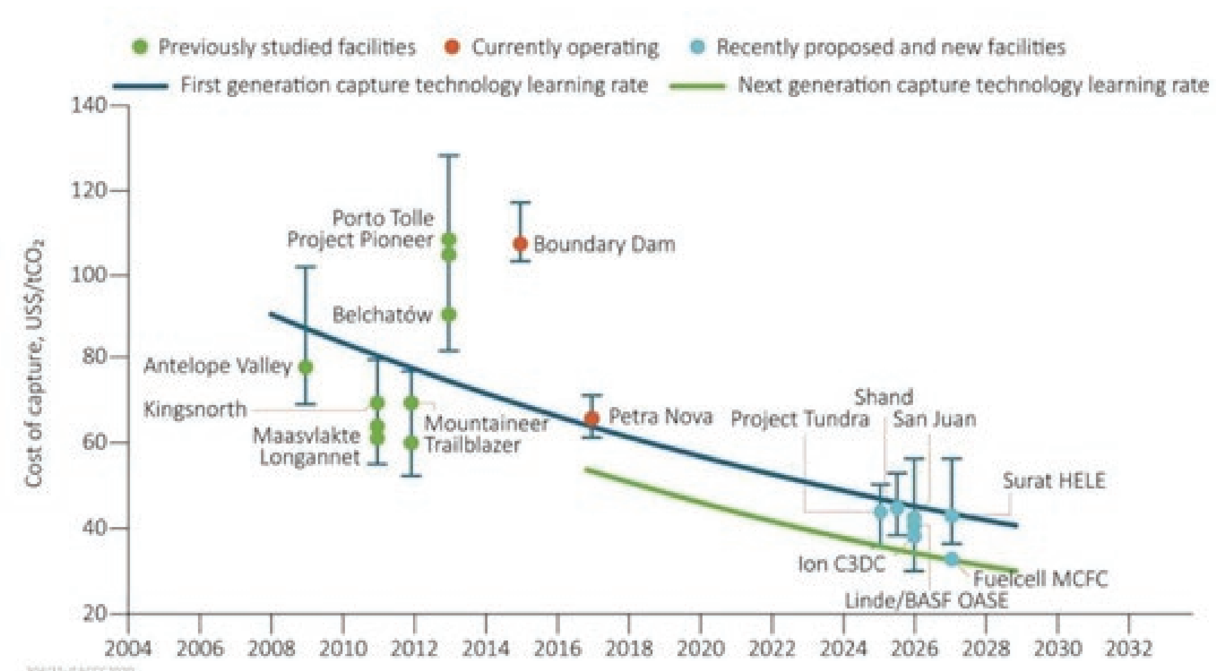
Similarly, conventional potassium carbonate solvents, used for decades in chemicals and natural gas processing, are effective carbon capture solvents. However, they have the disadvantage of slow rates of absorption of CO_2 , which has made them suitable only for high CO_2 partial pressures.

A novel absorption technology based on mature potassium carbonate solvents, CO_2 Solutions, has added a proprietary biologically derived enzyme, known as 1T1, to the potassium carbonate solution. This enzyme acts as a catalyst, speeding up the conversion of dissolved CO_2 in the solvent. This enzyme transforms a relatively slow absorption technology into a much faster one. This increased capture rate means a given CO_2 capture duty can be achieved with a much smaller absorber and stripper, making potassium carbonate solvents more cost-effective for post-combustion and other low partial pressure applications. The process is also competitive from an energy perspective – using hot water rather than steam as a heat source, with a claimed reboiler heat rate of 2.4 GJ/tonne of CO_2 captured (Saipem CO_2 Solutions).

Hot water offers a distinct advantage – it means lower temperature waste heat can be used to partially or fully supply the process with energy for the reboiler. Most absorption-based technologies require higher temperature steam, which requires additional heat. Enzyme enhanced potassium carbonate based solvents (TRL 5/6) can be an additional solvent type that can be taken to TRL 8/9 for complementing existing and mature chemical solvents for closing the technology portfolio gap.

Finally, it is important to leverage the science of CO_2 liquid solvents to design, build, and demonstrate reactors that can cost-effectively capture CO_2 at the giga-tonne scale for G20 deployability. An estimated economic trajectory of the solvent based technology is given in Figure 7-1.

Figure 7-1: Estimated Economic Trajectory of Solvent Based CO_2 Capture Technologies



Source: Zapantis A, Townsend A, Rassool D (2019) Policy Priorities to Incentivize Large Scale Deployment of CCUS

Physical Solvent Based Capture Technology Gaps

Many industrial processes like gasification, ammonia production, ethanol production, gas processing etc. have high partial pressure CO_2 -rich pre-combustion gas streams available for CO_2 capture. Physical solvent-based technologies, membrane technologies, and cryogenic technologies are most applicable for these carbon capture applications. The most widely used physical solvent-based technologies are the glycol-based Selexol™ and methanol-based Rectisol® systems. The Selexol process operates at ambient temperature, whereas the Rectisol process operates at a temperature as low as -60°C.

These solvents are operating at large-scale facilities in synthetic gas (syngas) purification and natural gas processing and operate at TRL 8/9. Physical solvent based technologies are mature, and further reductions in cost will be through learning curves and scale multipliers. This can be achieved through accelerated large-scale deployments of pre-combustion capture-based applications, typically for gasification, ammonia and natural gas processing plants.

Solid Adsorbent Based Technology Gaps

Different molecules have different affinities to the surface of a solid sorbent, which allows for the separation of a specific gas component from a mixture. Based on the interaction between gas molecules and the sorbent surface, adsorption can be characterized as chemical adsorption or physical adsorption. Chemical adsorption via chemical bonding results in a strong interaction between the gas molecule and the sorbent, and is an appropriate choice for CO_2 separation from low-concentration gas streams. Regeneration is typically accomplished using a thermal/Temperature Swing Adsorption (TSA) process, where the adsorbent is regenerated by raising its temperature to liberate the CO_2. On the other hand, physical adsorption, via van der Waals forces, has a weaker interaction between the gas molecule and sorbent and is typically applied to high CO_2 concentration feed streams. For physical adsorbents, sorbent regeneration is generally based on a Pressure Swing Adsorption (PSA) mechanism with TRL 8/9.

An emerging adsorption technology for low-concentration CO_2 sources is based on a rapid-cycle Temperature Swing Adsorption (TSA) process. This technology uses an adsorbent architecture arranged in a circular structure to simultaneously expose different sectors of the structure to each step in the process and is claimed to be 40 to 100 times faster than conventional TSA processes due to its use of innovative adsorbent materials that enable rapid temperature swings from 40 to 110°C (NETL 2018a). This is currently at TRL 6 and opportunities for closing the gap exist through larger-scale deployments and FEED engineering to take it to TRL 8/9.

While PSA systems have achieved maturity at scale and provide attractive economics, TSA has significant potential for techno-economic evolution and learning curve multiplier effects. Newer solid sorbents have a high storage capacity for carbon dioxide. A sugar-cube sized quantity of advanced MOF (Metal Organic Framework) sorbent materials has the surface area of a football field. Advanced structured adsorbent beds (filters) can capture and release CO_2 in less than 60 seconds, compared to hours for previous-generation solid sorbent technologies. MOF sorbent material can be effective at separating CO_2 from nitrogen contained in diluted flue gas from cement, lime, steel, aluminum, fertilizer, pulp & paper, oil & gas, and hydrogen plants, as well as future Direct Air Capture systems.

Membrane Based Technology Gaps

A membrane is a barrier or medium that can separate chemical constituents of a gas mixture based on the permeation of the constituents through the membrane at different rates, i.e. particular components of a mixture pass through the barrier faster than the other components. Generally, gas separation is accomplished by physical or chemical interaction between the membrane and the gas being separated. Membrane separation uses partial pressure as the driving force and is usually more favourable when the feed gas stream is at high pressure.

Process innovations such as the incorporation of countercurrent sweep in polymeric membranes from Membrane Technology and Research's (MTR) Polaris™ process and the integration of molten carbonate fuel cells (MCFCs) in capture systems have enabled the use of membranes in low-concentration CO_2 applications also. Polymeric membranes consist of banks of pressure vessels that are combined to form a single "mega-module". For a 240 MWe coal-fired power plant (eg. the flue gas stream from Petra Nova Unit 8), around 60 mega-modules with a membrane area of approximately 0.2 to 0.4 million m^2 would be required to capture 1.4 mtpa of CO_2 .

Polymeric membranes and electrochemical membranes for low-concentration CO_2 capture are currently at TRL 6, and further engineering and deployments can take them to the TRL 7/8/9 levels in a reasonable period of time.

Cryogenic Capture Technology Gaps

Cryogenic CO_2 capture is considered a novel capture technology in which CO_2 is separated from water and other incondensable components based on differences in their dew and freezing points, and gaseous CO_2 is transformed into its solid phase. Cryogenic CO_2 capture is advantageous as the captured CO_2 product can simultaneously potentially reach high purity (~99.9%) along with high CO_2 capture efficiency. Cryogenic CO_2 capture minimizes further purification, compression, and transport costs and also lowers the additional energy consumption required for downstream CO_2 processing, which is advantageous for the whole CCUS value chain.

However, the energy/power requirement for cryogenic conditions to realize CO_2 capture is the major obstacle to its expansion for commercial-scale depl-oyment. Unlike chemical solvent-based capture, cryogenic capture requires little steam or water and is based primarily on meeting the energy requirements from electrical power. Reducing energy requirements through optimization and improvement of the distillation column can help minimize overall project costs. More advanced cryogenic technology for process separation through cryogenic packed beds, anti-sublimation, controlled freeze zones, and cryocells will help reduce energy requirements, improve scale and move the technology from TRL 6/7 to higher TRL levels.

Direct Air Capture (DAC) Technology Gaps

DAC processes that are presently deployed at pilot and demonstration scales commonly start with fans to move the ambient air through contactors. The contactors apply a chemical or physical process to separate CO_2 from other molecules in the air. Chemical processes, which are currently the most developed DAC approaches, fall into two main classes of technologies: solid sorbents and aqueous-based solvents. Sorbents usually contain amines that react with CO_2 molecules to form carbamate (including carbamic acid) and/or bicarbonate bonds, while solvents commonly contain hydroxide groups that react with CO_2 to form carbonates and/or bicarbonates. After the CO_2 from the air has been chemically captured in the contactors, the CO_2 -laden material undergoes temperature, pressure, moisture, power supply, and/or chemical swings to release the CO_2 in a concentrated stream, and the sorbent/solvent is regenerated for re-use. The released CO_2 is then compressed and geologically sequestered or converted into value-added products.

The deployment of large-scale DAC technologies has the potential to capture CO_2 from the atmosphere at rates of one to tens of Gtpa CO_2 (CDR Primer 2021, IEAGHG 2021, IPCC 2022). However, presently there are only 19 demonstration or small-scale DAC plants in the world (IEA 2021), with a total capture capacity of about 11,000 tonnes of CO_2 per year. DAC has several challenges to overcome for it to scale to giga-tonne levels at cost structures that are competitive.

i) **Cost:** The levelized cost of DAC projects varies significantly (Realmonte 2019, Young 2022) and is currently reported in the range of US$350-$700+ per net tonne of CO_2 removed (Evans 2017, Gertner 2019, IEAGHG 2021, McQueen 2021, Ozkan 2022b). The estimates are highly dependent on factors such as the scale of the project, location, purity of CO_2 captured, financial assumptions, the type of capture technology employed, the type of energy used in the process, local conditions like climate, and other factors.

ii) **Energy Use:** DAC systems typically need a large amount of energy, roughly 5–10 GJ/tonne CO_2 removed (Baker 2020, Mulligan 2020, NASEM 2019), with an energy mix of 60-80% heat (for CO_2 release and sorbent/solvent regeneration) and 20-40% electricity (for fans, vacuum pumps, and process units) - IEAGHG 2021, NASEM 2019. Assuming an energy requirement of 10 GJ/t CO_2, DAC would require about 10% of the total annual US energy consumption to scale to a capture rate of 1 Gtpa. Sorbent-based and solvent-based approaches require about 180 GW and 310 GW of power, respectively, to capture 1 Gtpa of CO_2.

iii) **Land Use:** The land area footprints for sorbent-based DAC plants (not considering energy source or compression equipment) capturing 1 mtpa of CO_2 are estimated to range from 0.1 to 2 km^2 (Baker 2020, Beuttler 2019, Lebling 2022a, Ozkan 2022b). For solvent-based DAC, the land area required for a 1 mtpa CO_2 capture facility is estimated to be about 0.5 km^2 (Lebling 2022a, Ozkan 2022b). The total land area, including land use for energy generation outside the facility fence line, depends largely on the source of heat and power. Natural gas energy source requires 1,400 m^2/MW, nuclear energy requires 2,500 m^2/MW, solar PV requires 120,000 m^2/MW and wind energy requires 240,000 m^2/MW. With today's technology, a DAC plant capturing 1 mtpa of CO_2 would require up to about 20 km^2 of additional land area if powered entirely by PV. These estimates highlight that regardless of the DAC process, the size of the overall plant could become limited by the land area required for the energy source.

iv) **Water Use:** Operating a DAC process can consume a significant amount of water, or conversely, it could produce water, depending on the process. In solid sorbent processes, water usage is highly variable. Processes that incorporate the use of steam condensation for the regeneration of solid sorbents may contribute to water being lost to the environment at a ratio of 1.6 tonne of H_2O per tonne of CO_2 captured. Significant amounts of water (1 to 7 tonnes of H_2O per tonne of CO_2 captured) are typically lost to the environment in the form of evaporation during the air-contacting step in liquid solvent-based DAC processes.

v) **Material Performance:** CO_2 loading capacity and sorbent/solvent lifetime are important parameters driving operating costs. These costs can be reduced with sorbent/solvent materials that have higher CO_2 capture capacities and longer-term stability in the air.

vi) **CO_2 Capture and Desorption Kinetics:** The rate of CO_2 capture affects the capture and regeneration cycle time and, therefore, the overall operating efficiency of a DAC plant.

The local temperature and humidity of the DAC plant site affect the reaction rates and complicate efforts to optimize the absorption and desorption rates. Therefore the location of a DAC plant becomes an important determining factor of the performance.

DAC systems are currently at about TRL 6 and can be accelerated to scale to higher TRLs through improvement, deployment and research around the key levers mentioned above.

Calcium Looping Technology Gaps

The Calcium Looping (CaL) process is based on the abundant availability of natural materials like limestone, which is also non-toxic and non-reactive. The CaL process can be a cost-effective technology for CO_2 capture from post-combustion lean sources. Lean flue gases typically contain a CO_2 mole fraction in the range of 10–15% - this requires an optimal carbonation temperature of around 650 °C to achieve a high capture efficiency of 90% in the necessarily short residence time of a few minutes.

Several issues need to be addressed for the successful deployment of the CaL technology at a larger scale. CaO multicyclic activity needs to be increased to achieve an efficient CO_2 capture energy integration and ensure adequate handling of the solids; CaO reactivity towards carbonation decays progressively with the number of cycles before reaching a low residual. Under CO_2 capture conditions, the loss of multicycle activity is mainly due to the sintering of CaO grains at high temperatures, which reduces the surface area available for fast carbonation. Conditions that would optimize the integration of the CaL process involve calcination at lower temperatures, whereas carbonation could be carried out at higher temperatures with pure CO_2. CaO deactivation would be mitigated under these conditions if particles are small enough to avoid pore plugging.

Proper energy integration is crucial for the feasibility of the CaL integration on a commercial scale. Due to the high enthalpy of the reaction and the high turning temperature (~896 °C at atmospheric pressure), a large amount of thermal power is required and released during the calcination and carbonation reactions, respectively. An adequate integration between both reactors is essential to reduce both the energy penalty and the equipment size, which critically determines capital expenditures. Solid-solid heat exchangers would be useful for improving the integration, albeit they are not yet available at the commercial scale.

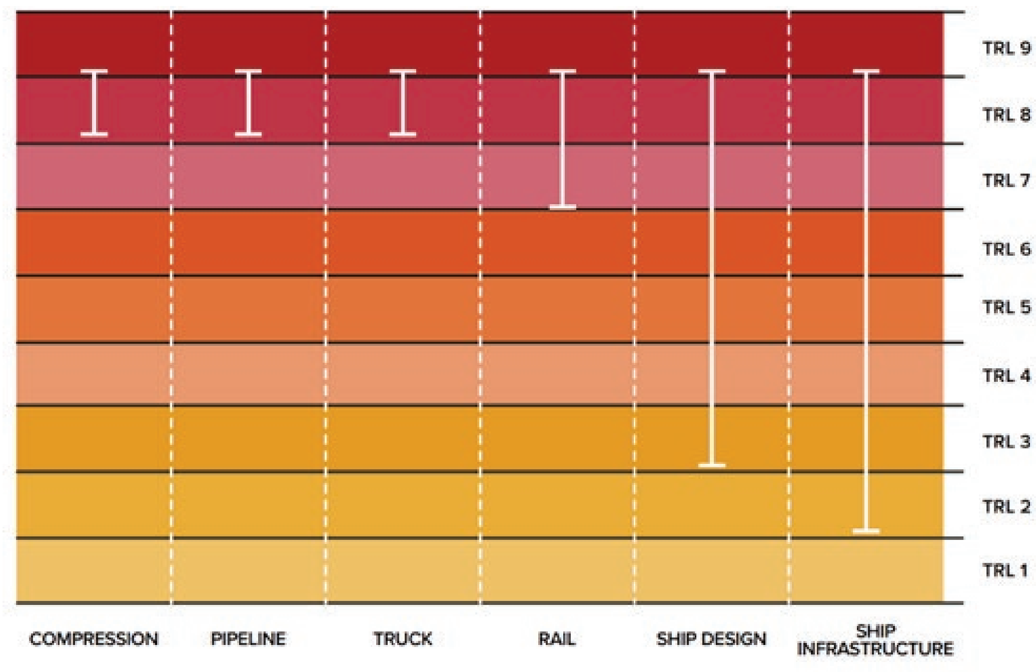
The efficiency of integration greatly conditions the energy consumption per kilogram of CO_2 avoided (SPECCA), whose value for mature amines based carbon capture technology is around 2-3 GJ/t CO_2 . The CaL process has the potential to reduce the energy requirement to around 2–3 GJ/t CO_2 . Other challenges for commercial-scale CaL are related to achieving efficient solid handling through the different components of the plant. This involves high-temperature particle conveying, reactors, and storage tank feeders to counteract the negative effect of the cohesiveness on the powder flowability if fine particles are used.

CaL systems are at TRL 6/7 at this point and have the potential to reach TRL 8/9 in a decade’s time.

7.3 Technology Readiness of CO_2 Transport Technologies

The transport of CO_2 is an essential part of the CCUS value chain, for connecting CO_2 source(s) to CO_2 storage or utilization and conversion sites. CO_2 is compressed and transported primarily through pipelines and, to some degree, by ships. CO_2 is also transported by truck and rail. Fundamentally, the transportation of gases and liquids via any of these methods is mature, with TRL 9. However, the transportation of CO_2 at a very large scale associated with CCUS requires that pipelines and ships be organized in a multi-modal and scalable architecture through hubs and clusters, both within land and offshore, so that eventually they can work at giga-tonne or GT scale. While pipeline TRLs are at 9, the TRL level of the multi-modal transport system at scale is still evolving.

Figure 7-2: TRL of CO_2 Compression and Transport Infrastructure



Source: Global CCS Institute, 2021

While hub and cluster architectures need to be developed to enhance scale and economics, there is an opportunity to further enhance the economics and safety of pipelines and ship transport.

i) Pipelines:

Of all CO_2 transport modes, only pipelines are transporting CO_2 at a significant scale. Over 8,000 kilometres (5,000 miles) of pipelines stretch across the United States. The United States comprises 85% of all CO_2 pipelines, with a capacity of moving approximately 70 mtpa of anthropogenic and natural CO_2 (National Petroleum Council 2019). Therefore, technological development should focus on cost reduction and reducing health, safety and environmental risks. Efforts to close the gap, among others things, should be directed at developing models and tools for sizing pipelines without expensive margins while still avoiding longitudinal breaks (i.e. damage to the pipe causing it to rupture lengthwise).

Improved flow models are also key to further development as optimal pipeline design and operations require the CO_2 flow to be in the right phase in the right place at all times. Precipitation of dry ice or hydrate can have serious adverse consequences, and two-phase flow can present challenges in maintaining the necessary capacity in the pipe system.

There is less experience with pipeline systems for offshore CO_2 transport than with onshore, in terms of the number of km and pipe systems in use. One of the main differences is that components are placed on land at the start of the pipeline, which ends at the injection well on the seabed. The pressure is higher in the offshore pipe system than in onshore systems, as the injection pressure comes from the onshore pumping station at the start of the pipeline. In a land-based system, this will usually be done at the injection well itself. Among other things, this makes it hard to produce good flow modelling tools to design the system for phase transitions and possible multi-phase flows to maintain control of the flow rate to the injection well.

The CLIMIT-sponsored CO2FACT project is developing and validating software to simulate the flow of CO_2 through the pipeline and injection well for this type of system.

ii) Ships:

CO_2 is presently transported by small-scale ships of 800 - 1,800 m^3 size from production sites to distribution terminals and distributed via train or truck to end-users. According to the IEAGHG (IEAGHG 2020a), the maximum load size in terms of techno-economic value would be 10,000 tons of CO_2. To increase the efficiency of transporting larger quantities of CO_2 by ships, development to close the technology gaps should focus on developing ship designs based on lower pressures and temperatures than are used in today's tankers. It may be possible in theory to approach the triple point of CO_2, which is 4.5 bar and -56.4°C, but in practice, 5 to 10 bar and -55°C to -40°C will be used to ensure that dry ice is not formed when the CO_2 is handled in the systems for liquefaction, intermediate storage, and loading. The main advantage of transport at lower pressure is that the cargo tanks can be built with a larger diameter/cross-section, which generally means that the ships themselves can be bigger. The TRL for CO_2 shipping ranges from 3 to 9. The lowest TRL 3 relates to offshore injection into a geological storage site from a ship. The TRL 9 rating refers to conventional onshore CO_2 injection from onshore facilities.

The primary improvement areas to close the economic gaps in multi-modal integrated CO_2 transport systems at scale are:

- Analyzing how different impurities and combinations of impurities in CO_2 affect phase behav ior and how corrosive compounds/conditions may arise.

- Improvement of simulation models and tools, related to flow modelling, sizing of pipelines, and dispersion of CO_2 in case of leaks, for example.

- Development of more efficient ship designs.

- Development of new polymer materials that can withstand direct contact with liquid / supercritical CO_2 (for gaskets and seals in pipe and process systems).

- Development and optimization of hub and cluster pipeline-ship integrated models for optimizing economics, scale and reach. This requires extensive modelling and optimization of multi-commodity flow type of networks and dynamic routings of flow based on the value /cost of CO_2 .

These areas cut across the transport methods and raise fundamental choices underlying the structure of all value chains within CO_2 handling.

7.4 Technology Gaps for CO_2 Utilization

The technology gaps with respect to CO_2 utilization, as described in Chapter 5, are summarized in Table 7-2 below.

Table 7-2: CO_2 Utilization - Technology Gaps

Sl. No	Type of CO_2 Utilization	Area of Challenge	Technology Gaps
1	CO_2 to Building Construction Materials	Poor compressive strength	Compressive strength of various carbonation cured products eg., concrete, pre-casted bricks/blocks, and aggregates, need to meet the desired values as per the regular comparative testing standards of similar categories of products in the market.
		Passivation of carbonation curing leads to lesser uptake of CO_2	Optimization of various parameters affecting the CO_2 uptake during mineral carbonation i.e., operational conditions (temperature, pressure, and CO_2 concentration), composition of the contaminant in the CO_2 stream, particle size and mineralogy of the ingredients.
		Availability of abundant and sustainable feedstock	The oxides of alkaline earth metals, essentially CaO, MgO and also silicates, are the prime materials in this mineral carbonation technology and responsible for the CO_2 uptake; unfortunately, the availability of these is finite in nature. Therefore R&D should focus on developing sustainable and cost-effective synthetic and/or natural alternatives with optimum performance of CO_2 uptake.

Sl. No	Type of CO_2 Utilization	Area of Challenge	Technology Gaps
2	CO_2 to Chemicals & Fuels	Catalysts	• Develop low-cost and mechanically-chemically stable catalysts for meeting the desired rate of reaction kinetics, which can facilitate the reaction at a lower temperature for converting CO_2 to a CO & H_2 mixture for conversion to chemicals and fuels • Lower temperature and corrosion inhibition for electrolysis of very high TDS water.
		Electrode development	• Economically affordable metal based mechanically robust and electro-chemically suitable electrodes for seawater and high TDS industrial wastewater • Electrolysis for green hydrogen generation while withstanding higher current density and corrosion resistance.
		Reactor development	• Develop reactor technologies tailored to the demands of carbon dioxide (to CO or mixture of CO_2 /CO/H_2 etc.) conversion processes • Systems that integrate capture with conversion.
3	CO_2 to Carbon Nano-Tubes	Stability & reproducibility	• Challenges in controlling CNT size and creating CNT arrays of high pore density while maintaining requisite mechanical properties.
		Shape & structural compatibility	• Non-conventional & odd geometrical-shaped CNT membranes require more advanced nano-scale fabrication techniques at the atomic level.
		Toxicity & environmental impact	• Raw CNTs are more toxic than functionalized CNTs because of the existence of metal catalysts. Thorough investigations are required on this subject.
		Bio-suitability	• Stability of enzymes in carbon-based electrodes and related wiring in the internal structure of nanomaterial walls.
		Mechanical resilience & biofouling	• Mechanical robustness to be maintained in dynamic biological environments without triggering any biological growth or degradation.

7.5 Technology Readiness of CO_2 Storage

CO_2 storage is the final step in the disposition of CO_2 in the CCUS value chain. Storage requires CO_2 to be compressed to very high pressures (the absolute minimum is above 74 bar, which is the critical pressure of CO_2 and typically 100 bar or more to provide a suitable safety margin and account for pressure drop in pipelines). The storage formation must be at a depth of at least 800 m to ensure that this pressure is maintained. At these high pressures, CO_2 is in its dense phase, i.e. it has a density similar to water but the properties are somewhere between a liquid and a gas.

CO_2 storage or sequestration has been practised in the form of EOR for over 50 years. However, there are several opportunities for enhancing the available volumes of storage space across various geo-structures for CO_2 injection that are economical and monitorable. While some G20 countries, particularly the US, have developed extensive and verifiable storage infrastructure over the past two decades and created an effective CO_2 sequestration Atlas, that is not the case with most of the G20 countries. This is a significant strategic gap (not related to the TRL level) for CCUS to move forward at scale. It is imperative for G20 countries with significant storage potential to rigorously assess and map the storage availability within their boundaries so that CCUS can be deployed at scale over a reasonable time horizon.

i) CO_2 Storage through EOR:

Storage through CO_2 -EOR has been in operation for nearly 50 years and is at TRL 9 (National Petroleum Council 2019). Currently, there are over 40 CO_2 -EOR operations, with the vast majority of the projects being in the US. The primary aim of CO_2 -EOR is to maximize oil recovery and not store CO_2 . However, CO_2 is permanently stored in the course of EOR, becoming trapped in the pore space that previously held hydrocarbons. Additional CO_2 specific monitoring to verify the permanent storage of the injected CO_2 is required if CO_2 -EOR is to be used as an emissions reduction option.

ii) Storage in Saline Formations:

The rapid advancement of the technology and knowledge developed from the initial projects in the US and Norway (Sleipner) is significant for developing saline formation storage. CO_2 is stored in different geographies, terrains, and geological conditions. Geological storage always requires site-specific analysis, modelling and monitoring. This includes storage capacity prediction, injection optimization and CO_2 verification and quantification through monitoring. The technology and tools required to identify, appraise, utilize, monitor and close a geological storage resource are all well-established and mature. Storage of CO_2 in saline formations has a TRL of 9. However, there is a need to close the gap in many G20 countries by taking advantage of the available international knowledge and experience and using the same to explore, ascertain, and map cost-effective storage options across the G20 countries.

iii) Storage in Basalt and Ultra-Mafic Rocks:

Storage of CO_2 in basalts and ultramafics depends on mineral carbonation. The mineralogy of those rock types enables CO_2 to react very rapidly and form carbonate minerals. 90% of the injected CO_2 is predicted to be mineralized in these rock formations within a period of a few months to decades. Basalts are a common rock type, particularly in India, and in nearshore oceanic crusts worldwide. The estimated storage potential of mineral carbonation is in thousands of giga-tonnes of CO_2.

Basaltic rock has very low permeability and hence hydrologically fractured basalt or permeable zones between basalt flows are targeted for CO_2 injection. Overall, basalt is not a naturally permeable rock and permeability is difficult to predict. Even within permeable zones, the injection rates are low. The majority of tools for conventional CCUS cannot be applied to monitor a CO_2 plume in a basalt. Monitoring tools for CO_2 plume verification and quantification in basaltic formations are still in the research phase. TRL levels of injection in these formations range from 2-6.

iv) Enhanced Coal Bed Methane:

Coal seams naturally incorporate fractures known as cleats, which allow gases to permeate through the coal and are essential to the operation of an ECBM storage system. Between these fractures, the coal has abundant micropores that can hold many gases, predominantly methane. Coal has a higher affinity to gaseous CO_2 than methane. For ECBM, CO_2 is injected into the coal seam, where it diffuses into these micropores and is adsorbed, displacing the methane. The methane is then produced for sale.

Four pilot ECBM operations have been completed: one in China and three in the USA. The San Juan ECBM project in the USA was the largest pilot, injecting 18,000 tonne of CO_2. Presently there are no active ECBM projects (Global CCS Institute 2021b). ECBM is a viable technology and can increase methane production (compared to standard coal drainage) by 90%. The produced methane provides revenue to the operations while also storing the CO_2. The major difficulty associated with ECBM is that the injection of CO_2 significantly reduces the permeability of coal due to ‘plasterisation’ and swelling of the coal (reducing the size and connectivity of the fractures). Reduced permeability requires additional wells leading to additional costs and increasing operational complexity. Moreover, ECBM can only be applied to coal seams which will never be mined; otherwise, the CO_2 stored in them would be released into the atmosphere. For this reason, deep un-mineable coal seams are potential targets for ECBM operations. ECBM is currently at TRL 2-3.

With respect to CO_2 storage, the other key focus areas for future research & development are cap rock fracture, smart well monitoring techniques, well integrity, seismic studies and enhancing the role of collaboration between academia and industry in developing CO_2 sequestration projects.

7.6 International Collaboration in CCUS Technologies

Given the scale of today’s net-zero energy transition challenge, no single organization or industrial sector can alone tackle decarbonization through CCUS. Close collaboration is needed between Government and industry as well as participants through the entire CCUS value chain and CCUS ecosystem, to work as partners and make sure that the business case of short and long-term investments in industrial decarbonization and CCUS is sound. CCUS will require largescale and sustained investments across the industrial value chain. Some of the needed technologies go beyond any single industrial sector and form societal endeavors that require public support and acceptance. Public policy tools such as carbon incentives and/or carbon pricing mechanisms will play a central role in shaping the carbon-neutral economy and must be designed in a way that embeds carbon costs across whole value chains and gives low-carbon solutions a competitive edge.

Importantly, the deployment of CCUS technologies in both the power and industrial sectors is supported by the multiple benefits: carbon emissions reduction that mitigates climate change, the opportunity to increase economic growth, and, in many G20 nations, enhancing energy security. For example, since many G20 nations, like China, India, and the United States have large coal reserves, policymakers are often interested in finding ways to sustainably develop and utilize domestic coal resources and CCUS offers a low-carbon pathway for that goal. Many of the opportunities and challenges related to CCUS deployment vary on a regional basis, so it is necessary to consider these regions on the basis of their emissions profile, re-use and storage opportunities for captured carbon, and the readiness of their legal and regulatory frameworks.

Coordinated Policy

G20 nations could agree or be encouraged to prepare national readiness assessments or action plans for clean energy technologies. In CCUS, these initiatives could include a legal analysis of measures needed to facilitate commercial deployment of large-scale CO_2 storage, internal analysis of other domestic policies that could incentivize CCUS to create a level playing field with other clean energy technologies, and business model analysis to determine what types of partnerships and arrangements would best facilitate deployment.

Global Finance

Given the ongoing need to build technical and financial capacity for pilot-scale and eventually commercial-scale CCUS projects, there is an opportunity for G20 nations to increase funding for the CCUS Trust Funds of the World Bank and the Asian Development Bank. Private sector banks can partner with these CCUS Trust Funds through risk-sharing agreements and amplify the impact of the investments. Multilateral Development Banks can also frequently provide updates at G20 meetings on how CCUS technologies can help achieve their goals with respect to climate change.

Integrated Collaboration

The G20 coordination mechanisms offer opportunities to make progress on shared commitments to advance CCUS technologies and specifically advance CCUS through international shared commitments and collaborations:

i) **Expand Funding:** A G20 commitment to expand and better fund the International Test Centre Network and the CO_2 Storage Data Consortium can accelerate pilot and demonstration projects.

ii) **Facilitating Large-Scale Cross-Border CCUS Value Chains:** There is an urgent need for nations to ratify and allow CO_2 to be exported for offshore and onshore sequestration. In addition, focusing on cross-border CCUS projects is especially important because the subsurface often crosses national boundaries. The G20 can facilitate large-scale CCUS chains, including cross-border geo-mapping of storage space and CCUS projects.

iii) **Maximizing CO_2 Conversion & Utilization:** A new carbon recycling initiative by G20 nations could be to create a task force with representatives from major businesses to explore options expand markets, gauge consumer interest and consider how to create markets and supply chains for building materials, products and fuels made from captured carbon.

iv) **Restriction on non-carbon abated products:** Voluntary quotas/limits on the consumption of non-carbon abated and high carbon footprint products and tagging & monitoring their consumption using innovative technologies.

v) **Accelerating CCUS through Hydrogen:** A G20 commitment to partner and focus on capacity building or demonstration projects in priority areas, such as hydrogen production from fossil fuels with CCUS could encourage investor participation in CCUS deployment. Integrating shared initiatives on gasification with CCUS for hydrogen across Japan, India, Australia, and Indonesia might open the pathway for accelerated CCUS deployment with concomitant economic and energy security benefits.

vi) **Technology support:** Enabling new R&D and technology development of the CCUS value chain and providing support to low per capita emitters within the G20.

vii) **Institutional mechanisms:** Creating and funding a CCUS body headquartered in New Delhi and with co-headquarters in other G20 countries like Australia and Canada. The focus of the body will be tracking and promoting the research, development and implementation of CCUS projects across the G20 and ensuring the utlization of grant funds for implementing various CCUS initiatives across the G20 nations.

7.7 Key Enablers for CCUS at Scale

The key enablers for CCUS at scale are summarized below:

i) **Policy framework and Government support:** The review of CCUS projects in the G20 countries reveals that enabling policies and Government support & funding are essential for CCUS projects to achieve scale and to manage project costs & risks across the value chain. Policies need to channel private sector investments in CCUS by either creating sufficient incentives for CCUS projects (US approach) or conversely by penalizing inaction (EU approach). The policy framework may be either credit/incentives based or based on taxation of emissions – the choice is very country-specific and depends on the nature, maturity and development of the country's economy, key sectors which need carbon abatement, the current state of CCUS in the country, energy mix & emission targets, viability of alternate decarbonization routes, per capita income & ability to absorb the cost of carbon abatement/green premium.

Along with policy support, Governments also need to create a positive signalling effect by committing investments and risk capital to early stage or demonstration CCUS projects, as well as the creation of shared CO_2 transport infrastructure, which will subsequently attract and de-risk private sector investments, thus enabling CCUS to reach scale.

ii) **Development of CO_2 utilization technologies:** Carbon utilization technologies are relatively less mature and at a more nascent stage of development compared to carbon capture technologies. The traditional CO_2 disposition pathway for carbon capture projects has been CO_2 EOR and, to a limited extent, CO_2 storage. Given the limitations of CO_2 EOR in terms of the dependence on geology and availability of ageing oil fields amenable for CO_2 EOR in all regions or countries and the absence of financial returns from CO_2 storage projects, carbon utilization technologies have an important role to play in providing a pathway for the disposition of CO_2 by converting captured CO_2 emissions to marketable value-added products.

In the present scenario, most products manufactured through the CO_2 utilization route require significant subsidy/green premium to compete with the conventional fossil fuel based production routes. However, as CO_2 utilization technologies develop, production costs are likely to decrease with economies of scale and learning curve effects. As markets become more carbon conscious and ascribe a carbon price to CO_2 unabated products, CO_2 utilization products will eventually become competitive compared to the hitherto conventional fossil fuel based production routes. This will lead to expanding markets for CO_2 utilization based products and a circular carbon economy, thus creating sufficient demand pull and enabling the entire CCUS value chain to attain scale.

iii) **Addressing technology gaps through international collaboration:** The development of CCUS technologies and projects widely varies not only across the G20 countries, but also across the spectrum of the CCUS value chain. The technologies for carbon capture from power plant and industrial flue streams, CO_2 sequestration and EOR have been operating at a commercial scale for decades now, especially in North America. This makes a strong case for international collaboration so that the entire G20 can benefit from the technology transfer of commercially proven TRL 8 and TRL 9 technologies. International collaboration and technology transfer will avoid reinvention of the wheel and reduce the costs & risks of CCUS projects in G20 countries where CCUS is still nascent and relatively unexplored.

CO_2 capture technologies have already seen significant R&D and investments in developing efficient and cost-effective solutions; the cost range for most commercial-scale carbon capture technologies is also well established and understood. Hence R&D efforts should focus on addressing the specific technology gaps to improve scale & costs, and meeting the low-grade steam and electricity duty requirements of CO_2 capture technologies more efficiently, at lower costs and with lower secondary emissions.

Evolving CO_2 capture technologies such as DAC or calcium looping and CO_2 utilization technologies are the other relatively less developed areas which can benefit immensely from international technology collaboration. These technologies provide the option to remove the CO_2 stock from the atmosphere or convert the captured CO_2 to useful value-added products; hence scaling up and commercializing these technologies is vital to a net-zero future. Technology development is multi-faceted and it is difficult to predict the development trajectory and timelines of individual technologies. In this regard, international collaboration can have a critical role to play by supporting and funding an ecosystem for fostering R&D and innovation in such nascent technologies. International collaboration will also create cross learning opportunities for the academia and industry in different countries and will lead to lower risks and costs for individual countries, while also providing access to the latest technology developments across the G20 member states.

iv) **Availability and flexibility of options for CO_2 disposition at scale:** CCUS at scale requires not only the development, demonstration and commercial implementation of carbon capture and utilization technologies but also the creation of infrastructure and options for the transportation and disposition of CO_2 at scale.

The CCUS value chain consists of multiple tightly linked sub-systems and hence the weakest link/part in the chain can create risks for the entire CCUS value chain. To avoid being held hostage by the failure of individual sub-systems/counterparties and to reduce systemic risks, CCUS value chains should have optionality for the disposition of CO_2 at scale, viz. both CO_2 sequestration and EOR, and the flexibility to switch between different options depending on market dynamics. The availability and flexibility of options also de-risks upstream CCUS investments, enabling it to attain scale.

v) **Hub and cluster frameworks:** Given the costs and risks associated with CCUS projects, CCUS hubs and clusters are necessary to spread the costs and risks across multiple parties across the value chain. Hub and cluster frameworks make it easier for participants across the CCUS value chain to participate in a CCUS project without needing to have a presence or make investments across the entire value chain or enter into bilateral agreements with multiple counterparties. At the heart of any CCUS hub & cluster is the creation of adequately sized & provisioned CO_2 transportation infrastructure for seamlessly connecting multiple CO_2 sources and sinks. Creating such infrastructure is challenging due to the high costs & lower CO_2 volumes in the initial years and typically requires significant Government support and funding.

Multiple emitters can form a capture cluster and connect to the shared transport infrastructure without needing to invest in CO_2 transport, utilization or disposition infrastructure or needing to enter into bilateral agreements with counterparties. Similarly, there can be CO_2 disposition clusters consisting of CO_2 utilization, CO_2 EOR and storage projects, depending on the geology and geographic location of the hub. Just like emitters, a CO_2 disposition cluster can connect to the CO_2 transportation hub for the required supply/off-take of CO_2 without needing to invest in carbon capture projects or entering into bilateral agreements.

The development of CCUS hubs and clusters can drive CO_2 capture, transport and disposition at scale by enabling emitters and disposition sites to seamlessly connect through shared transportation hubs/ infrastructure, similar to natural gas hubs for the collection and distribution of natural gas across different producers and consumers.

vi) **Development of markets:** CCUS projects involve significant cost build-up across the value chain from capture, compression & dehydration, transportation, utilization and disposition; the high costs are one of the key impediments to the development and implementation of CCUS projects. In this context, markets provide an avenue for lowering costs and prices by encouraging scale and innovation by participants across the CCUS value chain. The innovations could be in the form of rapid commercialization of CO_2 utilization technologies for value-added products such as chemicals, construction materials or high-end carbon-bearing materials. These innovations would drive demand and prices for CO_2 by creating new opportunities for using and considering CO_2 as a feedstock and not as an undesirable waste product.

The presence of a market structure will enable participation and competition on both the CO_2 demand and supply side, and participants need not enter into bespoke and higher risk bilateral agreements.

Markets also enable the pricing of CO_2 based on future demand-supply expectations and incentivize new entrants both on the demand and supply sides. Like hubs and clusters, CCUS market mechanisms also need Government support in the form of grants or subsidies, tax credits and carbon taxes during the initial period to encourage market participation till the market reaches scale and efficiency.

vii) Facilitating CCUS enabled projects:

- Streamlined processes and rules for fast tracking the permitting and clearance for CCUS enabled projects.
- Providing subsequent market support by sensitizing and incentivizing customers regarding low carbon products, thereby driving demand.
- Creating differentiation for low-carbon products from conventional products with appropriate tagging mechanisms.

7.8 Feasibility of CCUS Enabled Low Carbon Products

CO_2 utilization technologies cannot compete with conventional fossil fuel-based production routes in the absence of supportive markets for low-carbon products, Hence adequate Government support for low-carbon products is needed to create a level playing field. The support could be in the form of preferential public procurement policies, minimum price guarantees, production incentives or CO_2 abatement tax & cash credits. The initial support is essential for enabling CO_2 utilization to scale up over time, reduce costs and eventually be competitive in the market.

Figure 7-3: Incentive Required for Feasibility of Low Carbon Products

The extent of support needed depends on the decarbonization costs for each industry and the incremental carbon abatement cost on the per unit production cost, like per tonne of steel or cement or per kWh of electricity generated. So, any scheme for supporting/promoting low carbon products needs to take care of the following factors:

i) Carbon capture and abatement cost in the particular industry

ii) Cost structure of the CO_2 utilization-based production route for producing the low carbon products

iii) CO_2 emission intensity in the traditional fossil fuel-based and polluting conventional process

iv) Criticality of the product in the economy and likely inflationary ripple effect in the economy by switching to the green but more expensive option.

7.9 Key Risks Associated with CCUS

CCUS projects integrate various sub-systems such as carbon capture, transportation, utilization, EOR and sequestration. They involve complex interfaces between the subsystems, which leads to risks associated with CCUS projects. Some of the key risks are described below:

Technical Risks

i) CO_2 volumes available for capture: This risk emanates from changes in the process of the emitting plants, viz., the use of electricity or new clean energy carriers like hydrogen to replace/reduce fossil fuel consumption in steel plants or cement plants. This will reduce the quantity of CO_2 emissions available for capture and subsequent disposition, thus potentially stranding the CCUS infrastructure and making it financially unviable. Macro-economic and policy-related factors may also reduce the quantity of CO_2 emissions, viz. base-load power plants shifting to peaking operations, higher taxes of fossil fuel consumption, and electric vehicles (EVs) reaching scale leading to reduced demand for clean transportation fuels. Therefore it is important to understand the future trajectory of sectoral, technology and demand-supply trends and the potential impact on CO_2 volumes available for capture.

ii) Product CO_2 quality and specifications: CO_2 quality specifications in terms of moisture and impurity tolerances are generally very strict, especially in the case of CO_2 utilization in downstream chemicals or food-grade applications. Maintaining the CO_2 quality may be difficult if multiple and different types of CO_2 sources are combined and may necessitate additional purification facilities. In the case of CO_2 storage, the presence of non-condensable and inert impurities like nitrogen and argon in the product CO_2 may affect the pipeline and reservoir capacity.

iii) Alternate modes of CO_2 transport: Alternate (i.e. alternate to CO_2 transport by pipelines) modes of CO_2 transport, such as road or ships require pressurized tanks and liquefaction of the CO_2 to very low temperatures of about -50 °C. Maintaining the temperature during transport and increasing the temperature to make the CO_2 suitable for injection requires significant electric and heat energy, leading to additional costs and emissions, thus lowering the net carbon abatement, when viewed from a systems perspective.

iv) **Competition for CO_2 EOR:** The attractiveness and viability of CO_2 EOR depend on various factors such as the comparative performance and cost effectiveness with respect to other tertiary recovery methods, which use nitrogen, polymers, steam, natural gas and foaming agents, and the complexity of the depleting oil field where EOR is planned. This affects the volume of CO_2 that can be disposed of optimally through EOR operations.

v) **Inadequate pore space mapping and site characterization:** Within the G20, only few countries have undertaken extensive pore space mapping and site characterization programmes for developing an extensive CO_2 storage Atlas. Given the order of magnitude difference of scale in the volume of CO_2 emitted from the thermal power sector and hard to abate industries and the volume of CO_2 that can be utilized for value-added products over a reasonable time horizon, the lack of characterized sites and regions ready for CO_2 storage can seriously derail efforts to scale up CCUS.

vi) **Storage site risks:** For CO_2 storage projects, it is important to maintain an inventory of alternate storage sites ready for injection to mitigate the technical risks and uncertainties in accurately estimating the total sub-surface storage capacities of individual wells. However, fully characterizing multiple wells is an expensive proposition. Instead, quick access to rigs and well supplies may be ensured so that additional wells can be drilled quickly based on the evolving requirements.

Financial Risks

i) **Cost of capture:** CO_2 capture is the largest cost component in the CCUS value chain, especially for large emitters like thermal power plants and cement plants with dilute flue gas streams. This leads to financial risks for the entire CCUS value chain, which need to be addressed through appropriate commercial arrangements.

ii) **Financing risks:** CCUS value chains consist of multiple sub-systems, which require investment and financing at different stages of the evolution of the project. For example, the initial or "anchor" stages of a CCUS project requires the creation of adequately sized and shared CO_2 transport and disposition infrastructure to attract other CO_2 emitters for joining the project in a low-cost manner. Unavailability or delays in securing adequate financing during the initial period may lead to both time and cost escalations. These risks need to be addressed through bridge financing and provisions for contingency & additional funding.

iii) **Price competitiveness:** Carbon-abated and green products are likely to face price competition from their non-abated counterparts. While the difference may be initially covered through Government subsidies or grants, eventually, the cost of carbon abatement has to be passed onto the end consumers.

iv) **Attracting long-term investments:** CCUS projects are capex intensive and require long-term financing; hence there is a need to attract long-term investments and link the investment returns/payoffs to the level of carbon abatement achieved.

To attract investors seeking carbon reductions, investing directly in CCUS projects should involve lower risks and costs vis-à-vis buying carbon abatement certificates. There should also be options for trading the investment exposure in secondary markets by routing the investments into the CCUS projects through appropriately designed financial instruments.

v) **Counterparty risk and impact on project cost & timelines:** The CCUS value chain consisting of capture, CO_2 processing, transportation, utilization and disposition consists of multiple partners forming a tightly linked system. Weakness/loss of any part/partner of the value chain may jeopardize the entire value chain and hence contractual arrangements should be designed to de-risk the project from individual counterparty risks.

Safety Risks

i) **CO_2 leakage from storage sites:** Generally, storage sites have very low leakage rates. However, any large leakage could lead to safety incidents. Hence there should be reliable systems to monitor the injected CO_2 plume and any potential leakages.

ii) **Pipeline accidents:** Pipeline related accidents pose serious safety risks and would not only impact CO_2 transportation for a particular CCUS project, but would also have a spillover effect on other CCUS projects, both commissioned and under development, due to the requirement of upgrading safety protocols. Hence it is necessary to adopt best in class international safety standards (similar to those followed in the LNG industry) to prevent any incidents.

iii) **Pipeline traversing through populated areas:** Large diameter pipelines generally have a lower frequency of accidents. However, large diameter pipelines carrying dense phase or supercritical CO_2 through populated areas pose a safety risk as CO_2 , while not dangerous in lower concentrations/quantities, becomes lifethreatening above certain thresholds. Hence pipelines should have automatic isolation valves at short intervals and leak monitoring systems to isolate and localize any leakages and accidents, as well as adequate safety & failsafe systems and well defined & communicated emergency response protocols.

Conclusions

8.1 CCUS is imperative for reaching net zero and needs to scale significantly for meaningful decarbonization

Reaching net zero and limiting global temperature rise within 1.5 to 2 ^{o}C from pre-industrial levels is not possible without CCUS. 30% of global anthropogenic CO_2 emissions originate from the hard to abate and hard to electrify industrial sector – CCUS is the only scaleable solution to decarbonize these sectors as well as vast parts of the power sector, which will continue to be dominated by fossil fuel based generation for at least the next decade and beyond, to ensure affordable & reliable baseload power supply. However, presently operating CCUS projects account for only 42 mtpa of CO_2 abatement, against global anthropogenic CO_2 emissions of 36 Gtpa, i.e. a share of only 0.1%. Hence CCUS needs to scale up significantly to make a meaningful contribution to global decarbonization.

8.2 Understanding and addressing "Technology Gaps" across the CCUS value chain is critical in the decarbonization pathway

The "Technology Gaps" across the complete CCUS value chain i.e., capture, transport, utilization and storage, are described earlier in this report and are summarized in Table 8-1 overleaf.

8.3 The sustainability of key sectors of the economy depends on CCUS

Sectors such as fossil fuel based power generation, steel, cement, oil & gas, chemicals & petrochemicals are key pillars of the global economy and critical for ensuring food security, energy security and materials security. These sectors account for 60% of global anthropogenic CO_2 emissions – even with the growth of renewables, process & energy efficiency gains, the emergence of new technologies & production routes and reduction of carbon intensities across industries, the CO_2 footprint of these sectors is unlikely to decrease significantly in the next decade and beyond. In an increasingly carbon constrained world, CCUS offers the only scaleable and viable solution of ensuring the sustainability of these sectors.

8.4 CCUS is nascent in most G20 nations and international collaboration is a must to scale and spread CCUS across the G20

In terms of key enablers and actual operating projects, CCUS is most developed in the US and Canada, followed by other G20 countries such as Australia, France, Germany, Saudi Arabia, the UK and the EU. In other countries, the concept of CCUS is relatively new. Hence to spread and accelerate the rate & scale of CCUS adoption and deployment, international collaboration across the G20 countries is critical. Also, the scale of the net zero and decarbonization challenge is such that no single country or organization can alone scale up CCUS to the required levels. Close collaboration between Government, institutions and industry across the G20 countries is required to ensure coordinated policy mechanisms, technology support & development, enhanced funding & financing, facilitating cross border CCUS value chains, maximizing CO_2 conversion & utilization to value-added products, restricting non-carbon abated products, accelerating CCUS through blue hydrogen and setting up institutional mechanisms to support & monitor international collaboration in CCUS.

Table 8-1: Summary of Technology Gaps Across the CCUS Value Chain

Technology	Technology Sub-type	Technology Gaps	Potential Solutions
CO_2 Capture Technologies			
Solid Adsorbent	Temperature Swing Adsorption	Poor efficacy with lean CO_2 concentration	Novel adsorbent architecture can accelerate the process by 40-100 times
	Pressure Swing Adsorption	Slow process – cycle time in minutes /hours	Advanced MOF (Metal Organic Framework) – exponentially high surface area
Chemical Solvent	-	• Moderate energy intensity • Solvent life • Tolerance level with industrial SOx & other gaseous effluent	Development of new molecules & chemistry
Membrane	-	Poor 'selectivity' & 'purity'	• New polymeric membranes & electro-chemical membrane • Enhancing 'countercurrent sweep' in polymeric membranes
Direct Air Capture	-	High energy & water intensity, large land requirement and poor life of chemical media	Development of new 'Chemical Loop' and reagents
CO_2 Transport Technologies			
Pipework	-	• Two phase flow of CO_2 • Precipitation of dry ice or hydrate	Development of 'Flow Model' for CO_2 – including trans-critical, super-critical and sub-critical phase – for on/off shore application
CO_2 Utilization Technologies			
CO_2 to Building Construction Materials	-	Limited knowledge of 'process' and quality of product	Development of 'Design Mix' and 'Process'
CO_2 to Hydrocarbon (Chemicals & Fuels)	Chemical Process	Low 'Selectivity' and 'Conversion Efficiency'	• Development of new mechanically and chemically stable catalysts with desired rate of reaction kinetics • Design of efficient reactors
	Electro-chemical Process	Limited knowledge on electro-chemistry	• Development of co-electrlyzer for direct synthesis of chemicals and liquid/gaseous fuel • Development of electrolyzer for sea water and high TDS wastewater

Technology	Technology Sub-type	Technology Gaps	Potential Solutions
	Biological Process	Limited knowledge on bio-species & bio-chemical process	• Development of bio-catalyst for efficient synthesis of CO_2 & lean syngas • Development of innovative photo-bio-reactor for synthesis of human grade compounds
CO_2 to Carbon Morphology (Carbon Black, Carbon Nano Tubes etc)	-	Shape & structural compatibility	Non-conventional & odd geometrical-shaped CNT membranes require more advanced nano-scale fabrication techniques at the atomic level.
	-	Toxicity & environmental impact	Raw CNTs are more toxic than functionalized CNTs because of the existence of metal catalysts. Thorough investigations are required on this subject.
	-	Mechanical resilience & biofouling	Mechanical robustness need to be maintained in dynamic biological environments without triggering any biological growth or degradation.
CO_2 Storage Technologies			
CO_2 Injection Well	-	Limited understanding of CO_2 flow characteristics	Development of modelling tools for understanding multi-phase CO_2 flow in injection wells and geological formations
CO_2 Storage	Basalt and Ultra-Mafic Rocks Abandoned Coal Fields	Assessment of long-term CO_2 storage potential	• Advanced geological modeling alongside specials conditions viz seimic, rock fracture etc • Smart well monitoring techniques

8.5 The CCUS value chain consists of multiple sub-systems and technologies, with varying levels of development & maturity – the key enabler for CCUS to scale is addressing technology gaps across the entire CCUS value chain

The CCUS value chain consists of multiple tightly linked sub-systems: CO_2 capture, processing, transport and disposition/conversion of CO_2. The strength & resilience of the overall CCUS value chain is contingent upon the weakest link and hence its imperative to address technology gaps across the entire CCUS value chain. Technologies in the areas of CO_2 capture, processing, pipeline transportation and certain types of storage are fairly mature and operating at the commercial scale, whereas certain emerging CO_2 capture technologies, CO_2 utilization and multi-modal CO_2 transportation are more nascent. Accordingly, a differentiated approach should be adopted for addressing the technology gaps in each part of the CCUS value chain.

a) **Established carbon capture technologies:** The different types of carbon capture technologies (physical solvents, chemical solvents, adsorption and cryogenic separation) are mostly mature and operating at a commercial scale, with Technology Readiness Levels (TRL) of 8 and 9. Hence technology development should focus on cost reduction through levers such as learning curves & knowledge sharing, increasing scale, developing improved solvents, sorbents & membranes, and optimization & improvement of design for achieving cost reduction.

b) **Emerging carbon capture technologies (Direct Air Capture and Calcium Looping):** Direct Air Capture (DAC) and Calcium Looping (CaL) are emerging novel carbon capture technologies and provide an opportunity to complement the established carbon capture technologies, which are associated with significant steam & power duties and high regeneration energy requirements & secondary emissions.

DAC: DAC involves CO_2 removal from the atmosphere using chemicals, refrigeration or membranes and is presently at about TRL 6. The key improvement areas to target for DAC are reducing capture cost from US$ 350 to 700 per tonne of CO_2 to below US$ 100 by reducing energy, land & water use, better material performance and improving process efficiency & kinetics.

CaL: It is a CO_2 capture method and an alternative to emerging & cost-cutting early-stage oxyfuel combustion technologies. The CaL process captures CO_2 based on the multicyclic calcination-carbonation of $CaCO_3$ or limestone, a cheap and abundantly available material. CaL systems are at TRL 6/7 and need to address issues around increasing CaO multicyclic activity to ensure efficient CO_2 capture, proper energy & heat integration and efficient high temperature solid handling.

c) **CO_2 compression, dehydration and transportation:** CO_2 compression and dehydration are required to make the captured CO_2 ready for transportation – large scale CO_2 transportation is generally done through pipelines in the supercritical state at a pressure of 125 – 150 bar, thus requiring significant compression at the capture end. Dehydration is also important to prevent the formation of corrosive products such as carbonic acid and sulphuric acid in the presence of CO_2 and sulphur. CO_2 compression and dehydration technologies are at TRL 9.

CO_2 transportation by pipelines is at commercial scale, with more than 8000 km of CO_2 pipelines, primarily in the US.

Thus technological developments should focus on reducing costs and HSE risks, as well as developing offshore pipelines for offshore CO_2 storage. One other mode of CO_2 transport is using small scale ships; ship designs need to scale up, based on lower operating pressure and temperatures. The TRL for CO_2 shipping ranges from 3 to 9. The lowest TRL 3 relates to offshore injection into a geological storage site from a ship. The TRL 9 rating refers to conventional onshore CO_2 injection from onshore facilities. CO_2 transport at giga-tonne scale will require the multi-modal transport of CO_2 – this is another area which needs to develop through the modeling and optimization of integrated multimodal hub and cluster models.

d) **CO_2 utilization:** CO_2 can be converted to value-added products creating economic value from waste products and contributing to the circular economy. Other than the conversion of CO_2 to urea which is commercially established, CO_2 utilization is a relatively evolving area compared to carbon capture; the key challenge with utilizing CO_2 is that it is a very low-energy molecule and requires significant energy for conversion, leading to high production costs and secondary emissions. The most promising areas for CO_2 utilization are: building construction materials, fuels & chemicals and carbon nano-materials. All these applications have technology gaps in terms of high energy requirements, scalability, conformity to standards, which have to be addressed so that they can reach commercial scale in the next decade or so. Nevertheless, CO_2 utilization technologies should be supported through both R&D support and policy support for low-carbon products as they provide a pathway for deriving economic value from CO_2 , reduce wastes to drive the circular economy and provide a complement for CO_2 sequestration.

e) **CO_2 storage:** Underground geological storage of CO_2 is critical for CCUS to reach the GT (giga-tonne) scale. While CO_2 utilization technologies are fast evolving and provide multiple pathways for the conversion of CO_2 to different value-added products, they cannot match the scale of global anthorpogenic CO_2 emissions. Thus identifying, exploring and quantifying options for the permanent geological storage of CO_2 (across CO_2 EOR, ECBMR, saline aquifers and basaltic rocks) is critical to support CCUS and CO_2 disposition at the GT scale. Theoretically derived estimates suggest that the underground CO_2 storage space across the world can store global CO_2 emissions for centuries, but precious little has been done (except for a few countries) for detailed analysis, characterization and mapping of the pore space available for CO_2 storage.

The technology and tools required to identify, appraise, utilize, monitor and close a geological storage resource are all well-established and mature with TRL 9. It is imperative for G20 countries with significant storage potential to collaborate and adopt these technologies and tools for rigorously assessing and mapping the storage availability within their boundaries. This is perhaps the most significant risk and strategic gap for CCUS to move forward at scale.

8.6 CCUS also requires other enablers

Apart from addressing technology gaps across the CCUS value chain and promoting international collaboration across the G20 nations, there are several other key enablers needed at the national lavel for ensuring CCUS at scale:

a) Policy framework and Government support for facilitating CCUS enabled projects.

b) Development of CO_2 utilization technologies through support for low-carbon products

c) Development of markets for low-carbon products

d) Hub and cluster frameworks and the availability & flexibility of options for CO_2 disposition at scale.

Annexure

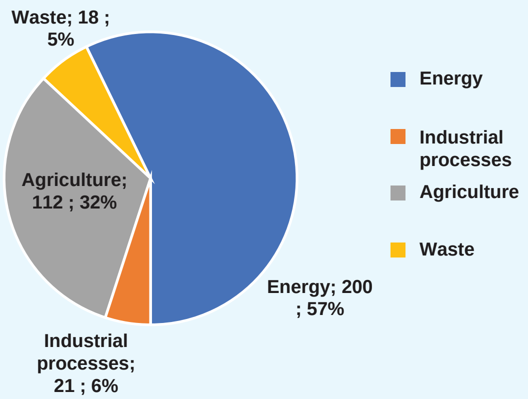
Annexure: CCUS in G20 Countries

A.1 Argentina

A.1.1 Background

Argentina is the 2nd largest country in South America, with a population of over 45 million people, largely concentrated in its urban centres. The country has significant biodiversity with a large range of latitudes, altitudes and 18 eco-regions. The country is quite vulnerable to climate change and has recently seen a growing frequency of extreme climate events, as well as changing climate patterns. During 1960-2010, the average temperature in Argentina increased by 0.5 °C and by 1 °C in parts of Patagonia. The GHG emissions of Argentina are estimated at 351 mtpa of CO_2-eq. The majority of these emissions arise from the energy (57%) and the agriculture & animal husbandry (32%) sectors.

Figure A-1: Argentina's GHG Emissions – 351 mtpa CO_2 -eq (2021)



Source:
Climate Action Tracker and Climate Transparency Report
Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

A.1.2 CCUS Policy & Regulatory Framework

Given the backdrop where industrial processes do not contribute significantly (only 6%) to GHG emissions, the Argentine Government's focus has primarily been on:

i) **Diversification of the energy matrix and the promotion of rational and efficient use of energy-**
larger participation of non-conventional renewable sources, hydroelectricity, nuclear power, and the replacement of fossil fuels by biofuels. In July 2022, the Argentine Government announced that household electricity subsidy shall be capped at 400 kWh per household per month; this measure is aimed at increasing the efficient use of energy.

ii) **Institutional mechanisms for better land management –**
this includes enrichment, restoration, conservation, harvesting and sustainable management of native forests. Some of the measures include no-till agriculture with adequate fertilization and crop rotation, soil moisture retention and improved soil structure and fertility, precision agriculture, development of biomass energy, promotion of organic agriculture, as well as the sustainable management of forest plantations.

A.1.3 Status of CCUS Projects

There are no existing or in-pipeline CCUS projects in Argentina.

A.1.4 CCUS Project Financing Mechanism

Argentina has implemented a carbon tax on liquid and solid fuels; the tax came into being in 2018 and proposed a price of US$ 10/tonne CO_2 -eq, which was then reduced to US$ 5/tonne CO_2 -eq. The tax was also extended to other fuels in 2019, i.e. fuel oil, mineral coal, and petroleum coke. The tax rate has been kept at 10% of the full tax rate, with a 10% step increase every year, thus reaching 100% in 2028. The tax will cover only 20% of the country's GHG emissions and is aimed at the energy sector emissions. Natural gas, CNG, fuel consumption in international aviation & shipping, and fuel exports are exempted from this tax.

Though there are no specific financing and/ or incentive framework for the GHG emission abatement or CCUS, the existing carbon tax may be considered as the first step in this direction. However, significantly higher carbon prices of US$ 50–100/tonne CO_2 -eq by 2030 are required to meet the 2016 Paris accord targets.

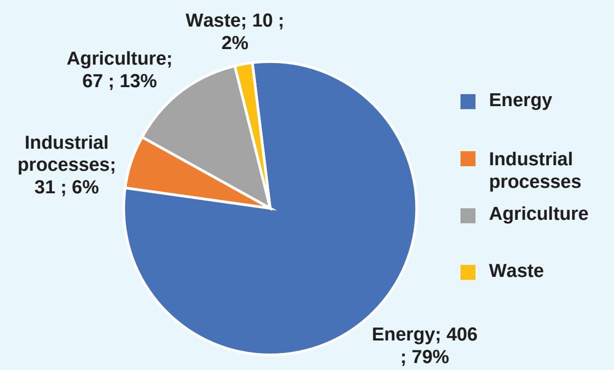
A.2 Australia

A.2.1 Background

Combating climate change is a focus area for the Australian Government given the severe challenges posed to its diverse natural ecosystems, especially the iconic natural features such as the Great Barrier Reef, south-western Western Australia, the Australian Alps, the Queensland Wet Tropics and the Kakadu wetlands.

As per the Australian national GHG inventory, the annual GHG emissions in Australia was 514 million tonnes of CO_2 -eq in 2021. The primary source of emissions is the energy sector (79%).

Figure A-2: Australia's GHG Emissions – 514 mtpa CO_2 -eq (2021)



Source: Climate Action Tracker and Climate Transparency Report
Note: Excludes LULUCF emissions

A.2.2 CCUS Policy & Regulatory Framework

Australia has significant potential for developing CCUS projects. In this regard, states like Victoria and Queensland enacted legislation more than 10 years ago, apart from Federal legislations.

A.2.2.1 Federal Legislation: The Offshore Petroleum and Greenhouse Gas Storage Act of 2006 (OPGGSA) provides the framework for CCUS projects in the Commonwealth waters of Australia, including aspects of licensing, regulatory monitoring & reporting and environmental standards to be maintained and complied. The applicability is for storage projects located within 3 to 200 nautical miles (270 km) from the coast. The Environment Protection and Biodiversity Conservation Act of 1999 (EPBC Act) is also applicable for CCUS projects, irrespective of their location and jurisdiction, as approvals are required under the EPBC Act from an environmental point of view.

A.2.2.2 Permits: The required permits for CCUS projects are given in Table A-1.

Table A-1: Australia – Permits for CCS Projects

Permit	Purpose
GHG Assessment Permits	• Required for exploring geologic formations for storing GHGs. Permits granted for 6-year terms through competitive tendering
Declaration of Identified GHG Storage Formation	• Ministerial/Governmental declaration indicating that a particular geologic formation is eligible for GHG storage. • Required for transitioning from GHG Assessment Permit to GHG Holding Lease or GHG Injection Licence.
GHG Holding Leases	• Allows exploration activities and injection for testing purposes in storage formations and injection sites • Issued to persons not eligible for GHG Injection Licenses but may become so after 15 years • The term is of 5 years and is extendable
GHG Injection Licence	• The licensee can inject and permanently store GHGs in identified formations. • Termination of licence if no injection is done within 5 years from the grant of a license

A.2.2.3 State Legislations: The states of Victoria, Queensland, and South Australia have CCS legislation with similar permitting requirements to the OPGGSA. However, project developers do not have indemnity from post-closure leakage, thus exposing them to risks which can last an indefinite period and are difficult to insure. It is likely that legislation would also be introduced for the other states (in the drafting stage for Western Australia) to promote CCUS projects.

A.2.3 Status of CCUS Projects

The status of various CCS projects in Australia is tabulated below:

Table A-2: CCS Projects in Australia

Sl. No.	Project	CCS Capacity	Owner(s)	Status
1.	Bayu Undan CCS Project (Northern Territory)	10 mtpa	Santos, Timor Leste, Inpex, Eni, SK E&S and Tokyo Timor Resources	FEED commenced.
2.	CTSCo Project (Queensland)	110,000 tpa	Glencore	FID yet to be taken. Awaiting environmental approvals.
3.	CO2CR Otway Project (Victoria)	Research facility	CO2CR	Research phase
4.	Gorgon CCS Project (Western Australia)	4 mtpa	Chevron	Developed and operational.
5.	Karratha CCS Project (Western Australia)	TBC	Woodside, BHP, BP, Chevron, Shell, MIMI	Research phase
6.	Moomba CCS Project (South Australia)	1.7 mtpa	Santos Beach Energy	FID taken.
7.	NT Hub (Northern Territory)	TBC	NT Gov, CSIRO, Santos, INPEX, Woodside, Eni, Origin Energy and Xodus	Research phase
8.	South West Hub (Western Australia)	800,000 tpa	TBC	Research phase
9.	The CarbonNet Project (Victoria)	5 mtpa	Victorian Government	FID aimed for 2024.

A.2.4 CCUS Project Financing Mechanisms

A.2.4.1 Special Purpose Grants from the Federal Government: CCUS projects traditionally require government funding and support to be viable investment propositions. In this regard, the Federal Government of Australia has set up two funds for CCUS projects:

i) AU$ 50 million Carbon Capture, Use and Storage (CCUS) Development Fund – for providing grants in the range of AU$ 500,000 to AU$ 25 million. Notable grants include AU$ 15 million to the Moomba CCS Project.

ii) AU$ 250 million CCUS Hubs and Technologies Program - for providing grants in the range of AU$ 500,000 to AU$ 30 million, focused to deploy CCUS at scale.

Both the above funds are closed, but the Government of Australia has announced funding of AU$ 300 million for the NT Hub “to support low emissions LNG and clean hydrogen production at Darwin, together with associated carbon capture and storage infrastructure”. Two other current avenues of federal government funding for CCUS projects are:

i) Finance from the Low Emissions Technology Commercialisation Fund, administered by the Clean Energy Finance Corporation (CEFC); and

ii) Grants from the Australia Renewable Energy Agency (ARENA).

A.2.4.2 State Government Funding: States have provided direct support to CCUS projects such as CarbonNet, NT Hub and South West Hub projects. Although there is no established fund, it is likely that state government funding may also be available for CCUS projects on a case-to-case basis, depending on the merits and viability of the project and support to local industries.

A.2.4.3 Carbon Credits: CCUS projects in Australia can also earn Australian Carbon Credit Units or ACCUs. Industrial facilities with emissions above 100,000 tpa of CO_2 per year need to report their emissions and energy consumption and also contain the same within the baselines defined by the regulator. Facilities which exceed the baselines need to purchase ACCUs to offset the same. The legislative framework for ACCUs is provided by the Carbon Credits (Carbon Farming Initiative) Act of 2011. CCS projects generate ACCUs, which can be sold to other entities which need them to offset their emissions.

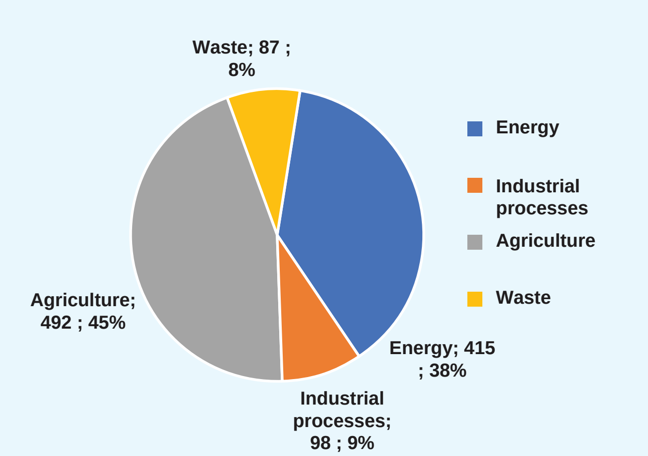
A.2.4.4 Carbon Tax: There is presently no carbon tax in Australia. However, the Federal Government is planning an AU$ 25/tonne of CO_2 voluntary incentive as part of its strategy to achieve net zero by 2050. Such an incentive is likely to incentivize CCS projects in Australia. Additionally, exporters to Europe will have to face the EU’s Carbon Border Adjustment Mechanism (CBAM); this is also likely to incentivize major emitters to take up CCUS projects.

A.3 Brazil

A.3.1 Background

Brazil has committed to ambitious GHG emission reduction targets of 50% reduction by 2030 (compared to 2005 emissions) and achieving climate neutrality by 2050, based on the condition of receiving external financial support. Brazil’s NDCs also cover almost every sector of its economy. Brazil’s annual GHG emissions are about 1093 mtpa of CO_2-eq. However, the break-up is very dissimilar to other countries, as the largest contributor is not energy consumption but rather the agricultural sector, with a 45% share. This is because of Brazil’s dependence and skew towards hydroelectricity rather than fossil fuelbased power and absence of many CO_2 -emitting industries.

Figure A-3: Brazil's GHG Emissions – 1093 mtpa CO_2 -eq (2020)



Source: Climate Action Tracker and Climate Transparency Report.
Note: Excludes LULUCF emissions

The share of fossil fuels in Brazil's energy mix is likely to increase given the economic and sectoral economic outlook and recent drought conditions, which have led to an increased focus on natural gas based power. This will lead to a higher carbon intensity energy grid, contrary to the pathway adopted by other major economies of the world. Given this backdrop, strong policy action is required to promote CCUS for abating emissions from fossil fuel based energy generation and consumption.

A.3.2 CCUS Policy & Regulatory Framework

The focus of Brazil's NDC are on biofuels, reduced deforestation, renewable energy, energy efficiency and sustainable agriculture. There is no focus on CCUS for abating emissions from the fossil fuels based energy sector or other industrial emitters. However, CCUS has significant potential for decarbonization of different sectors, such as the production of biofuels, natural gas based power generation, oil & gas exploration and production with CO_2 -EOR.

A.3.3 Status of CCUS Projects

Brazil has significant CO_2 storage potential, particularly in the area of CO_2 EOR. However, given the lack of focus on CCUS, there have been only a handful of CCUS projects in the country, as tabulated below.

Table A-3: CCUS Projects in Brazil

Sl. No.	Project	CO_2 Injection	Company	Status	Fuel	Capture	Storage
1.	Charqueadas ECBM Pilot, Porto Batista, Porto Alegre	-	Petrobras, CEPAC, COPELMI Mining Corp	Pilot	Unknown	Unknown	Coal Seam
2.	CCP Project - Oxy-firing FCC Demonstration, Sao Mateus do Sul, Parana State	-	CO_2 Capture Project (CCP)	Pilot	Oil	Oxyfuel	No storage

Sl. No.	Project	CO_2 Injection	Company	Status	Fuel	Capture	Storage
3.	Lula Oil field, 300 km offshore from Rio de Janeiro	1 mtpa CO_2	Petrobras, with BG E&P Brasil and Petrogal Brasil	Operational	Gas	Other	EOR
4.	Buracica Field EOR Project, Eastern Bahia State	-	Petrobras, FAFEN, Oxiteno	Operational	Gas	Other	EOR with MVR
5.	Miranga Field EOR Pilot, Miranga, Pojuca, Bahaia province	-	Petrobras	Pilot	Unknown	Post combustion	EOR

A.3.4 CCUS Project Financing Mechanism

There is no CCUS project financing mechanism available from the Brazilian Government. Some of the largest private sector players, such as Petrobas (oil & gas), Vale (mining) and Votorantim Cimentos (cement) have committed to reduce their carbon intensity and emissions but have not yet taken up any CCUS projects.

A.4 Canada

A.4.1 Background

Canada has committed to achieving a GHG emission reduction of 40-45% by 2030, compared to its 2005 emissions and reaching net-zero emissions by 2050. Greenhouse gas emissions in Canada in 2020 were 672 mtpa CO_2 -eq in 2020, down by 9% from 738 mtpa CO_2 -eq in 2019 due to the impact of the COVID-19 pandemic. The principal source of CO_2 emissions is the energy sector, accounting for about 80% of emissions.

In 2016, Canada adopted the Pan-Canadian Framework on Clean Growth and Climate Change (PCF), aimed at reducing GHG emissions and promoting clean economic growth. Before the adoption of the PCF, it was projected that GHG emissions in Canada would grow to 815 mtpa CO_2 -eq by 2030, i.e. 10% higher than the 2005 base levels of 741 mtpa CO_2 -eq. The adoption of the PCF and related clean energy measures are expected to lower 2030 emissions to 468 mtpa CO_2 -eq., about 37% lower than the 2005 baseline.

A.4.2 CCUS Policy & Regulatory Framework

Canada has enacted several legislations and policies, such as carbon taxes and clean fuel standards (both at the State and the Federal government level), to enable the transition to a low-carbon economy. The immediate CCUS target is capturing and storing 15 mtpa CO_2 by 2030.

It is very likely that the carbon tax and clean fuel standard will play a significant role in incentivizing CCUS, especially for the hard-to-abate energy sector and industrial emitters. Every state in Canada has its carbon pricing system or is covered by the Federal government system. The latter consists of a carbon tax or fuel charge on the production and distribution of gasoline and natural gas; there is also a cap & trade system wherein industrial emitters are allocated certain emission limits, with the option of trading any unused/ excess allowances.

Table A-4: Carbon Pricing System Adopted by Different Provinces of Canada

States	Federal system	Federal cum provincial system	Provincial system
Yukon	✔		
Nunavut	✔		
Manitoba	✔	✔	
Alberta		✔	
Saskatchewan		✔	
Ontario		✔	
Prince Edward Island		✔	
British Columbia			✔
Northwest Territories			✔
Quebec			✔
Newfoundland and Labrador			✔
Nova Scotia			✔
New Brunswick			✔

The Federal Government has fixed the minimum CO_2 price at CA$ 40 per tonne, which will increase to CA$ 170 per tonne by 2030. The Clean Fuel Standard (to be implemented in 2023) will focus on reducing the lifecycle carbon intensity of fossil fuels sold in Canada. For example, refineries need to reduce emissions by 2.4 grams of CO_2 -equivalent per megajoule (gCO_2e/MJ) in the first year; this target will accelerate and reach 12 gCO_2e/MJ by 2030. These two regulations and the increased carbon constrained Canadian economy are forcing hard-to-abate emitters like steel plants, oil & gas refineries, and power generators to seriously look at CCUS for reducing their emissions. The focus of CCUS related activities is concentrated in the states of Alberta and Saskatchewan, given the availability of oil fields for enabling CO_2 EOR. Even geological storage is being explored, with Shell's Quest Carbon and Storage project being the first attempt to store CO_2 in geological formations in Canada.

A.4.3 Provincial Policies

A.4.3.1 Alberta: Alberta passed the Carbon Capture and Storage Funding Act in 2013 to provide funding up to CA$ 2 billion to CCUS projects. About CA$ 1.2 billion has been committed to two commercial scale projects capturing over 2 mtpa, including a CO_2 transport trunkline with a capacity of 14 mtpa.

A.4.3.2 Saskatchewan: The measures include a 20% investment tax credit for CO_2 pipeline infrastructure, lower royalties for CO_2 EOR projects, updated regulations for CO_2 storage and utilization and exploring & promoting CCUS hubs.

A.4.3.3 Prince Edward Island: Prince Edward Island has targeted reaching net zero by the year 2040, and one of the identified focus areas is investing in CCUS projects by adopting both technological and biological approaches.

A.4.4 Status of CCUS Projects

A summary of Canada's major known CCS projects is provided in Table A-5.

Table A-5: CCUS Projects in Canada

Sl. No.	Project	CO_2 Injection	Company	Status	Fuel	Capture	Storage
1.	Weyburn- Midale CO_2 Project, Weyburn, Saskatchewan	3 mtpa	EnCana, Dakota Gasification Comp	Operational	Coal	Precombustion	EOR with MVR
2.	Boundary Dam, Estevan, Saskatchewan	1 mtpa	Saskpower	Operational	Coal	Postcombustion	EOR with MVR
3.	Quest, Fort Saskatchewan, Alberta	1 mtpa	Shell Canada	Operational	Gas	Other	Saline formation
4.	Alberta Carbon Trunk Line, Redwater, Alberta	1 mtpa	Wolf Carbon Solutions, Enhance Energy	Under construction	Other	Other	EOR
5.	Nutrien Redwater Nitrogen Plant, Redwater, Alberta	-	Nutrien Ag, Enhance Energy, Wolf Carbon Solutions	Under construction	Gas	Other	EOR with MVR
6.	North West Redwater, Redwater, Alberta	1 mtpa	North West Upgrading, Canadian Natural Resources	Under construction	Other	Precombustion	EOR with MVR

Sl. No.	Project	CO_2 Injection	Company	Status	Fuel	Capture	Storage
7.	Zama, Zama city, Alberta	-	Apache Canada	Pilot	Gas	Other	EOR
8.	CO2MENT Pilot, Richmond, BC	-	Svante, LafargeHolcim, Total	Pilot	Other	Postcombustion	No storage
9.	Miranga Field EOR Pilot, Miranga, Pojuca, Bahaia province	-	Petrobras	Pilot	Unknown	Postcombustion	EOR
10.	CO_2 Solutions Capture Pilot - Test Site, Montreal East	-	CO_2 Solutions Inc	Pilot	Gas	Postcombustion	No storage
11.	GTI/CanmetENERGY Pilot Plant, Kanata, near Ottawa	-	Gas Technology Institute (lead)	Pilot	Unknown	Oxyfuel	No storage

A.4.5 CCUS Project Financing Mechanism

The key project financing mechanisms available in Canada are:

i) Strategic Innovation Fund's CA$ 8 billion Net-Zero Accelerator Fund for decarbonization projects for large emitters

ii) In 2021, the Federal Government granted CA$ 35 million to fund the Centre for Innovation and Clean Energy for undertaking R&D projects, including CCUS.

iii) Future investment tax credit for CCUS project investments for incentivizing private investment for meeting the goal of 15 mtpa of carbon capture and storage by 2030. However, this tax credit will exclude CCUS projects involving CO_2 EOR, which traditionally has been the disposition pathway of choice for carbon capture projects in Canada.

A.5 China

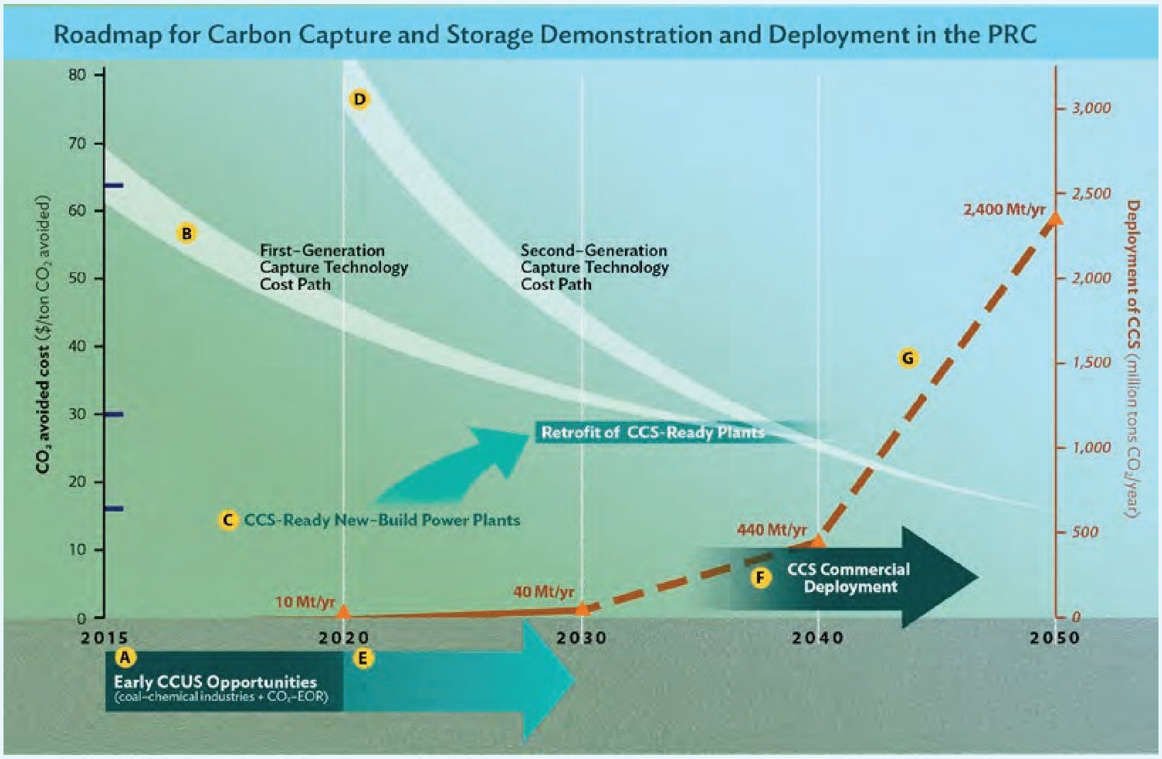
A.4.1 Background

China is the largest emitter in the world, accounting for 14.4 Gt of CO_2 eq. of GHG emissions in 2021. China has committed to peak its CO_2 emissions by 2030 and reach net zero by 2060, as part of its Nationally Determined Contributions with respect to combating climate change. China's primarily coal based energy sector accounts for 76% of its GHG emissions, with industrial processes contributing another 15%.

A.5.2 CCUS Policy & Regulatory Frameworks

China's CCUS policy framework is guided by the country's dependence on coal for reaching its economic and developmental goals. China had proposed a CCUS roadmap in 2015 wherein significant investments were only planned after 2030, with commercial deployment after 2040. The roadmap targets CCUS contributing to decarbonization in the following phased manner: 10 – 20 mtpa by 2020; 40 mtpa by 2030; and 440 mtpa by 2040.

Figure A-4: CCUS Roadmap for China



The key phases of the roadmap are as follows:

i) 2015 to 2020: CCUS and CO_2 – EOR of 10 – 20 mtpa, contributing to 30 mn barrels of incremental oil production. CCUS demonstration projects are to be set up for 5 to 10 coal to chemicals plants and 1 to 3 coal fired power plants. The main aim of these projects would be to address the technical challenges and concerns of CCUS.

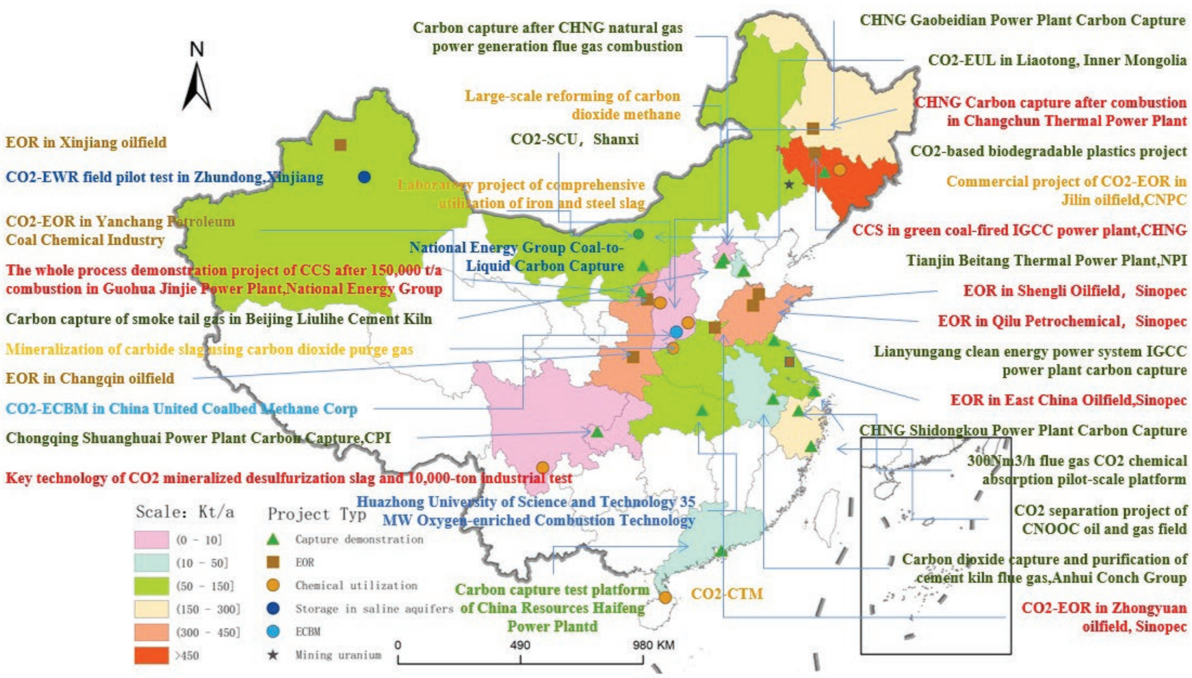
ii) 2021 to 2030: Market creating incentives such as carbon tax, and emission ceilings to be announced to incentivize CCUS. CCUS to reach commercial scale in coal to chemicals and coal to power sector and implemented at demo scale in other sectors. A CCUS regulatory framework shall be implemented.

iii) Beyond 2031: It is anticipated that CCUS will achieve significant scale and cost reductions to merit economy-wide commercial application.

A.5.3 A.5.3 Status of CCUS Projects

A large number of CCUS pilot and demonstration projects are underway in different provinces of China (Figure A-6); the total capture capacity is about 3 mtpa and the total storage capacity is about 2 mtpa.

Figure A-5: CCUS Projects in China



A few key CCUS projects in China are tabulated below.

Table A-6: CCUS Projects in China

Project	Location	Scale of Capture	Capture/ End use	Timeline
Research and Demonstration of CO_2 -EOR in PetroChina Jilin Oilfield	Jilin Oilfield	0.3 mtpa	CCUS-EOR	Operational since 2008
Shanghai Shidongkou CO_2 Capture and Storage Demonstration Project of Huaneng Group	Shidongkou, Shanghai	0.12 mtpa	Post-combustion capture	Operational since 2009

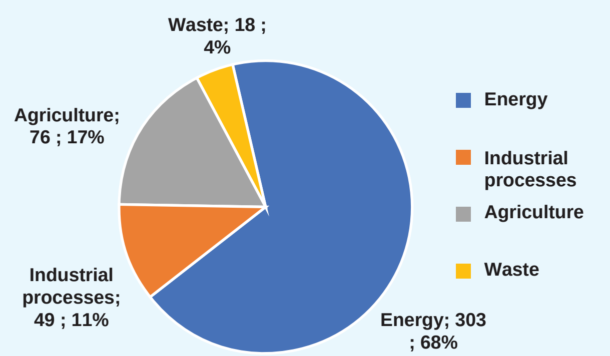
Project	Location	Scale of Capture	Capture/ End use	Timeline
Coal-to-Liquids CO_2 Capture and Storage Demonstration of Shenhua Group	Ordos, Inner Mongolia	0.1 mtpa	Coal liquefaction plant + saline aquifer	Operational since 2011
CO_2 Capture from Coal Chemical Industry and CO_2 Flooding Demonstration of Yanchang Petroleum Group	Yulin, Shaanxi	0.3 mtpa	CO_2 CCUSEOR from the coal chemical industry	Operational since 2016
EOR Demonstration in Sinopec East China Oilfield	Dongtai, Jiangsu	0.156 mtpa	EOR	Operational since 2005

A.6 France

A.6.1 Background

The European Union (EU) has committed to reducing GHG emissions by 55% within 2030, as compared to 2005 levels. As a member country of the EU, France is a signatory to these targets and also has set specific domestic targets of 75% GHG reductions by 2050. France's GHG emissions in 2019 were 446 mtpa CO_2 eq. – there has been a gradual decrease in emissions of 19% since 1990, given the French economy's transition towards the services sector and the shifting of carbon-intensive industries outside France. The sectoral break-up is provided in Figure A-7.

Figure A-6: France's GHG Emissions – 446 mtpa CO_2 -eq (2019)



Source: Climate Action Tracker and Climate Transparency Report
Note: Excludes LULUCF emissions

A.6.2 CCUS Policy & Regulatory Frameworks

France's National Low Carbon Strategy (Stratégie Nationale Bas Carbone or SNBC) incorporates CCUS as an important lever for decarbonizing the hard to abate industrial sector: steel and chemicals by 2030 and cement by 2035. However, the role of CCUS is not envisaged to be integral to the decarbonization of the energy sector, where the focus is on renewables, biomass and other forms of low-carbon power and heat generation to replace the use of fossil fuels. CCUS is primarily envisaged for industrial decarbonization. One specific area for CCUS is enabling the production of low-carbon transport fuels, given the fact that out of different energy uses, energy consumption in the transport sector accounts for 30% of emissions.

A.6.3 Status of CCUS Projects

The CCUS projects in France are at various stages of operation.

Table A-7: CCUS Projects in France

Project	Type of carbon capture	Participants	Status	Start Timeline	CCUS Capacity (mtpa)
Demonstration in Dunkirk	Industrial capture - steel mill	ArcelorMittal, Axens, TotalEnergies, ACP, Brevik Engineering, CMI, DTU, Gassco, RWTH and Uetikon	Advanced development	2025	0.1
Pycasso – Pyreanean Carbon Abolition through Sustainable Sequestration Operations	Industrial capture (multiple industrial sources)	Avenia, CAPBP, Terégа, Schlumberger, Lafarge, Repsol, UPPA, BRGM, IFPEN, Sofresid, Geostock, SNAM	In planning	2030	1
K6	Industrial capture from cement plant	Air Liquide, EQIOM, VDZ	Early development	Data NA	0.8
CalCC	Industrial capture from cement plant	Air Liquide, Lhoist	In planning	2028	0.6
Cryocap	Blue H2	Air Liquide	In operation	2015	0.1
D'Artagnan	In transport sector	-	In planning	2025	12

Additionally, there are multiple R&D and demonstration CCUS projects involving both CO_2 capture and utilization in diverse applications such as utilization in steel & chemicals plants, mineralization of concrete, production of algae from CO_2 emitters and biological methanation. Apart from CO_2 utilization, France also has the potential for the permanent geo-sequestration or storage of CO_2 ; the Paris and Aquitaine basins have an estimated CO_2 storage capacity of 27 Gt CO_2 -eq. However, the potential needs to be better characterized before being considered for commercial applications.

A.6.4 CCUS Project Financing Mechanism

There are no specific funding mechanisms for CCUS; however, France has pledged to double funding for clean energy innovations (which included CCUS) by 2020, compared to the baseline of 2015. The private sector has an important role to play in CCUS R&D and demonstrations, given the presence of strong French companies in this sector, viz.: Air Liquide, Total, IFPEN, Axens, BRGM. For example, Total is involved in major CO_2 transport and storage projects in the North Sea, which is expected to drive CCUS investments in France.

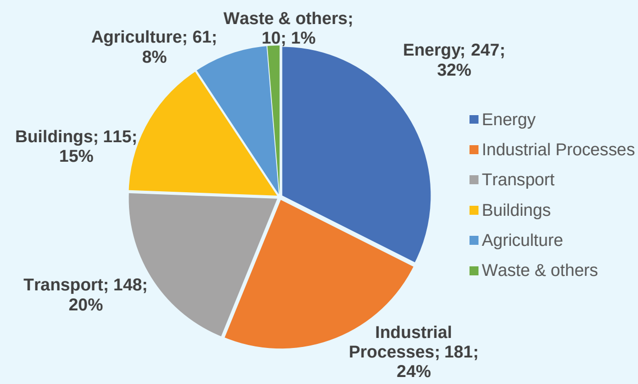
A.7 Germany

A.7.1 Background

Similar to France, Germany is also a signatory to EU's commitment of reducing 55% emissions by 2030, compared to 2005 levels. Additionally, Germany has set a target of reaching net zero by 2045.

Germany's overall GHG emissions in 2021 were 762 mtpa CO_2 -eq, down from the prepandemic levels of 800 mtpa CO_2 -eq. in 2019. The energy industry is the largest contributor, accounting for a 32% share of the emissions.

Figure A-7: Germany's GHG Emissions – 762 mtpa CO_2 -eq (2021)

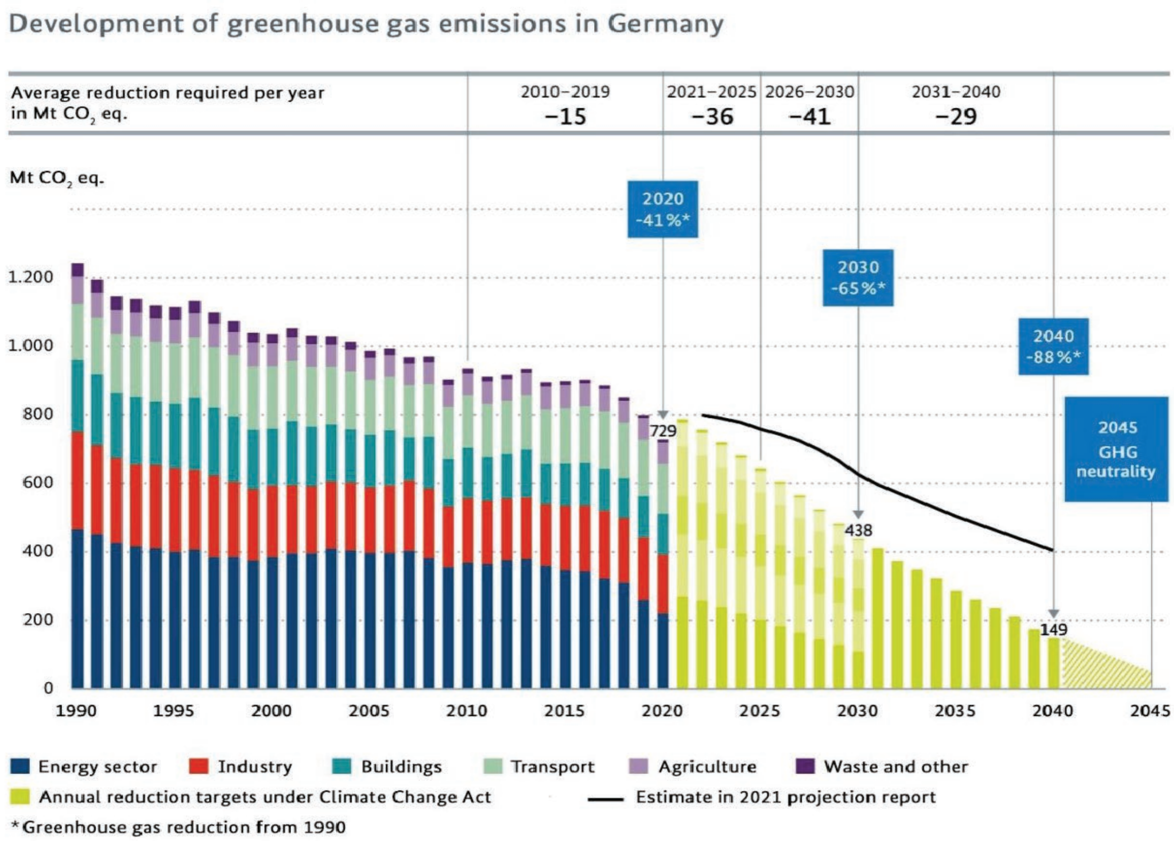


Source: Climate Action Tracker and Climate Transparency Report
Note: Excludes LULUCF emissions

A.7.2 CCUS Policy & Regulatory Frameworks

From 2011 to 2021, Germany's GHG emissions have reduced by 150 mt, i.e. by about 15 mt per year. However, this decrease in emissions needs to accelerate to 35 – 40 mt per year up to 2030 for Germany to meet its long-term climate and decarbonization goals. The 2030 Climate Action Program of the German Government includes mandatory decarbonization and emission reduction targets across various sectors. One of the key areas from a CCUS point of view is promoting decarbonization, electrification, energy & resource efficiency, circular economy and new energy carriers such as hydrogen in the industrial sectors. The program also identifies the direct capture, storage and utilization of CO_2 as an important element for capturing unavoidable emissions and enabling the energy transition of the industrial sector. Funding directives have also been issued by the Government for scoping CCUS projects, with second stage funding also envisaged for demonstration projects across capture, storage, utilization and transport.

Figure A-8: Germany's Decarbonization Pathway



Source: www.bmwk.de

A.7.3 Status of CCUS Projects

The CCUS projects in Germany at various stages of operationalization are tabulated below.

Table A-8: CCUS Projects in Germany

Project	Type of carbon capture	Participants	Status	Start Timeline	CCUS Capacity (mtpa)
H2morrow	Blue H_2	Equinor, OGE, Steel Europe	In planning	2030	1.9
Leilac 2	Industrial Capture (cement plant)	Calix (Europe) Limited - Engie Laborelec - HeidelbergCement AG - Geological Survey of Belgium - Lhoist Recherche et Developpement SA - BGR - Calix Limited - Politecnico Milano - Port of Rotterdam - Centre for Research & Technology Hellas - CEMEX - CIMPOR – IKN	Advanced development	2023	0.1
BlueHyNow	Blue H_2	Wintershall Dea, Nord-West Oelleitung (NWO)	In planning	Data not available	Data not available
Oxyfuel 100	Methanol synthesis	EDF Germany, Holcim Germany, Ørsted Germany, Raffinerie Heide, Stadtwerke Heide, Thügaans thyssenkrupp Industrial Solutions, Heide development agency, Westküste University of Applied Sciences	In planning	Data not available	Data not available
H2GE Rostock	Blue H_2	Equinor, VNG AG	In planning	2029	2

A.7.4 CCUS Project Financing Mechanism

In 2021, a funding directive was issued to support CCUS technologies and projects towards market maturity. The areas of support include CO_2 storage in the North Sea, DAC combined with CO_2 disposition and BECCS. The initial budget was set at €105 million for 2021 and thereafter €120 million per year until 2025.

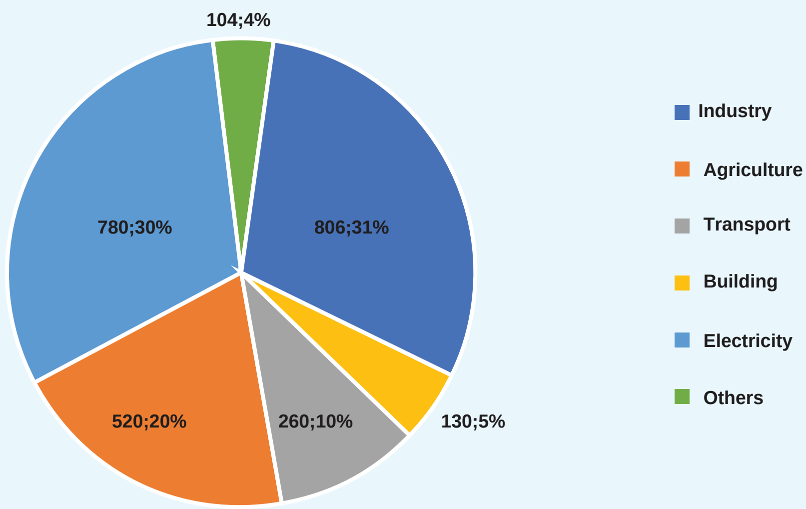
A.8 India

A.8.1 Background

India is the 4th largest emitter of CO_2 in the world among G20 economies after China, the US and the EU, with estimated GHG emissions of 3.4 Gtpa of CO_2 eq. in 2021. The emissions had reduced to 3.1 Gtpa in 2020 due to the impact of the COVID-19 pandemic. India's per capita emissions are less than 40% of the global average and about one-fourth of that of China.

However, with rapid economic growth, infrastructure and industrial development, as well as a growing population (expected to cross 1.50 billion by 2036), the total emissions are expected to reach 4 to 4.4 Gtpa by the year 2030. The sectoral break-up of emissions reveals that while renewable energy is making great strides in India, it can theoretically contribute at most 30% of the desired decarbonization by replacing fossil fuel-based power generation.

Figure A-9: India – GHG Emissions of 3.4 Gtpa CO_2 eq (2021)



Source:
Climate Action Tracker and Climate Transparency Report
Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

A.8.2 CCUS Policy & Regulatory Frameworks

The apex policy think tank of the Government of India, the NITI Aayog, has recently published a report on the policy framework and enabling mechanism required for CCUS projects in India. The report proposes a supportive cash & tax incentive-based policy framework for promoting CCUS in India. The key elements of the proposed policy framework are provided below.

Table A-9: Proposed CCUS Policy Framework for India

Element	Details
Policy path	• In the near term, CCUS policy should be carbon credits or incentives based, to seed and promote the CCUS sector in India through tax and cash credits • Over time (probably beyond 2050), the policy should transition to carbon taxes, to enable reaching India's netzero goals by 2070 • The policy should establish early-stage financing and funding mechanisms for CCUS projects
Hub & Cluster model	• Regional hub & cluster models need to be established to drive economies of scale • The role of emitters, aggregators, hub operators, disposers and conversion agents needs to be defined
Low carbon products	• Preferential procurement in Government tenders for lowcarbon or carbon-abated products • Incentives to foster innovation for low-carbon products through schemes like PLI
Environmental and social justice	• Distribution of benefits of economic value added created to communities most affected by environmental and climate change • Protection of communities and jobs, especially in sectors affected by clean energy regulations
Accounting and regulatory framework	• Regulated emission levels and allowances for different sector • Adoption of a Life Cycle Analysis (LCA) framework to take into account Scope 2 and Scope 3 emissions and drive effective carbon abatement
Risk mitigation	• Limiting the CO_2 liability and ownership of participants across the CCUS value chain • Monitoring, Verification and Accounting (MVA) framework and monitoring for risk management

Source: Carbon Capture, Utilisation, and Storage Policy Framework and its Deployment Mechanism in India, 2022

A.8.3 Status of CCUS Projects

Apart from the CCUS policy framework and agenda, that is likely to be driven and implemented by the Government of India, several companies are pursuing different CCUS projects and initiatives, particularly in the area of CO_2 conversion and utilization. Some of these key initiatives are tabulated below.

Table A-10: Key CCUS Projects and Initiatives in India

Company	Sector	Details
NTPC	Power	CO_2 utilization pilot project at NTPC's Vindhyachal thermal power plant: for capturing 20 tpd of CO_2, with future plan of utilizing the same for producing 10 tpd methanol
	Power	Development of zeolite and 'Pressure Swing Adsorption' process for CO_2 capture
	Power	Development of amine and process for CO_2 capture
	Power	Demonstration of micro algae based CO_2 capture
	Power	CO_2 utilization pilot project: 10 tpd CO_2 to generation 4 ethanol plant at NTPC power plant
	Power	CO_2 utilization pilot project: Production of carbonated aggregates using fly ash and CO_2 from power plant flue gas
	Power	CO_2 storage: mapping of geological storage potential of CO_2 in category 1 field in India, in association with the National COE-CCUS of IIT Bombay
ONGC & IOCL	Oil & Gas	Feasibility study for capture of 0.7 mtpa of CO_2 from HGU at IOCL Koyali refinery and utilizing the CO_2 for EOR at ONGC's Gandhar oilfields and F&B grade usage
ONGC	Oil & Gas	MoU with Shell for cooperation on exploring CO_2 storage study and EOR in key basins in India and with Equinor for developing CCUS hubs and projects
BPCL	Petrochem	Feasibility study for gasification of 1.2 mtpa petcoke and conversion to carbon abated chemicals, hydrogen and power
Tuticorin Alkali & Chemicals	Chemicals	Commissioned a 200 tpd plant. Captured CO_2 is utilized for the production of baking soda.
BHEL & CSIR-CIMFR	Chemicals	Coal to methanol: pilot scale plants for carbon capture and conversion to methanol
Tata Steel	Steel	Commissioned a plant for capture of 5 tpd CO_2 capture from Blast Furnace gases at TSL Jamshedpur, with future plans to re-use the CO_2 within the steel value chain
JSPL	Steel	Capture of 2000 tpd concentrated CO_2 from commercial scale coal gasification operations at Angul for enabling carbon abated steel producing using blue hydrogen (as part of syngas). Also exploring CO_2 utilization to bio-ethanol, methanol and soda ash
Dalmia Cements	Cement	500,000 tpa carbon capture plant planned at their Tamil Nadu plant – MOU with technology provider

A.8.4 CCUS Project Financing Mechanism

The report by the NITI Aayog proposes different pathways and mechanisms for supporting and financing CCUS projects in India.

i) Set up a "Carbon Capture Finance Corporation (CCFC)" for India. The CCFC will be a financial institution for funding CCUS projects through debt and equity. The seed capital for the CCFC will either be provided through direct budget support by the Government of India or by diverting the clean energy cess levied by the Government on the consumption of coal in India.

ii) Production-linked incentives (PLI) for low-carbon products

iii) Subsidizing CO_2 abatement projects through cash credits (for operating costs) and tax credits (for capital costs).

iv) Fund demonstration projects to identify the most appropriate CCUS technologies for different sectors and applications in the Indian context.

A.9 Indonesia

A.9.1 Background

In 2015, the Government of Indonesia enhanced its climate pledge by raising the earlier emission reduction target set in 2010. Indonesia has committed that it would reduce its GHG emissions during the 2020-2030 period by 32% (in the unconditional scenario) and up to 43% (in the conditional scenario, i.e. with international financial support) as compared to 2030 business-as-usual GHG emissions. Indonesia has also committed to achieve carbon neutrality by 2060.

Currently ranked 8th in the world in terms of emissions, Indonesia's GHG was at 1543 mtpa CO_2 -eq in 2021, which is 5% lower than 2020 emissions of 1625 mtpa CO_2-eq. Studies note that Indonesia needs to reduce its emissions to below 662 mtpa tonne CO_2 -eq by 2030 and below 51 mtpa CO_2 -eq by 2050 to contribute to its "fair-share" of global decarbonization required for limiting global temperature rises to 1.5°C above preindustrial levels. However, Indonesia's 2030 NDC would limit its emissions to 1,817 mtpa CO_2 -eq and hence there is clearly a need for deeper emissions cuts. In this regard, CCUS may be considered as a key tool in furthering GHG emissions reduction by capturing and utilizing or storing CO_2 emissions in Indonesia.

A.9.2 CCUS Policy & Regulatory Frameworks

The Indonesian Government is targeting a progressive emissions reduction program to control carbon trade, including incentives based on success in lowering greenhouse gas emissions and also imposing a carbon tax. It was slated to implement a carbon price of US $2.1/ tonne of emitted CO_2 on coal-fired power plants in 2022; however, the same has been put on hold. At present, there are no existing laws and regulations governing CCUS in Indonesia.

A.9.3 Status of CCUS Projects

There are no operational CCUS projects in Indonesia as of 2022. However, there are recent developments in terms of project studies and investment plans:

i) Mitsubishi with JOGMEC, PT Panca Amara Utama (PAU) and Bandung Institute of Technology commenced a study on a project to produce low-emission ammonia in Central Sulawesi Indonesia (March 2021)

ii) J-POWER and Japan NUS Co, in co-operation with PT Pertamina are exploring a project to demonstrate CO_2 storage of up to 300,000 tpa of CO_2 at the Gundih gas field in Central Java, Indonesia (September 2020). The project builds on detailed studies conducted between 2012 and 2019.

iii) Repsol SA indicated in its 2020 Sustainability Plan for Indonesia that they will carry out a study for a large-scale CCUS project in their Sakakemang Block natural gas development in South Sumatra

iv) Studies are underway for two projects in Indonesia related to enhanced gas recovery (EGR) at Sukowati and Tangguh. BP also has plans for a CCUS scheme in the next phase of its Tangguh liquefied natural gas project in the West Papua province of Indonesia.

However, with regard to storage, it is to be noted that limited information on depleted oil fields, lack of exploitation data and unidentified potential storage are impediments for estimating the potential CO_2 storage space available in Indonesia. Preliminary estimates indicate 8.4 Gt CO_2 as the storage potential for CCUS in Indonesia (Table A-11).

A.9.4 CCUS Project Financing Mechanism

Indonesia leads the planned CCUS investments in the South-east Asia region – IEA estimates that Indonesia accounts for 80% of Southeast Asia's planned CCUS investment by 2030. Various entities are working on project-specific funding mechanisms to support the CCUS ecosystem in Indonesia. For eg., Japan's Joint Crediting Mechanism (JCM) scheme and ADB CCS Fund supported feasibility studies for the Gundih pilot CCUS Project, including risk assessments and project management plans. Sukowati Field in Indonesia has received support from Japan's JCM.

Table A-11: CO_2 Storage in Indonesia

Type of Storage	Estimated volume (Gt CO_2)
South Sumatra Basin	7.650
Java Basin (deep saline layers)	0.386
Tarakan Basin	0.130
Central Sumatra Basin	0.229
Total	**8.4**

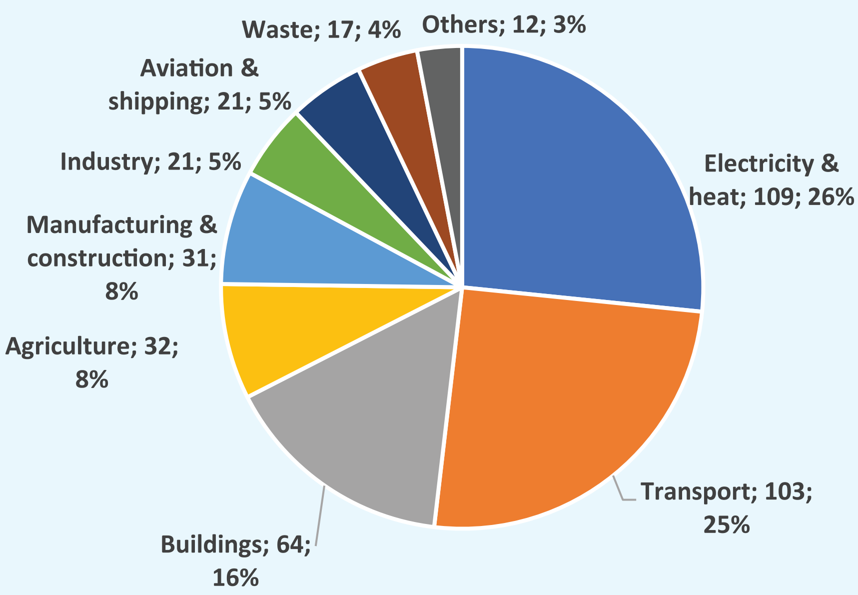
A.10 Italy

A.10.1 Background

Italy is a signatory to the EU's commitment to reducing 55% of emissions by 2030 compared to 2005 levels; Italy has also set a target of reducing emissions by 60% by 2030. Italy's overall GHG emissions in 2020 were 381 mtpa CO_2 -eq. Sector-wise GHG emissions data of 2019 indicate that the electricity, heat and transport industries contribute to over 51% of the total emissions.

Thus, the thrust of CCUS on the industrial sector is less relevant compared to other G20 economies. However, the relevance of CCUS for decarbonizing the power sector is important, as the sector accounts for a quarter of Italy's total GHG emissions.

Figure A-10: Italy– GHG Emissions of 410 mtpa CO_2eq (2019)



Source:
Climate Action Tracker and Climate Transparency Report
Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

A.10.2 CCUS Policy & Regulatory Frameworks

The National Energy and Climate Plan of Italy is focused on the country's transformation to a low-emission economy and consists of two pillars:

- increase renewable energy consumption to 30% of gross final energy consumption
- improve energy efficiency by reducing energy consumption by 43% and 40% of primary and final energy consumption respectively by 2030.

Italy has no explicit economy-wide GHG reduction target, but by combining its targets addressing its emissions covered by the EU ETS and non-ETS-related emissions, a 2030 target of 29% below 1990 levels can be derived. In 2021, explicit carbon prices in Italy consisted of emissions trading system (ETS) permit prices, which cover 36.2% of the GHG emissions. In total, 82% of GHG emissions in Italy are subject to a positive Net Effective Carbon Rate (ECR) in 2021, which is unchanged since 2018. Fuel excise taxes, an implicit form of carbon pricing, cover 71.1% of emissions in 2021, unchanged since 2018. Apart from the above Carbon Pricing mechanism, Italy does not have any other specific CCUS policy or a regulatory framework.

A.10.3 Status of CCUS Projects

There are no operational CCUS projects in Italy as of 2022. There are few pilot / feasibility projects undertaken by different industries. This includes a 30 tonne/day CCUS project at a thermal power plant in Northern Italy by a tripartite arrangement between Tenaris (steel products manufacturer), Siad (energy services company) and Saipem (the technology supplier). The utilization of the captured CO_2 is planned in the food and beverage industry, for crops, in water treatment, in metal processing and as a refrigerant gas.

Another demonstration project called CLEANKER, plans to capture CO_2 at a cement plant in Vernasca (in Piacenza) and is based on the calcium looping technology.

In 2011, Enel has inaugurated Italy's first carbon capture pilot project at its 2640 MW Federico II coal-fired power plant at Brindisi, South Italy. The pilot project has successfully completed its first test and was planned to capture 2.5 tonnes of CO_2 per hour up to a maximum of 8000 tpa of CO_2 using amine based solvent technologies. However, the project was later shelved.

A.10.4 CCUS Project Financing Mechanism

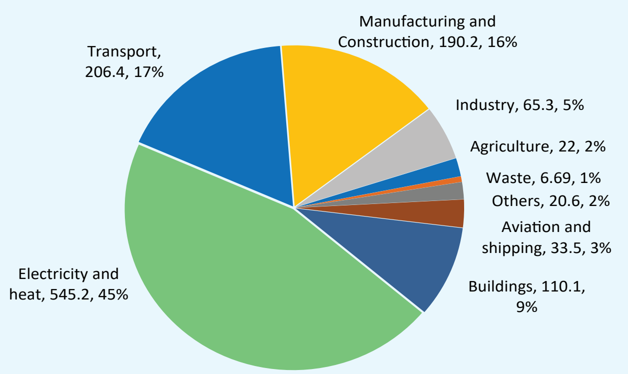
There is no project funding or financing mechanism specifically available in Italy. However, private players may seek support from the EU Innovation Fund. Eni, an Italian oil & gas major, is utilizing the Next Generation EU (NGEU) fund for the Adriatic CCUS project, consisting of a CCUS hub and storage site at depleted oil fields. The CLEANKER project is funded by HORIZON2020, EU's research and innovation funding programme.

A.11 Japan

A.11.1 Background

Japan is the 6th highest GHG emitter, with emissions of 1150 mtpa CO_2 -eq in 2021. GHG emissions in Japan have reduced for 7 consecutive years, due to reduced energy consumption (the result of improved energy conservation efforts and effects of COVID-19 in the last 2 years) and lower CO_2 emissions from the power generation sector due to an increasing share of low-carbon electricity, with a wider adoption of renewables and resumption of nuclear power. Japan's emissions are concentrated in electricity & heat, transport, manufacturing and construction sectors.

Figure A-11: Japan – GHG Emissions of 1200 mtpa CO_2eq (2019)



Source:
Climate Action Tracker and Climate Transparency Report
Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

Japan aims to reduce its greenhouse gas emissions by 46% in 2030 from its 2013 levels, setting an ambitious target aligned with the long-term goal of achieving net zero by 2050.

A.11.2 CCUS Policy & Regulatory Frameworks

Japan published its "Green Growth Strategy in line with Carbon Neutrality in 2050" in December 2020, where 14 sectors with high growth potential were identified to meet the 2050 climate neutrality target - thermal plants with CCUS was identified as one of the focus sectors. However, there is no explicit CCUS policy or regulatory framework in Japan. The industry ministry plans to create a legal framework for CCUS to enable companies to start storing carbon dioxide underground or under the seabed by 2030 to help the nation achieve its 2050 carbon-neutral goal. It is estimated that Japan can store 120-240 mtpa of CO_2 by 2050.

A.11.3 Status of CCUS Projects

There are no large-scale or commercial CCUS applications in Japan so far, but there are several Government funded and supported operational CCUS pilot projects in Japan.

In the power sector, a major carbon capture demonstration project began operations in November 2020 at the biomass-powered Mikawa plant in Fukuoka (Kyushu). The project is expected to capture up to 500 tonnes per day (tpd) of CO_2 , corresponding to about half of the plant's daily emissions. Carbon capture has also been deployed at the Saga incineration plant in Kyushu since 2016 for capturing 10 tpd CO_2 , and using the captured CO_2 to stimulate the growth of crops and algae cultures. Both projects use a post-combustion carbon capture process based on chemical absorption. Additionally, tests have started for CO_2 at an integrated coal gasification combined cycle (IGCC) power plant in Hiroshima (Chugoku) under the Osaki CoolGen Project. It is expected that the system will capture more than 90% of the CO_2 emitted in the coal gasification power generation plant, using a physical absorption technology. The project also seeks to demonstrate the potential for recycling captured CO_2 and, eventually, for incorporating the coal-sourced syngas (mixture of H_2 and CO) into fuel cells. Some of the other known CCUS projects at different stages of operationalization in Japan are listed below.

Table A-12: CCUS Projects at Different Stages of Operationalization in Japan

Type of project	Companies involved	Project details
Capture and Storage	Kansai Power, Kawasaki Heavy Industry and the Research Institute of Innovative Technology for the Earth	Demonstration project at the Maizaru thermal power plant using solid absorbent
Storage	Japan CCS KK.	The project has been running since 2012 in Tomakomai, Hokkaido. It has stored 300,000 tons of CO_2 under high pressure in the harbor seabed. Construction was completed in 2015, and storage started in 2019.

Type of project	Companies involved	Project details
Utilization	Hitachi Zosen	Methanation project using green hydrogen and CO_2 captured from a waste incinerator
Utilization	Sekisui Chemical	Producing syngas from green hydrogen and CO_2 captured from a waste incinerator. CO_2 utilization for producing ethanol using a microbial catalyst.
Capture	Kawasaki Heavy Industry	Solid absorbent based low energy capture process to capture CO_2 from gas mixtures with low CO_2 concentrations

A.11.4 CCUS Project Financing Mechanism

METI (i.e., Ministry of Economy, Trade and Industry) of the Government of Japan has decided to develop a Green Innovation Fund. The fund size will be JPY 2 trillion and the fund will be under the New Energy and Industrial Technology Development Organization (NEDO) of the Government of Japan. CCUS projects can also receive funding support from this fund.

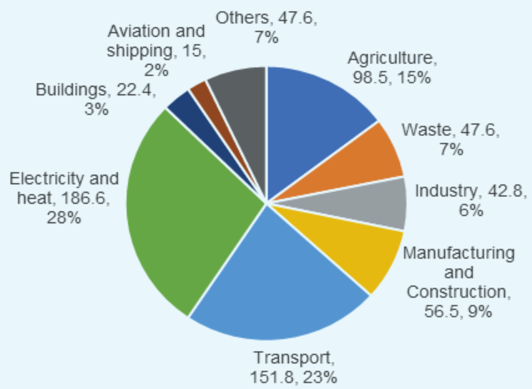
In particular, Japan is increasingly focusing on CO_2 utilization and using CO_2 as a raw material to produce value-added products, like fuels, chemicals and building materials. It established a Carbon Recycling Promotion Office within METI in February 2019 and launched a long-term Roadmap for Carbon Recycling Technologies. A carbon recycling budget of JPY 35 billion (USD 318 million) for 2019 was also created. In addition, CO_2 use and recycling are also a part of the Moonshot R&D programme, launched in 2019.

A.12 Mexico

A.11.1 Background

Mexico is the 11th largest GHG emitter globally, accounting for 669 mtpa CO_2 -eq of GHG emissions. Mexico's emissions largely emanate from the electricity & heat generation (28%) and transport (23%) sector. Agriculture comes 3rd with a 15% share.

Figure A-12: Mexico – GHG Emissions of 669 mtpa CO_2eq (2019)



Source:
Climate Action Tracker and Climate Transparency Report
Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

Mexico, in its updated 2030 NDC target, has stated that it aims to reduce GHG emissions by 35% within 2030 in the "unconditional" case (30% with its own resources and an additional 5% from international support) and by 40% in the "conditional case" (i.e., dependent on receiving international financial, technical and capacity building support), as compared to the expected emissions in the 2030 Business As Usual scenario.

A.12.2 CCUS Policy & Regulatory Frameworks

Mexico has a General Law on Climate Change, created in 2012 and amended in 2018; this law establishes Mexico's NDCs and commitment towards the goals and objectives of the Paris Climate Agreement, in terms of mitigation and adaptation to climate change. In 2014, the Government of Mexico also developed a CCUS roadmap till 2025. The most important activities in this roadmap are:

i) Pre-feasibility study of a proposed post-combustion capture (PCC) pilot plant at a natural gas-fired combined-cycle (NGCC) power plant in Mexico.

ii) A review of state-of-the-art practices for combining carbon dioxide enhanced oil recovery (CO_2 -EOR) with geological storage of CO_2 in Mexico.

iii) Study of the development of a CCUS regulatory framework for Mexico. This study undertook a comprehensive and in-depth assessment of the current regulatory framework for CCUS in Mexico and identified critical gaps & barriers.

A.12.4 CCUS Project Financing Mechanism

In the absence of a national CCUS policy, project financing is driven by specific-project funding measures, such as the World Bank CCUS Trust Fund, amongst others. At the same time, there are several activities in Mexico that are incentivized by the Government and CCUS can be categorized as such activiities – viz. 35% deduction of the price of new machinery for reducing pollutant emissions and the trading of energy certificates for mitigating costs in the generation of clean energy. However, there is no specific incentive for other activities in the CCUS value chain, such as the transport and storage of CO_2 .

With respect to carbon credits, there are regulations for creating national carbon markets. However, the market is not well defined and is not presently operational. Finally, Mexico also does not have any mandatory emission reduction targets or mandatory emission limitations for high-emitting sectors. As long as there is no cap on emissions for these sectors, the incentive to implement CCUS activities is likely to be low.

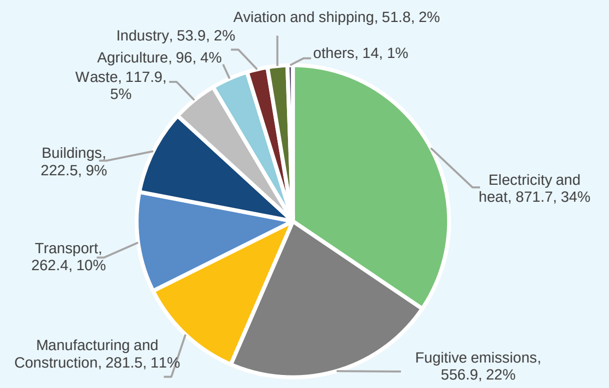
A.13 Russia

A.13.1 Background

Russia is the 4th largest GHG emitting country, accounting for 2529 mtpa CO_2 -eq of GHG emissions. This excludes 552 mtpa of CO_2 -eq of negative emissions from the land use, land use change and forestry (LULUCF) sector.

Thus, these carbon sinks, largely consisting of forests in Russia , offset about 20% of Russia's GHG emissions. Russia's emissions largely emanate from electricity & heat generation (34%) and fugitive emissions (22%) from different sectors. Manufacturing and construction is 3rd and accounts for 11% of total national emissions.

Figure A-13: Russia – GHG Emissions of 2529 Mtpa CO_2 eq (2019)



Source: Climate Action Tracker and Climate Transparency Report Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

Russia has pledged to keep its 2030 emissions to 30% below 1990 levels. Ahead of COP26, the Russian Government approved a strategy for "low-carbon development" with a goal of achieving carbon neutrality no later than 2060.

A.13.2 CCUS Policy & Regulatory Frameworks

Since the dissolution of the USSR in early 1990s, Russia's GHG emissions have fallen by 17% from 3048 mtpa in 1990 to 2529 mtpa in 2019; hence the incremental policy goal of 30% decarbonization by 2030 from 1900 levels is neither challenging nor adequate for Russia to meaningfully contribute its "fair share" to the global efforts for decarbonization and tackling climate change.

In June 2021, Russia adopted a heavily watered-down climate bill which does not enforce emissions quotas or impose penalties on large GHG emitters, who are only required to report emissions from 2024. The renewable energy sector is also very small in Russia, with a 2024 electricity generation target of only 4.5%, excluding hydropower – however, this target is likely to be missed. In the transport sector, Russia has taken steps to promote EVs and also proposed measures on low-carbon alternative fuels. However, there is no specific CCUS-focused policy or regulatory framework in Russia. Russia primarily aims to achieve a low-carbon economy through

i) increasing the production and export of natural gas, hydrogen and ammonia

ii) increasing amount of GHG absorbed by forests

A.13.3 Status of CCUS Projects

There are no operational CCUS projects in Russia as of 2022. Also, there are no known pilot or demonstration projects.

A.13.4 CCUS Project Financing Mechanism

There are no clear CCUS project financing mechanisms in Russia. However, the EU's CBAM can drive decarbonization in Russian exports to the EU, across sectors such as cement, iron & steel, aluminium, fertilizer, and power generation. Russian exports worth US$ 7.6 billion per year are likely to be exposed to CBAM measures from 2026.

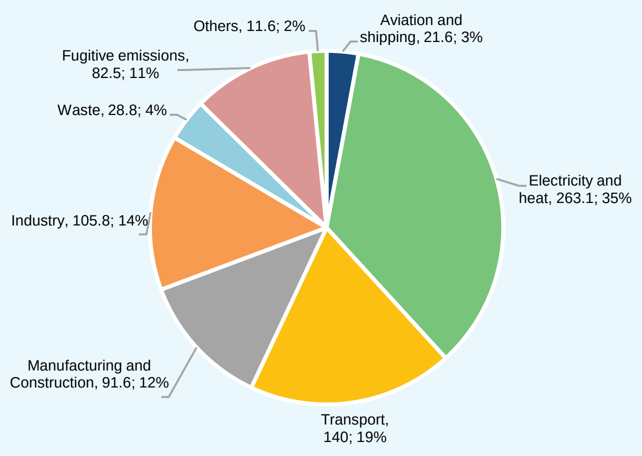
Given the likely impact of CBAM, some Russian companies such as steelmakers TMK and aluminium majors RUSAL are already planning different decarbonization projects (though not CCUS) in their manufacturing facilities. Russia has an export dependent economy; the share of exports as a % of the Russian economy has ranged from 25% to 30% in the last 15 years (source: World Bank). Given the impact of CBAM on Russian exports, it is expected that Russian corporations will increasingly look at decarbonization efforts and also seek to shape Russia's climate policy in this direction to support CCUS and other decarbonization projects, in addition to funding using their own internal accruals and debt.

A.14 Saudi Arabia

A.14.1 Background

GHG emissions per capita in Saudi Arabia are the second highest in the G20, only behind Australia. Driven by the oil & gas industry, Saudi Arabia's GHG emissions have tripled in the past 3 decades, rising from 252 mtpa CO_2 -eq in 1990 to 745 mtpa CO_2-eq in 2019. Saudi Arabia's emissions largely emanate from the electricity & heat production (35%) and the transport (19%) sectors. Industry (14%) and manufacturing & construction (12%) are the next top emitting sectors.

Figure A-14: Saudi Arabia – GHG Emissions of 745 mtpa CO_2 eq (2019)



Source: Climate Action Tracker and Climate Transparency Report Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

Saudi Arabia aims to reduce and avoid GHG emissions by 278 mtpa CO_2 -eq by 2030, compared to the emissions in 2019. However, based on the present trajectory of policies, it is more likely that GHG emissions will increase to 1.1 to 1.2 Gtpa of CO_2 -eq by 2030.

Saudi Arabia has also announced plans to 450 million trees by 2030; the long-term target is 10 billion trees. However, the current pace of tree planting (18 million trees planted since 2020) is not sufficient to meet the desired target.

Overall, the decarbonization pathway in Saudi Arabia is not sufficient for meeting the goals of the Paris Climate Agreement. The country would need to reduce its emissions to below 389 mtpa CO_2 -eq by 2030 and to 263 mtpa CO_2 -eq by 2050 to be within its emissions allowances under a 'fair-share' range compatible with limiting global temperature rises within 1.5°C. The country's 2030 NDC target of 861 - 1,105 mtpa of CO_2 -eq emissions by 2030 is thus widely considered to be insufficient.

A.14.2 CCUS Policy & Regulatory Frameworks

Saudi Arabia is focusing on the Circular Carbon Economy (CCE) Framework of reduce, reuse, recycle and removal, to meet its long-term climate goals. The motivation behind the CCE approach is the approach of the oil & gas sector, where from the 1970s onwards, waste gases produced during oil production were used to make petrochemicals instead of being flared. This approach reduced GHG emissions, diversified the Saudi economy and also created employment opportunities. However, this approach only addresses a fraction of the oil & gas sector emissions, as most emissions emanate from fuel combustion rather than oil and gas extraction and processing.

Saudi Arabia's present National Circular Carbon Economy Programme is focused on CO_2 -based EOR as a key utilization lever for driving large-scale CO_2 capture. Some of the key measures are:

i) CCUS Hubs: The Saudi Government plans to transform Jubail and Yanbu into global CCUS hubs, by leveraging the concentration of the various manufacturing industries (petrochemicals, steel and other heavy industries) and proximity to CO_2 sinks & transport infrastructures.

ii) Blue Hydrogen: Apart from the focus on large-scale and cost-effective production of green hydrogen (NEOM project), Saudi Arabia is also drafting a National Hydrogen Strategy, which would also include the production of blue hydrogen as a focus area, taking advantage of the natural resources of the country. In fact, blue hydrogen is a key lever for Saudi Arabia to reduce its dependency on crude oil exports.

A.14.3 Status of CCUS Projects

Saudi Arabia has one CCUS demonstration project, i.e. the Uthmaniyah CO_2 -EOR demonstration project in eastern Saudi Arabia in the natural gas sector. The project has been capturing 800 ktpa of CO_2 since 2015 for CO_2 -EOR at the Ghawar oil fields.

The Petro Rabigh CCUS project on the Red Sea Coast is a key upcoming project – the project has an offtake agreement with Gulf Cryo Company for supplying 300 tpd of food grade quality CO_2 . The remaining captured CO_2 will be liquified and supplied to other industrial consumers. The project is expected to become operational in 2023.

A.14.4 CCUS Project Financing Mechanism

The Government of Saudi Arabia has made multiple announcements which could potentially fund CCUS projects in the kingdom:

i) In 2021, Saudi Arabia's sovereign wealth fund PIF and the Saudi Stock Exchange Tadawul announced they would set up a voluntary carbon market in the Middle East and North Africa.

ii) In 2021, Saudi Arabia also committed to establish a fund to improve carbon sequestration and back a plan to produce clean cooking fuels.

iii) At COP27, Saudi Arabia announced a greenhouse gas credit scheme (to be launched in 2023) for enhancing the Kingdom's action on climate change.

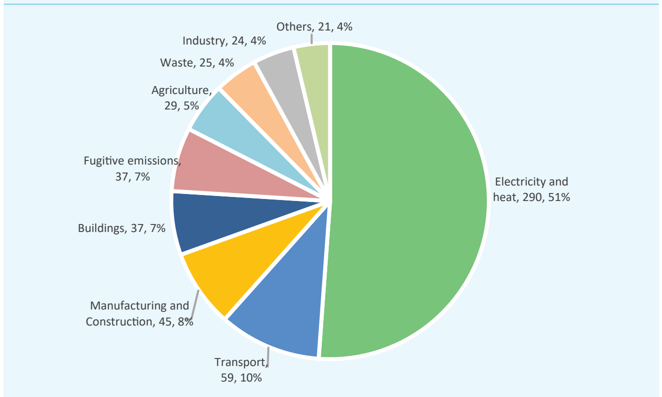
iv) Multiple announcements regarding supporting CCUS based blue hydrogen production.

A.15 South Africa

A.15.1 Background

South Africa is a coal dependent economy and the 14th largest GHG emitter in the world, with estimated GHG emissions of 567 mtpa CO_2 -eq in 2019. The main source of emissions is the electricity & heat (51%) sector – over 75% of domestic electricity production is coal based. Apart from ensuring the country's energy security, coal is also an important export item for South Africa - exports account for over 25% of the domestic coal production.

Figure A-15: South Africa – GHG Emissions of 567 mtpa CO_2 eq (2019)



Source: Climate Action Tracker and Climate Transparency Report Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

South Africa's NDC entails GHG emissions peaking from 2020 to 2025, remaining flat till 2035 and then starting to fall. The GHG emission targets are 398-510 mtpa CO_2 -eq by 2025, and 350-420 mtpa CO_2 -eq by 2030. The targets are quite ambitious, given the coal dependency and requires actions to develop CCUS technologies and projects in the country.

A.15.2 CCUS Policy & Regulatory Frameworks

In 2011 South Africa formulated a National Climate Change Response Policy (NCCRP) to provide a policy framework for mitigating climate change. The NCCRP formulated 8 "Near-term Priority Flagship Programmes", one of which is "carbon capture and sequestration". The National Climate Bill was enacted in 2022, the salient features of which are as follows:

i) A national greenhouse gas emissions trajectory to be defined to quantitively specify the national GHG reduction targets

ii) Establish sectoral emission targets, which shall be reviewed periodically reviewed based on socio-economic impacts and the latest scientific evidence

iii) Listing the most impactful greenhouse gases and defining threshold levels for initiating corrective actions

iv) Define carbon budgets or limits for large GHG emitting sectors and sub-sectors

v) Create a market mechanism to enable the emissions reduction targets through measures such as carbon pricing, emissions offsets and emission reduction trading mechanisms

South Africa's National Development Plan 2030 also takes into consideration the impact of climate change and the steps required to mitigate the impacts. The plan targets include 20 GW of renewable electricity, reducing the power sector CO_2 intensity from 0.9 kg/kWh to 0.6 kg/kWh and an economy-wide carbon pricing mechanism by 2030. Thus, the National Climate Change Bill and the National Development Plan 2030 have created sufficient enablers for CCUS projects in South Africa.

A.15.3 Status of CCUS Projects

As per publicly available information, South Africa has one operational industrial-scale CO_2 capture and on-site usage project. The project is operational since 2013 and is located in the KwaZulu-Natal province of South Africa. The project is called the Lanxes Newcastle CO_2 Concentration Unit, and involves carbon capture from the flue gas of NG based steam boilers using the Shell Cansolv CO_2 post-combustion amine based solution. About 60,000 tpa of 99% purity CO_2 is produced and consumed on-site for producing sodium dichromate.

The first carbon capture and storage (CCS) project in South Africa is expected to be commissioned in 2023 in the Mpumalanga province of South Africa. The project, titled the Pilot Carbon Storage Project (PCSP), will source CO_2 from various coal based power plants and Sasol's coal-to-liquids fuel plant in Secunda. The CO_2 would be compressed and transported to an injection site with an impermeable rock cap. The targeted injection rate is 10,000 to 50,000 tpa of CO_2 for storage at a depth of 1 km. The World Bank has provided a US$ 23 million grant for the project.

A.15.4 CCUS Project Financing Mechanism

The World Bank CCS Trust Fund has supported CCUS in South Africa, including US$ 1.35 million funds supporting the following studies by the Government of South Africa:

i) Development of a regulatory framework for CCUS in South Africa

ii) Techno-economic review of CCUS implementation in South Africa

iii) Development of a national and local public engagement plan for the Pilot Carbon Storage Project (PCSP)

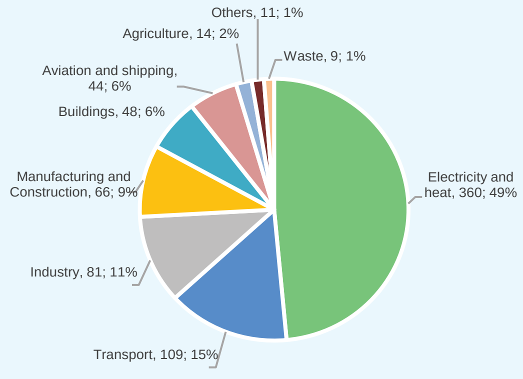
The international community (US, UK, France, Germany, and the EU) has also committed to supporting South Africa's clean energy transition and reducing dependency on coal for power generation; these countries announced a US$ 8.5 billion fund for South Africa during the COP26 in Glasgow in 2021, under the Just Energy Transition Partnership (JETP) programme.

A.16 South Korea

A.16.1 Background

South Korea's GHG emissions have grown 2.5 times in the past 3 decades, from 287 mtpa CO_2 -eq in 1990 to 742 mtpa CO_2 -eq in 2019. This increase in emissions is primarily from electricity and heat generation, where emissions increased nearly 6-fold from 65 mtpa CO_2 -eq in 1990 to 360 mtpa CO_2 -eq in 2019. The sector accounts for nearly half of South Korea's GHG emissions; this is consistent with South Korea's overall fossil fuel dependence with coal, oil & gas accounting for 70% of the country's primary energy supply.

Figure A-16: South Korea – GHG Emissions of 742 mtpa CO_2 eq (2019)



Source: Climate Action Tracker and Climate Transparency Report Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

As part of its NDCs, South Korea has targeted to reduce GHG emissions by 40% by 2030, compared to 2018 levels and reach carbon neutrality by 2050. South Korea has also joined the Global Methane Pledge to reduce methane emissions 30% by 2030. However, as per independent studies, the targeted 40% cut in GHG emissions by 2030 will be insufficient to meet the 2050 carbon neutrality goal – instead, almost 60% cut in GHG emissions is required to be achieved by 2030.

A.16.2 CCUS Policy & Regulatory Frameworks

South Korea has adopted a Framework Act on Low Carbon, Green Growth in 2013 to focus on low carbon, green growth and by utilizing green technology. The key CCUS specific measures include establishing a carbon market, focus on increasing carbon sinks by preserving & developing farmland and sea groves, and utilization of biomass from forests.

Recently the Carbon Neutrality Bill ("Carbon Neutrality and Green Growth Act for Climate Change") was passed and South Korea became the 14th nation to commit to achieving carbon neutrality by 2050. A key feature is a trading system for GHG emissions; allowable GHG emissions are capped and the rights are tradeable in the market, thus creating incentives for industries to invest in CCUS.

A.16.3 Status of CCUS Projects

There are no operational CCUS projects in South Korea as of 2022. However, at least three projects are in the pilot stage:

i) Hadong Pilot Carbon Capture (PCC) plant: 10 MW post-combustion capture pilot unit at Hadong power station - completed in August 2013. The unit uses dry regenerable sorbent technology scaled up from a 0.5 MW experimental unit which was scaled up. The project cost of US$ 40 million was met with 50% state funding.

ii) Boryeong Pilot Carbon Capture (PCC) plant: 10 MW post-combustion capture pilot unit with 200 tpd capture capacity - operational since May 2013. The project cost of US$ 42 million was met with 50% state funding. In 2016, the plant operator signed an agreement with Hankook Special Gases to supply the captured CO_2 for industrial and greenhouse uses.

iii) Youngil Bay CO_2 Injection Demonstration project: The project was launched in 2013 to develop technology and demonstrate small scale offshore CO_2 injection and storage in the Youngil Bay. The project cost of US$ 16.7 million was 50% funded by the state.

A.16.4 CCUS Project Financing Mechanism

South Korea's Framework Act on Low Carbon, Green Growth provides the basis for carbon markets in South Korea, thus providing an incentive to fund & finance CCUS projects. South Korea has an emissions trading scheme covering nearly 70% of GHG emissions in different sectors such as power, industries, buildings, transport, aviation and waste management. The emissions were priced at US$ 21 per tonne of CO_2 . In 2021, this scheme generated revenues of US$ 258 million, which were contributed to a Climate Response Fund for supporting climate mitigation, low-carbon innovation, and technology development of ETS-covered entities.

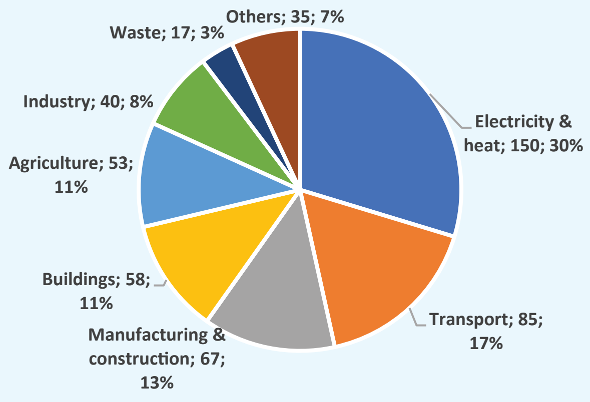
CCUS pilot projects in South Korea have received 50% state funding; hence it is likely that Government funding will also be available for larger scale CCUS projects, especially for CCUS from fossil-fuel based power generation.

A.17 Turkey

A.17.1 Background

Like South Korea, Turkey's GHG emissions have also grown 2.5 times in the past 3 decades, from 206 mtpa CO_2 -eq in 1990 to 505 mtpa CO_2 -eq in 2019. The growth in emissions is primarily from the electricity & heat generation and the transport sector; emissions in these two sectors has grown from 40 mtpa CO_2 -eq in 1990 to 150 mtpa CO_2 -eq in 2019 and from 29 mtpa CO_2 -eq in 1990 to 85 mtpa CO_2 -eq in 2019, respectively. These two sectors account for nearly half of Turkey's overall GHG emissions, as the country is largely dependent (over 80%) on fossil fuels (coal, natural gas and oil) for meeting its primary energy needs.

Figure A-17: Turkey – GHG Emissions of 505 mtpa CO_2 eq - 2019



Source: Climate Action Tracker and Climate Transparency Report Note: Excludes Land Use, Land Use Change and Forestry (LULUCF) emissions

In 2021, Turkey became the last G20 economy to join the Paris Climate Agreement. As part its NDC, Turkey aims to reduce its 2030 GHG emissions by 41% compared to the normal business as usual GHG emission trajectory and reach carbon neutrality by 2053. However, Turkey does not currently have any specific plan or trajectory which specified the time periods when emissions would peak, stagnate and thereafter reduce. Also, Turkey is largely dependent on coal and lignite for power generation and has 32 GW of thermal power projects in the construction pipeline.

A.17.2 CCUS Policy & Regulatory Frameworks

The Eleventh Development Plan (2019-23) of Turkey provides a broad framework for emissions reductions in the energy sector. Some of the key features of the plan are:

i) reducing share of natural gas in electricity production from 30% to 21%

ii) increasing the share of renewable energy sources in electricity generation from 32% to 39%

Turkey's domestic CO_2 reduction strategy is outlined in the 2010 National Climate Change Strategy for 2010-2023 and the 2011 National Climate Change Action Plan (NCCAP) for 2011-2023. There is no focus on CCUS - the plan is primarily based on GHG mitigation through higher energy efficiency and expansion of renewable power.

A.17.3 Status of CCUS Projects

There are no commercial scale operational CCUS projects in Turkey as of early 2023. However, as per publicly available information, there are two pilot/lab CO_2 capture projects:

i) TKI - Coal gasification pilot plants in Tunçbilek area, with CO_2 capture and methanol production

ii) TRIGEN lab scale project – The project uses coal and biomass as feed to produce liquid products. This project is financed by the Turkish Scientific and Technical Research Institute (TUBITAK)

A.17.4 CCUS Project Financing Mechanism

The focus of the energy transition funding from the Turkish Government is on renewable energy and increasing energy efficiency. There has also been some funding for fossil fuel (coal, oil & gas) conversion – however, there is no funding for CCUS projects, except the pilot/lab scale project funded by the TUBITAK, which is a Government entity. However, the demonstration scale or commercial scale would have significantly larger funding requirements.

A.18 United Kingdom (UK)

A.18.1 Background

The United Kingdom has GHG emissions of about 421 mtpa of CO_2 eq., with 80% of the emissions coming from the energy and power sectors. The UK's GHG emissions have almost halved from 800 mtpa CO_2 eq. in 1990. As per the Nationally Determined Contributions, the UK has committed to reducing its GHG emissions by 68% by 2030 (i.e. 256 mtpa), compared to the 1990 levels. The UK has also committed to reaching net zero by 2050. Other commitments include ending the sale of new petrol and diesel vehicles by 2030, and all new cars and vans achieving net zero emissions by 2035. The UK Government views CCUS as a critical element in achieving its climate leadership goals and plans to develop four CCUS hubs in the UK by 2030 to capture and utilize/sequester at least 10 mtpa of CO_2 , to be expanded to 20–30 mtpa, subsequently.

A.18.2 CCUS Policy & Regulatory Frameworks

A new element of the UK decarbonization policy is the carbon price. In 2021, a new UK Emissions Trading Scheme covering energy-intensive industries, power generation, and certain parts of aviation was implemented. By 2023, an emissions cap will be implemented for a net-zero trajectory and strategy. Additionally, the UK Government is considering economic support for projects in different parts of the CCUS value chain, including CO_2 transit & storage and industrial & power projects with CCUS.

The Climate Change Act of 2008 has mandated the creation of "carbon budgets," which set emissions-reduction objectives in five-year intervals. According to the most recent carbon budget, the UK will need to capture and store 47 mtpa of CO_2 to achieve the 2050 net-zero targets. Accordingly, a CCUS Deployment Pathway Action Plan has been published outlining the targets for addressing policy impediments and establishing market mechanisms for CCUS.

A.18.3 Status of CCUS Projects

The UK is planning four CCUS hub and clusters to come up by 2030, and two of them by 2025, to support the goal of capturing and sequestration of 10 mtpa of CO_2 by 2030. These hub and clusters are based on the co-location of coast-based industries and, power generating facilities and CO_2 storage facilities; the four hub & clusters are planned in the North East (Teesside), Humberside, Scotland and Wales. The Teesside and Humberside CCUS clusters will come first in sequence and are located near the North Sea, which is the UK's oil & gas production hub. The UK government has planned to invest up to GBP 1 billion to support these CCUS hub and cluster projects, at least one of which will be a CCUS retrofit on a gas based power plant.

UK's first industrial-scale carbon capture demonstration plant is being built by Tata Chemicals Europe at its sodium bicarbonate plant in Northwich. The project aims to capture about 40,000 tpa of CO_2 , or about 11% of the plant's emissions. The UK government has supported the project through a GBP 4.2 million grant from the Energy Innovation Program.

A.18.4 CCUS Project Financing Mechanism

The UK Government has created a Carbon Capture and Storage Infrastructure Fund (CIF) with a funding of GBP 1 billion to support CCUS projects by covering part of the capital expenses. There is also a GBP 315 million Industrial Energy Transformation Fund (IETF) for supporting CCUS projects and also de-risk such projects by providing funding for feasibility and engineering studies.

A.19 United States of America (USA)

A.19.1 Background

The US is the second largest emitter in the world, with GHG emissions of 6.3 Gtpa of CO_2 eq. in 2021. The emissions have come down about 15% from the 2005 levels of 7.43 Gtpa of CO_2 eq.; as part of its Nationally Determined Contributions, the US has committed to reducing its net GHG emissions by 50-52% below 2005 levels by 2030. The US has committed to reach net zero emissions by 2050 and a net zero & pollution free electricity sector by 2035. One of the pathways to achieve these targets is to promote CCUS projects for both existing power plants and industrial emitters. This will reinforce the US's position as the leader in CCUS projects.

A.19.2 CCUS Policy & Regulatory Frameworks

The key policy enablers for CCUS in the US are the 45Q tax credits, California's LCFS standards, State Primacy for CO_2 injection and the SCALE Act.

i) 45Q tax credits: The 45Q provides tax credits for CCUS, starting from US$ 12.83 for each tonne of CO_2 utilized for EOR in 2017, linearly increasing to US$ 35/tonne in 2026. The credits for geologically stored CO_2 were US$ 22.66/tonne in 2017, linearly increasing to US$ 50/tonne of CO_2 in 2026. The recently enacted Inflation Reduction Act of 2022 has substantially increased the maximum level of credits available from US$ 50 to US$60/tonne of CO_2 utilized and US$ 50 to US$85/tonne of CO_2 sequestered. Tax credits of up to US$ 180/tonne have also been introduced for CO_2 capture through Direct Air Capture. The Inflation Reduction Act of 2022 has also introduced an option of direct pay, where cash payments would be made in place of the carbon credits.

ii) California Low Carbon Fuel Standard (LCFS): LCFS is specific to California and aims to reduce the CO_2 intensity of the fuel mix consumed in the state. CCUS projects (whether storage or EOR) qualify for credits which can be traded under the LCFS, thus creating a strong incentive for CCUS projects in the state for supplying clean fuel in the state.

iii) State Primacy for CO_2 Storage: The permanent underground sequestration of CO_2 requires obtaining Class VI well permits. In order to ease the permitting process, the states of Wyoming and North Dakota have been authorized to grant Class VI well permits for dedicated geological storage of CO_2 . Other states like Texas and Louisiana are also attempting to attain this authority/approval, given the significant carbon capture and storage opportunities in these two states.

iv) US Department of Energy (US DOE): One of the key focus areas of the US DOE is to promote R&D and demonstration projects in carbon capture technology as well as pore space mapping for geological storage and EOR of the captured CO_2 . The recently enacted Bipartisan Infrastructure Law (BIL) provides US$ 62 billion of funding for the US DOE to build an equitable clean energy future in the USA, out of which more than US$ 10 billion is earmarked for carbon capture, direct air capture and industrial emission reduction projects.

A.19.3 Status of CCUS Projects

The US is the world leader in CCUS projects, with 14 operating facilities with a CO_2 capture capacity of 25 mtpa, with the first CCUS projects in the world being commissioned in the US in the 1970s. The US also leads in terms of pore space mapping and characterization of potential CO_2 storage basins and reserves through the US DOE funded Regional Carbon Sequestration Partnerships (RCSPs) program, which has developed the regional infrastructure for CO_2 storage across seven identified regions of the US. The US is also the leader in CO_2 transportation, with over 5000 miles of dedicated CO_2 pipelines, delivering CO_2 for EOR projects.

A.19.4 CCUS Project Financing Mechanism

The US DOE has heavily invested in CCUS R&D, funding various CCUS studies and since 1997 as part of its Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment program (FECM) portfolio. The US DOE has also funded CCUS demonstration projects such as NRG Energy's Petra Nova project. The recently enacted Bipartisan Infrastructure Law (BIL) will further fund up to 6 carbon capture demonstration projects with total funding limit of US$ 2.5 billion.

A.20 European Union (EU)

A.20.1 Background

The European Union accounts for 3.5 Gtpa of CO_2 eq. GHG emissions and is the 3rd largest emitting region or economy after China and the US. The EU has been at the forefront of climate action with the European Union Emissions Trading System (EU ETS) as the world's first GHG trading scheme (introduced in 2005) and the recently approved European Green Deal, which seeks to reduce GHG emissions to 55% below 1990 levels by the year 2030 and eventually reach net-zero by 2050.

A.20.2 CCUS Policy & Regulatory Frameworks

The key policies and legislations with respect to CCUS are the EU ETS and the European Green Deal

i) EU ETS: The European Union Emissions Trading System is the world's first GHG emissions trading scheme, covering the EU countries, Iceland, Liechtenstein and Norway. The EU ETS covers about 40% of the GHG emissions of the participating countries and seeks to limit the emissions of about 10,000 GHG emitters under a cap & trade scheme, with caps reducing over time, forcing the emitters to decarbonize the plants and facilities. The price of CO_2 is market determined and imposes a cost of carbon on emitters who are not able to contain their emissions within the capped limits. As of 2019, facilities under the EU ETS have reduced their emissions by 35% from 2005 to 2019.

ii) European Green Deal: The European Green Deal targets 55% decarbonization (vis-à-vis 1990 levels) by 2030 and net-zero by 2050 across the entire EU. The focus is on curbing emissions across sectors, and particularly the energy sector, which accounts for 75% of GHG emissions. The European Green Deal proposes gradual withdrawal of the free emission allowances allowed under the EU ETS, thus aligning it with the "Fit for 55" target of 55% decarbonization by 2030. The European Green Deal also imposes a Cross Border Adjustment Mechanism (CBAM) to prevent countries with no carbon price, or abatement compulsions from gaining an unfair advantage over European producers while exporting goods to the EU, thus preventing carbon leakage.

A.20.3 Status of CCUS Projects

Some of the key CCUS projects in EU (and Europe) are the Sleipner CO_2 storage project and Snohvit CO_2 storage project in Norway. These projects are associated with natural gas processing plants and capture 1 mtpa and 0.7 mtpa of CO_2 , respectively for storage in the North Sea. Apart from the above, CCUS hub and cluster projects are in various stages of development in Le Havre and Marseille (France), Rotterdam (the Netherlands) and Skagerrak/Kattegat (Denmark).

A.20.4 CCUS Project Financing Mechanism

The EU has several funding schemes for CCUS projects, as tabulated below in Table A-13.

Table A-13: EU Funding Schemes for CCUS

Funding scheme	Objectives	Fund size
EU Innovation Fund	• Fund for demonstration of low-carbon technologies • Part of the fund allocated to CCUS	• EUR 38 billion support for 2020-2030, depending on the carbon price
Connecting Europe Facility (CEF)	• Supports cross-border CO_2 transportation	• EUR 25.8 billion CEF transport budget • EUR 11 billion budget for cohesion countries
Recovery and Resilience Facility (RRF)	• Mitigate the economic and social impact of COVID • Investment in flagship areas (including CCUS & renewable energy)	• Funds raised by issuing bonds on behalf of the EU • EUR 723.8 billion funds available • EUR 385.8 billion in loans and EUR 338 billion in grants
Just Transition Fund (JTF)	• Support provided to territories facing socio-economic challenges due to climate neutrality transitions	• EUR 19.2 billion fund
Horizon Europe	• Program supports the R&D and demonstration of CCUS related projects	• EUR 95.5 billion budget for the period of 2021-2027

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